Nuttall Consulting

Regulation and business strategy

Report – Capital Expenditure
Victorian Electricity Distribution Revenue Review
Revised Proposals

A report to the AER

Public - Final Report

26 October 2010

Table of contents

Executive Summary 10

1 Introduction 15

1.1 Structure of report 16

2 DNSP expenditure analysis 17

2.1 Actual expenditure levels 17

2.1.1 Major state comparison 17

2.1.2 DNSP comparison 18

2.2 Forecasting accuracy 20

2.2.1 Next Regulatory Control Period forecast accuracy 21

2.2.2 Current period estimate forecast accuracy 22

2.3 Expenditure trends 23

2.3.1 Actual to forecast 23

2.4 Summary 26

3 Comments relevant to the overall review process 28

3.1 Reinforcement 28

3.2 RQM review 31

3.3 Non-network 37

3.3.1 Non-network - general IT 37

3.3.1.1 Industry overview 40

3.3.2 Historical underspend 45

3.3.3 Forecast increases 47

3.3.4 Approach 48

4 Appendix A - CitiPower review 50

4.1 Overall capex 50

4.2 Reinforcement 52

4.2.1 Load duration curve assumptions 52

4.2.2 Project review updates 54

4.2.2.1 CBD security project and Metro 2012 project 54

4.2.2.2 11 kV CBD Feeder Works 56

4.2.2.3 3rd BQ Transformer 60

4.2.2.4 Docklands Area Substation Upgrade 62

4.2.2.5 Summary findings 64

4.3 Reliability and quality maintained 65

4.3.1 Zone substation Secondary Systems Replacement 66

4.3.1.1 Summary of Nuttall Consulting’s original review 66

4.3.1.2 Nuttall Consulting’s discussion of matters raised in DNSP revised proposal 67

4.3.2 Reliability 69
4.3.2.1 Summary of Nuttall Consulting's original review 69
4.3.2.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal 70
4.3.3 Nilsen LV circuit breakers – HV switch replacement 70
4.3.3.1 Summary of Nuttall Consulting's original review 71
4.3.3.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal 71
4.3.4 Fault Mitigation project 73
4.3.4.1 Summary of Nuttall Consulting's original review 73
4.3.4.2 Nuttall Consulting's discussion of matters raised in the DNSP revised proposal 74
4.4 Environmental, Safety and Legal 76
4.5 SCADA and Network Control 78
4.5.1 DMS Field Devices 79
4.5.2 Historical underspend 81
4.5.3 Strategic plan linkages 83
4.5.4 Historical trend 85
4.5.5 Summary 86
4.6 Non-network general – IT 87
4.7 Non-network general other 90

5 Appendix B - Jemena findings 91
5.1 Overall capex 91
5.2 Reinforcement 93
5.2.1 Load profile 93
5.2.2 Project review updates 93
5.2.2.1 Preston / East Preston Conversion 94
5.2.2.2 Pascoe Vale Transformer Upgrade 95
5.2.2.3 Tullamarine Substation Establishment 98
5.2.2.4 TTS-CN-CS-TTS 66 kV line re-conductor 100
5.2.2.5 KTS-MAT-AW-PV-KTS 66 kV Loop Upgrade 101
5.2.2.6 Distribution substations 103
5.2.2.7 Summary findings 105
5.3 Reliability and quality maintained 106
5.3.1 Categories without specific criticisms in the revised proposal 107
5.3.1.1 Distribution transformers 107
5.3.1.2 Underground cables 108
5.3.1.3 Protection 111
5.3.2 Distribution switchgear 112
5.3.3 Zone substation 114
5.3.3.1 Summary of Nuttall Consulting original review 114
5.3.3.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal 115
5.3.4 Reliability and performance 116

5.3.4.1 Summary of Nuttall Consulting's original review ... 117

5.3.4.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal ... 117

5.4 Environmental, Safety and Legal 119

5.5 SCADA and Network Control 119

5.6 Non-network general – IT 119

5.7 Non-network general other 122

5.7.1 Zone substation land purchases 122

5.7.2 Broadmeadows depot 122

5.7.2.1 Timing of expenditure ... 123

5.7.2.2 Costing of works ... 124

5.7.2.3 Recognition of operating benefits ... 124

5.7.2.4 Summary ... 125

6 Appendix C - Powercor 127

6.1 Overall capex 127

6.2 Reinforcement 129

6.2.1 Load duration curve assumptions 129

6.2.2 Updated project assessments 130

6.2.2.1 Eaglehawk substation upgrade ... 131

6.2.2.2 Gisborne Substation Establishment ... 131

6.2.2.3 Bendigo to Charlton (BETS-CTN) Sub-transmission Line Upgrade ... 133

6.2.2.4 The GLE upgrade ... 135

6.2.2.5 GTS 66 kV lines upgrade ... 136

6.2.2.6 NKA-CME 66 kV line upgrade ... 136

6.2.2.7 Summary findings ... 138

6.3 Reliability and quality maintained 138

6.3.1 Zone substation plant replacement 140

6.3.1.1 Summary of Nuttall Consulting original review ... 140

6.3.1.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal ... 140

6.3.2 Zone substation Secondary Systems Replacement 143

6.3.2.1 Summary of Nuttall Consulting original review ... 143

6.3.2.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal ... 143

6.3.3 Conductor 145

6.3.4 Reliability 147

6.3.4.1 Summary of Nuttall Consulting's original review ... 148

6.3.4.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal ... 148

6.4 Environmental, Safety and Legal 149

6.5 SCADA and Network Control 151

6.5.1 DMS Field Devices 152

6.5.2 Historical underspend 154

6.5.3 Strategic plan linkages 156
6.5.4 Historical trend 158
6.5.5 Summary 159
6.6 Non-network general – IT 159
6.7 Non-network general other 163

7 Appendix D - SP AusNet review 164
7.1 Overall capex 164
7.2 Reinforcement 166
7.2.1 Load profile assumptions 166
7.2.2 Project review updates 167
7.2.2.1 Mooroolbark Zone Substation Establishment 168
7.2.2.2 Wollert Zone Substation Establishment 171
7.2.2.3 KMS-SMR No.2 66kV line Establishment 174
7.2.2.4 Zone substation transformers.. 177
7.2.2.5 Distribution transformers 179
7.2.2.6 Other projects reviewed to test findings.. 181
7.2.2.7 Summary findings 185
7.3 Reliability and quality maintained 186
7.3.1 Zone substation plant 187
7.3.1.1 Summary of Nuttall Consulting original review 187
7.3.1.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal... 188
7.3.2 Cross arm replacements 195
7.3.2.1 Summary of Nuttall Consulting original review 195
7.3.2.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal... 196
7.4 Environmental, Safety and Legal 196
7.5 SCADA and Network Control 197
7.6 Non-network general – IT 197
7.7 Non-network general - other 201

8 Appendix E - United Energy review 203
8.1 Overall capex 203
8.2 Reinforcement 205
8.2.1 Maximum Demand assumption 205
8.2.2 Load profile 206
8.2.3 Project review updates 206
8.2.3.1 Templestowe (TSE) Zone Substation Establishment 206
8.2.3.2 Keysborough (KBH) Zone Substation Establishment.......................... 209
8.2.3.3 Mentone (M) Zone Substation Upgrade.. 211
8.2.3.4 MTS-BW-MTS 66kV line upgrade 212
8.2.3.5 TBTS-DMA-RBD-STO 66kV Network Reinforcement 213
8.2.3.6 Distribution substations 214

8.2.3.7 Summary findings ... 217
8.3 Reliability and quality maintained 218
8.3.1 Zone substation 219
8.3.1.1 Summary of Nuttall Consulting original review ... 219
8.3.1.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal... 219
8.3.2 Reliability and performance 221
8.3.2.1 Summary of Nuttall Consulting's original review ... 221
8.3.2.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal... 222
8.4 Environmental, Safety and Legal 224
8.5 SCADA and Network Control 225
8.6 Non-network general – IT 225
8.7 Non-network general other 230
9 Appendix F – Opex Step Changes 231
9.1 CitiPower 231
9.1.1 West Melbourne Demand Management 231
9.2 Jemena 232
9.2.1 IT Opex 234
9.2.1.1 Introduction of new systems ... 234
9.2.1.2 Increased support of current systems ... 235
9.2.1.3 New data centre facilities ... 238
9.2.2 Additional maintenance arising from capex step changes 239
9.3 Powercor 244
9.3.1 At Risk Township Protection Plans 244
9.4 SP AusNet 247
9.4.1 IT opex 247
9.4.1.1 AMI related ... 248
9.4.1.2 Program related ... 250
9.4.1.3 Project delivery ... 252
9.4.1.4 Service changes... 254
9.4.2 Demand management costs 255
9.4.2.1 Non-networks Team... 255
9.4.2.2 Deferral of capex... 257
9.4.2.3 DM Programs ... 258
9.4.2.4 Tariffs ... 260
9.4.3 Power cable test program 261
9.4.4 Condition monitoring and power transformer refurbishment 262
9.4.5 Substation earthing systems 264
9.4.6 Substation site cleanup 265
9.4.7 Substation civil infrastructure works 266
9.4.8 Substation fire systems 267
9.4.9 Process and configuration management 268
9.4.10 Quality of supply 269

9.5 United Energy 272
9.5.1 Demand management initiatives 272
9.5.1.1 Background 272
9.5.1.2 Summary of proposed activities 273
9.5.1.3 Use of AMI data for Demand Management 274
9.5.1.4 Critical Peak Pricing 275
9.5.1.5 Demand Management engagement and the new Regulatory Test 276
9.5.1.6 Broad Based Demand Management Initiatives 278
9.5.1.7 Demand Management Team 279
9.5.1.8 Summary and conclusion 280
9.5.2 ZS power quality metering maintenance 280
9.5.3 ZS secondary spares maintenance 281
9.6 Industry-wide step changes 283
9.6.1 Outcomes monitoring and compliance 283
9.6.1.1 CitiPower outcomes monitoring and compliance 285
9.6.1.2 Powercor outcomes monitoring and compliance 290
9.6.1.3 Jemena outcomes monitoring and compliance 290
9.6.1.4 United Energy outcomes monitoring and compliance 292
10 Appendix G – Unit cost review 293
10.1 CitiPower 293
10.1.1 Electricity Safety (Electric Line Clearance) Regulations 293
10.1.1.1 Maintenance of the Clearance Space – LBRA 294
10.1.1.2 Reduced clearances for insulated conductor - ABC 295
10.1.1.3 Reduced clearances for insulated conductor - Services 297
10.1.1.4 Environmentally or culturally significant (native) trees 298
10.2 Jemena 299
10.2.1 Strategic planning expenditures 300
10.2.1.1 ESMS Process Compliance Costs 300
10.2.1.2 Replacement of Non-Preferred Services 301
10.2.2 Installation of Neutral Condition Monitors 302
10.2.3 Removal of Public Lighting Switch Wires 303
10.2.4 Ground Fault Neutralisers and Removal of SWER 304
10.2.5 Pole Top Fire Mitigation 305
10.2.6 Pole Top Replacement (Age & Condition) 306
10.2.7 Pole Replacement 307
10.2.8 Overhead Conductor Replacement 308
10.2.9 HV Installation Replacement 308
10.2.10 Distribution Substation & Overhead Switch Maintenance 309
10.2.11 Zone Substation Asset Conditioning Monitoring 309
10.2.12 Zone Substation Transformer Replacement 310
10.2.13 Zone Substation Circuit Breaker Replacement 310
10.2.14 Electricity Safety (Electric Line Clearance) Regulations 311
10.2.14.1 Maintenance of the Clearance Space – HBRA pre-summer 311
10.2.14.2 Maintenance of the Clearance Space – HBRA cyclic 312

10.2.14.3 Maintenance of the Clearance Space – LBRA 313
10.2.14.4 Notification & Consultation 314
10.2.14.5 Reduced clearances for insulated conductor - Services 315
10.2.14.6 Habitat Trees.. 316
10.2.14.7 Hazard Trees 318
10.3 Powercor 319
10.3.1 Removal of HBRA exemptions 319
10.3.1.1 Maintenance of the Clearance Space – HBRA pre-summer................. 319
10.3.1.2 Maintenance of the Clearance Space – HBRA cyclic 320
10.3.2 Reduced clearances for insulated conductor - ABC 322
10.3.3 Reduced clearances for insulated conductor - Services 324
10.3.4 Removal of LBRA clearance exemptions 324
10.3.5 100m span clearances 326
10.3.6 Environmentally or culturally significant (native) trees 327
10.4 SP AusNet 328
10.4.1 Enhanced replacement programs 328
10.4.1.1 Asset inspections by helicopter 329
10.4.2 Electricity Safety (Electric Line Clearance) Regulations 331
10.4.2.1 Hazardous trees 331
10.4.2.2 HBRA clearance exemptions... 332
10.4.2.3 LBRA clearance exemptions.. 333
10.4.2.4 Habitat trees... 334
10.4.2.5 Reduced clearances for insulated conductor – services...................... 334
10.4.2.6 Overhangs... 335
10.5 United Energy 337
10.5.1 Strategic planning expenditures 338
10.5.1.1 ESMS Process Compliance Costs 338
10.5.1.2 Replacement of Non-Preferred Services 339
10.5.2 Removal of Public Lighting Switch Wires 342
10.5.3 Ground Fault Neutralisers and Removal of SWER 343
10.5.4 Pole Top Fire Mitigation 344
10.5.5 Pole Top Replacement (Age & Condition) 345
10.5.6 Install ABC in HBRA 346
10.5.7 Pole Replacement 347
10.5.8 Overhead Conductor Replacement 347
10.5.9 Zone Substation Transformer Replacement 348
10.5.10 Zone Substation Circuit Breaker Replacement 348
10.5.11 Backup earth fault protection 349
10.5.12 Electricity Safety (Electric Line Clearance) Regulations 349
10.5.12.1 Maintenance of the Clearance Space – HBRA pre-summer............ 350
10.5.12.2 Maintenance of the Clearance Space – HBRA cyclic....................... 351
10.5.12.3 Maintenance of the Clearance Space – LBRA 352
10.5.12.4 Additional resources... 353
10.5.12.5 Mid-cycle pruning program 353
10.5.12.6 Notification & Consultation 354

10.5.12.7 Reduced clearances for insulated conductor - Services 354
10.5.12.8 Habitat Trees.. 356
10.5.12.9 Hazard Trees 358
10.5.13 Overhanging trees 358

Executive Summary

Background

The Australian Energy Regulator (AER) is assessing the revised proposals from the five Victorian Distribution Network Service Providers (DNSPs) to determine their regulated revenues for the period 1 January 2011 to 31 December 2015. These revised proposals have been provided by the DNSPs in response to the AER's draft decision.

Nuttall Consulting has been engaged by the AER to provide technical advice on the DNSPs proposals. This engagement is focused on the capital expenditure (capex) proposals of the DNSPs, but also includes support and advice in relation to operating expenditure (opex) and other technical matters on an "as needs" basis.

Nuttall Consulting undertook a review of the DNSPs' original proposals. This review, including its findings and recommendations, was documented in a previous report to the AER. The findings of this previous review were an input to the AER's deliberations on its draft decision.

This report details our subsequent review of the DNSPs' revised proposals. This report largely addresses criticisms in the revised proposals of our original advice to the AER and considers new information provided by the DNSPs subsequent to our previous review.

It is important to note that this report does not provide a complete description of the overall review and process, and so it is important that matters discussed in this report are considered in the context of the review process and findings discussed in our previous report.

In undertaking our capex and opex reviews, we have been mindful of the capital and operating expenditure objectives, criteria, and factors defined in the National Electricity Rules (NER).

Since the AER's draft decision, Energy Safe Victoria (ESV) has reviewed a number of items within each of the DNSPs revised proposals. We understand that the ESV review is in response to the Victorian Bushfires of 2009 and the Bushfire Royal Commission report. It is also in response to changes to regulatory obligations including the safety management scheme and line clearance requirements. Based upon this review, ESV has recommended volumes for each of these items that it considers prudent to undertake in the next period. The AER has requested that, for these specific items, Nuttall Consulting only undertake a review of the efficient unit costs. The review of unit costs has not allowed for consideration of the overall benefits, synergies and capex/opex trade-offs that may occur from these increases in overall expenditure.

Overview

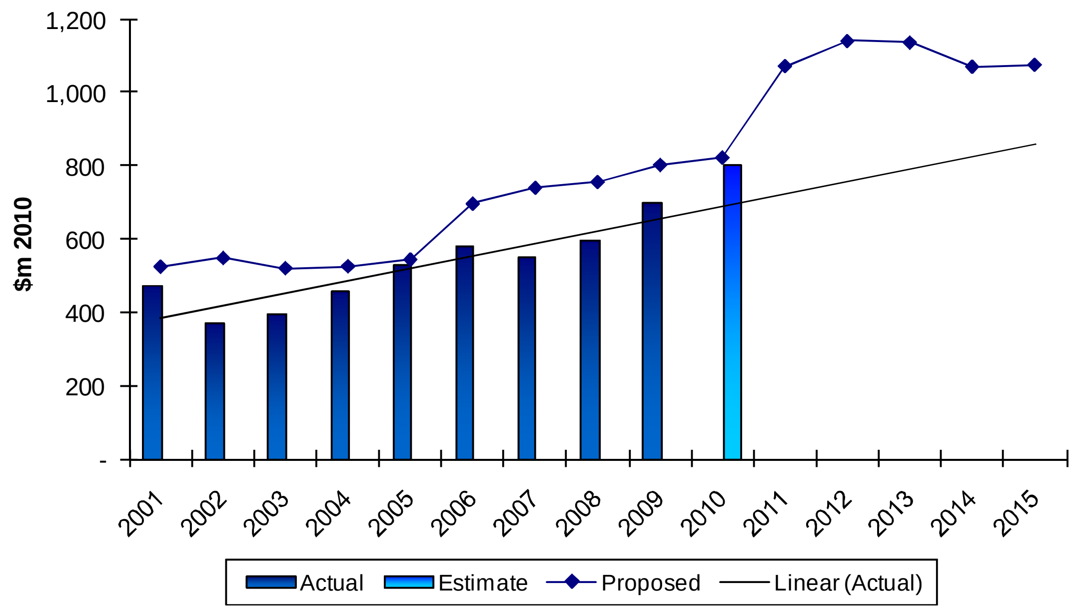
Our overall review process has involved:

- analysis of historical and forecast expenditure, including Victorian and interstate benchmarking and trend analysis
- modelling of asset replacement needs (repex modelling), including benchmarking asset lives to historical replacement volumes

- a review of documented capital governance processes and forecasting methodologies
- detailed reviews of selected projects and programs
- a number of meetings with the DNSPs
- the provision of additional information requests.

In their original proposals, the DNSPs identified significant capital expenditure increases for the next regulatory control period. The following chart shows the actual expenditure for the last 9 years and the capital expenditure proposed by the DNSPs for each regulatory control period[1].

Figure ES1 - Victorian Capex



Based upon our review of the DNSPs original proposals, we did not consider that any of the DNSPs had adequately demonstrated that their overall proposed expenditure increases could be considered prudent and efficient. We recommended significant reductions to the DNSPs expenditure proposals. Our recommended capex[2] represented approximately a 40% reduction on the proposals of the DNSPs, but still allowed for a 35% average increase on the actual expenditure incurred over 2006 to 2008.

The DNSPs to a large extent have not accepted our previous recommendations. Their revised proposals include a number of criticisms of our approach and have provided further information to address some of our concerns.

Our review of the revised proposals has involved:

- consideration of the criticisms of our approach to assess the expenditure proposals and develop substitute allowances

[1] This chart is based upon the revised proposals, but is very similar to the original proposals.
[2] excluding "new customer connections", which was not part of our review

- revised expenditure analysis and repex modelling to allow for 2009 actual data, which was not available at the time of our previous review[3]
- the provision of further information requests to the DNSPs
- revised detailed project and program reviews to account for the additional information provided by the DNSPs
- a review of the efficient unit costs for those volumes reviewed and recommended by the ESV.

Expenditure analysis

The benchmark analysis shows that the current expenditure levels of the Victorian DNSPs appear efficient when compared with expenditure levels in other states[4]. This relative efficiency was evident at the state level as well as at the individual DNSP level.

The Nuttall Consulting review of the historical expenditures of the DNSPs highlighted significant variations between the expenditures proposed by the DNSPs for each period and the actual expenditures that were subsequently incurred. The magnitude of the variations is very significant and, on average, the proposed expenditures were much greater than those expenditures that were actually incurred. These variations suggested that the DNSP forecasting processes used when preparing proposals may overstate prudent and efficient expenditure.

General criticisms of our approach

The DNSPs have criticised the approach we took to reject their proposals and develop a substitute forecast. Significant matters raised are that we were too reliant on historical expenditure levels and did not sufficiently consider the detailed information provided. In particular, the DNSPs have criticised our use of the repex model and questioned its validity. The DNSPs have also criticised our probabilistic assessment we applied to develop our recommendations of reinforcement expenditure. In this regard, they consider our approach was too subjective and was not reflective of expenditure drivers.

We consider that the basis of many of the criticisms, to a large extent, do not reflect our review process, for which a significant element was the detailed review of the information provided by the DNSPs to support the project and programs we selected. Furthermore, we still consider that the use of the repex model is valid, and consider that many of the specific criticisms do not sufficiently recognise the similarities with models and benchmarking processes applied by others, most notably the UK regulator, Ofgem.

With regard to our probabilistic assessment of reinforcement projects, we do not accept that it is too subjective and does not account for the drivers. In our view, the detailed review of information provided on each project is similar to that applied by other reviewer in other AER decisions, assessing the need and timing, alternative options and efficient costs. We also consider that it has been as objective as could reasonably be expected in the circumstances. We do accept however that the determination of probabilities for each project is less often applied – although, this is not

[3] Revised repex modelling was only undertaken in limited circumstances were this was considered necessary

[4] Other states in the National Electricity Market – NSW, Queensland, Tasmania, South Australia.

without precedence. Nonetheless, we still maintain that an "on balance" view of the probability of the funding requirement is a more reasonable approach to developing the expenditure allowance for this category than the reviewer attempting to determine the "on balance" view of the scope, timing and cost for each project reviewed.

Review findings and recommendations

Nuttall Consulting has carefully considered the additional information provided subsequent to the AER's draft decision. Overall, we do not consider that this has addressed many of the concerns we expressed in our original report. Based upon our review of this additional information, we still consider that the DNSPs have not adequately demonstrated that their overall proposed capex increases can be considered prudent and efficient. However, we have accepted that increases from our previous recommendations are justified in a number of places.

The following provides a summary of our main findings in the various capex categories.

Reinforcement expenditure

We still maintain that the DNSPs have not demonstrated that their reinforcement expenditure can be considered prudent and efficient. To allow the AER to develop a substitute allowance, we have revised our probabilistic assessment based upon the additional information provided by the DNSPs. Our review of this information has still found that for many projects, the risks (e.g. unserved energy to customers) was not sufficient to justify the timing. We also found that there was a reasonable possibility that other lower cost alternatives may be found, and that in some cases reliability improvements should result such that a portion of the project would be funded through the reliability incentive scheme.

Our recommended allowances represent approximately 70% of the DNSPs forecast, with CitiPower the highest at approximately 80% and Jemena the lowest at approximately 55%. These represent increases of approximately 15% from our previous recommendations. This increase is mainly due to a change to the AER's position on the load forecasts prepared by the DNSPs and new information that addressed some of our previous concerns.

Reliability Quality Maintained (RQM)

For some of the DNSPs, a significant portion of the asset volumes associated with the RQM expenditure were reviewed and recommended by the ESV. As such, it is difficult to directly compare our previous recommendations with our revised findings. Nonetheless, for the majority of asset categories we have been tasked to review, we still maintain that the DNSPs have not demonstrated that their proposed expenditure can be considered prudent and efficient.

We still consider that in the absence of information to the contrary, expenditure forecasts determined via the repex model with asset lives benchmarked to recent historical replacement volumes, represent a reasonable and conservative estimate of expenditure requirements. We have accepted however that our previous allowance should be increased. This increase partly reflects our acceptance that the 2009 actual data should be used where we have used the repex model to determine an allowance. Other increases have also been applied in various circumstances where we considered that our detailed review supported the view that the repex model would most likely understate future expenditure requirements.

Non-network IT

We have reviewed the information provided by the DNSPs in relation to non-network other IT capex. Following this review, we have identified that the forecasting processes used by the DNSPs have largely proven to be significantly inaccurate, and that the DNSPs have not advised of any actions to change or improve these processes. The proposed expenditures are generally significantly greater than recent expenditure levels and the DNSPs have not sufficiently substantiated these increases as being prudent and efficient. We have provided substitute amounts for the proposed IT expenditures based on our review of the overall programs and historical expenditure levels.

ESV unit cost review

We have undertaken a review to determine appropriate efficient unit costs for those activity volumes that were assessed by the ESV. This review has compared unit costs between DNSPs and other sources, and considered the rationale provided by the DNSPs to justify that the costs can be considered efficient.

In a number of cases, we have not accepted that the unit costs can be considered efficient and have recommended a substitute unit cost.

1 Introduction

The Australian Energy Regulator (AER) is assessing the revised proposals from the five Victorian Distribution Network Service Providers (DNSPs) to determine their regulated revenues for the period 1 January 2011 to 31 December 2015. These revised proposals have been provided by the DNSPs in response to the AER's draft decision.

The five DNSPs are:

- CitiPower Pty - "CitiPower"
- Jemena Electricity Networks (Vic) Ltd- "Jemena"
- Powercor Australia Limited - "Powercor"
- SPI Electricity Pty Ltd - "SP AusNet"
- United Energy Distribution Pty Ltd - "United Energy"

Nuttall Consulting has been engaged by the AER to provide technical advice on the DNSPs proposals. This engagement is focused on the capital expenditure (capex) proposals of the DNSPs, but also includes support and advice in relation to operating expenditure (opex) and other technical matters on an "as-needs" basis.

In undertaking our capex and opex reviews, we have been mindful of the capital and operating expenditure objectives, criteria, and factors defined in the National Electricity Rules (NER).

This report details our review of the DNSPs' revised proposals. This report largely addresses criticisms in the revised proposals of our original advice to the AER. The original advice was based upon our review of the DNSPs' original proposals and was used by the AER to inform its draft decision.

It is important to note that this report does not provide a complete description of the overall review and process, and so it is important that matters discussed in this report are considered in the context of the review process and findings discussed in our previous report[5].

In keeping with our original review, the structure of this review is aligned with the capex categories that have been defined in the Regulatory Information Notices (RIN). These categories include:

- reinforcement
- reliability and quality maintained (RQM)
- environmental, safety and legal (ESL)

[5] Nuttall Consulting report, "Report – Capital Expenditure Victorian Electricity Distribution Revenue Review", 4 June 2010, available on AER website

- non-network general (including IT and other assets).

Finally, it is important to note that since the AER's draft decision, Energy Safe Victoria (ESV) has reviewed a number of items within each of the DNSPs revised proposals. We understand that the ESV review is in response to the Victorian Bushfires of 2009 and the Bushfire Royal Commission report. It is also in response to changes to regulatory obligations including the safety management scheme and line clearance requirements. Based upon this review, ESV has recommended volumes for each of these items that it considers prudent to undertake in the next period. The AER has requested that, for these specific items, we only undertake a review of the efficient unit costs. The review of unit costs has not allowed for consideration of the overall benefits, synergies and capex/opex trade-offs that may occur from these increases in overall expenditure.

1.1 Structure of report

The report is structured as follows:

- In section 2, we provide a summary of our revised expenditure analysis. This has been revised to allow for 2009 actual data – only 2009 estimates were available for our original review.
- Section 3 provides a discussion of general criticisms of our original review that are similar across the DNSPs.
- Our revised detailed reviews of each of the capex categories for each of the DNSPs are provided in Appendix A to E.
- Appendix F provides the Nuttall Consulting targeted review of opex step change areas identified by the AER. It is important to note that the review of these opex matters is included in this report for completeness. The main body of the report only discusses matters associated with the capex review.
- Appendix G provides Nuttall Consulting's review of the unit costs associated with the volume reviewed and recommended by the ESV.
- Attachment A includes the Curriculum Vitae of the main review team members.

2 DNSP expenditure analysis

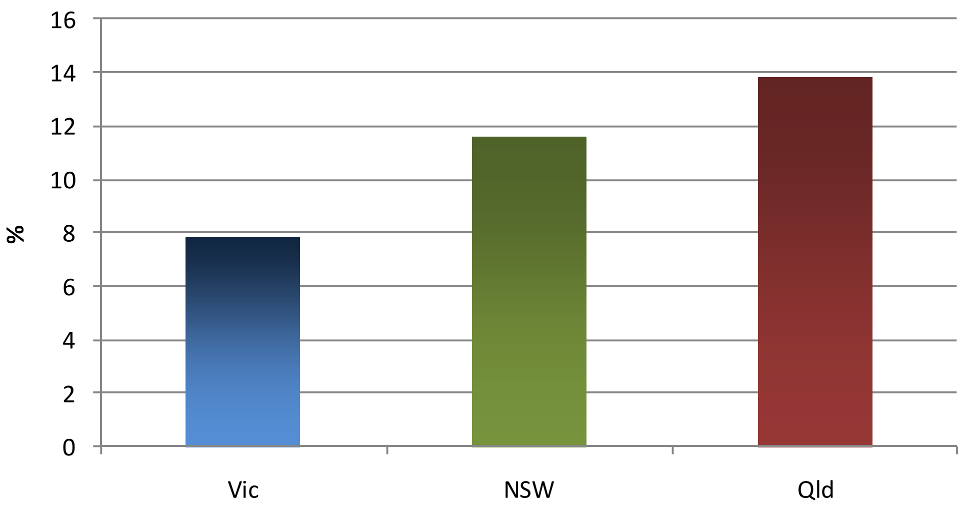
This section presents our analysis of the DNSPs historical expenditure, including an assessment of the relative capex efficiency of the Victorian DNSPs, an assessment of the accuracy of the DNSPs' previous capex forecasts, and the variation from trend of the DNSP's capex forecasts for the next period. This analysis has been revised since our original report, making use of the audited capex of the DNSP for 2009, their revised estimates for 2010, and their revised proposals for 2011 to 2015.

2.1 Actual expenditure levels

2.1.1 Major state comparison

The Victorian DNSPs compare well when overall capex is compared with that of Queensland and NSW[6]. The following figure shows the average level of capex for the last 5 years for each state compared with the current regulated asset value.

Figure 1 - Capex as a percentage of asset value



There are a number of factors that are beyond the immediate control of the DNSPs that may impact this comparison. In addition, the review of capex does not consider the trade-offs with opex and service standards. For this reason this comparison is not intended as the mechanism for setting capex levels, but of identifying areas for specific review.

This comparison has been undertaken for different benchmark measures including the number of customers served, length of overhead and underground lines, energy delivered and maximum system demand. These benchmarks were chosen to provide a selection of

[6] These states are considered most comparable based on the number of customers served and that each state has more than one supplier.

efficiency measures. In isolation, any single comparative measure will have strengths and weaknesses. In aggregate, these measures provide a strong indication of the relative capital efficiency of each state.

The above chart is representative of the mix of benchmark measures that were assessed by Nuttall Consulting. The Victorian DNSPs were placed as the most capital efficient in each of these measures with the exception of the "per km of line" measure where they were second to NSW. A complete listing of the benchmarks used is provided in Appendix F.

This range of measures would seem to suggest that the overall Victorian levels of capex as revealed for the last 5 years are relatively efficient when compared with Queensland and NSW.

Observation: The overall level of capex in Victoria as revealed in the previous 5 years appears relatively efficient.

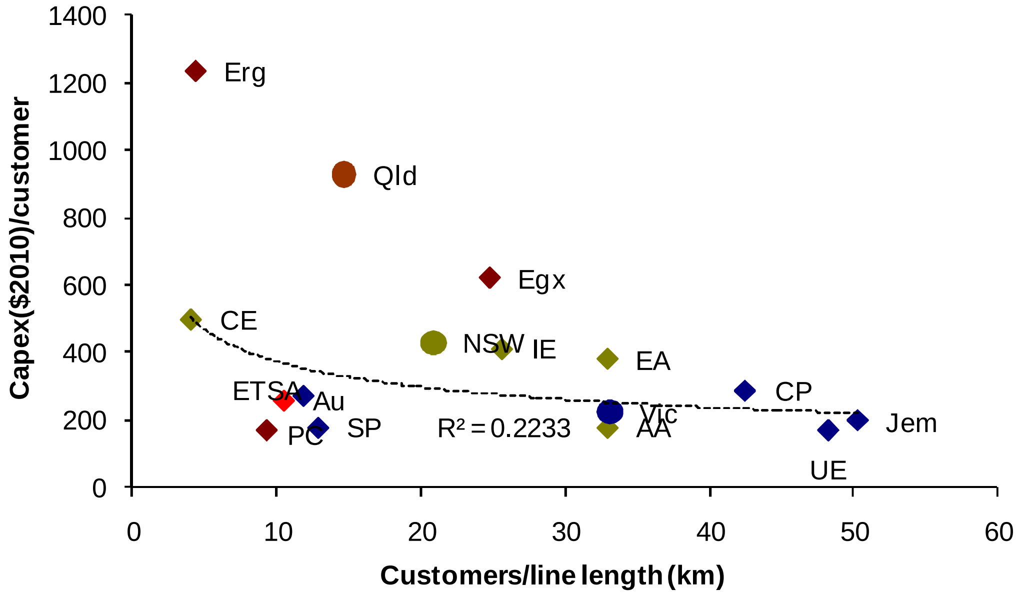
2.1.2 DNSP comparison

When comparing capex at an individual company level there are factors that significantly impact expenditure and influence the value or accuracy of the benchmark. The most significant of these factors is the customer density of the areas serviced by the DNSP. One way of considering the customer density is to take account of the number of customers per km of overhead or underground distribution lines.

The following chart shows the capex spent[7] per customer for each of the NEM DNSPs.

[7] Reported capex for last 5 years in $2004.

Figure 2 - capital expenditure per customer[8]



The above chart appears to indicate that the overall level of capex for the Victorian DNSPs is broadly below the level of comparable DNSPs.

The above benchmark has been undertaken for different comparison measures including the value of the regulated asset base, length of overhead and underground lines, energy delivered and maximum system demand.

These benchmarks were chosen to provide a selection of efficiency measures. A complete listing of the benchmarks used is provided in Appendix F. In isolation, any single comparative measure will have strengths and weaknesses. In aggregate, these measures provide a strong indication of the relative capital efficiency of each of the DNSPs.

The above chart is representative of the mix of benchmark measures that were assessed by Nuttall Consulting. The Victorian DNSPs placed as relatively capital efficient in most of these measures, with CitiPower and Jemena appearing above the trendline in a couple of instances.

In aggregate, these charts would suggest that the revealed capex of the Victorian DNSPs for the last 5 years is relatively efficient and that individual DNSPs appear to benchmark consistently well in comparison to other NEM businesses.

Observation: The individual Victorian DNSPs appear reasonably efficient when compared to interstate DNSPs.

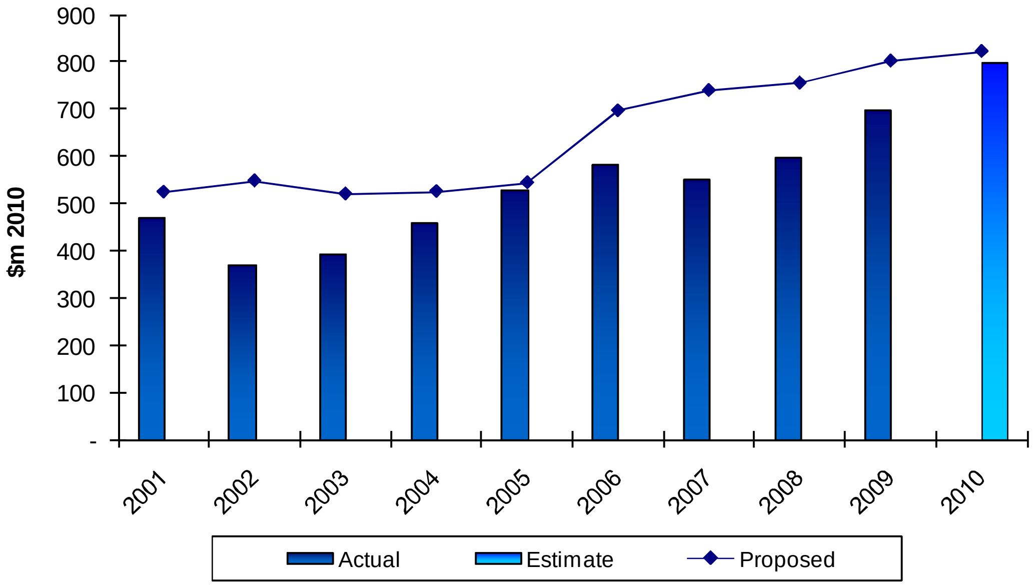
[8] Legend: AA – Actew/AGL, AGLE – Jemena (formerly AGL and Alinta), Au – Aurora Energy, CE – Country Energy, CP – CitiPower, EA – EnergyAustralia, Egx – Energex, Erg – Ergon Energy, ETSA – ETSA Utilities, IE – Integral Energy, PC – Powercor, SP – AP AusNet, UE – United Energy

2.2 Forecasting accuracy

The Victorian DNSPs are commercial operations and therefore have a strong profit motive. One means for increasing profitability is for the businesses to spend less capital than the regulatory forecast. This can be achieved in the longer term by improving efficiency or by having a more favourable capital benchmark established for the next regulatory control period.

The accuracy of the DNSP forecasts for the previous 2 regulatory periods is highlighted in the following chart.

Figure 3 - Proposed and actual capex for Victorian DNSPs



It is clear from the above chart that the actual expenditure levels are more closely related to future expenditures than the forecasts. The overall trend in expenditures is generally upwards and this trend would appear to be a much more accurate predictor of future capex requirements than the forecast figures.

The DNSPs have proposed capital forecasts for the next regulatory control period. It is the purpose of this paper to review that forecast and make a recommendation to the AER on whether those forecasts are reasonable. If the forecasts are not considered reasonable, Nuttall Consulting is required to recommend an alternative forecast.

There are two aspects to the DNSP forecasts contained in their proposals:

- the forecasts for the 5 years of the next Regulatory Control Period
- the estimates of expenditure for the remaining year (2010) of the Current Regulatory Control Period.

This report is primarily focussed on assessing the forecasts for the next Regulatory Control Period, however the estimates for the remaining year of the current period are important in understanding the base or starting point for the next 5 years.

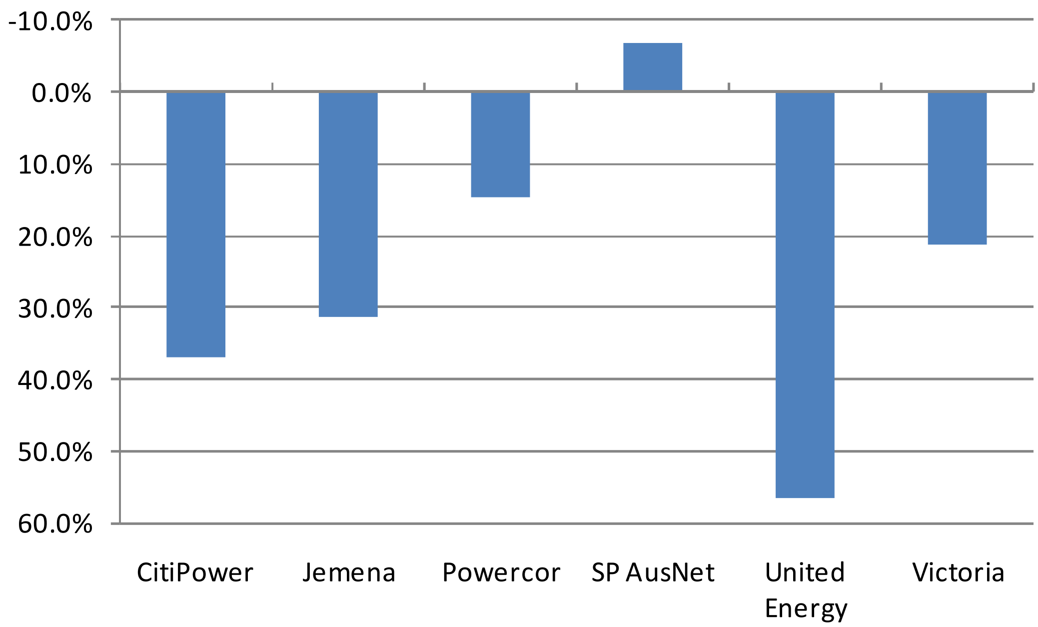
The DNSP forecasting accuracy for both of these aspects are considered below.

2.2.1 Next Regulatory Control Period forecast accuracy

The average level of forecasting inaccuracy for the Victorian DNSPs over the last 9 years is 21.3%. This means that proposed expenditures are on average 21.3% more than the actual expenditures incurred by the DNSPs for the last two Regulatory Control Periods[9].

This measure considers actual expenditure in the current regulatory control period as well as the previous period. Capital expenditure trends are reasonably variable from year to year, so it is necessary to consider a longer period of time to assess the accuracy of the DNSP forecasts.

Figure 4 - Forecasting (actual vs forecast capex)



The results of this assessment shows that the Victorian DNSPs have consistently overforecast the capital requirements in the previous and current Regulatory Control Periods with the exception of SP AusNet who have slightly underforecast.

Observation: The Victorian DNSPs have consistently forecast higher levels of expenditure than have actually been required, although there is a significant level of variability in the level of forecast inaccuracy.

[9] Using actual expenditure as the baseline.

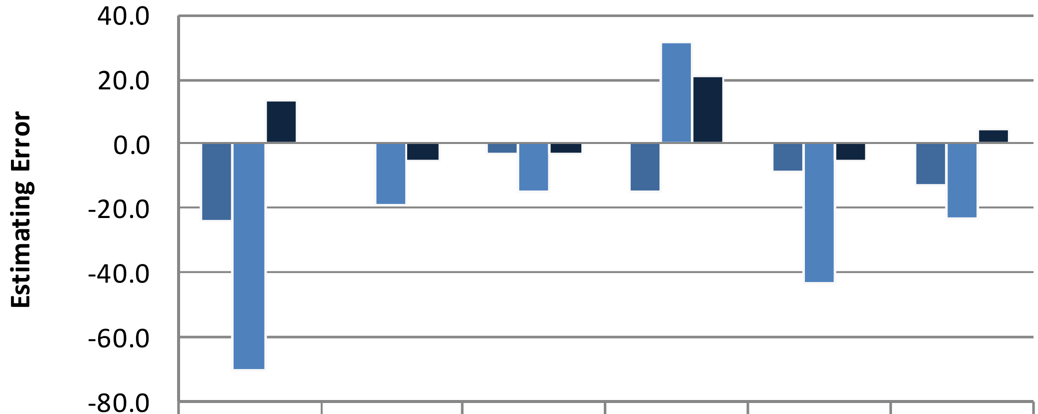
2.2.2 Current period estimate forecast accuracy

The remaining year of the current regulatory control period is 2010 and the DNSPs have each provided estimates of the 2010 capital expenditures.

Although the calendar year 2009 is complete the audit and reporting of this years' expenditures was not available to Nuttall Consulting until April 2010. These estimates are not the focus of this review but are important as they set the starting point or base years for considering the next Regulatory Control Period.

Nuttall Consulting has reviewed the accuracy of the estimates provided by the DNSPs as part of the 2005 EDPR process and the current 2009 figures. The results of this review are provided in the following chart.

Figure 5 – 2004, 2005 and 2009 DNSP Estimating Accuracy



	Jemena	CitiPower	Powercor	SP AusNet	United Energy	Victorian Avg
2004	-24.1		-3.4	-14.9	-9.1	-12.9
2005	-70.7	-19.0	-14.9	31.2	-43.3	-23.3
2009	13.3	-5.2	-2.9	21.0	-5.6	4.1

The above chart highlights that there has been a consistent level of inaccuracy[10] in the estimating of capex in the remaining years of a Regulatory Control Period. SP AusNet is the only DNSP to provide an estimate that was subsequently overspent in 2004 or 2005. All other estimates were over-forecast when compared to the expenditure that did eventuate.

If we consider the absolute error in terms of 2009 forecasting, the average for Victoria is 9.6%. This is a very large forecasting error considering the relatively short timeframes involved.

It may be argued that efficiency improvements by the DNSPs have contributed to the overall underspend, however this is not considered likely to account for the majority of the differential.

[10] Both positive and negative accuracy

Observation: The DNSPs provide estimates of the remaining 1 to 2 years of a regulatory period when forecasting for the next period. These estimates in the current and previous regulatory periods, as provided by the DNSPs, show a high degree of inaccuracy when compared with actual expenditures.

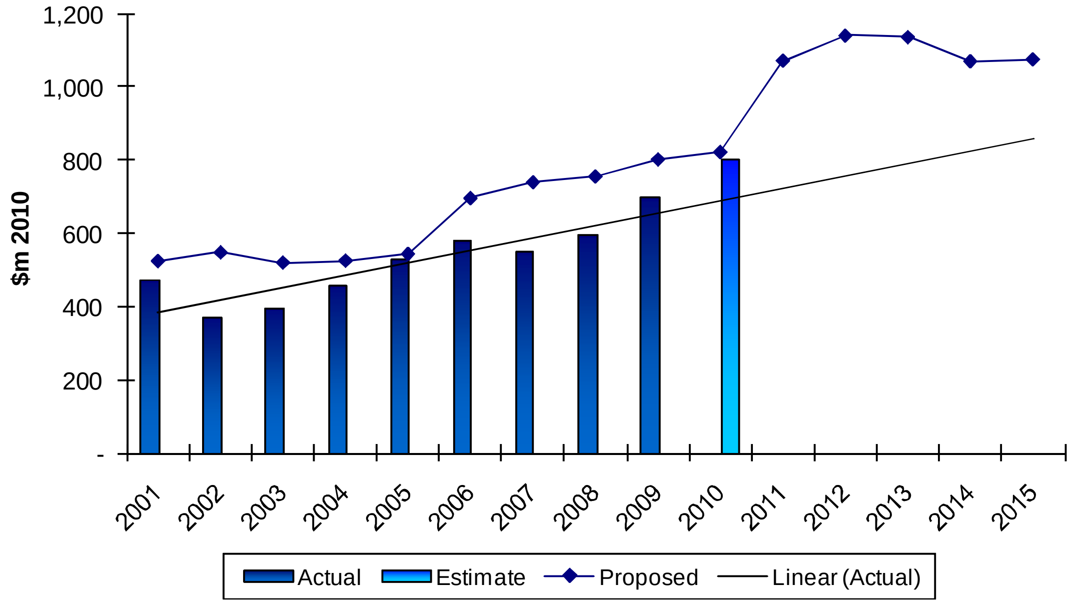
2.3 Expenditure trends

This section reviews the trends revealed by historical levels of capex and compares these with the DNSP forecasts.

2.3.1 Actual to forecast

The Victorian DNSPs are forecasting capex that is considerably higher than current levels of expenditure. The following chart shows the actual capex incurred in the two previous control periods and current Regulatory Control Period. The chart also shows the sum of the capex that was proposed by the Victorian DNSPs for each of the Regulatory Control Periods.

Figure 6 - Victorian Capex



As discussed in the previous chapter, the DNSPs have consistently forecast expenditures that have been well above the resultant capex that was incurred. The above graph also provides a linear trendline based on the actual capex incurred since 2001. This trendline does not include the estimated figures for 2010 as previous estimates have proven to be inaccurate.

As discussed in the previous section, the overall accuracy of the DNSP forecasts has been quite low over the current and previous Regulatory Control Periods. It is clear from the above chart that previous actual expenditures are more closely aligned to the forecast expenditure than the DNSP forecasts. The simple trendline used in this chart is also much better aligned with actual expenditures than the DNSP forecasts.

It may be argued that efficiency improvements by the DNSPs have contributed to the consistent underspend that has been observed since 2001, but it is unlikely that such improvements would account for the majority of the difference. In this regard, efficiency gains would most likely occur incrementally and result in greater levels of underspend occuring in the later years of the regulatory period. However, the above chart indicates that the greatest levels of underspend have occured in the earlier years of the regulatory period.

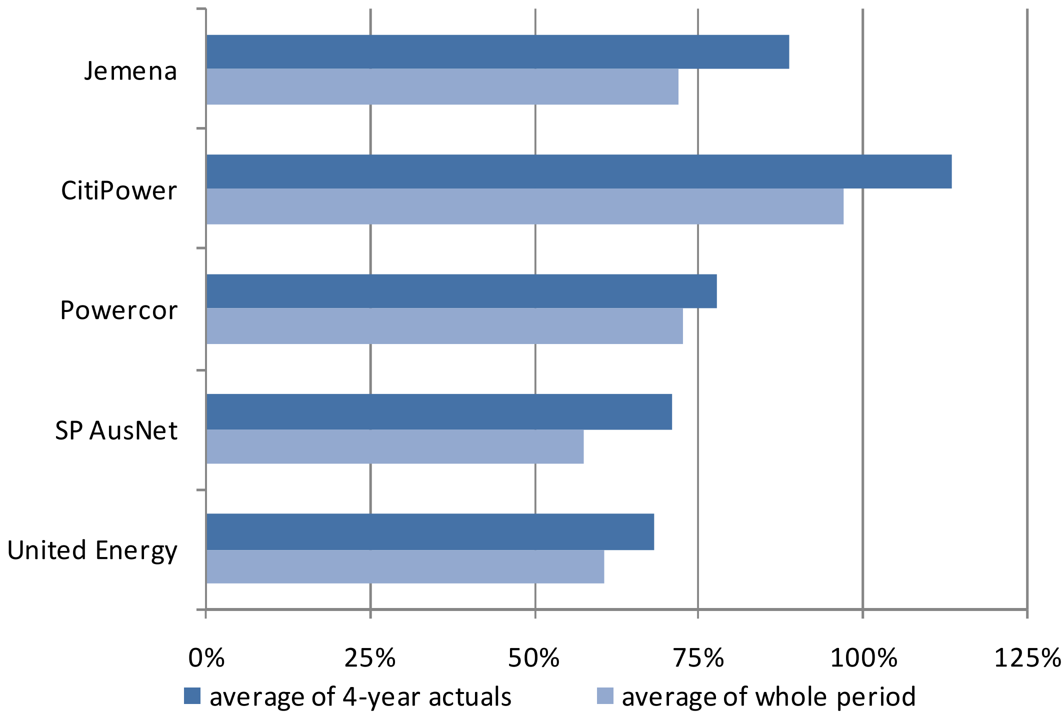
All Victorian DNSPs are forecasting significant increases to capex. These forecast increases to capex are significantly higher than the existing levels of expenditure and are higher than the linear trendline of actual expenditures. The relationship between these factors is similar to the same time 5 years ago when the previous EDPR was being assessed.

The following chart provides the individual increases in capex that are forecast by each DNSP. The calculation of the expenditure increase has been done by comparing the average 5 year forecast capex with:

- the average of the actual expenditure in the current Regulatory Control Period
- the average of the actual and estimated expenditure in the current Regulatory Control Period.

Due to the historical estimating errors identified in the previous section, the 4-year variation comparison is considered most representative of the proposed increase in capex.

Figure 7 - Actual to forecast capex comparison



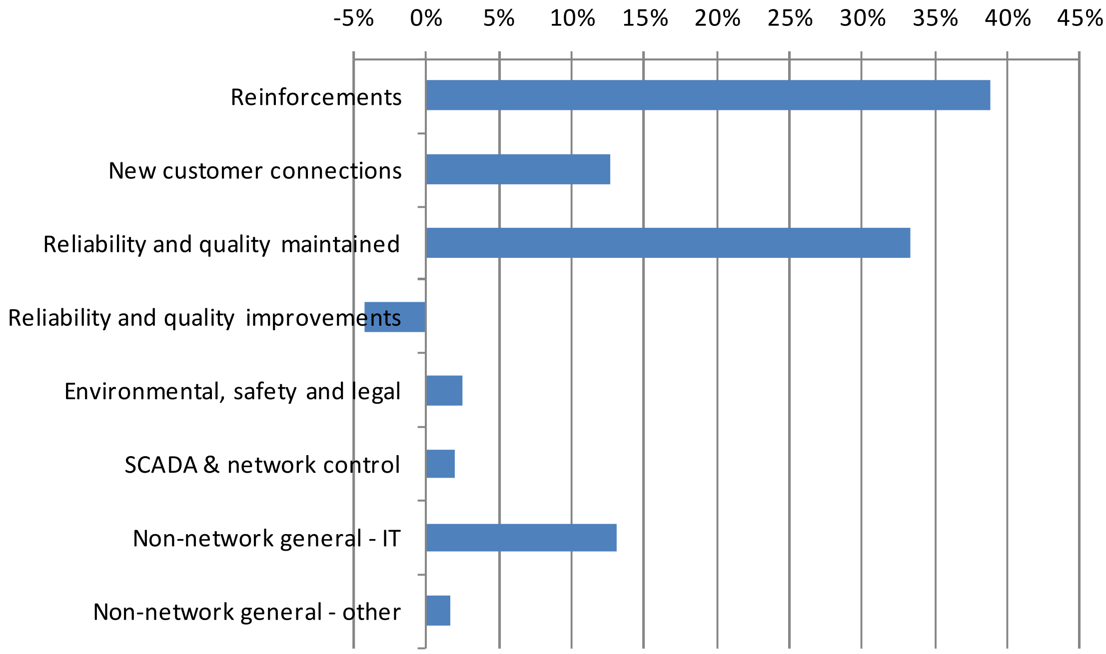
CitiPower are forecasting the greatest increases in capex for the next Regulatory Control Period. Powercor, SP AusNet and United Energy appear to have the most conservative forecast increases, although these increases are still substantial.

The majority of forecast increases in capex are occurring in three main categories:

- reinforcement
- new customer connection and load movement
- reliability and quality maintained
- non-network general IT.

These three categories account for over 80% of the forecast capex increases when compared against actual expenditure for the last three years. The reliability and quality improvements category shows a slight decrease as no DNSPs have forecast expenditures in this category.

Figure 8 - Capex category contributions to increases



Observation: The capex forecasts for the next Regulatory Control Period are significantly above the actual expenditure trendline. Capex categories that represent the greatest contribution to these increases are reinforcement, new customer connection, load movement, reliability and quality maintained, and non-network general IT.

2.4 Summary

This section has considered the historical expenditures of the Victorian DNSPs in aggregate and individually. These expenditures have been compared against other DNSPs and states in the National Electricity Market. The section also reviews the overall accuracy of the forecasts from previous capex proposals and considers the implications for this review.

In summary, the observations from this section are:

- The overall level of capex in Victoria as revealed in the previous 5 years appears relatively efficient.
- The individual Victorian DNSPs appear reasonably efficient when compared to interstate DNSPs.
- The Victorian DNSPs have consistently forecast higher levels of expenditure than have actually been required, although there is a significant level of variability in the level of forecast accuracy.
- The overall bias towards over-forecasting may be in some part due to the DNSPs achieving efficiencies in capex. However, these potential efficiencies do not appear

to provide sufficient explanation for the variations between forecast and actual capex.

- The Victorian DNSPs have generally estimated higher levels of expenditure for the remaining years of a regulatory control period than have actually been required.
- The capex forecasts for the next regulatory control period are significantly above the actual expenditure trendline. Capex categories that represent the greatest contribution to these increases are reinforcement, new customer connection and load movement, reliability and quality maintained, and non-network general IT.

3 Comments relevant to the overall review process

3.1 Reinforcement

The revised proposals include a number of criticisms of the process Nuttall Consulting applied in determining the capex associated with our reinforcement recommendations. This specifically relates to our development of probabilities for a selection of projects (project probabilities), which related to our views on capex funding requirements; and the use of these probabilities to determine the overall reinforcement allowance.

This section attempts to address the main criticisms.

Too subjective and relying on judgement

All the revised proposals consider that our process to develop the project probabilities was too subjective and reliant on judgement[11].

We consider that this view misrepresents the process we undertook. Our probabilities were based upon a detailed review of the information made available to us on each project, including:

- the expected energy at risk and/or the value of other benefits driving the project
- the options considered.

It followed a fairly objective assessment of this material to determine the factors that may result in the deferral of the project or a lower cost option being selected. This included an assessment of whether the timing would result in a net benefit, and when this may be maximised.

As noted in our original report, it did also allow for higher level findings, but we consider this is completely in line with the NER and range of capex factors we should account for.

We do accept that we could be criticised for not including sufficient detail of our review, or our development of the probabilities. For this reason, in this report we have included more detail of the main issues we have with each project and the derivation of the probabilities.

Does not account for the drivers

All the revised proposals consider that our process to develop the reinforcement allowance did not account for the drivers of reinforcement capex[12].

[11] SP AusNet revised proposal, pg 7, CitiPower revised proposal, Pg 274, UED revised proposal, pg 123
[12] SP AusNet revised proposal, S6.6.2, CitiPower revised proposal, Pg 279, UED revised proposal, pg 123

As with the above issue, we consider that this view is not correct and misrepresents the process we undertook. Our review of each project *did* carefully consider the drivers. As noted above, this included a detailed review of the key drivers of the reinforcement program. This review considered numerous relevant factors for each project, including:

- the year-by-year demand growth relevant to the identified needs
- the rating of plant, and in turn, the year-by-year utilisation of the plant
- the year-by-year demand at risk
- the year-by-year energy at risk
- the year-by-year expected energy at risk.

Where other factors, such as asset condition, were the main drivers of a project, these matters were also assessed.

As such, although arguably not evident from the output probabilities, the probabilities will intrinsically allow for the main drivers.

Uniqueness of process

A number of the revised proposals consider that our process to develop the reinforcement allowance was unique and has not been applied before.

While we do not disagree with this view, we do not consider that, in the context of our overall review findings, this means that our approach should be considered invalid or not in accordance with the NER.

In appreciating our view, we consider it important to note the following:

- As discussed for the above two criticisms, we do not consider that the approach we took to the individual project reviews was unique. We consider that it followed a typical project review process, as applied in many other revenue/price control processes. With regard to the information reviewed and types of consideration we gave to various matters, we consider that it was similar to reviews of capex projects that Nuttall Consulting has undertaken for the AER on numerous other occasions.
- With regard to our determination of individual project probabilities, while we agree that this is not always attempted by the AER or its advisors. We do not consider that it has no precedence in regulatory reviews. In this regard, we have applied a similar approach when reviewing a number of substation refurbishment projects in the recent Transend review, conducted by the AER. We understand that this approach was accepted by the AER in its final decision. We also consider that this approach of defining probabilities for projects (where the probability reflects the likely funding requirements through the capex mechanism) is a far more pragmatic and robust approach to producing a forecast of the overall capex allowance within a revenue/price control review. In our opinion, this should be a more appropriate approach than attempting to define the “best estimate” of each project’s timing, scope, and cost - as is often attempted by the AER or its advisors.

- Finally, with regard to the process of trending the capex using the weighted average project probability and a constant expenditure growth rate to derive an overall expenditure profile, we accept that this step is possibly the most unique. However, given our findings on past actual expenditure trends and past forecast accuracy, we do not consider that this approach is unreasonable. In this regard, where a clear deviation from this type of trend was justified (e.g. CitiPower's Metro 2102 and CBD security projects), we adjusted our approach to reflect this.

Inappropriate or insufficient selection of projects

A number of the revised proposals consider that our process to develop the reinforcement allowance did not allow for a sufficient number of projects[13].

While we accept that only a limited number of projects were reviewed for each DNSP, in the context of our overall review, we consider that the number was not unreasonable. For each DNSP, we consider that it reflected a large enough portion of expenditure to gain a conservative view of the expenditure needs in the broader context of our review findings.

In the case of SP AusNet, we do accept that the project selected did not adequately represent the first half of the next period. Therefore, we have included a number of other projects in our review to address these concerns.

Bias in process

All the revised proposals consider that our process introduced a bias in our estimate[14]. This related to our use of 90% as the highest probability (not 100%) and a lack of recognition that projects could be advanced.

We disagree that the use of 90% represented a bias. Based upon our high level findings of consistent historical over-forecasting, a reduced probability for even the very high probability projects seems reasonable. It is also worth noting that the 90% probability for very likely projects has be viewed against a 33% probability applied for low probability projects. It could easily be argued that this represents a bias in the other direction.

With regard to the lack of recognition that projects could be advanced, we do not consider that this is correct view of our analysis. Our probabilities need to be viewed with a portfolio mindset. That is, for a set of similar projects, on average, what probability appropriately reflects the funding requirements through the capex mechanism. Our probabilities are set to reflect our view of the "most likely" position given the information we have reviewed.

As such, a specific project may well be advanced or be more costly than estimated now – in fact, we could expect that this will be the case for a number of projects. However, counter to this, other projects will be delayed or be less costly than our probabilities suggest.

On this point, it is important to note that our probabilities are not set to reflect changes to key assumptions such as demand growth, which are considered fixed in our analysis.

[13] SP AusNet revised proposal, S6.6.2, CitiPower revised proposal, Pg 279, UED revised proposal, pg 123
[14] SP AusNet revised proposal, pg 7, CitiPower revised proposal, Pg 274, UED revised proposal, pg 123

3.2 RQM review

All the revised proposals include a number of criticisms of Nuttall Consulting's process to review RQM expenditure, including its use of the repex model. Broadly, we consider that many of the criticisms misrepresent our use of the repex model. Furthermore, we also consider that at times they confuse the use of replacement modelling as a tool for regulatory analysis with "reliability" modelling as may be used internally within a business. As such, we do not agree that our use of the repex model within the overall RQM review process was invalid.

This section attempts to address the specific issues raised in the various proposals and associated expert opinions.

Apparent contradiction in Nuttall Consulting's views on DNSPs' modelling

The revised proposals raise an apparent contradiction in Nuttall Consulting's views that the DNSPs' model were appropriate for asset management purposes, but inappropriate for regulatory purposes[15] [16].

We do not consider there is any contradiction here. We consider it normal that internal planning models and associated criteria would err on the side of caution. An aim of these processes is to ensure all matters begin to be considered and addressed with sufficient time. Any conservatism in these plans is then optimised through the capital governance processes.

This differs from the regulatory needs, where we are attempting to determine the expenditure needs that most likely reflect the resultant output of these governance processes.

Relationship between the repex model and detailed review

In a number of locations, a view is expressed that it was inappropriate to reject the DNSP's forecast based upon the repex model. For example, the independent expert, PB, engaged by Jemena, CitiPower and Powercor states:

> "*while the Nuttall report contains little fundamental analysis of the business' needs, risks, and proposed expenditure (prudency and efficiency) to support the dismissal of the business' AMP's, it relies on comparison to an unreviewed age based proprietary model to accept/reject the business proposals...*[17] [18]".

We consider that this view represents a fundamental misunderstanding of our review process and use of the model with regard to rejecting the DNSPs forecasts. The calibrated repex model, among other things (e.g. significance of expenditure), was used as a guide to whether or not we considered a detailed review of a specific asset category should be undertaken. The decision to reject the forecast was based upon the findings of the detailed review of the information made available to Nuttall Consulting to support the

[15] Jemena revised proposal, A8.2 – PB report, "JEN Forecast Asset Replacement Volumes", Pg iv
[16] CitiPower and Powercor revised proposals, PB report, "Repex Model Review", Pg iii
[17] Jemena revised proposal, A8.2 – PB report, "JEN Forecast Asset Replacement Volumes", Pg iv
[18] CitiPower and Powercor revised proposals, PB report, "Repex Model Review", Pg iii

forecast. As noted in our original report, this review process also included further information requests and meetings with each of the DNSPs to discuss the forecasting methodology used by the DNSPs. For the sake of brevity and confidentiality, we did not include detailed discussions of the DNSP's plans in our original report. However, we did discuss our basis for rejecting specific matters, and noted the deficiencies in the information.

The integrity of the repex model

The integrity of the repex model appears to be questioned in a number of places. For example, as stated in the text above, it is described as an "unreviewed age based proprietary model".

It is not entirely clear the reasoning for descriptions of this type, but we consider it important to note the following.

With regard to its form, it is based upon well accepted probability theory, which is widely used and relatively simple to validate. Although the model itself could be considered proprietary, the theory behind the replacement algorithm is not and is used by a number of other parties.

For example, it is our understanding the equivalent probabilistic approach has been applied by Ofgem, the UK energy regulator, to undertake replacement modelling. It is also important to note that, as far as we understand, SP AusNet's proposal uses an equivalent probabilistic approach for a number of its asset categories. Finally, and possibly most importantly, it is our understanding that PB, itself, has used this form of probabilistic modelling on a number of occasions, including regulatory reviews in the UK[19].

It is also worth noting that it is our understanding that the AER undertook some form of comparative analysis of the model against the Ofgem model, and did not find any significant differences.

The repex model does not align with risks

The revised proposals suggest that the repex modelling has not been aligned with the specific risks faced by the DNSPs in the next period[20] [21] [22]. This largely goes to the view that, as the repex model was calibrated to historical volumes and expenditure, it would not account for changes to risks from the current period to the next.

We consider that this view only appears valid because the DNSP's and their experts have accepted that the prospective risks are valid, and moreover, they are significantly different to the current period.

This view is fundamentally different from our findings of the detailed reviews, where we considered that the DNSPs had not provided sufficient evidence that risks faced in the next

---

[19] For example, J Douglas, "REPLACEMENT OF THE AGEING ASSET BASE – THE CHALLENGE TO REGULATORS", CIRED 19th International Conference on Electricity Distribution, May 2007

[20] Jemena revised proposal, A8.2 – PB report, "JEN Forecast Asset Replacement Volumes", Pg iv

[21] CitiPower and Powercor revised proposals, PB report, "Repex Model Review", Pg iii

[22] UED revised proposal, pg 108

period were significantly different from those faced, and accepted, in the current. The need for a robust demonstration by the DNSPs of changing risks was considered important, given the very large increases in capex that the DNSPs are proposing in a number of asset categories.

It is important to note that our view did not attempt to pre-empt the findings of the Bushfire Royal Commission. Furthermore, based upon discussions with the ESV, we did not receive any formal (or informal) advice that the ESV would be accepting a fundamentally different risk position in gauging safety-related replacement needs in the next period. As such, we did not use these matters as a reason for a step change in risk perception.

As is discussed in the introduction, following the conclusion of the Bushfire Royal Commission, it is our understanding that this change in risk perception has since been accepted for a number of safety related issues, and so, adjustments to the expenditure requirements have been made to various asset categories based upon this view.

The assumption that age is a proxy for condition within the repex model

Related to the matter above on risk, the DNSPs consider that the repex models assumption that age can be used as a proxy for condition is not valid when applied across all categories[23] [24] [25]. The view here is that this assumes a level of "homogenisation" within the asset categories, and does not account for changing drivers.

As with the above issue on risks, we consider that that this view only appears valid because the DNSP's and their experts have accepted that the condition of assets or other drivers are significantly different to the current period. As with risks, this view is fundamentally different from our findings from our detailed reviews, where we considered that there was not sufficient evidence that the condition of assets or other drivers faced in the next period were significantly different from those faced in the current, particularly to the extent that the large proposed step increases in a number of asset categories was warranted.

It is correct that, where we rejected forecasts for specific asset categories, in most cases we used the outputs of the calibrated repex model to determine the substitute allowance. However, in some circumstances where we did consider that asset condition information (or other information) suggested that the repex model would not be a reasonable forecast, we made an alternative allowance. In our original report, this was most notable for the SP AusNet zone substation assets. In this review, revised information has resulted in further adjustments occurring in a number of other places.

Further details of these instances are provided in the specific asset category discussions in the respective DNSP sections.

[23] Jemena revised proposal, A8.2 – PB report, "JEN Forecast Asset Replacement Volumes", Pg iv
[24] CitiPower and Powercor revised proposals, PB report, "Repex Model Review", Pg iii
[25] UED revised proposal, pg 108, and pg 130

Inappropriate repex model assumptions

The DNSPs, via their experts, have questioned the appropriateness of the probabilistic assumptions underpinning the repex modelling. This specifically concerns two main issues:

- the assumption that the replacement distribution can be represented by a normal distribution, rather than a Weilbull distribution, as is normally used for reliability modelling
- our simplification of using the square root of the mean replacement age to represent the standard deviation of the normal distribution.

With regard to both assumptions, we consider that they are reasonable approximations to make in the absence of the more complete data set that would be required to determine a more accurate distribution.

With regard to the issue of a normal or Weibull distribution, we certainly do not disagree that a Weibull distribution is often used for reliability analysis, including replacement modelling. However, we do not consider that this means the use of a normal distribution, calibrated as we have, is not appropriate in these regulatory circumstances. In defence of our use, we consider the following observations are relevant:

- as far as we are aware, a normal distribution is used in the Ofgem model noted above; this model has been applied for around the last 15 years in the UK for regulatory purposes
- PB has accepted the use of a normal distribution in replacement modelling it has undertaken for Ofgem[26] – as far as we are aware, the PB modelling was the genesis of the Ofgem model
- SP AusNet has also assumed a normal distribution for the majority of the probabilistic modelling it has applied to support its proposed RQM expenditure.

With regard to the standard deviation, we consider that this assumption will tend to understate the standard deviation. Although this may understate replacements due to young assets, it will tend to overstate the replacement needs of older assets. We generally found that this assumption would result in a conservative estimate of the rates of increase in replacement needs (i.e. overstate volume growth rates).

We also consider it important to note that it is our understanding that this assumption is also applied by Ofgem to allow it to calibrate its replacement models. On this point, we note that even PB has conceded that in most circumstances the DNSPs were not able to provide standard deviation data[27]. If this is accepted to be the case, it is not clear how easy it would be to develop Weibull distribution for each asset category, where we would need the two parameters that define such distributions. It is our understanding that it is this difficulty in defining the parameters for such a distribution that is the main reason for

[26] For example, see Appendix F, PB Power report "DPCR4 – FBPQ ANALYSIS AND CAPEX PROJECTIONS", October 2004, available on Ofgem website

[27] Jemena revised proposal, A8.2 – PB report, "JEN Forecast Asset Replacement Volumes", Pg 7

most users opting to use the simplification of the normal distribution for regulatory purposes.

Finally, in the context of how we have used the model results, we do not consider that the DNSPs, or their experts, have presented any compelling evidence that these simplifications are resulting in a consistent understatement of the needs in a material way. We note that PB has presented some analysis of different distributions that it considers demonstrates our assumptions would understate needs[28]. However, it is not clear how PB has developed the Weibull distributions it has used, and as such, it is not clear whether it is reasonable to compare these distributions against our assumptions.

For example, as noted above, we would expect our assumed standard deviation to be less than the actual, but in the PB analysis it appears they have evaluated our assumption as if it was either around the same or even longer than the actual standard deviation. We consider that it is this possible error that is resulting in the appearance that our assumptions will understate the replacement volumes in a material way.

The repex model is inappropriate as a substitute forecast

The DNSPs, and their experts, consider that the repex model cannot be used as a substitute forecast[29]. This relates to a number of concerns, namely:

- it is not based upon the current proposal
- it has not been demonstrated to provide the minimum adjustment necessary.

We consider that the above, at least in part, are legal issues that should be considered by the AER.

With regard to the first matter, we do note however that the modelling was undertaken using information made available through the RIN process and through further information requests administered by the AER.

With regard to the second matter, we consider it important to note that the calibrated repex model generally result in a predicted expenditure increase that is greater than the longer-term historical increases. As such, we did not consider that our use of the repex model was understating needs. Moreover, we consider it a conservative estimate.

Bias in use of repex model when rejecting forecasts

It is considered that there was an inherent bias in using the model to accept or reject forecasts at an asset category level[30 31 32]. This is considered to be due to the view that we allowed forecasts that were below the repex model, but rejected those that were above; rather than assessing at a total network level with the repex model.

[28] Jemena revised proposal, A8.2 – PB report, “JEN Forecast Asset Replacement Volumes”, Pg 13
[29] Jemena revised proposal, A8.2 – PB report, “JEN Forecast Asset Replacement Volumes”, Pg 7
[30] Jemena revised proposal, A8.2 – PB report, “JEN Forecast Asset Replacement Volumes”, Pg 8
[31] CitiPower and Powercor revised proposals, PB report, “Repex Model Review”, Pg 14
[32] UED revised proposal, pg 138

We consider that this view is due to a misunderstanding of our process. As noted above, the rejection was due to a detailed review of the asset category – not the repex model. If this detailed review lead to an acceptance of some increase then this was allowed. We consider that this approach, in principle, should not result in a bias in the forecast. We do accept however that adjustments from the model outputs only occurred in limited circumstances. Nonetheless, given the point above - that we considered that at the asset level, the model was most likely overstating needs - we do not consider that it is clear that any bias has been introduced.

Accuracy of calibration - lives

The DNSPs, and their experts, consider that the calibration of the repex model has not been shown to be appropriate. In support of this view, they note a) the variability between DNSPs of the benchmark lives that we derived through the calibration process; and b) the view that in many cases these are well in excess of typical industry benchmarks[33 34 35].

We do accept that the our benchmark lives are variable and longer than many typical Australian benchmarks. However, we do not consider that this demonstrated that the calibrated repex model was not fit for purpose.

As noted in our section on the replacement model in our original report, the typical benchmark lives provided by the DNSPs would have considerably overstated the proposed replacement needs of the DNSPs. Based upon other modelling we undertook for the AER in developing the repex model, it was also seen that typical benchmark lives would have significantly overstated historical expenditure from that which actually occurred[36]. It is also our understanding that the replacement model used by the ESC in 2000[37] also significantly overstated replacement needs from that which eventuated when benchmark lives were used.

With regard to our calibrated repex model output, we do accept that metrics that would define the "goodness of fit" were not provided, as is noted by some experts[38]. However, we are not sure with the information available, what methodology could have been applied. We do consider it important to note however that our calibration exercise did result in forecast expenditure being in line with the historical trend – in fact it was slightly above the historical trend. Possibly more importantly, as part of our repex modelling discussed above, we found that lives calibrated to historical expenditure were a much more accurate predictor of the actual future RQM expenditure than typical industry benchmark lives.

We consider that this is fairly compelling evidence that the use of typical industry benchmark lives in such age-based replacement models would most likely significantly

[33] Jemena revised proposal, A8.2 – PB report, "JEN Forecast Asset Replacement Volumes", Pg 18
[34] CitiPower and Powercor revised proposals, PB report, "Repex Model Review", Pg 32
[35] UED revised proposal, pg 137
[36] Based upon modelling using 1999 age profiles and benchmark lives available through the ESC.
[37] This is a form of the PB Model that has been used Jemena and UED in preparing its forecasts.
[38] Jemena revised proposal, A8.2 – PB report, "JEN Forecast Asset Replacement Volumes", Pg 17

overstate needs. We note that the DNSPs, and their experts, do not provide any useful opinion on this issue. We also note that no studies have been presented by the DNSPs to show what lives (and probability distributions) would more appropriately reflect historical expenditure, such that they can demonstrate a better "goodness of fit" for alternative assumptions.

Finally, it is noted that United Energy questioned the accuracy of the calibrated model output as it did not predict a "bow wave" of expenditure[39]. We consider it important to note that replacement models, using the typical industry benchmark lives, have predicted fairly significant "bow waves" of expenditure that have not eventuated. As noted in our original report (Fig 14), the calibrated repex model is still predicting a fairly significant increase in expenditure over historical levels. Furthermore, this increase may continue over the next 10 to 20 years (i.e. the model predicts a "bow wave" but it is far more gradual than suggested by the DNSPs).

Accuracy of calibration – 2009 and 2010 data

The DNSPs question the appropriateness of the calibration exercise as it did not account for 2009 actuals and the 2010 estimate[40]. As all DNSPs were expecting a significant increase in expenditure (and replacement volumes) in these years, they considered it important that the review should reflect this.

At the time of undertaking our original review, we only had estimates for 2009 and 2010. It was agreed with the AER that we would only rely upon audited figures for our analysis, and as such, we did not use the 2009 and 2010 figures in our calibration process.

Since our original review, audited figures for 2009 have been made available. In this report we have updated our analysis to account for 2009 data.

We are still in agreement with the AER however that the 2010 estimates should not be used.

3.3 Non-network

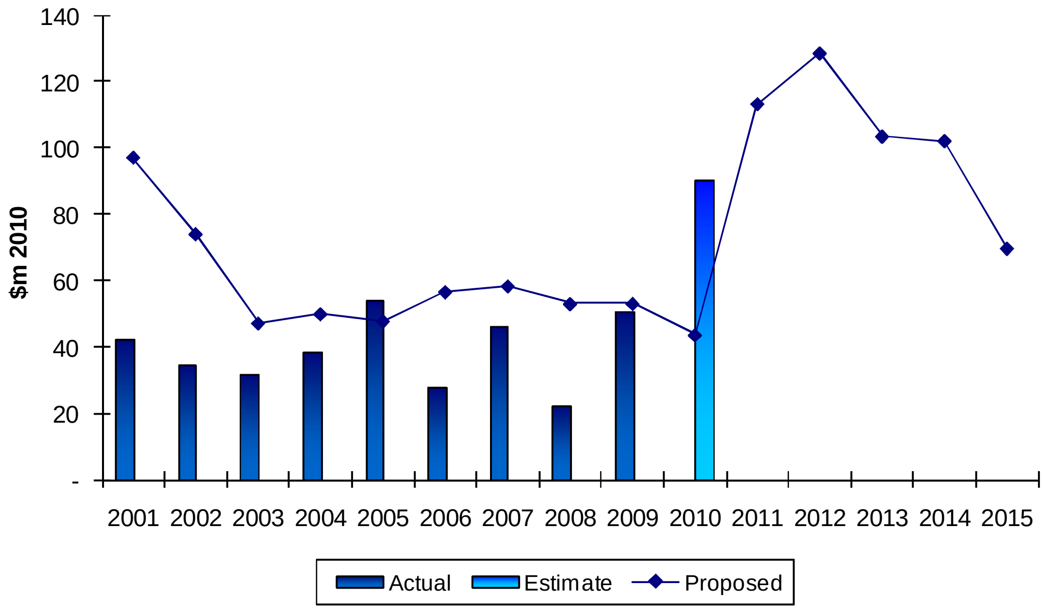
3.3.1 Non-network - general IT

The Victorian DNSPs are proposing an increase of 221% in non-network IT capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. The DNSPs estimate that non-network IT capital expenditure for the 2006-10 regulatory control period will be $238 million[41]. It is forecast that this will increase to $516 million in the 2011-15 regulatory control period. The forecast expenditures for the next regulatory control period are significantly greater than previous and current levels of expenditure, and do not appear to be in line with the overall trend in non-network IT capex.

[39] UED revised proposal, xxviii
[40] SP AusNet revised proposal, S6.7.2
[41] IT expenditure is forecast to increase significantly in the remaining years of the current control period.

The following chart provides a summary of non-network IT capex for the Victorian DNSPs, including subsequent resubmissions following from the Draft Determination.

Figure 9 - Victorian non-network IT capex



There is significant variability in the scale of the increases proposed by the DNSPs. United Energy is seeking the greatest level of increase at 548%, while Jemena is seeking the least at 22%.

Table 1 - Proposed non-network IT capex increases

DNSP	% increase[42]
CitiPower	196%
Jemena	22%
Powercor	427%
SP AusNet	130%
United Energy	548%
Victoria	**221%**

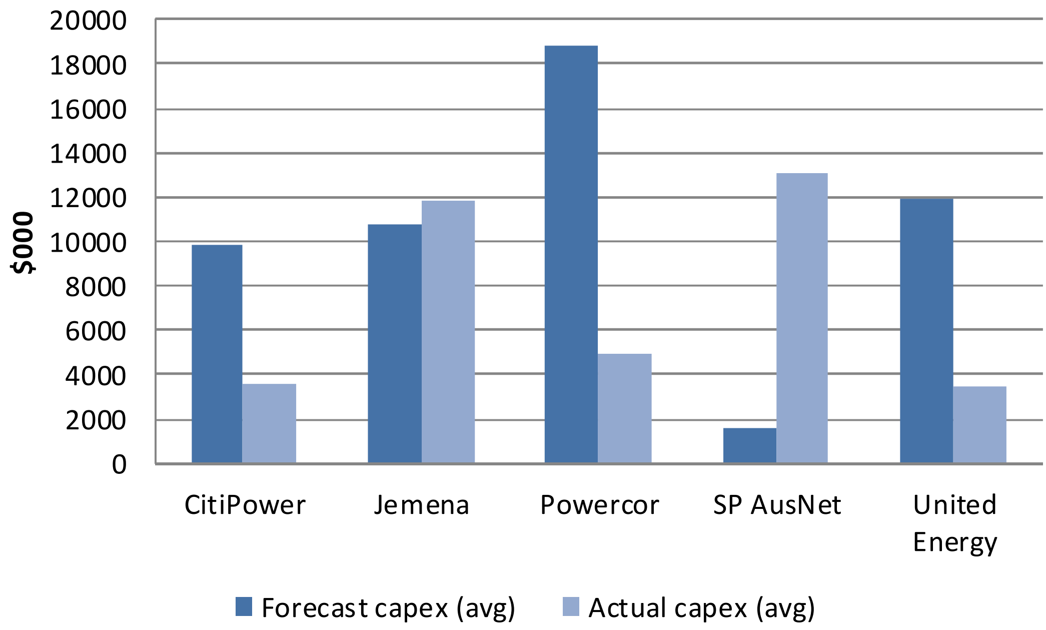
In the current regulatory control period, the DNSPs have generally over forecast their non-network IT capex requirements. The exception to this is SP AusNet who have significantly overspent on their original forecast[43] and Jemena who has marginally overspent against

[42] Increased based on comparison with most recent 4 years of actual non-network general IT capital expenditure.
[43] Jemena was overspent in 2006 and 2007, but is underspent in aggregate.

their forecast. Powercor forecast an expenditure that was 282% higher than average actual expenditure in the period.

The following chart shows the average annual capex proposed by the DNSPs for the current control period as well as the current period actuals (4 years).

Figure 10 - DNSP average non-network IT proposed and actual capex ($000)

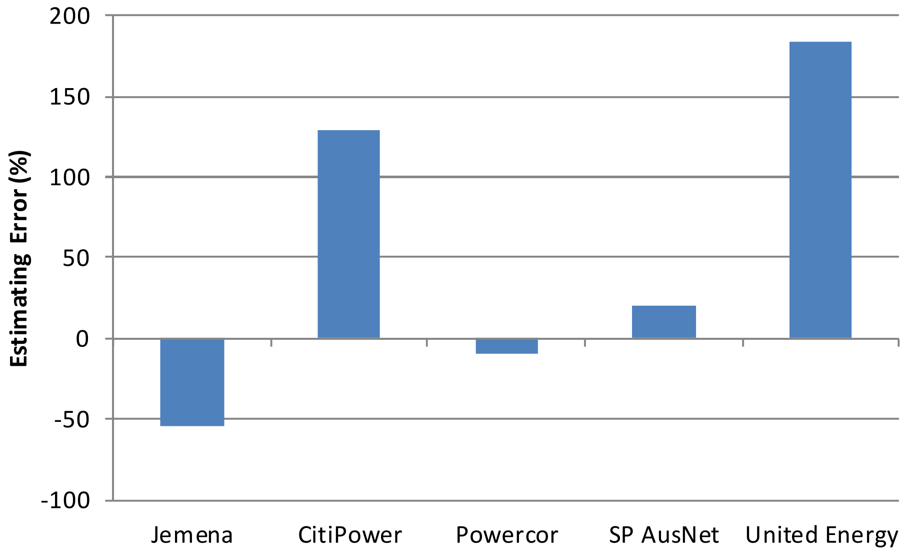


The remaining year of the current regulatory control period is 2010. The calendar year 2009 is now complete and the audit and reporting of this years' expenditures were provided to the AER in early 2010.

Although these estimates are not the focus of this review they are important as they set the starting point or base years for considering the next Regulatory Control Period.

Nuttall Consulting has reviewed the accuracy of the IT expenditure estimates provided by the DNSPs for 2009. The estimates for 2009 provided by the DNSPs in November 2009 are compared with the actual expenditures provided by the DNSPs in early 2010. The results of this review are provided in the following chart.

Figure 11 - 2009 DNSP Estimating Accuracy



The above chart highlights that there is a high level of inaccuracy in the estimating of capex in the remaining years of a Regulatory Control Period. Powercor provided the most accurate estimate for the 2009 IT expenditure with a 10% variation. United Energy provided the most inaccurate estimate of expenditure with a 184% variation from actual.

If we consider the absolute error in terms of 2009 forecasting, the average for Victoria is 79%. This is a very large forecasting error considering the relatively short timeframes involved. The problems with forecasting IT expenditure both in the longer (e.g. 5 year) and shorter (e.g. 3 months) terms have been considered by Nuttall Consulting. The high level of inaccuracy suggests a systemic problem with the forecasting processes that have been used to develop the forecasts for the next regulatory period.

3.3.1.1 Industry overview

The following section provides an overview of IT industry factors that are relevant to the review of the DNSP IT capex forecasts.

Data Centre Consolidation

The physical space in which to host the IT infrastructure consisting of compute, connectivity and storage are expensive to procure, build and/or lease. This is due to the large power requirements of modern processors and the need to provide redundant power and cooling to all these systems. For any large organisation (like DNSPs) the data centre costs are a significant overhead. As a result, many organisations have been aggressively "consolidating" data centres to save significant costs.

Typically data centre consolidation projects, have resulted in at least a 1:2 data centre consolidation ratio. As an example, the US Navy's Cyber Asset Reduction and Security (CARS) project is on target to reduce the Navy's IT server infrastructure by 51%. Since 2007, the National Australia Bank (NAB) has been on a mission to become carbon neutral by September 2010, including having 50% of the power it requires for its data centre to cogeneration and tri-generation techniques.

In a period when most organisations are actively decreasing their data centre space, most of the DNSPs have actually increased their data centre space. The reason typically stated was as a result of AMI, which require a separate highly isolated environment, where the development of the AMI systems could not impact the DNSPs production system.

Most of the DNSPs intend to consolidate the current production systems, that are not decommissioned by AMI, to the new AMI data centre at some future date.

IT Agility

Information Technology presents a number of challenges to the DNSPs due to the rapid advancement of technology. The DNSPs operate in a regulatory and commercial environment that is also subject to change. Changes of ownership, evolving regulatory requirements and new obligations (e.g. the requirement to deliver AMI) require the DNSPs to be adaptable and flexible. Therefore to support its business, the IT systems need to be flexible or agile.

Nuttall Consulting's original report concluded that all of the DNSPs were not sufficiently agile in the design and operation of their IT environment. Each of the DNSPs responded to the AER Draft Determination stating that their systems were sufficiently agile. In this report, Nuttall Consulting provides further analysis and conclusions in the following sections on the agility of the DNSPs, based upon the additional information that was provided.

Nuttall Consulting believes that the options available to the DNSPs to deliver new applications, to upgrade and decommission existing applications, and manage the supporting IT infrastructure are complex. Individual choices have ramifications for many years after the actual decision point. With the benefit of hindsight, some decisions may have been inappropriate, but it might be just too cost prohibitive to remediate. These are the fundamental challenges of IT infrastructure management, you must plan for the future in an environment where the actual requirements are evolving, whilst dealing with the consequences of the decisions of the past.

IT Infrastructure Agility

IT agility is defined as the capability to rapidly and cost effectively adapt to change. In terms of IT infrastructure it refers to the ability to rapidly deploy in the key areas of Compute, Storage and Connectivity (Networking).

Nuttall Consulting believes that the DNSPs have a series of common challenges in designing, building and meeting their internal business requirements. The evolution of technology is constant but in recent years a number of technologies have become mainstream for businesses (including DNSPs) evolving to deliver faster and lower cost IT as historic bottlenecks have been removed. These include:

- The rapid adoption of 64 Bit computing has practically eliminated the "memory bottleneck" common with large 32 bit applications like CIS, CRM and OLAP systems.

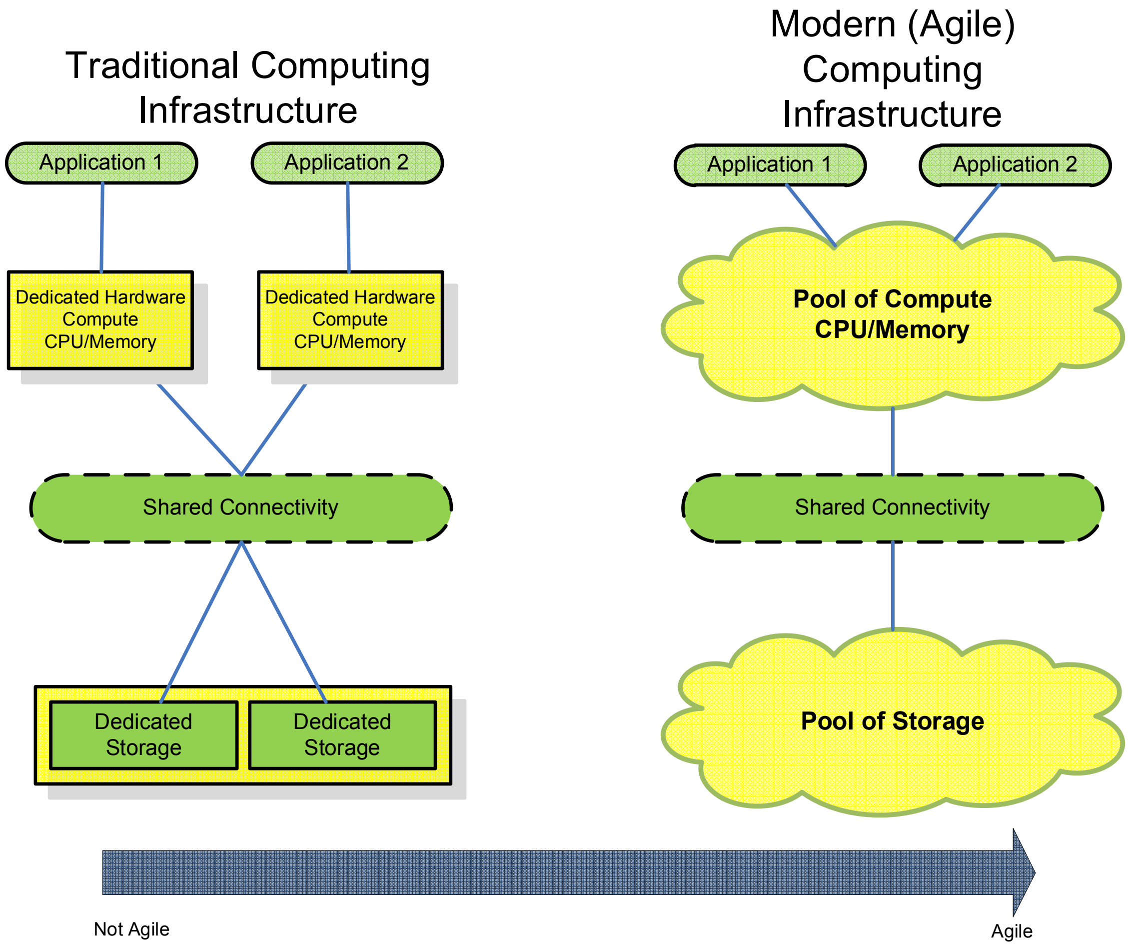
- The rapid advancement of CPU technology (under Moore's Law[44] the number of transistors that can be placed inexpensively on an integrated circuit will double every two years) means that CPU bottlenecks on modern hardware are almost always eliminated. It also allows more consolidation of Compute resources, so that workloads can be run across a smaller and more compact number of physical systems.
- The adoption of much cheaper SATA disk drives, supplemented with a small number of SSD (Solid State Disk) or large memory caches, delivers identical or substantially faster performance than traditional FC (Fibre Channel) disk arrays at a lower price. The rise of simpler, cheaper and easier to administer NAS (Network Attached Storage) for many workloads, generate significant CAPEX and OPEX saving opportunities as well.

Technologies and approaches such as a "Virtualisation", "Software as a Service", "Service Orientated Architecture", "Thin Provisioning", "Storage Virtualisation", and "Infrastructure as a Service" are components in the transformation toward IT infrastructure agility, commonly described as "Cloud Computing" or sometimes "Elastic Computing". Fundamentally, it means that the IT infrastructure components (compute, connectivity and storage) can be purchased, delivered and installed rapidly to meet overall computing needs. This is in comparison to the more traditional approach of ad-hoc/tactical/quick fixes for poor performing applications or for capacity issues on a project-by-project basis with little long term planning.

The following figure provides an illustration of the above approach.

[44] Noting that this is an observation, rather than a law or proven theorem.

Figure 12 - Computing infrastructure



Traditional approaches to IT, lead to dedicated infrastructure that is based upon worse-case scenarios that typically or rarely ever happen. As the individual application and its dedicated infrastructure ages, functionality is slowly moved to other applications, which rely upon other (often duplicated) infrastructure. However, the original infrastructure will become less utilised, but typically can be reused or downscaled to reduce space, cooling and power required. In addition, relocating workloads to more modern hardware is severely restricted or often impossible. As a result, the infrastructure is much larger than it needs to be and is also often very underutilised. This translates into significant higher capital and operating costs, but most importantly, constrains the ability for IT to respond and deliver the business needs.

The first step towards complete IT infrastructure agility, is the adoption of virtualisation which creates the initial "pool" of computing (CPU/memory) independent of the underlying hardware. This in turn delivers further benefits of "portable machines" that can be moved between different hardware. Most DNSPs have already adopted some virtualisation functionality, but when responding to Nuttall Consulting questions none of the DNSPs could articulate/describe the reasons behind the current level of adoption of virtualisation.

Nuttall Consulting believes some of the benefits available to the DNSPs through a more fuller adoption of virtualisation include:

- **Lower Cost - High Availability** – individual hardware can fail, but the “machines” will just “reboot” on another set of hardware. Some virtualisation products allow the machine to run concurrently on two independent pieces of hardware; preventing any outages as a result of single hardware failure. This is considered superior to the more traditional clustering approaches.
- **Lower Cost - Disaster Recovery** – in advent of a major site disaster the machines can be moved (provided the underlying storage has been replicated) and business can return to normal.
- **Less Power Usage** – as machines become less utilised they can be consolidated to more highly utilised hardware. The old hardware can be automatically powered off. In advent that requirements increase (e.g. a large batch job), the machine can be moved to less utilised hardware in real-time.

Whilst all of these benefits can be accomplished manually, some only with significant business interruption, the virtualisation products allow this to be done automatically, delivering large TCO (Total Cost of Ownership) savings for both CAPEX (hardware costs can be deferred or even eliminated) and OPEX (less resources are required). In reviewing the IT Strategies of the DNSPs and their responses to the Draft Determination, Nuttall Consulting believes that the DNSPs are not forecasting reasonable increases to the level of adoption of virtualisation technology. Whilst the exact level of adoption of virtualisation, varied between DNSPs, overall the DNSPs have adopted minimal to low levels of virtualisation.

In responses to questions and in their submissions most DNSPs reported, that they only “virtualised” where it made sense or when support was available from the vendor. Nuttall Consulting considers that the modern virtualisation products today are perfectly capable of virtualising even the most CPU and database intensive applications. As an example, the leading VMware product, nearly doubles its consolidation capability every 18 months via a simple software upgrade. In Nuttall Consulting’s experience support concerns can be adequately dealt with via individual negotiation with the software vendor. Also, very few software vendors certify specific commodity hardware like a Dell or HP server. Instead they specify a configuration (CPU type, amount of memory, disk requirements) that can be adequately emulated by the virtualisation product.

The concept of virtualisation can be taken further. “Virtual Data Centre” or “Multi-Tenanted Data Centres” permit complete isolation of infrastructure and applications into “Zones” or “Containers” that are as secure as physical separation, whilst being much more flexible and cheaper to implement and manage, without the need to procure additional data centre space or even complete data centres. Since AMI required the development of new systems, and whilst the existing production system needed to largely be left alone, the DNSPs typically chose to deploy to new physical data centres. Whilst Virtual Data Centres may have represented too great a step at present, the possibility does exist that DNSPs could have achieved the isolation required of AMI “virtually”. Likewise, in cases, where data centre capacity had been exceeded, or was approaching capacity or where there was a contractual requirement to relocate, a fully virtualised environment could be relocated to a new facility, very simply and quickly, allowing for the original data centre facility to be closed down.

Nuttall Consulting believes that future events, such as change of government policy, regulations and industry structure will continue to occur, but cannot be predicted with any reasonable level of certainty. The rapid evolving nature of IT technology, coupled with the evolving requirements during the regulatory period and how these may impact actual IT costs are difficult for the DNSPs to forecast. Historically, the DNSP have been very poor in the forecasts of their IT expenditure compared to the audited actual spends.

In reviewing the IT Strategies of the DNSPs, including the subsequent information made available in response to Nuttall Consulting's original report, Nuttall Consulting was surprised that concepts such as "doing more with less", "reducing Total Cost of Ownership", "consolidation of resources" and "reducing space and power" were absent from many of the discussions within the IT strategies. An adequate strategy towards "Cloud Computing", 'Elastic Computing" and "Infrastructure as A Service" was not evident in any of the DNSP submissions.

Nuttall Consulting concludes that the DNSPs have a vision for the IT infrastructure that does not reflect current, and recognise evolving, best practice. This results in proposed expenditures containing IT costs that do not maximise the utilisation of compute and storage infrastructure in an agile manner.

Capacity Planning

One of the long term cost benefits of implementing IT agility is better capacity planning. Since capacity is consumed across the entire infrastructure, not individual systems, the utilisation and requirements are larger and more easily and reliability trended. Infrastructure that is close to fully utilised can be easily expanded or reduced as required. Ultimately, this leads to the situation where IT resources such as compute and storage could be "rented" instead of being a capital purchase. Whilst it would not be reasonable to expect the DNSPs to have adopted these approaches at this stage, such capability is already available in the market place via such vendors as Google and Amazon.

3.3.2 Historical underspend

As described above, the DNSPs forecasts of IT capex have proven to be highly inaccurate. A number of the DNSPs identified the AMI project as contributing to underspend in the current period. However, this does not explain all of the underspend in the current period or in the previous regulatory period.

Nuttall Consulting notes that there have historically been a number of factors that have contributed to the delay or deferral of IT projects. For example; CitiPower and Powercor identified a number of project deferrals that contributed to an expenditure underspend. These included[45]:

- delays to "lead-in" projects such as the GIS[46] and OMS[47] migrations and SCADA system replacement;
- delays due to the structure, resourcing and management of the service provider's offshore development program;
- underestimation of the complexity of the project by the service provider; and
- underestimation of the level of testing required.

Nuttall Consulting accepts that the deferral causes identified by the DNSPs may reasonably have contributed to actual expenditure being less than was originally proposed. The deferral causes identified above support the Nuttall Consulting view that the forecasting processes do not adequately recognise or account for external and internal project delay mechanisms that may impact the ability to deliver the forecast IT capex amounts.

The DNSPs have provided no evidence to suggest that the historical IT expenditures resulted in an imprudent outcome. As there is no discernible evidence of failure to invest adequately and/or any adverse consequences we must assume that the resultant levels of expenditure were prudent.

Based on the above, it is reasonable to accept that the historical levels of IT capex incurred by the DNSPs are both prudent and efficient.

Looking at the forecast IT capital expenditure proposed by the DNSPs for the next regulatory control period we see that it is significantly greater than the level of capital expenditure that has been incurred in the previous 9 years[48].

When we consider the IT capex that was forecast for the current Regulatory Control Period we can also see that the overall DNSP forecast for the current period is much higher than the actual level of expenditure.

The DNSPs have identified that their forecasts for the current regulatory control period did not take into account the impact of unforeseen project deferrals. Nuttall Consulting considers that this lack of account of project deferrals is a systemic problem with the capex forecasting process.

Capital projects, particularly IT projects, are often complex and require many interactions with third parties. These interactions can include other related projects, resources providers and contractors, hardware and software vendors, system wide impacts, etc. While it is not always possible to identify which of these interactions may result in a delay to a project, it is good practice to make a reasonable allowance for these delays.

---

45 Note: although these projects are categorised in the SCADA and Network Control expenditure category, they are essentially IT projects and interact with other IT systems.

46 Graphical Information System

47 Outage Management System

48 2001 to 2009 inclusive.

The information provided by the DNSPs show that project delays have not been sufficiently allowed for in the planning processes.

Nuttall Consulting considers that recognition of the potential impacts of project delays in forecasting and planning is good electricity industry practice. A commonly accepted definition of good electricity industry practice is the exercise of that degree of skill, diligence, prudence and foresight reasonably expected of a distribution business working under the prevailing conditions consistent with applicable regulatory, service, safety and environmental objectives.

The DNSPs were requested by the AER to provide details where the policies, strategies and procedures provided to support their submission have changed during the current regulatory period and the effects of these changes[49]. The DNSP responses to this request did not identify any changes to the policies, procedures or strategies for expenditure forecasting. On this basis, we must assume that the forecasting processes and procedures utilised by the DNSPs have not changed and that allowances for delays in capital projects have not been adequately accounted for.

To summarise the above;

- the historical planning processes and procedures used by the DNSPs do not adequately account for interactions with other projects and third parties and have resulted in forecasts greater than actual expenditure
- the DNSPs have not identified any changes to the historical planning processes and procedures
- the IT capex forecast for the next regulatory control period do not adequately account for interactions with other projects and third parties that may result in delays
- if allowances are made for interactions with other projects and third parties, the resultant expenditure would be lower than that proposed by the DNSPs.

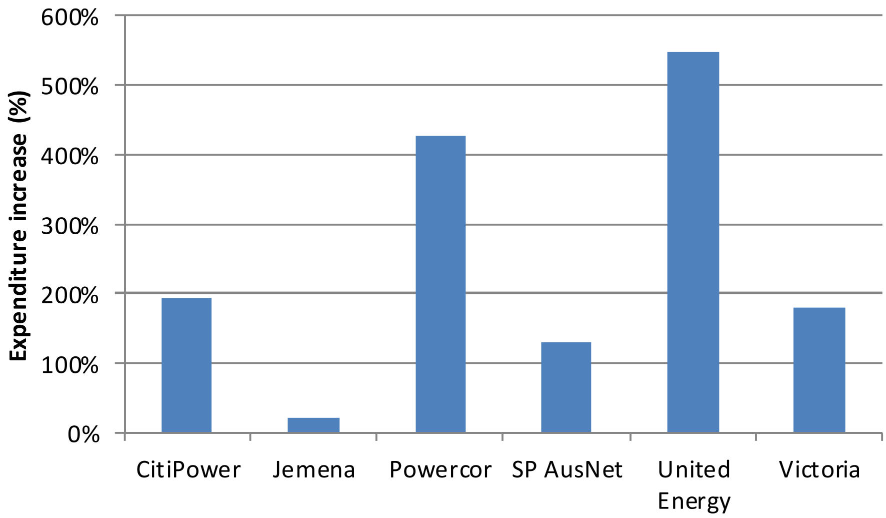
3.3.3 Forecast increases

On average the Victorian DNSPs are proposing to increase IT expenditure by 180% from current levels.

The following chart provides a breakdown of the proposed increases in IT capex for each DNSP. The increases are presented in percentage terms based on the actual expenditures in the current regulatory period.

[49] Regulatory Information Notice Under Division 4 Of Part 3 Of The National Electricity (Victoria) Law Issued By The Australian Energy Regulator, Section 3.1 – 14/10/2009.

Figure 13 – IT capex increases



With the exception of Jemena, all of the DNSPs are proposing to double, or more, their level of IT expenditure. This doubling of expenditures is inconsistent with the historical trend in expenditures. Jemena is proposing a 22% increase from current levels of expenditure.

3.3.4 Approach

Each DNSP provided detailed cost justification and detailed documentation for each of their proposed IT projects. Many also included detailed third-party (independent) assessments of their projects.

Nuttall Consulting does not dispute the DNSPs justifications for individual IT capital projects; in general these were comprehensive and appeared to be individually prudent and efficient. However, these individual project costs are made on the basis of very specific requirements related to a specific IT project. As a result, components could be duplicated, over-specified and/or incompatible with the rest of the IT environment, all of which would reduce flexibility, eliminate reuse/sharing of expensive components and lead to a more complex environment to manage & support. Nuttall Consulting concludes that all the DNSPs have a relatively inflexible (non-agile) IT infrastructure and are not forecasting steps to adequately address this.

Noting also the historical precedent of being unable to accurately forecast IT expenditure and the impact of internal and external project delays, Nuttall Consulting recommends that the AER reject the Non-Network IT Capital expenditure from all of the DNSPs as it is not prudent or efficient.

Nuttall Consulting recommends that a new forecast be substituted, based upon a 67% allocation of the individual DNSP five year forecasts.

This allocation is based upon three times the average annual proposed capex expenditure for each of the DNSPs. Nuttall Consulting considers that this allowance errs in favour of the DNSPs as:

- the allowance is greater than the long term historical IT expenditure trends for each DNSP
- recognises the overall level of proposed project expenditures in the next regulatory period rather than relying on historical expenditures alone.

The exception to the above approach is the proposed treatment of Jemena. Nuttall Consulting recommends that the Jemena proposed IT capex be allowed in full for the following reasons:

- the Jemena proposed IT capex for the current period is significantly more accurate that the other DNSPs
- the Jemena proposed IT capex for the next period is much more closely aligned with current levels of expenditure than the other DNSPs.

Summary capex recommendations

The following table provides the recommended Non-network general IT capex for the Victorian DNSPs.

Table 2 - Recommended non-network general IT capex

	$millions (2010)				
	2011	2012	2013	2014	2015
CitiPower – proposed	9.9	9.0	8.9	14.0	11.1
CitiPower – recommended	6.4	6.4	6.4	6.4	6.4
Powercor – proposed	26.5	23.1	21.0	32.9	26.3
Powercor – recommended	15.6	15.6	15.6	15.6	15.6
Jemena – proposed	20.3	21.0	17.2	6.6	6.8
Jemena – recommended	20.3	21.0	17.2	6.6	6.8
SP AusNet – proposed	32.8	38.6	28.6	32.4	18.1
SP AusNet – recommended	18.0	18.0	18.0	18.0	18.0
United Energy – proposed	23.5	36.5	27.6	16.0	7.2
United Energy – recommended	13.3	13.3	13.3	13.3	13.3

4 Appendix A - CitiPower review

The CitiPower and Powercor franchises are both owned by the same investment group and share management and executive services. The CitiPower and Powercor proposals share a great deal in common including structure and significant areas of content. There are also areas of differentiation between the proposals; specifically in relation to individual projects and programs.

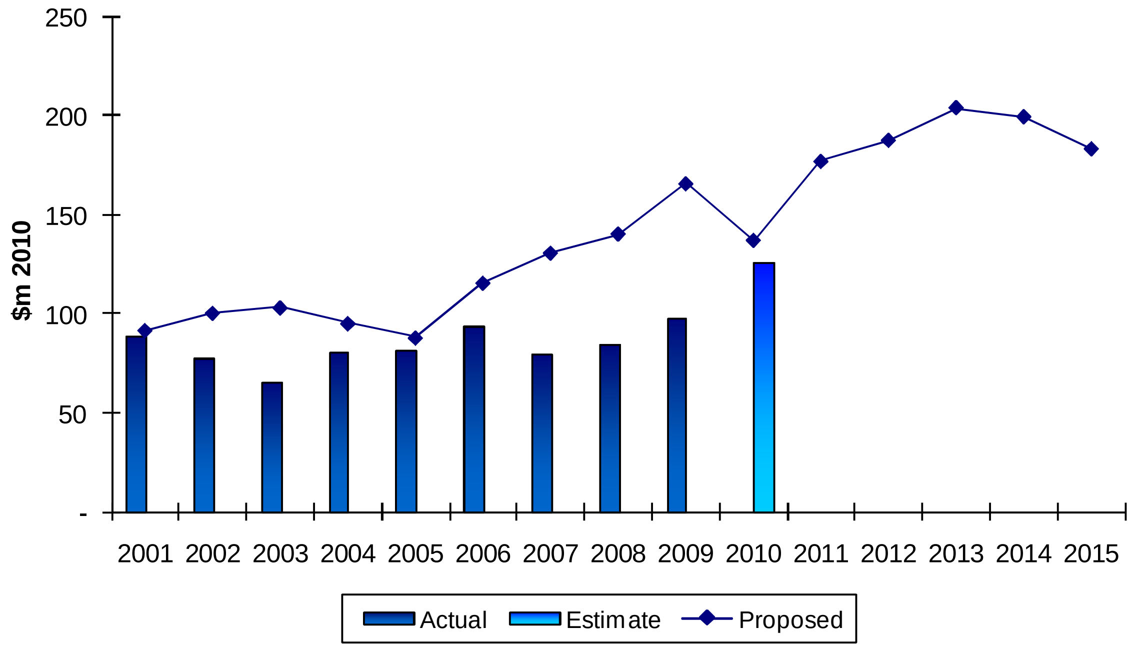
4.1 Overall capex

Overall capex is forecast to increase by 113% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement, reliability and quality maintained and new connections.

The following chart provides a summary of the overall capex figures for CitiPower. Key aspects of this chart include:

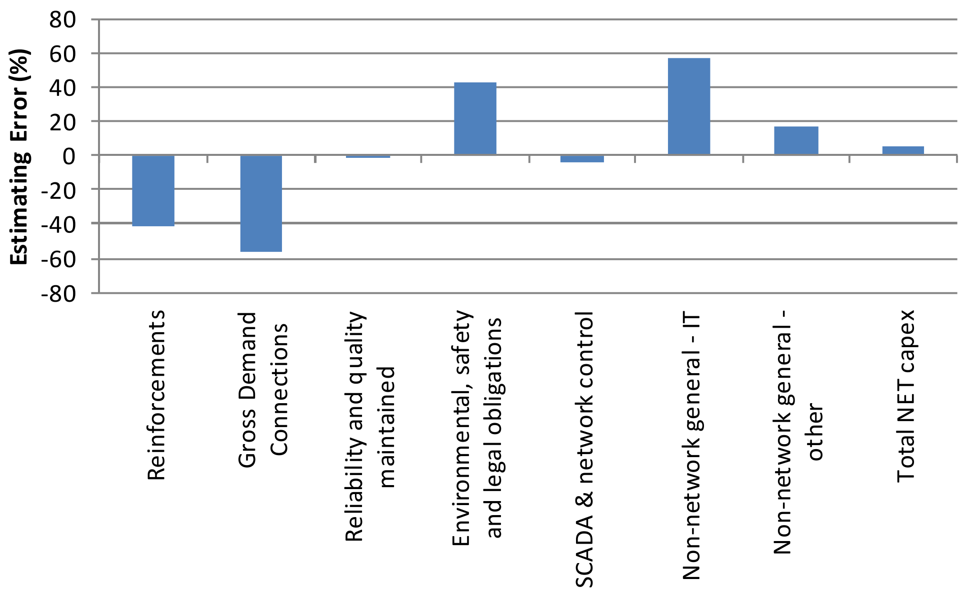
- CitiPower has consistently spent less than they proposed in the 2001 and 2006 EDPRs
- CitiPower is proposing a future level of capex that is significantly higher than the historical levels of expenditure and is not consistent with the historical trend in capex.

Figure 14 - CitiPower Capex Summary



The following chart considers the accuracy of the November 2009 CitiPower proposal compared with the actual 2009 audited data.

Figure 15 – 2009 estimating accuracy



The estimated figures for 2009 were provided by the DNSPs in November 2009; two months prior to the completion of the financial period. The actual figures for 2009 have been subject to audit and were provided to the AER in early 2010.

The overall accuracy of the 2009 CitiPower forecasts was reasonable with actual net capex only varying by 5% from that estimated. However, the above chart highlights that the

DNSP forecasts at the individual capex category show significant levels of variation from the actual 2009 capex. This highlights a concern with the forecasting processes utilised by CitiPower and calls into question the veracity of the forecasts for 2010 and the next regulatory control period of 2011 to 2015.

When considered in conjunction with the historical levels of forecasting inaccuracy as described in section 2.2, Nuttall Consulting observes that the processes used by CitiPower to forecast expenditure in this category have not produced reliable forecasts.

Nuttall Consulting requested CitiPower to provide an explanation of the methodology applied to determine the 2009 and 2010 estimates and to explain the relationship of this methodology to the methodology used to produce the 2011-2015 forecasts[50]. CitiPower did not identify any changes or variations between the forecasting methodologies.

This raises a concern relating to the accuracy of the DNSP forecasts for the next control period as the methodologies used to create these forecasts are the same methodologies that have produced the previous inaccurate estimates and forecasts.

To be clear, although the above information provides sound reason to question the accuracy of the DNSP forecasts, Nuttall Consulting has not taken this as proof that the forecasts do not meet the capital expenditure objectives. The Nuttall Consulting review of the forecasts has been undertaken on a case-by-case basis with due consideration of the information provided by the DNSPs.

4.2 Reinforcement

CitiPower's revised proposal makes a number of criticisms of the process and findings of Nuttall Consulting's original review of CitiPower's reinforcement expenditure.

General criticisms of the process we applied, which are similar between DNSPs, have been discussed in Section 3.1 above. This section deals with matters more specific to our findings on CitiPower's reinforcement forecasting methodology and our review of a number of reinforcement projects. Importantly, this section includes revised project probabilities, which will be important for the AER in its considerations of the appropriate reinforcement allowance.

4.2.1 Load duration curve assumptions

Nuttall Consulting considered that the need for the reinforcement projects may be overstated due to assumptions associated with the energy at risk calculations that supported the need and timing for projects, and specifically the load profile assumed in these calculations. In this regard, CitiPower is using a load profile based upon the average profile over 2001 to 2005.

This view related to the fact that the Victorian load is becoming more "peaky" as demand growth outstrips energy growth. This peakiness may tend to reduce the energy at risk (and associated value of the expected energy at risk) as the load at risk increases in the

[50] Nuttall Consulting information request – 18 January 2010.

future. Nuttall Consulting undertook some trend analysis of historical load profiles that it considered justified this position.

CitiPower has disagreed with Nuttall Consulting's view and has supplied a report by SKM to support its view. The following discusses the matters raised in the SKM report.

The SKM report considered CitiPower's assumptions were reasonable, based upon analysis of the sensitivity of a notional project timing with different historical load profiles.

Nuttall Consulting has reviewed this analysis and disagrees that it shows that our views are not valid. The SKM analysis only assesses project timing against 3 years: 2007/08, 08/09, and 09/10 and, importantly, assumes a 5% growth rate. We have a number of concerns with this analysis.

We consider that the results support our view that project timing will be sensitive to load profile assumptions, with results showing a variation of 1 year depending on the profile assumed. Moreover, we consider that SKM's assumption of load growth of 5% will reduce timing sensitivity over lower growth rates. On this matter, it is noted that 5% is higher than CitiPower's forecast growth. As such, it is not clear why this has been chosen and why the sensitivity to the load growth assumption is not discussed.

Furthermore, while we can see that the SKM results show a sensitivity in timing, they do not clearly show whether a trend is up or down or immaterial. This was the important point in our analysis. For example, they do not compare the average profile presently used by CitiPower against the three load profiles selected. It is not clear why this has not been undertaken.

We also note that this report indicates that Nuttall Consulting's findings are fundamentally flawed as our analysis places great weight on the top 1% of the load profile. But this is not the case; our analysis considered scenarios from 1% to 20%, with all showing a material trending decline in energy at risk (see Fig 144 in the original report).

In our view, SKM should have undertaken some form of trend analysis of historical load profiles, or at least assessed our trend analysis, to refute our position. This should have more transparently shown the sensitivity of its findings to the load growth assumptions, and ideally used some "real world" examples from the CitiPower program. In our view, we do not consider that the analysis as it stands has clearly demonstrated that the CitiPower assumptions are reasonable.

All that said, it is worth noting that in Nuttall Consulting's probabilistic assessment, our view on the load profile assumptions have a low sensitivity on the project probabilities.

We do note that the SKM report also considered CitiPower's assumptions underpinning its expected energy at risk (EEAR) calculations, and considered these to understate actual expected energy at risk. This view is based upon:

- 50% PoE – which may understate risks associated with worse temp conditions – accept this may be the case, but not clear how material
- not allowing for other equipment failures

- not allowing for more minor transformer failures.

While we do not disagree with the points above, we do not consider that this means that the overall process is understating risks. For example, although SKM has undertaken some benchmarking that shows the major failure rates and repair times are in accordance with industry levels. It has not undertaken any analysis of historical data to see whether there is any case that these may still overstate risks. We do not consider that there is anything that the industry is not aware of in the matters noted by SKM, and as such, it seems reasonable to assume that the industry is satisfied that these risks are either immaterial or allowed for in the existing assumptions.

This is different from the load profile issue, where the load profile assumption should be being made to reasonably reflect the most likely conditions in the future i.e. the assumptions on the PoE, failure rate, and repair time may be relatively static in the medium term, but the load profile assumptions would be dynamic (undergoing an annual review and updating).

4.2.2 Project review updates

The following projects were assessed as part of Nuttall Consulting's review of CitiPower's reinforcement expenditure:

1. CBD security project
2. Metro 2012 project
3. 11kV CBD Feeder Works
4. 3rd BQ transformer
5. 3rd SB transformer
6. Docklands Area Substation Upgrade

In CitiPower's revised proposal it has removed the "3rd transformer at SB" project. For the remaining projects, it has disagreed with our findings. The following sections discuss our reassessment of these projects, based upon CitiPower's revised proposal.

It is also important to note that we understand that the AER will largely be accepting CitiPower's demand forecast. In our original review we had allowed for a reduction in the demand forecast, based upon advice from the AER. In the discussions below and the revised project probabilities, we have not allowed for any reductions from CitiPower's demand forecast. This has resulted in increased project probabilities in some cases.

4.2.2.1 CBD security project and Metro 2012 project

In our original report, our review of the CBD security project and Metro 2012 project had been treated differently to the other projects discussed below, and was not included in our probabilistic assessment. This treatment has been maintained in this revised report.

The different treatment of these two projects was because both of these projects have been through an external approval process: the CBD security through the ESC detailed review process and the major portion of the Metro 2012 project through the public regulatory test. As such, we did not consider the need for these two projects in our review. Instead, we only reviewed the justification for the cost increases from the previous amounts that have been proposed by CitiPower. In real terms, these increases are approximately 10% for the CBD security project and 20% for the Metro 2012 project.

For both projects, we did not accept the increase proposed by CitiPower, and considered that the allowance should reflect the previously approved costs. This view was largely based upon our view of the lack of evidence provided by CitiPower to support the increases. This followed a request for more information that did not result in any meaningful additional information to support the increases.

We also noted that if costs were to be accepted then CitiPower would need to provide detailed cost build ups, clearly indicating where the costs had increased and basis for the increase. CitiPower should also be required to include evidence of its own analysis that it has undertaken to arrive at the view that these can be considered a reasonable estimate of efficient costs.

We also noted concerns that it was not clear whether the higher costs (plus some other concerns associated with the relationship of the need with other projects) would still result in the projects passing the regulatory test; however this was not a major factor in our recommendation.

CitiPower's revised proposal allows for the full reinstatement of its increased costs for these two projects. To support this position CitiPower has provided further information to address our concerns over the limited evidence provided in our original review[51]. This information covers the following:

- The main variation in the costs is due to increases in cable route costs and building refurbishment costs.
- For the cable and substation refurbishment costs, further details have been provided that indicate where the specific differences have occurred between the previously approved costs and those in the revised proposal, and the basis for the changes.
- For the cable costs, details are provided of a market tender process conducted by CitiPower for a significant portion of the cable works, which it considers demonstrates that the cost can be considered to be efficient[52]. Some discussion is also provided of how these tender costs have been used to develop the cable forecast.
- For the refurbishment costs, details are provided of an independent review of refurbishment options for one of the substations (VM)[53] and civil design brief for another (W)[54]. CitiPower considers that these support the need for increased costs.

[51] Appendix 9.1, CitiPower revised proposal
[52] Attachment 259, CitiPower revised proposal – confidential board memo, dated May 2010
[53] Attachment 256, CitiPower revised proposal – Maunsell report
[54] Attachment 258, CitiPower revised proposal – PNS report

It is also noted that firm quotes, based upon a market tender process, appear to have been received for the works at two of the substations – although, details of the tender process and quotes have not been provided.

- Details are also provided on the staging of the projects, which differs from the approved projects. Details are also provided on the implications of the cost increases on regulatory test findings, of which CitiPower considers the projects would still pass the regulatory test as the value of customer reliability has increased significantly since the test was performed.

Nuttall Consulting has reviewed the additional information provided by CitiPower and considered the matters raised in CitiPower's revised proposal. Overall we consider that this addresses our information concerns expressed in our original report. Although we note that information on the tender process associated with the substation reinforcements is lacking, on balance, we are satisfied that significant cost increases above the approved costs are most likely warranted. Furthermore, given the explanation for the basis for the increases and the competitive tender process that has lead to much of the project costs, we are satisfied that the costs in the revised proposal can be considered a reasonable estimate.

4.2.2.2 11 kV CBD Feeder Works

The 11 kV CBD feeder works project includes a large number of HV feeder augmentations. This group of works was assessed as part of Nuttall Consulting's probabilistic analysis of CitiPower's reinforcement needs. Based upon our original review, this project was given a low probability (33%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that:

- Only approximately half of the works (by expenditure) were clearly required to comply with the enhanced CBD security obligations in the Distribution Code; however, it was not clear whether the timing was still justified, via the regulatory test, if these costs were allowed for.
- For the remaining half, we considered that these works were driven by capacity needs. Our analysis of relevant energy at risk indicated that the economic timing for this portion should be deferred.
- We also considered that there was a reasonable possibility that a lower cost alternative may be found to be the preferred option – we noted the option of developing an existing switching station, Waratah Place (W), into a 66/11 kV substation.

The CitiPower revised proposal does not accept our views and considers that the project should be viewed as 100% required as originally proposed. Additional information has been provided by Citipower to support its position[55].

[55] Table 9.5 of CitiPower's Revised Proposal and the revised 11 kV CBD Feeder Works Project Network Planning Proposal attached to CitiPower's Revised Regulatory Proposal (Attachment 161)

Nuttall Consulting has considered CitiPower's contention in its revised regulatory proposal that the 11 kV CBD Feeder Works project is 100% required in the forthcoming regulatory period. A review has subsequently been performed on the additional information.

With regard to code obligations associated with the enhanced CBD security portion, we note that CitiPower does not discuss our contention that the costs associated with these works may result in the economic timing being deferred[56]. Rather the proposal notes that the Distribution Code obligates CitiPower to undertake the security elements of the works. Nuttall Consulting considers that the AER is in the best position to assess whether this is the appropriate interpretation across all of CitiPower's obligations. In what follows, we have assumed CitiPower are obligated to undertake the works associated with the enhanced security requirements, which we accept is suggested by the wording of the clauses in the Code that specifically relate to the enhanced CBD security project.

It is noted that the 11 kV works proposed by CitiPower differ from those presented in the ESCV's final decision on the CBD security project. Further, we still consider that only about half of the proposed works will ensure CitiPower meets its obligations under the final decision of the ESCV and the Distribution Code to provide a secure supply to the Melbourne CBD. The other works are driven by system capacity and energy at risk considerations alone. These capacity driven works are not required to provide a secure CBD supply and should not be considered as being mandated by the ESCV. We consider that the capacity driven works should be considered independently and this review has looked at the security of supply driven and capacity driven project groups separately. Our view appears to be supported by CitiPower's additional information, which also discusses the works in terms of the parts associated with enhanced security and those associated with additional capacity.

Security of Supply Driven Projects

As indicated by CitiPower in their revised Network Planning Proposal the group of projects proposed to ensure CitiPower meets its obligation to provide a secure supply to the Melbourne CBD are as follows:

- 6 feeders between JA & LQ (30 MV.A) - $3.92 million
- 5 feeders between JA & VM (25 MV.A) - $2.91 million
- 3 feeders between SB & LQ (20 MV.A) - $4.31 million
- 5 feeders between FR & MP (25 MV.A) - $3.53 million

The total cost of this group of projects is $14.67 million.

As noted above, CitiPower are proposing a different group of feeder projects from those presented in Appendix B.1.8 of the final decision of the ESCV, and are arguing that these projects are the preferred option because they have a lower net present value cost than the originally proposed projects.

[56] It is noted that the information indicates that the works will still be "NPV positive" due to VCR increases. However, we do not disagree with this view. The issue we were referring to, with regard to the regulatory test, is whether the timing of the option will maximise the NPV i.e. have the greatest positive NPV.

The revised CitiPower information indicates the difference in cost and NV between the two alternatives, which supports its view that the proposed works should be a lowest cost than its original set of feeder works. However, we still do not consider that Citipower has adequately demonstrated that the range of options it has considered were reasonable and comprehensive. In particular, we still consider that an additional option involving the advancement of the conversion of W switching station to a 66/11kV zone substation could be a reasonable option that may maximise the net benefits.

W station is located close to LQ, MP and WA zone substations and it seems reasonable that this option could facilitate the required post contingency load transfers. CitiPower agrees in their revised Network Planning Proposal that W zone substation is closer to WA and MP, but argues that for the proposed cost of the distribution transfers, it will not be able to build a new zone substation in the heart of the CBD.

We contend that the cost of the alternative W project would not be equivalent to building a new substation, and consequently, should not be as high as indicated by CitiPower. W is approved to be partly rebuilt as part of the CBD security of supply works with the existing isolators replaced with GIS switchgear, and therefore, the cost of these works should not be included in the costs to further upgrade W to allow the 11kV transfers. We are therefore not sufficiently satisfied that the cost of adding transformers to the partly rebuilt W is comparable to the development of a completely new substation. We note that the cost of adding a transformer to an existing substation such as BQ is around $5 million[57].

As this option has not been assessed by CitiPower, it is difficult to say with certainty what the cost of this option may be. However, given W's more centralised location than BQ, it could reduce feeder works by up to 50%. Even allowing for the additional transformer, this may result in a cost below CitiPower's preferred option. Possibly more importantly, this option would defer the need for the separate 3rd BQ transformer project discussed below. It may also have higher benefits as it may allow pre-contingent switching of the feeders.

All that said, we do accept that the probability is low that this alternative will be found to be the preferred option.

Capacity and Energy at Risk Driven Projects

As indicated by CitiPower in their revised Network Planning Proposal the group of projects proposed to ensure CitiPower addresses zone substation capacity and energy at risk issues are as follows:

- Transfers to BQ: 310 LaTrobe St Group (JA and MP) - $4.87 million
- Transfers to BQ: Exhibition-Exchange Group (WA) - $2.53 million
- Transfers to BQ: via Exhibition-Exchange Group (FR) - $1.94 million
- Transfers to BQ: Rathdowne Group (WA) - $1.62 million

[57] Source - Network Planning Proposal for the 3rd BQ transformer.

- Transfers to BQ: North Wharf Group (JA) - $3.82 million

The total cost of this group of projects is $14.78 million.

The purpose of these feeder projects is to address excessive substation loading at JA, MP, WA and FR substations. Although CitiPower considers that its revised planning proposal demonstrates that energy at risk is sufficient to justify this project, we do not consider that the information provided is sufficient for these purposes. It does provide an indication of the forecast maximum demand and cyclic ratings at relevant substations. It also notes that its policy for multiple transformer switched substations is that there can be no loss of supply following the loss of a transformer. However, it does not provide any details of the energy at risk calculations it has undertaken to determine that energy at risk is economically sufficient. Moreover, there is no clear presentation of the results to justify this claim.

Based upon our calculations, using the individual zone substation forecasts provided by CitiPower, we have estimated that the combined value of the expected unserved energy at these substations in 2015 is $379,619[58]. Avoiding this energy at risk, would only justify a project with a capital cost up to approximately $4 million, which is well below the cost of this portion of the feeder works. We therefore consider that the capacity portion of the proposed feeder works has not been sufficiently shown to be economically justifiable, and it would appear that these elements could be deferred for 2 to 3 years.

It is also worth noting that, as highlighted in the next section of this review, the proposed installation of a 3rd transformer at the BQ substation is partly driven by the transfer of load to BQ due to the proposed 11kV feeder project i.e. energy at risk is not being avoided, but moved. In this case, the economic test for the project should allow for the $5.12 million cost of the 3rd BQ transformer i.e. in terms of how the transfer is advancing the need for the transformer upgrade. As such, the true economic timing for the project may be even further delayed beyond the forthcoming regulatory period.

Conclusion

To aid in the development of a more accurate probability for this group of projects we have split the project into the security and capacity elements.

For the security elements, we have assigned a high probability (90%). For the capacity elements, we have assigned a moderate to high probability of 70%[59]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects our view that the energy at risk can be prudently and efficiently managed for another 2 to 3 years.

It is important to note that this represents a significant increase from the original probability. This increase has been partly due to the AER's changed position on the CitiPower demand forecast. However, a significant matter has been our further consideration of the original probability, which we did not consider appropriately captured the portfolio view of our analysis. In this regard, the original 33% did capture our view of

[58] Source – Energy at Risk Spreadsheets provided to the AER by Citipower.

[59] Probability based upon: 95% (historical accuracy) x 95% (load profile) x 70% (energy at risk)

the probability that the capex for this group of projects will be required in the next period, but did not reflect the general view of how funds for other similar projects (in other years) may be required.

4.2.2.3 3rd BQ Transformer

The “3rd BQ transformer” project is a later stage of the Metro 2012 project, and includes the installation of a 3rd transformer and capacitor banks at BQ (Bouverie-Queen zone substation) to cater for the projected demand at this substation. This project was assessed as part of Nuttall Consulting’s probabilistic analysis of CitiPower’s reinforcement needs. Based upon our original review, this project was given a low probability (33%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER’s position on the demand forecast, this probability reflected our views that:

- Our analysis of relevant energy at risk indicated that the economic timing for this portion should be deferred, particularly given are findings that load transfers to BQ due the 11 kV feeder works may be deferred.
- We also considered that there was a reasonable possibility that a lower cost alternative to the 11 kV transfers to BQ may be found to be the preferred option – we noted the option of developing an existing switching station, Waratah Place (W), into a 66/11 kV substation. If this option occurred then the need for the 3rd transformer would be deferred.

The CitiPower revised proposal does not accept our views and considers that the project should be viewed as 100% required as originally proposed. Additional information has been provided by Citipower to support its position[60].

We have considered CitiPower’s contention in its revised regulatory proposal that the 3rd BQ Transformer project is 100% required in the forthcoming regulatory period. A review has subsequently been performed of the additional information.

With regard to the energy at risk, CitiPower considers that this is sufficient to justify the project. In this regard, the planning proposal provides the results of its analysis that supports this view. The analysis considers the load transfer to BQ due to the 11 kV feeder works plus the additional load due to a proposed new development (the CUB development)[61]. This analysis considers a number of scenarios covering:

- 100% of the anticipated load due to the 11 kV feeder works plus the CUB development
- 50% of the anticipated load due to the 11 kV feeder works plus the CUB development
- transformer ratings cover 55, 60 and 65 MVA.

[60] Table 9.5 of CitiPower’s Revised Proposal and the revised 3rd BQ transformer Project Network Planning Proposal attached to CitiPower’s Revised Regulatory Proposal (Attachment 161)

[61] The loading also includes that due to transfers from VM and BS/BQ, which are part of the Metro 2012 project. These are considered fixed and not variable in the scenario analysis.

CitiPower considers that all scenarios indicate that the energy at risk is sufficient. Furthermore, CitiPower considers that the scenario assuming 50% loading is conservative, and as such, the timing should be considered reasonable.

We have assessed CitiPower's analysis and accept that, based upon its scenario, energy at risk is sufficient. However, in light of our findings above and other matters assessed by the AER, we do not accept that the 50% loading scenario can be considered conservative.

Firstly, the forecast loading at BQ is dependent on the assumed demand of the CUB development. CitiPower has assumed that at worst this will be 50% of the anticipated amount by 2015. However, in its draft determination, the AER considered the forecast loading for the CUB development load and considered that there was insufficient evidence that the project would take place within the proposed timing[62]. In its reply to the draft determination, CitiPower made no explicit response to this rejection of the CUB development. As such, it seems reasonable to assume there is a high probability that the demand due to CUB will not have occurred by 2015.

Secondly, as discussed above on the 11 kV feeder projects, we still maintain that energy at risk does not appear to be sufficient to justify the 11 kV feeder transfers by 2015. As such, we also consider it is reasonable to assume there is a high probability that the load due to the transfers will be far less than 50% in 2015.

It would require a combination of these factors to remove the need for the upgrade; however, this seems reasonable, based upon the above. As such, we consider it reasonable that the transformer could be deferred by up to 3 years, depending on the timing of the CUB development.

It is also worth noting that:

- CitiPower considers that a 60 MVA transformer is most likely. However, it has not presented analysis to determine whether the 65 MVA unit may be more cost effective. Furthermore, it is not clear from CitiPower's discussion whether the ratings cover cyclic capability, which would provide some additional capacity.
- The proposed substation establishment works at BQ (to be undertaken under the Metro 2012 works) include 24Mvar of capacitor banks. The impact of these capacitor banks on the MV.A loading of the substation and the energy at risk is not clear from the information presented by CitiPower in their Network Planning Proposal. However, it may be that this will provide a small amount of some additional capability.

With regard to the possibility of the W development reducing the need for this project, as discussed above, CitiPower does not consider that this will be a lower cost project as it will be equivalent to the construction of a new zone substation (i.e. approximately $23 million).

As also discussed above, we still maintain that CitiPower has not adequately justified that the W option should not be considered a reasonable alternative. However, we do accept

[62] Source - AER Victorian Distribution Draft Decision 2011-2015

that the likelihood is low. As such, we have not given this issue much weight in determining our project probability.

Conclusion

Based upon the above, we have revised the project probability from low (33%) to moderate (50%). In addition to the general concerns of historical over-forecasting of reinforcement needs, this revised probability reflects[63]:

- our view that the energy at risk can be prudently and efficiently managed for another 3 years
- to a lesser extent, the possibility, of a lower cost alternative option.

The increase is largely due the AER's change in its position on the CitiPower maximum demand forecast, but also allows for the reduced impact of a lower-cost, alternative option.

4.2.2.4 Docklands Area Substation Upgrade

The Docklands area (DA) substation upgrade project involves the upgrade of the existing 22/11 kV DA zone substation to a high capacity 66/11 kV CBD style zone substation. This project also includes the upgrade of the existing 22 kV line that supplies the DA substation to 66 kV. The key driver for this project is the projected loading at the existing substation.

This project was assessed as part of Nuttall Consulting's probabilistic analysis of CitiPower's reinforcement needs. Based upon our original review, this project was given a moderate probability (50%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that:

- We considered that the energy at risk only marginally supported the project around the end of the period.
- There was a reasonable possibility that a lower cost alternative to the upgrade would be found to be the preferred option – we noted the option of developing a new zone substation, supplied from FBTS.
- We also considered CitiPower had not adequately demonstrated that its cost estimate for this project ($21 million) could be considered efficient. We estimated the cost to be $10-13 million.

The CitiPower revised proposal does not accept our views and considers that the project should be viewed as 100% required as originally proposed. Additional information has been provided by Citipower to support its position[64].

[63] Probability based upon: 95% (historical accuracy) x 95% (load profile) x 70% (energy at risk) x 96% (options)
[64] Table 9.5 of CitiPower's Revised Proposal and in the Docklands Area Substation Upgrade Material Project Template attached to CitiPower's Revised Regulatory Proposal (Attachment 161)

We have considered CitiPower's contention in its revised regulatory proposal that this project is 100% required in the forthcoming regulatory period. A review has subsequently been performed of the additional information.

With regard to the possibility of a lower cost alternative, CitiPower does not consider that our suggested alternative will be lower cost. CitiPower considered that our suggested alternative would cost in the order of $22 million to $28 million. In support of this view, CitiPower noted that additional costs would be required to cover land purchases, additional sub-transmission line costs, additional distribution feeder costs. Given the further clarification on the likely cost of this alternative, we are satisfied that it is unlikely it would be a lower cost alternative.

With regard to the cost estimate, CitiPower's revised proposal indicates that it maintains that its proposed cost for this project is reasonable. However, its revised material project template indicates that the project cost has been revised to $15.2 million ($2009 excluding overheads). This does not reconcile with the project cost provided in the revised RIN, which indicates $18.9 million (excluding overheads plus a further $1.7 million direct overheads).

If the revised cost of $15 million is correct, then we accept that it can be considered a reasonable estimate. However, if the revised RIN estimate is correct then we do not accept that this can be considered reasonable, given CitiPower has not provided additional information to justify its cost.

Finally, with regard to our concern on the significance of the energy at risk, CitiPower has provided further information on the energy at risk that it considers shows that the timing is justified. In this regard, it notes that load growth has been historically high, above 6% per annum, and that it is well above its N-1 rating. It also notes a planned 7 MVA load transfer away from DA will still result in the substation exceeding its N rating by 2014/15.

We agree with CitiPower that the loading at DA is high and that this places load at risk in both summer and winter at the substation. We do note however that the 2014 energy at risk value at DA has been increased in CitiPower's revised regulatory proposal from 5742.75 MW.h to 9986.6 MW.h[65]. CitiPower has indicated that this increased figure accounts for the 4243.86MW.h of energy at risk in winter at the substation[66].

We still have some concerns with the expected cost of energy at risk being used by CitiPower to economically justify the project and to determine the optimal timing of the project. The permanent 7 MV.A transfer to WG substation from DA, discussed in their Material Project Template has not been included in the forecast load at risk presented in in CitiPower's Docklands Area Substation Upgrade Material Project Template (Table 3). If the 7 MV.A transfer is included then energy at risk will be reduced and the substation loading will not exceed the N rating of the substation until summer 2015/16, when CitiPower forecasts the substation loading will be 45 MV.A.

[65] These values are the raw energy at risk above the N-1 rating of the substation and do not consider the probability of transformer outage. The energy at risk values accounting for the probability of transformer failure are 17.9MW.h and 13.3MW.h in summer and winter respectively

[66] CitiPower Email to AER 20 August 2010.

Furthermore, it is noted that demand growth above the N rating is the main contributor to the rapidly increasing energy at risk. Given the scale of the project, this energy at risk may be able to be offset for a temporary period (e.g. 1 or 2 years), by cogeneration or demand side initiatives. On this, we note that the demand management costs associated with the WMTS project would indicate that this may be cost effective.

Conclusions

Based upon the above, we have revised this project probability from moderate (50%) to moderate to high (70%)[67]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects our view that the energy at risk can be prudently and efficiently managed for another 1 to 2 years.

The increase is largely due the AER's change in its position on the CitiPower maximum demand forecast, but also allows for the removal of the impact of a lower-cost, alternative option and the high cost estimate.

It is important to note that the revised probability assumes that the project cost is $15.2 million ($2009 excluding overheads), not the cost indicated in the revised RIN.

4.2.2.5 Summary findings

Based upon the above, we have accepted CitiPower's costs associated with the CBD security project and the Metro 2012 project. For the remaining projects we have revised our project probabilities as indicated in the Table below.

Table 3 CitiPower reinforcement project summary

Project	original probability	revised probability
11kV CBD Feeder Works	Low (33%)	Moderate to high (70%)
3rd BQ transformer	Low (33%)	Moderate (50%)
3rd SB transformer	Low (33%)	Low (33%)
Docklands Area Substation Upgrade	Moderate (50%)	Moderate to high (70%)
Weighted average	**38%**	**71%**

The project probabilities largely reflect the concerns we raised in our original review:

- energy at risk is insufficient to justify the timing
- alternative lower cost options
- conservative load profile assumptions
- previous forecasting accuracy.

[67] Probability based upon: 95% (historical accuracy) x 95% (load profile) x 90% (impact of transfer) x 94% (DM/gen impact)

The increases are largely due to the increased demand forecast and updates or clarification on the DNSPs project justifications. In the case of the 11 kV feeder project, a large part of the increase reflected an error on our part in determining the original probability.

4.3 Reliability and quality maintained

Our original review considered CitiPower's RQM forecast based upon the DNSP's internal activity codes. This break-down was used as it was considered to be the most consistent between the historical and forecast allocation of expenditure. This breakdown largely reflects various asset classes, but is slightly different to the AER's revised RIN asset categories. This review lead to various parts of the forecast being accepted, and others being rejected with the substitute forecast based upon the calibrated repex model for that category.

CitiPower has not agreed with Nuttall Consulting's rejection of a number of categories. For these categories, the revised CitiPower proposal provided further discussion and information to support these categories and address Nuttall Consulting's concerns expressed in our original report.

General criticisms of Nuttall Consulting's approach to assessing RQM expenditure and determining substitute allowances, which are similar between DNSPs, are discussed in Section 3.2. This section discusses the asset categories where specific criticisms or new information has been provided in the revised proposal.

The table below lists the various categories and indicates where additional information has been provided by CitiPower.

Table 4 CitiPower RQM category summary

Category	Original finding	DNSP revised proposal
Cross-arm Replacement	Accept	Accepted
Fault level mitigation project	Reject	Accepted, but substitute project proposed
Fault related	Accept	Accepted
HV Fuse Unit & Surge Divert. Repl.	Reject	Accepted
HV Switch Replacement	Reject	Rejected – additional information provided.
OH/UG Line Replacement	Accept	Accepted
Pole	Accept	Accepted
Reliability Improvement	Reject	Rejected – additional information provided.
Services	Reject	Accepted
Transformer Replacement	Reject	Accepted
Zone Substation Plant Replacement	Reject	Accepted
ZSS - Secondary Systems Replacement	Reject	Rejected – additional information provided.

4.3.1 Zone substation Secondary Systems Replacement

The zone substation secondary systems category covers a large number of separate programs. The most significant is an ongoing "age relay" replacement program, which covers approximately 45% of the expenditure. There are a number of much smaller ongoing programs covering another 25%, with the remainder being due to a significant number of new programs.

This category represents 20% of CitiPower's RQM forecast for the next period. CitiPower has forecast this category to have a significant increase in expenditure from recent levels.

4.3.1.1 Summary of Nuttall Consulting's original review

Nuttall Consulting did not consider that CitiPower had adequately demonstrated that its forecast expenditure associated with this RQM category was reasonable (i.e. it could be considered a disaggregated component of the overall prudent and efficient capex[68].

The key matters we raised to support this view were:

[68] Nuttall Consulting report, pg 114

- with regard to the aged relay programs, it appeared that the volume of replacement proposed in the next period was not significantly different to that in the current[69]
- lack of information that showed changes to risk levels associated with the relays replacement program[70]
- for the other ongoing and new programs there was no economic analysis that demonstrated the prudency and efficiency of the proposed increases[71]
- with regard to the new programs, we considered that there was no evidence that such a significant step increase would not result in a step reduction in risks.

Nuttall Consulting's recommended allowance was based upon the average historical level of expenditure in this category (2006-2008) with an additional component based upon the annual expenditure increase predicted by the calibrated repex model.

It is our understanding that the AER accepted our view in forming its overall capex allowance for SP AusNet.

4.3.1.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The CitiPower revised proposal details a number of criticisms associated with this category. These broadly fall into the following matters:

- aged relay replacement program
- other programs
- our allowance.

These matters are discussed in turn below.

With regard to the aged relays program (approximately 45% of the category), CitiPower considers that Nuttall Consulting was in error in thinking that the quantity of relay replacement is proposed to be lower in the next period compared to the current – CitiPower noted that this is due to the asset replacement volumes that it defined for the current period being expressed in terms of the number of relays and the volumes defined for the next period being expressed in terms of the number of schemes, where there will be multiple relays associated with a single scheme[72].

Nuttall Consulting accepts that it was in error on this matter (although we do not accept that this was because we "misunderstood the difference between relays and protection schemes" [73] as stated in the CitiPower proposal). We do however note that there still appears to be some confusion over the replacement volumes given in CitiPower's revised

[69] Ibid, Pg 113
[70] Ibid, Pg 114
[71] Ibid, Pg 114
[72] CitiPower revised proposal, pg 299
[73] CitiPower revised proposal, pg 299

RIN template (Schedule 2.7), which still appears to indicate lower volumes in the next period compared to the current.

Nonetheless, accepting that the number of schemes to be replaced is as given by CitiPower in its revised proposal (65 pa in the next versus 38 in the current), we still do not consider that CitiPower has adequately demonstrated that its proposed volume and associated expenditure are reasonable.

On this matter, CitiPower has provided a revised asset management plan[74]. In addition, it also provides some commentary of the number of relays in various risk categories and how these volumes change through the next period, based upon various replacement scenarios[75]. Nuttall Consulting has reviewed this information, but still considers that it is lacking in clearly demonstrating the validity of the modelling that underpins these results, both in terms of the estimation of end-of-life associated with the risk scores and the algorithm used to predict the changes in risk levels with time. This in turn relates to our concern that the need for a significant increase from historical levels has not been shown.

Turning now to the other programs (which constitute about 55% of the expenditure), the CitiPower revised proposal includes a table that provides some commentary on the assets and risks associated with some of these programs[76]. CitiPower has also provided a number of attachments on a selection of these programs[77]. Nuttall Consulting has reviewed this material; however, we do not consider that it has addressed the concerns we expressed in our original report. Although the material provides some information (generally in a qualitative way) on the risks and obligations associated with the programs, it does not provide meaningful information that can inform a review of this form. Such information would include explanations of how the risks have been managed in the current period, how they have changed in the current period, and how they are predicted to change in the next period. This in turn would allow us to evaluate whether we could expect a step change in the risk position of the business associated with such an increase in replacement. Based upon the information made available to us, it is not clear why a far more gradual increase in expenditure from historical levels would not more reasonably reflect the prudent and efficient level.

Based upon the above, we still do not consider that CitiPower has justified the need for such a significant increase in expenditure in this category.

With regard to our allowance, we have reviewed our approach in light of the new information, and do accept that a significant increase from our allowance is warranted. In this regard, we do not consider that our original allowance will be sufficient to allow for the likely increases in the ongoing programs, and still allow for a modest increase to address new needs.

[74] Attachment 255, to CitiPower revised proposal
[75] Powercor proposal, Pg 300
[76] CitiPower revised proposal, Pg 301
[77] Attachment 164, to CitiPower revised proposal

We do note that CitiPower considers it is inappropriate to use the repex model to determine the allowance as many needs are not related to aging factors[78]. While we do not disagree entirely with this view (we accept that a number of the programs are not directly related to age factors), in the absence of any other more appropriate guidance, we still consider that the rate of increase suggested by the repex model can be considered the most reasonable guide.

That said, in the case of the secondary systems, we consider that the actual expenditure in 2009 is the appropriate base-line to increment expenditure from. This year captures the commencement of a significant number of the ongoing programs, and so should better reflect the ongoing needs. We have also re-calibrated the growth rates to allow for historical replacement volumes – this has resulted in increases in the expenditure growth rates from the base-line.

The table below provides our revised estimate for this allowance (estimate exclusive of overheads and escalation). This represents a 62% increase in expenditure over the current period.

Table 5 CitiPower substation secondary

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	7.6	7.8	7.9	7.8	7.7
Recommended	**2.0**	**2.2**	**2.3**	**2.3**	**2.3**

4.3.2 Reliability

The reliability category covers a number of programs to address worst served customers.

This category only represents approximately 2.5% of RQM capex. The expenditure is broadly in line with CitiPower's 2010 estimate, but is a significant increase over historical levels, where CitiPower had allocated zero expenditure to this category over 2006-2008 and very little in 2009.

4.3.2.1 Summary of Nuttall Consulting's original review

Nuttall Consulting did not consider that CitiPower had provided sufficient information to justify any expenditure in this category[79]. We considered that, given there was zero expenditure in this category between 2006 and 2008, expenditure we allowed in other categories should be sufficient (i.e. to maintain reliability) noting these allowances were largely based upon an extrapolation of these costs.

[78] CitiPower revised proposal, Pg 299
[79] Nuttall Consulting original report, Pg

4.3.2.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The CitiPower revised proposal requests the reinstatement of the reliability expenditure[80]. It considers that these should be considered prudent and efficient, and are necessary to "meet reasonable expectations of reliability of supply" as required by Clause 5.2 of the Distribution Code.

CitiPower also noted that PB reviewed this category[81] and stated that we did not reject this category based upon any fundamental analysis. Furthermore, CitiPower noted that PB considered that the expenditure should be accepted as it was in line with our overall repex model findings.

CitiPower also provided further details of the individual programs that made up the reliability expenditure.

Nuttall Consulting has reviewed the material provided by CitiPower and considered its position. We still maintain that there is insufficient information to justify that any capex allowance is required to allow for these programs.

Importantly, in forming this view, we have considered the information provided on the individual programs advised by CitiPower, and note that these all appear to be reliability improvement programs targeted at the worst served customers. As such, it is reasonable to consider that these programs would be funded through the reliability incentive scheme.

On this view, we note that these types of programs were rejected on these grounds by the ESC in its decision for the current period[82].

We do note that it could be that the costs outweigh the funding through the reliability incentive scheme. However, in this case, we would expect CitiPower to provide some analysis to justify the prudency and efficiency of the incremental capex requirement. This type of information has not been provided. On this matter, we note PB's comment that we have not undertaken any fundamental analysis to support our rejection. However, we consider that the onus is on CitiPower to provide this analysis for us to review. We do not consider it is reasonable that such analysis could be undertaken independently without significant input from CitiPower.

Based upon the above, we consider that CitiPower's forecast for reliability expenditure should be rejected. Furthermore, we consider that an allowance of zero should be substituted. It is important to note, this is not to say works should not be undertaken; rather, it will be funded through other mechanisms.

4.3.3 Nilsen LV circuit breakers – HV switch replacement

The HV switch replacement category broadly covers the age/condition based replacement of HV and LV switchgear. A significant portion of the proposed expenditure related to the planned replacement of a type of LV switchgear (Nilsen air circuit breakers) in the next

[80] CitiPower revised proposal, pg 306
[81] CitiPower revised proposal, Attachment 171 – PB report
[82] ESC Final Decision Volume 1, Electricity Distribution Price Review 2006-10, pg 297

period (approximately 100 units). The Nilsen CB fleet had sustained two recent major failures, one in 2005 and one in 2007.

This category represents 9% of CitiPower's RQM forecast for the next period. CitiPower has forecast this category to have a very significant step increase in expenditure from recent levels.

4.3.3.1 Summary of Nuttall Consulting's original review

Nuttall Consulting did not consider that CitiPower had adequately demonstrated that its forecast expenditure associated with this RQM category was reasonable[83].

The key matters we raised to support this view was the lack of evidence that the scale of the increase could be considered prudent and efficient. We accepted that the risks associated with the assets existed, but did not consider that CitiPower had provided sufficient quantitative and economic analysis to justify that the scale of the programs was necessary (e.g. replacing all Nilsen LV breakers over the next period). We also noted that we had requested further information on the risks and how these would change if the programs were deferred or spread over a long period, but considered that CitiPower's response to this request did not adequately address our requirements.

Nuttall Consulting's recommended allowance was based upon the average historical level of expenditure in this category (2006-2008) with an additional component based upon the expenditure annual increase predicted by the calibrated repex model.

It is our understanding that the AER accepted our view in forming its overall capex allowance for CitiPower.

4.3.3.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The CitiPower revised proposal details a number of criticisms associated with this category[84]. These criticisms specifically concern the Nilsen LV circuit breakers, as follows.

- Given the two recent failures, CitiPower does not consider that it is appropriate to assume that it is managing the risk, and considers that the risks justify the proposed replacement program.
- CitiPower notes that the Nilsen breakers are at least 40 years old and considers that the recent failures indicate the population is entering its "end-of life" phase, which can involve a rapid increase in the failure rate. As such, unless a prudent replacement program is established, more failure would be expected at an increasing rate.
- CitiPower considers that based upon our allowance only 25% of the Nilsen breakers could be replaced in the next period. At that rate, it would then take a further 15 years to replace the population, indicating the oldest would be over 60 year.

[83] Nuttall Consulting report, pg 117
[84] CitiPower revised proposal, pg 304

CitiPower has also provided a revised project template for the Nilsen circuit breaker replacement program[85].

Nuttall Consulting has reviewed the material provided by CitiPower and considered its arguments summarised above. We do not consider that this has adequately addressed our concerns expressed in our original review, and as such, we still do not consider that CitiPower has justified that the proposed increase in expenditure can be considered prudent and efficient.

With regard to the issue of managing the risks and the age and recent failure justifying the program, as noted in our original review, we do not deny that the risks exist and a planned replacement program is required. Our concern relates more to CitiPower's view that the whole population will need to be replaced by the end of the next period. We still do not consider that CitiPower has provided compelling evidence that this is required.

With regard to CitiPower's analysis of the implication of our recommendation on the worse-case life of the Nilsen breakers, we consider that this is not an accurate representation of our findings. Our repex modelling was forecasting a significant growth in expenditure in this category – this was at a rate of approximately 10% per annum. Based upon this rate of increase and CitiPower's proportion of replacement in the next period, we have estimated that all breakers would be replaced within approximately 12 years i.e. the oldest would be around 52 years.

Moreover, as noted in Section 3.3, we have accepted that 2009 actuals can be applied in our repex modelling. Allowing for the increases due to this, we have estimated that approximately 40% of the breakers will be replaced in the next period, with the remaining being replaced before the end of the period that follows the next i.e. within 10 years. Based upon this, the breakers would not reach 50 years before replacement, with an average life of around 45 years. We consider that this is a reasonably conservative life for such breakers[86].

Based upon the above, we still consider that the proposed expenditure in this category should be rejected, and that a reasonable allowance can be based upon the historical expenditure (2006 to 2009) adjusted to reflect the increases indicated by the calibrated repex model.

The table below provides our revised estimate for this allowance (estimate exclusive of overheads and escalation).

Table 6 CitiPower HV switch replacement

	$millions (2010)				
	2011	2012	2013	2014	2015

[85] CitiPower revised proposal, Attachment 164

[86] For example, based upon Ofgem analysis, in the UK, typical lives for LV switchgear were between 67 and 85 years and HV ground mounted switchgear was between 43 and 55. Although we accept that, due to the different environments, these are not directly comparable, it does suggest that much longer lives for LV assets are achievable.

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	3.5	3.5	3.3	3.2	3.0
Recommended	**1.0**	**1.1**	**1.2**	**1.3**	**1.5**

4.3.4 Fault Mitigation project

The fault level mitigation project (FLM project) is a new project CitiPower is proposing to undertake in the next period to allow it to manage its forecast fault levels. In CitiPower's original proposal, the FLM project involved a major upgrading of the existing network, with CitiPower proposing the need for $100 million in capex, $75 million of which was allocated to the RQM category. This major upgrade was required to remove the need to manage fault levels via operational measures (e.g. forming open points at curtain substations), which is a method presently used – but CitiPower considered may not be viewed as strictly compliant with the Distribution Code.

The project has significantly changed in scope and cost in the revised proposal resulting in a $12 million project, of which $7 million is allocated to RQM. As will be discussed further below, the change is based upon the AER's draft decision, which indicated that the operational measures would be considered code compliant. The project now involves a number of more minor alternative upgrades, but assumes the operational measure are acceptable.

4.3.4.1 Summary of Nuttall Consulting's original review

Nuttall Consulting rejected the need for any expenditure in the RQM category associated with the FLM project[87]. Our basis for this view was:

- The use of operational measures (e.g. open point at substations) was an accepted practice for managing high fault levels, and it was not clear to us why this practice would not be considered code compliant. We noted a letter from the ESC that CitiPower referred to which suggested that this approach **may** not be considered acceptable, but we could see no definitive explanation as to why this would be the case. As such, we considered that CitiPower would need to demonstrate the prudency and efficiency of any upgrade via an economic test – particularly given the scale of the proposed upgrade.
- CitiPower had provided independent reports (the SKM FLM reports)[88] that assessed future fault levels and developed a scope of work and cost estimate to ensure these would remain below Code obligations. This project however assumed that operational measures were not acceptable. Furthermore, this report did not provide any economic analysis or indicate the appropriate schedule for the works.

[87] Nuttall Consulting original report, Pg 107
[88] C002 and C0186 of CitiPower's original proposal

CitiPower did not provide any other detailed analysis to support the need for the project.

4.3.4.2 Nuttall Consulting's discussion of matters raised in the DNSP revised proposal

As noted above, CitiPower has proposed an alternative allowance for the FLM project[89]. The alternative project requires that the AER will accept that existing operational measures will be deemed code compliant – CitiPower is requesting a statement of intent from the AER on this matter.

The revised project involves a series of upgrades to address the issues that may arise when open points are used to manage fault levels. A significant issue raised by CitiPower concerns increased voltage variations, due to the open points. CitiPower notes a recent complaint it had received on this matter.

CitiPower considers that 16 additional zone substations will need to be operated with open points in the next period: 11 due to forecast increases in demand and 5 due to the connection of embedded generation[90].

CitiPower has developed a cost estimate based upon the individual locations it has forecast to exceed fault levels in the next period and the specific works at these locations, required to address the different issues it has noted.

Nuttall Consulting has reviewed the information CitiPower has provided on this project. We do not consider that CitiPower has provided adequate information for us to review this project, particularly given the changes that CitiPower has made. In this regard, although we do not disagree in principle with the issues and solutions CitiPower has raised when using open points to manage fault levels, we do not consider that CitiPower has provided sufficient information to demonstrate that the need exists for these works in the number of locations it is proposing.

On this matter, we note that most locations appear to be different to those highlighted in the previous SKM report[91]. However, the CitiPower revised proposal does not include any additional information that demonstrates how CitiPower determined these locations. As such, the only analysis we had to assess the need were the SKM reports.

The SKM analysis considered fault levels at 2019 and noted that the majority of zone substations forecast to exceed fault levels were those connected to FBTS. Based upon our review of this document, it appears that this was due to an assumption that an additional transformer would be installed at FBTS prior to 2019. Based upon the latest Transmission Connection Planning Report, it does not appear that this transformer will be in place in the next period, and as such, it is not clear from the SKM report why so many locations would require operational measures in the next period.

---

[89] CitiPower revised proposal, Pg 293

[90] It is assume that the allocation of expenditure to RQM is due to the load increases.

[91] Section 8 of the SKM report, provides the location forecast to exceed fault level obligations due to demand growth.

Due to the apparent inconsistency in information, we requested further information, via the AER[92]. This request sought an explanation of the inconsistency. More importantly, if CitiPower considered that the SKM analysis was no longer valid, the AER requested that CitiPower provide updated information that demonstrated a need would exist at each location. The request explicitly stated that this demonstration would need to address:

- the underlying assumptions (e.g. network developments, generation additions, etc) used to determine the locations
- an explanation of what assumptions have changed from the SKM report and why
- sufficient information to ensure that the significance/sensitivity of the most critical assumptions on the timing of the need at each location is clearly shown.

The AER also requested an explanation of what the primary contributing factor(s) was(were) for each location that has required operating restrictions in the current period to address fault level issues.

We do not consider that CitiPower's response[93] to this request was sufficient, particularly at providing technical information that we consider could be reasonably expected in these circumstances.

In this regard, the response did clarify what locations had changed from the SKM report, and did indicate that further analysis has been undertaken by CitiPower. This explanation suggested CitiPower's analysis only considered up to 2015 and did not assume the additional FBTS transformer was installed. It also indicated that plant ratings at various zone substations had been re-assessed, suggesting some equipment had been allowed a small increase from that assumed in the SKM study.

This however suggests that the number of locations should have reduced from the SKM FLM report. This does not appear to be the case for the load driven locations being considered here.

More importantly, the CititPower response did not provide any detailed technical information that specifically addressed our request to demonstrate the need at each location. It also did not address the second mater at all – i.e. the contributing factors to existing operational restrictions.

Given this lack of information to support the need for the revised project, which the previous analysis (the SKM FLM report) does not appear to support, we consider that the FLM project should be rejected.

With regard to the allowance, we do not consider that we can reasonably determine this without the information we requested (i.e. the allowance will reflect how many locations are needed). That said, given fault levels were managed in a number of locations in the current period via operational restrictions, it could be considered that some allowance already exists due to the process we have applied to derive the overall allowance in the RQM category.

[92] AER email to CitiPower, dated 15 September 2010

[93] CitiPower email, dated 21 September 2010

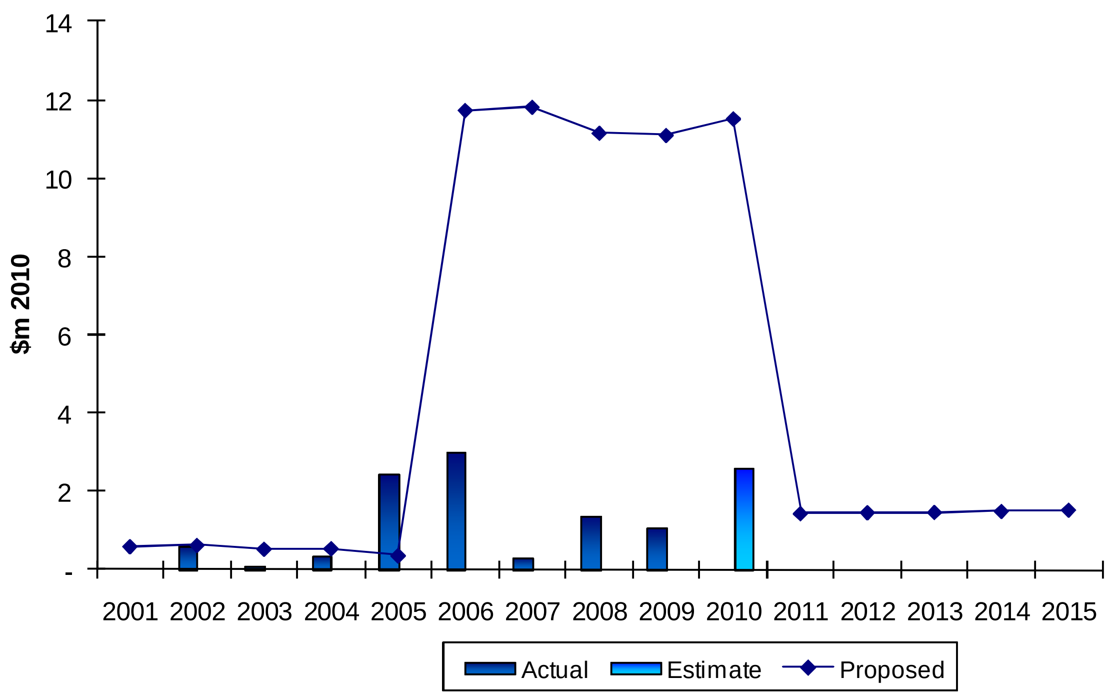
Therefore, we are not recommending any allowance for the FLM project. However, the AER may need to reconsider this matter in the context of its overall capex allowance and the issues we have discussed above regarding the lack of information to review the need for the revised project.

4.4 Environmental, Safety and Legal

The following chart shows the actual expenditure in the Environmental, Safety and Legal category compared to the amounts forecast by CitiPower prior to the commencement of each regulatory period. The chart highlights a very large proposed increase in Environmental, Safety and Legal expenditure for the current regulatory control period. A significant proportion of the proposed increase was related to changes in the ESMS regulations. Clearly many of the proposed expenditures did not eventuate or were undertaken at a significant discount.

In addition to these expenditures, CitiPower has proposed additional and new activities in response to changed safety and line clearance regulations, the Victorian Bushfires of 2009 and the Royal Bushfire Commission's final report. The proposed expenditures have been reviewed by Energy Safe Victoria (ESV) and recommendations made as to the future volumes of works required. The AER has requested Nuttall Consulting to review the unit costs associated with the ESV recommended volumes. This assessment is provided in Appendix G – Unit cost review of this report.

Figure 16 – CitiPower Environmental, Safety and Legal capex



The capex for Environmental, Safety and Legal as proposed by the AER in the draft determination is provided in the following table.

Table 7 – Draft determination CitiPower ESL capex

CitiPower	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Draft determination capex	1.2	1.2	1.2	1.2	1.2

CitiPower stated that it "does not contest the AER's Draft Determination with respect to environmental, safety and legal capex. However, CitiPower contends that the AER should include 2009 actual data in its trend analysis and in forecasting the capex required in the next regulatory proposal by reference to historical expenditure."[94]

Nuttall Consulting has reviewed the alterations for the trending analysis proposed by CitiPower and agrees with the inclusion of the 2009 actual data. This data has now been incorporated into the base information provided to Nuttall Consulting by the AER and has been used, where relevant, in any subsequent trending analysis.

The CitiPower revised proposal provides a revised capex for Environmental, Safety and Legal as per the following table.

Table 8 - Resubmitted CitiPower ESL capex

CitiPower	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Resubmitted capex	1.440	1.465	1.474	1.499	1.532

The revised expenditures proposed by CitiPower for the next regulatory control period are relatively consistent with the average level of expenditure in the current period. The average capital expenditure over the last four years is $1.451 million. This includes the 2009 actual data as submitted by CitiPower. Nuttall Consulting considers that this level of expenditure is consistent with the ongoing obligations for this capex category. Nuttall Consulting recommends the following capital expenditure for the next regulatory control period.

Table 9 - Recommended CitiPower ESL capex

CitiPower	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Recommended Expenditure	1.451	1.451	1.451	1.451	1.451

The recommended Environmental, Safety and Legal capex for CitiPower is based on the average actual expenditures incurred in the previous 4 years exclusive of indexation and escalation.

[94] CitiPower Pty Revised Regulatory Proposal 2011 to 2015 – July 2010.

Nuttall Consulting notes that CitiPower asserts the AER should include the following as nominated pass through events:

- recommendations arising from the Bushfires Royal Commission
- a general pass through event
- a financial failure of a retailer pass through event
- conditions or limitations imposed by ESV on provisional acceptance of an ESMS under the Electricity Safety Act.

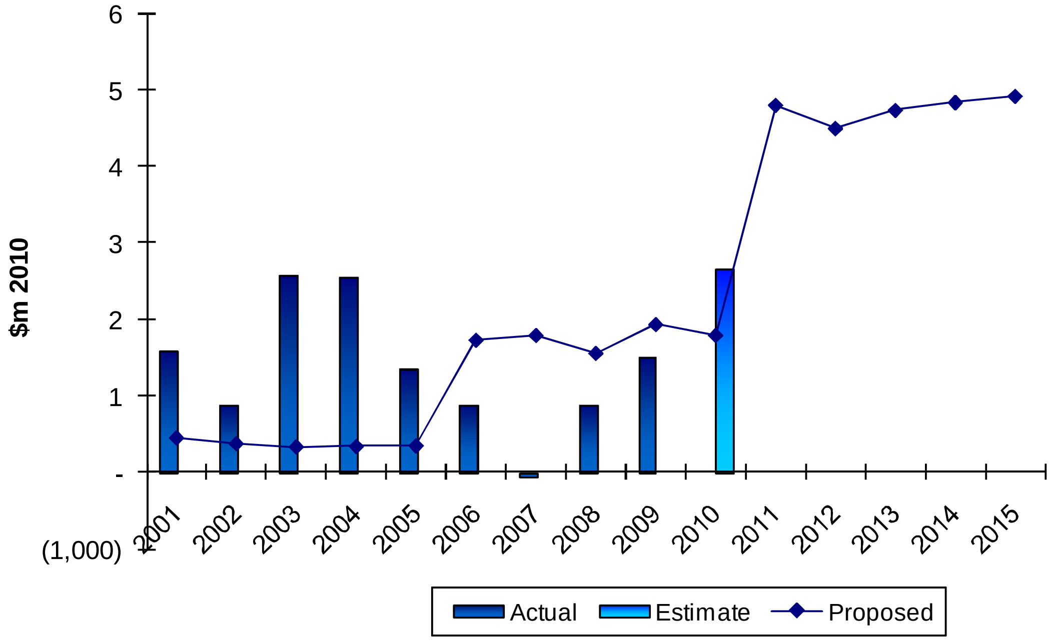
These items are not addressed in the above recommendations.

4.5 SCADA and Network Control

CitiPower is proposing an increase of over 490% in SCADA and Network Control capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. CitiPower estimates that its SCADA and Network Control capital expenditure for the 2006-10 regulatory control period will be $5.9 million. It is forecasting that this will increase to $23.7 million in the 2011-15 regulatory control period.

For the 2006 EDPR, CitiPower proposed SCADA and Network Control expenditure of $8.8 million. The resultant actual expenditure for this period is forecast to be $5.8 million. However, almost half of this current period expenditure is forecast for 2010.

The following chart provides a summary of Environmental, Safety and Legal capex for CitiPower.



In its draft determination, the AER recommended reductions to the CitiPower SCADA and Network Control forecast capex. The capex recommended by the AER is described in the following table.

Table 10 – Draft determination CitiPower Nuttall Consulting capex

CitiPower	Costs (2010 $M)				
SCADA and Network Control	2011	2012	2013	2014	2015
Draft determination capex	1.2	1.2	1.2	1.2	1.2

CitiPower's revised proposal states that the "AER has not considered the circumstances of CitiPower's network in assessing its proposed SCADA and network control capex. CitiPower contends that its SCADA and network control programs in the next regulatory control period are required ..."[95].

The key responses provided by CitiPower in relation to the proposed capex are that:

- Nuttall Consulting erred in concluding that the DMS field devices were included in the IT capex (non-network) category
- the AER erred in assuming that the underspend in the current period SCADA and Network Control capex was an efficient outcome
- CitiPower maintains that each of its proposed projects link with the Network Protection and Control Communications Strategy 2009-2014[96]
- the programs proposed by CitiPower for the next regulatory control period justify forecast expenditure greater than the historical trend.

The above CitiPower responses are discussed in detail in the following sections.

On the basis of the above responses, CitiPower is proposing SCADA and Network Control capex for the next control period as described in the following table.

Table 11 – Revised proposal CitiPower Nuttall Consulting capex

CitiPower	Costs (2010 $M)				
SCADA and Network Control	2011	2012	2013	2014	2015
Revised proposal capex	4.793	4.490	4.729	4.830	4.912

4.5.1 DMS Field Devices

CitiPower states that the DMS field devices are network data collection devices that sit on poles or in substations that provide interface with electrical assets. The revised proposal information provided by CitiPower makes it clear that there is a separation between DMS related works that are part of the general – IT capex and DMS field devices.

[95] CitiPower PTY's Revised Regulatory Proposal 2011-2015 – Page 249.
[96] Attachment P0030 to the Initial CitiPower Regulatory Proposal

Nuttall Consulting accepts the position put forward by CitiPower that the DMS field devices should therefore be considered as separate and additional to the DMS projects captured in the general – IT capex category.

CitiPower has provided an explanation of the capital forecast associated with the implementation of distribution management system (DMS) field devices[97]. This document identifies expenditures[98] of $500,000 for the first three years of the regulatory control period and $800,000 for each remaining year. The project is described by CitiPower as a new program that will commence in the next regulatory control period. There is no related expenditure on DMS field devices reported in the current control period.

The reasons provided by CitiPower that require the installation of the DMS field devices include the increase in network utilisation and an increase in embedded generation connections. Nuttall Consulting agrees that network utilisation and the incidence of embedded generation will continue to increase in the next regulatory control period. These are not new issues facing the network; both have been referenced as drivers of expenditure in CitiPower EDPR proposals from 2001 and 2006.

CitiPower has not identified any external obligations or regulations that require the installation of the DMS field devices. CitiPower has identified benefits from the field devices. These benefits and the Nuttall Consulting assessment of them are discussed in the following table.

Table 12 – Benefits of DMS field devices

CitiPower identified benefit	Nuttall Consulting assessment
Allowing network events to be modelled so that CitiPower can plan operational switching requirements that provide the best network performance and reliability	Incremental benefit above current network event information.
Maintaining the reliability of a network that is experiencing increasing utilisation levels and increased levels of embedded generation	Incremental benefit to existing levels
Allowing CitiPower to have full control and knowledge of the distribution network	Nuttall Consulting questions the validity of this statement. It does not appear likely that full control and knowledge is possible from the proposed program

[97] CP - 168 Implementation of DMS field devices.pdf
[98] Excluding overheads and escalation

CitiPower identified benefit	Nuttall Consulting assessment
Allowing CitiPower to avoid any increases in potential health and safety incidents	CitiPower does not describe the mechanisms by which the DMS field devices provide this benefit. Nuttall Consulting considers that the DMS field program will not allow CitiPower to avoid "any" increases in potential health and safety incidents, although there are foreseeable mechanisms that it could allow CitiPower to avoid "some" increases.

CitiPower does not provide any quantified benefits from the DMS field device installations. CitiPower does not provide any information to identify or quantify any efficiencies or opex trade-offs from the proposed DMS program.

In the absence of any quantification of benefits it is not possible to assess if the proposed benefits from this program outweigh the identified costs. Therefore it is not possible to assess if the proposed program is prudent and efficient.

The DMS field project is designed to provide capability and functionality, above current levels. CitiPower has not shown that these enhancements will provide consumers with a tangible benefit or service improvement.

Nuttall Consulting considers that CitiPower has not shown that the proposed expenditure is efficient or that it represents expenditure required to meet the capital expenditure objectives. Nuttall Consulting does not recommend that the expenditure should be included in the next regulatory control period.

Note: the implementation of the DMS project (general – IT capex) is discussed in the general – IT capex section below. The IT project can proceed independent of whether CitiPower chooses to proceed with the installation of DMS field devices or not.

4.5.2 Historical underspend

In its revised proposal CitiPower states that the AER erred in assuming that the underspend in the current period on SCADA and Network Control capex was an efficient outcome[99]. In support of this position, CitiPower identified a number of project deferrals that contributed to the resultant underspend. These include:

- delays to "lead-in" projects such as the GIS[100] and OMS[101] migrations and SCADA system replacement
- delays due to the structure, resourcing and management of the service provider's offshore development program
- underestimation of the complexity of the project by the service provider

[99] CitiPower Pty's Revised Regulatory Proposal 2011-15 – Page 314
[100] Graphical Information System
[101] Outage Management System

- underestimation of the level of testing required.

Nuttall Consulting accepts that the deferral causes identified by CitiPower may reasonably have contributed to actual expenditure being less than that proposed by the DNSPs. The deferral causes identified by CitiPower support the Nuttall Consulting view that the proposed SCADA and Network Control capex for the next regulatory control period does not meet the capex objectives.

With the advantage of hindsight, it is possible to assess the prudency and efficiency of the SCADA and Network Control capex that was proposed by CitiPower for the current regulatory control period.

In a previous review of NSW DNSP expenditure, prudency was considered as follows: "*Prudence is often best judged by the absence of evidence suggesting a lack of it. In the case of electricity networks, imprudence might be most discernible if there was evidence of failure to invest adequately, accompanied by identified adverse consequences, and is thus best assessed retrospectively*."[102]

CitiPower has provided no evidence that the underspend resulted in an imprudent outcome. As there is no discernible evidence of failure to invest adequately and/or adverse consequences we must assume that the level of expenditure was prudent.

The assessment of efficiency is based, in part, on the least-cost feasible option to meet the capital expenditure objectives. This requirement would appear to be satisfied by the incurred expenditure.

Based on the above, it is reasonable to accept that the historical levels of SCADA and Network Control capital expenditure incurred by CitiPower are both prudent and efficient.

Looking at the forecast SCADA and Network Control capital expenditure proposed by CitiPower for the next regulatory control period we see that it is significantly greater than the level of capital expenditure that has been incurred in the previous 9 years[103].

When we consider the SCADA and Network Control capex that was forecast for the current Regulatory Control Period we can also see that the CitiPower's forecast for the current period is much higher than the actual level of expenditure.

As noted above, CitiPower have identified that their forecast for the current regulatory control period did not take into account the impact of future project deferrals. Nuttall Consulting considers that this lack of account of project deferrals is a systemic problem with the capex forecasting process.

Capital projects are often complex and require many interactions with third parties. These interactions can include other related projects, resource providers and contractors, councils, planning authorities, health and safety authorities, environmental impacts, etc. While it is not always possible to identify which of these interactions may result in a delay to a project, it is good practice to make allowances for these delays.

[102] Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1 – Main Report, Final, October 2008 - Wilson Cook & Co, Page 8.

[103] 2001 to 2009 inclusive.

The information provided by CitiPower in relation to the delays in the current regulatory control period for the SCADA and Network Control project show that these delays have not been sufficiently allowed for in the planning processes.

Nuttall Consulting considers that recognition of the potential impacts of project delays in forecasting and planning is good electricity industry practice. A commonly accepted definition of good electricity industry practice is the exercise of that degree of skill, diligence, prudence and foresight reasonably to be expected of a distribution business working under the prevailing conditions consistent with applicable regulatory, service, safety and environmental objectives.

CitiPower was requested by the AER to provide details where the policies, strategies and procedures provided to support their submission have changed during the current regulatory period and the effects of these changes[104]. The CitiPower response to this request did not identify any changes to the policies, procedures or strategies for expenditure forecasting. On this basis, we must assume that the forecasting processes and procedures utilised by CitiPower have not changed and that allowances for delays in capital projects have not been adequately accounted for.

To summarise the above;

- the CitiPower SCADA and Network Control capex for the current regulatory control period is considered prudent and efficient
- the historical planning processes and procedures used by CitiPower do not adequately account for interactions with other projects and third parties and have resulted in forecasts greater than actual expenditure
- CitiPower has not identified any changes to the historical planning processes and procedures
- the SCADA and Network Control capex forecast for the next regulatory control period does not adequately account for interactions with other projects and third parties that may result in delays
- if allowances are made for interactions with other projects and third parties, the resultant expenditure would be lower than that proposed by CitiPower.

4.5.3 Strategic plan linkages

CitiPower "maintains that each of its proposed projects link with the Network Protection and Control Communications Strategy 2009-2014".[105] Nuttall Consulting agrees that there are links between the proposed projects and the Network Protection and Control Communications Strategy 2009-2014. Nuttall Consulting notes that the Network Protection and Control Communications Strategy 2009-2014 does not discuss capex

[104] Regulatory Information Notice Under Division 4 Of Part 3 Of The National Electricity (Victoria) Law Issued By The Australian Energy Regulator, Section 3.1 – 14/10/2009.

[105] CitiPower Pty's Revised Regulatory Proposal 2011-15, page 315

forecasting, or identify interactions with other projects and third parties that may result in delays to the identified projects.

Nuttall Consulting agrees that there are links between the proposed projects and the Network Protection and Control Communications Strategy 2009-2014. Nuttall Consulting notes that the Network Protection and Control Communications Strategy 2009-2014 does not discuss capex forecasting, or identify interactions with other projects and third parties that may result in delays to the identified projects.

Nuttall Consulting considers that the identification and linking of proposed projects with the overall business strategies is only part of a capital governance process to deliver a prudent and efficient outcome. CitiPower commissioned PB Power to review CitiPower's policies, practices, procedures and governance arrangements. This review provides a number of examples to highlight the process that impacts expenditures as a project moves from strategic intent to physical implementation. The following series of dot points provides examples from the PB Power report.

- *PB identified the significant corporate governance processes involving the capital investment committee, the network planning committee, and financial authorisation.*
- *A strength of the CitiPower approach is the senior level of the committee that approves all significant network investments and the inclusion of a technical expert on that committee.*
- *CitiPower does not delegate authority for network capital investment to a low level. While this ensures that all expenditure has been appropriately reviewed, this does add some complexity to the approval of expenditure.*
- *CitiPower uses an optimisation tool to optimise capital projects in the capital works program each year. The optimisation of the annual capital program results in the deferral of some low-risk projects and our review identified a number of augmentation projects which had been deferred.*
- *PB has identified three significant corporate governance processes that affect system capital expenditure. The three processes are: capital investment committee, network planning committee and financial authorisation.*
- *The process used to approve expenditure is documented in the Authorisation and Payment of Project Expenditure and Services Manual. The effect of these two documents is to require: documentation of all capital expenditure, for any capital expenditure in excess of $50,000, the completion of an Authority to Proceed document and review and approval by the Capital Investment Committee of any material expenditure.*
- *In addition to the formal approval process involving the preparation of an Authority to Proceed and approval of material expenditure by the CIC, CitiPower employs a Network Project Committee. This committee provides a forum for review of all network related projects, policies and strategies that have a financial impact of greater than $150,000 in a financial year.*

- *CitiPower utilises two committees to review network investments before committing to the expenditure. These committees operate in a hierarchy where the CIC is the peak committee that reviews all material, capital expenditure and the NPC reviews expenditure at lower levels. The NPC also ensures that expenditure proposals put to the CIC are appropriate.*
- *CitiPower generally relies on non-network proponents to respond to identified network constraints though there are cases where CitiPower has implemented embedded generation to ease a constraint and therefore defer network augmentation.*

From the above listing it is clear that CitiPower has a robust and comprehensive process for the governance of capital expenditure. The information provided by PB Power also highlights the large number of checks and balances that exist to ensure only prudent and efficient investment is undertaken.

The PB Power report provides examples of projects that were deferred by these processes. This report therefore provides clear evidence that the investment proposed within the strategic planning processes will be subject to significant review and assessment prior to implementation. The result of these processes will include the rejection or deferral of some projects.

On this basis, it is reasonable to determine that the summation of projects in the Network Protection and Control Communication Strategy does not represent the efficient level of future capital expenditure.

Nuttall Consulting notes that the PB Power report is focussed on the assessment of demand and non-demand related projects. This assessment did not directly consider the SCADA and Network Control category of costs. It is feasible that CitiPower may have lesser capital governance controls on this capex category. If this was the case, it could be argued that this may have resulted in less efficient outcomes. For the purposes of this review Nuttall Consulting has assumed that the controls for SCADA and Network Control are consistent with the controls for the other major capex categories.

4.5.4 Historical trend

The CitiPower revised proposal states that the programs proposed by CitiPower for the next regulatory control period justify forecast expenditure greater than the historical trend. CitiPower also note that “it is difficult to quantify the benefits likely to result from CitiPower’s proposed SCADA and network control capex in the next regulatory control period”[106]. CitiPower provides a number of qualitative benefits from the SCADA and Network Control proposed program[107]:

- “**improved** data for making operational decisions (e.g. information regarding outages, voltage control, plant and equipment availability, service conditions, operational planning);

[106] CitiPower Pty’s Revised Regulatory Proposal 2011-15 – Page 317
[107] Emphasis added

- **improved** data for making network planning decisions (e.g. information regarding network load and voltage modelling, contingency scenarios);
- **improved** data for condition monitoring assessments;
- **better** security of network sites;
- **improved** access to data for field technicians working at zone substations;
- **improved** ability to analyse network faults; and
- **better** ability to manage the network in relation to the uptake of household generation and electric vehicles, by having access to real time network loading where currently none exists."

The statement by CitiPower that "(e)ach of these benefits will allow CitiPower to ***maintain*** (emphasis added) reliability and performance of the network and justify the SCADA and network control capex proposed by CitiPower in the next regulatory control period"[108] appears inconsistent with the listing of benefits (above) which list improvements and betterments.

However, Nuttall Consulting does agree with CitiPower that the benefits of these programs are hard to quantify. On the basis of evidence available, it is not possible to state whether the proposed program will "improve", "better" or "maintain" reliability and performance.

4.5.5 Summary

Nuttall Consulting considers that the SCADA and Network Control capex proposed does not meet the capital expenditure objectives.

As CitiPower has not identified any changes in obligations or regulations that directly impact expenditure in SCADA and Network Control, the most reasonable substitute for forecast expenditure remains the historical level of expenditure.

Table 13 - Recommended CitiPower SCADA and Network Control capex

CitiPower	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Recommended Expenditure	0.915	0.915	0.915	0.915	0.915

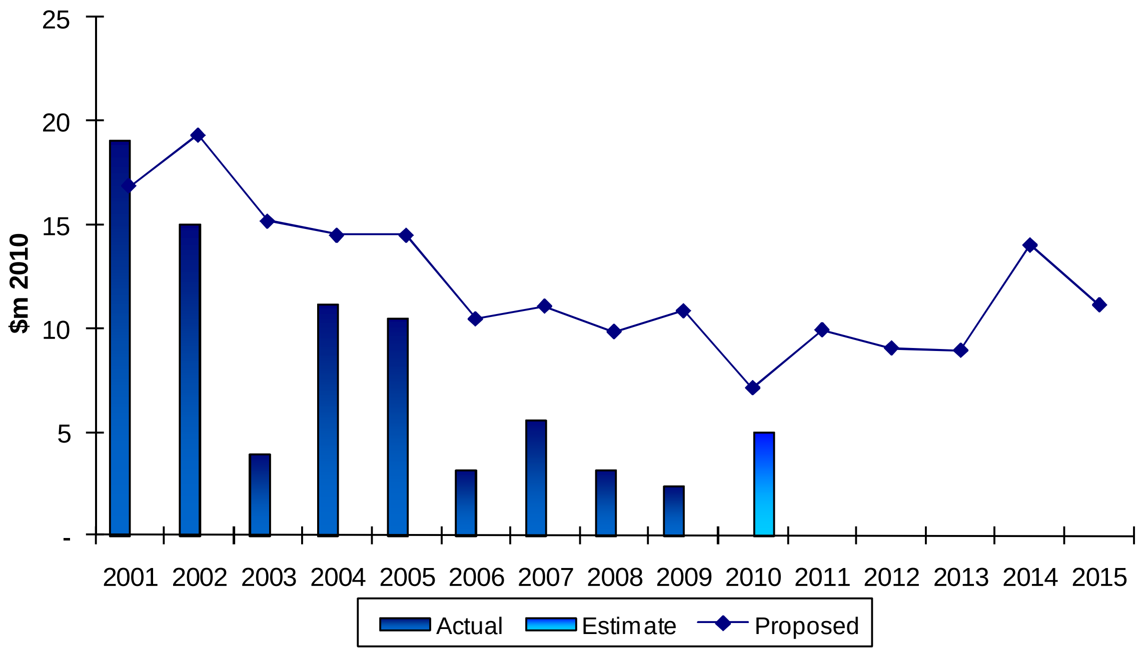
The recommended SCADA and Network Control capex for CitiPower is based on the average actual expenditures incurred in the previous 5 years[109] exclusive of indexation and escalation.

[108] Ibid – Page 318
[109] 2005 to 2009 inclusive

4.6 Non-network general – IT

In their revised proposal, CitiPower re-submitted IT capital expenditure of $53 million over the forthcoming regulatory control period, which represents an increase of 196% in average annual capital expenditure from that actually incurred in the current period. Major proposed IT capital projects include CIS replacement, leveraging off the AMI project and increasing the utilisation of mobile computing in the field.

Figure 17 - CitiPower IT capex



CitiPower and Powercor are related parties and each holds a separate electricity distribution licence for a defined geographical electricity distribution area in Victoria. The Distribution Networks are jointly managed and operated by Powercor Australia and CitiPower personnel and systems. Under the Cost Sharing Agreement, defined overhead costs incurred by Powercor Australia and CitiPower are apportioned between each respective business. CHED Services provides both CitiPower and Powercor with specialist corporate services including: the Chief Executive Officer; Finance; the Company Secretary and Legal; Human Resources; Corporate Affairs; Regulation; Customer Services; Information Technology; and Office Administration; and under the Metering Services Agreement a number of metering services. To assist us with the analysis, we again combined the CitiPower and Powercor submissions to review the actual proposed costs.

Table 14 – CitiPower and Powercor proposed IT capex

CitiPower & Powercor	Costs (2010 $M)

Non-network general – IT	2011	2012	2013	2014	2015
CitiPower – Proposed	9.6	8.7	9.5	13.7	10.8
Powercor – Proposed	25.3	21.5	21.3	30.0	23.7

The original Nuttall Consulting report rejected the IT capital program proposed by CitiPower and substituted a new IT Capital Allowance based upon audited historical expenditure.

In their response to the Draft Determination, CitiPower submitted that the AER should include 2009 actual data in its trend analysis and in forecasting the required capex for the next regulatory control period by reference to historical expenditure. Nuttall Consulting has incorporated the 2009 data, however our recommendation does not rely on the 2009 trend.

In their response to the Draft Determination, CitiPower submitted that they did not underspend on Non-network-IT capex because it was efficient to do so. They underspent because IT resources were redirected to the implementation of the mandated AMI rollout. CitiPower does not accept that this means it will likely defer or modify its proposed Non-network-IT projects in the 2011-15 period. However, the estimate of 2009 IT capex that was provided in the CitiPower November proposal was 129% above the actual expenditure for the 2009 year. This highlights a significant error in the forecasting process. As the requirements of AMI were known at the time CitiPower made the 2009 estimate, this suggests that AMI was not the cause of the underspend in this period.

A review of expenditure and forecasts for the previous 9 years highlights that CitiPower has a history of under-spending on its Non-Network IT forecasts. The Nuttall Consulting analysis highlights that this relates to a systemic problem in the forecasting process, including the lack of recognition of external and internal project delay mechanisms.

On the basis of the lack of IT agility and the forecasting process errors, Nuttall Consulting is unable to rely upon the forecasts as provided.

In their response to the Draft Determination, CitiPower submitted that the AER must make its assessment on the basis of a reasonable expectation of future external events. CitiPower maintains there is little possibility of a future event on the size and scale necessitated by the AMI rollout. Whilst a single event of the scale of AMI may or may not occur in the next period, Nuttall Consulting believes that CitiPower should be expecting and accounting for change. In the dynamic environment in which CitiPower operates its IT system should be designed to be sufficient agile to accommodate change and the potential for change should be better forecast. Whilst CitiPower deferred a number of Non-Network IT Capital Projects such as the upgrade of the CIS system due in part to the mandated rollout of AMI, CitiPower also deferred IT-related SCADA and Network Control capital projects, due to reasons totally unrelated to AMI. The stated reasons[110] include

[110] CitiPower Revised Submission. 9.11.3.2 Reasons for underspend in the current regulatory control period. P302-303.

complications arising with essential lead-in projects, vendor issues and an underestimation of the level of testing required. Whilst AMI was a significant requirement, Nuttall Consulting believes that CitiPower has over stated this impact and has not sufficiently considered the underlying IT systems not being sufficiently agile.

In their response to the Draft Determination, CitiPower rejects Nuttall Consulting's assertions that its IT systems are not agile. CitiPower states that Nuttall Consulting's analysis is not DNSP specific and its findings are gross generalisations and do not take into account the specific circumstances of CitiPower. Nuttall Consulting has examined all the information provided by CitiPower in reaching its conclusion. Whilst CitiPower's circumstances are unique and specific, the fundamental agile technology is largely a commodity, that could be customised for CitiPower's specific circumstances.

In their response to the Draft Determination, CitiPower considers that the AER appears to be implying that CitiPower and Powercor may defer the CIS replacement project again. Nuttall Consulting believes that the previous deferrals of the CIS project demonstrates a lack of overall IT agility. However, Nuttall Consulting is not recommending the deferral or advancement of any specific project. Nuttall Consulting considers that CitiPower will continue to prioritise its capex based on business needs and notes that the allowance that is made by the AER represents an estimate of efficient and prudent expenditure that the DNSPs may over or underspend based on their own business needs.

The allowance that is recommended by Nuttall Consulting is not specific to an individual project, but represents the prudent and efficient overall expenditure as recommended by Nuttall Consulting. As we have observed from previous periods, each DNSP will respond to the changing business requirements and resultant expenditures will vary from the recommended allowance.

In their response to the Draft Determination, CitiPower requested the AER actively engage in considering the material before it in both the initial and revised regulatory proposals. If it does so, CitiPower considers that the AER should be satisfied the proposed expenditure is prudent and efficient and reasonably reflects the capex criteria. Nuttall Consulting has reviewed all the submitted material and this information has been considered in forming our recommendations.

In their response to the Draft Determination, CitiPower states that the AER cannot discount the evidentiary value of the external cost benefit analysis CitiPower obtained from PwC in respect of its AMI leverage project on the basis that it is not an internal assessment. Nuttall Consulting has reviewed all the submitted material including the PwC opinion and has considered this in forming its recommendations.

In their response to the Draft Determination, CitiPower considers that the majority of the costs of the AMI leverage project will not be funded through the S-factor scheme. Nuttall consulting believes that if IT capital expenditure improves reliability of the distribution network, then the DNSP will be, at least partially, funded via the S-factor scheme.

In their response to the Draft Determination, CitiPower considers that the AER has incorrectly assumed that any reinforcement capex savings associated with the AMI leveraged project would be realised in the 2011-15 regulatory control period. Also, CitiPower believes that the AER would be expected to take into account capital deferral benefits likely to be realised in the 2016-20 period as a result of the AMI leveraged projects upfront. As a consequence, CitiPower believes that the benefit of any network deferral will be passed immediately through to customers without CitiPower obtaining any share of those benefits that could be directed towards partially funding the AMI leveraged project.

CitiPower is proposing $8.1m in capex to leverage the information from the AMI new meters. In the original Nuttall Consulting reports we stated that "Whilst we agree that there should be benefits through these "AMI leveraging projects", and these benefits may well outweigh the additional costs, we do not consider that the DNSPs have:

- adequately quantified all of the costs and benefits that may accrue through the use of the AMI data, and defined these in terms of those provided for through existing incentive mechanisms (e.g. STPIS, EBSS) and those external to these schemes
- adequately demonstrated that their proposed expenditure represents only the incremental level above that available through the existing incentive mechanisms."

The CitiPower responses to the Nuttall Consulting position are provided above. This response provided no additional quantification or estimates to address the concerns raised by Nuttall Consulting, we do not consider that the proposed AMI leverage expenditures are reasonable or meet the capex objectives.

Based on our review of the revised submission, Nuttall Consulting rejects the overall CitiPower IT capital forecast and recommends that a new forecast be substituted based upon a proportion of forecast expenditure. In our opinion, CitiPower has not fully considered the complexity of the totality of works that they are contemplating and the amount of change they can absorb, given the lack of agility in the IT environment. This is further demonstrated by their historical underspending of proposed IT capital expenditure and systemic errors in the forecasting processes. We consider it more likely that CitiPower will take considerably longer to complete many of these projects. Therefore, we recommend that the average forecast capex be reduced by 33%.

Table 15 – CitiPower recommended IT capex

CitiPower & Powercor	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
CitiPower – Proposed	9.9	9.0	8.9	14.0	11.1
CitiPower – Recommended	6.4	6.4	6.4	6.4	6.4

4.7 Non-network general other

CitiPower does not contest the AER's Draft Determination with respect to non-network – other capex. On this basis, Nuttall Consulting has not undertaken any further review of this capex category in relation to CitiPower.

5 Appendix B - Jemena findings

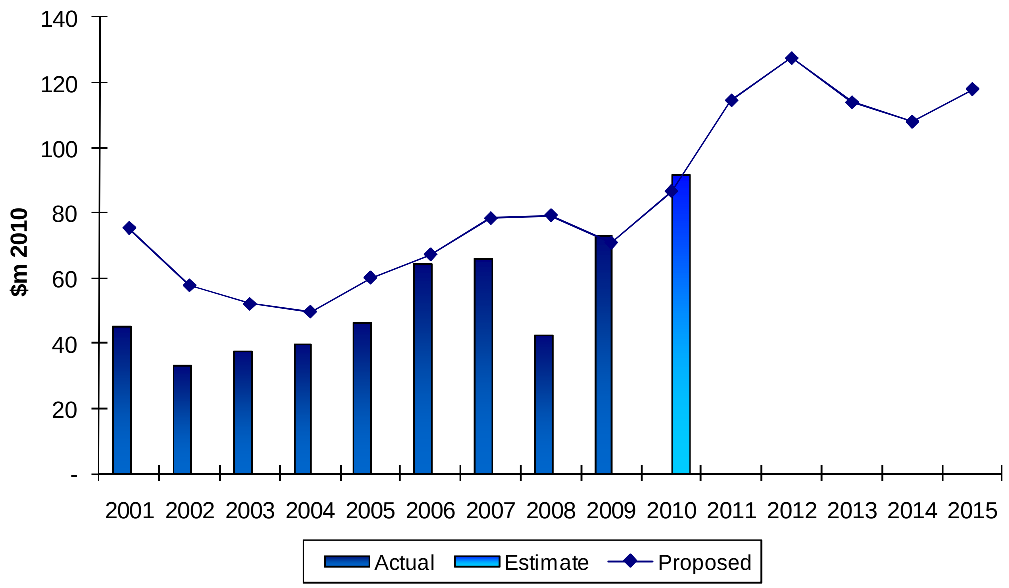
5.1 Overall capex

Overall capex is forecast to increase by 89% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement and reliability and quality maintained.

The following chart provides a summary of the overall capex figures for Jemena. Key aspects of this chart include:

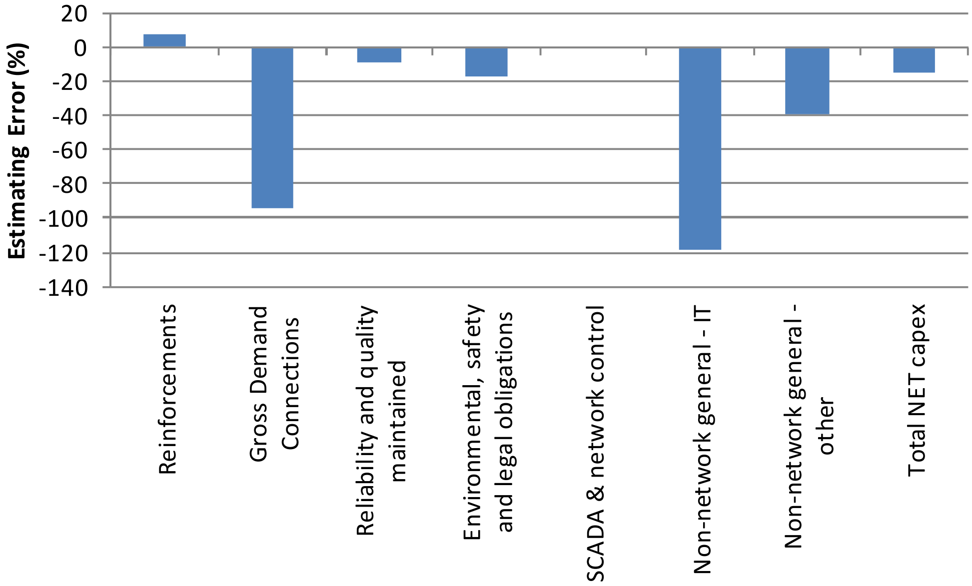
- Jemena has consistently spent less than they proposed in the 2001 and 2006 EDPRs, with the exception of 2009
- Jemena is proposing a future level of capex that is significantly higher than the historical levels of expenditure and is not consistent with the historical trend in capex.

Figure 18 - Jemena Capex Summary



The following chart considers the accuracy of the November 2009 Jemena proposal compared with the actual 2009 audited data.

Figure 19 – 2009 estimating accuracy



The estimated figures for 2009 were provided by the DNSPs in November 2009; two months prior to the completion of the financial period. The actual figures for 2009 have been subject to audit and were provided to the AER in early 2010.

The overall accuracy of the 2009 Jemena forecasts was relatively poor with actual net capex varying by 15% from that estimated. However, the above chart highlights that the DNSP forecasts at the individual capex category show significant levels of variation from the actual 2009 capex. This highlights a concern with the forecasting processes utilised by Jemena and calls into question the veracity of the forecasts for 2010 and the next regulatory control period of 2011 to 2015.

When considered in conjunction with the historical levels of forecasting inaccuracy as described in 2.2, Nuttall Consulting observes that the processes used by Jemena to forecast expenditure in this category have not produced reliable forecasts.

Nuttall Consulting requested Jemena to provide an explanation of the methodology applied to determine the 2009 and 2010 estimates and to explain the relationship of this methodology to the methodology used to produce the 2011-2015 forecasts[111]. Jemena did not identify any changes or variations between the forecasting methodologies.

This raises a concern relating to the accuracy of the DNSP forecasts for the next control period as the methodologies used to create these forecasts are the same methodologies that have produced the previous inaccurate estimates and forecasts.

To be clear, although the above information provides sound reason to question the accuracy of the DNSP forecasts, Nuttall Consulting has not taken this as proof that the forecasts do not meet the capital expenditure objectives. The Nuttall Consulting review of the forecasts has been undertaken on a case-by-case basis with due consideration of the information provided by the DNSPs.

[111] Nuttall Consulting information request (email) – 18 January 2010.

5.2 Reinforcement

Jemena's revised proposal makes a number of criticisms of the process and findings of Nuttall Consulting's original review of Jemena's reinforcement expenditure.

General criticisms of the process we applied, which are similar between DNSPs, have been discussed in Section 3.1 above. This section deals with matters more specific to our findings on Jemena's reinforcement forecasting methodology and our review of a number of reinforcement projects. Importantly, this section includes revised project probabilities, which will be important for the AER in its considerations of the appropriate reinforcement allowance.

5.2.1 Load profile

In our original report, we considered that Jemena's load profile assumptions, which were based upon the 1999/2000 load profile, would overstate energy at risk in the next period. This was based upon our analysis of historical load profiles, which indicated that the increasing peakiness of the load profile may result in future energy at risk being overestimated if a historical load profile is assumed.

We note that Jemena has revised its load profile assumptions it uses to calculate energy at risk. The load profile Jemena has used in its revised proposal is based upon the 2007/08 profile.

We accept that this should improve the accuracy of energy at risk forecasts. Nonetheless, we still consider that, based upon our analysis, this revised forecast may still materially overstate the energy at risk, particularly in the latter half of the next period.

We have revised our project probabilities to reflect this change. However, it is worth noting that the load profile assumptions have only a minor affect on our project probabilities.

5.2.2 Project review updates

The following projects were assessed as part of Nuttall Consulting's review of Jemena's reinforcement expenditure:

1. Preston area voltage conversions, including the new East Preston and Preston zone substations
2. Pascoe vale transformer upgrade
3. Tullamarine new zone substation
4. Craigieburn new zone substation (plus associated land purchases)
5. TTS-CN-CS-TTS 66 kV line re-conductor
6. KTS-MAT-AW-PV-KTS 66kV loop re-conductor and later splitting
7. Distribution substation upgrades.

In Jemena's revised proposal it has removed the Craigieburn new zone substation project. For the remaining projects, it has disagreed with the our findings.

The following sections discuss our reassessment of the remaining projects, based upon Jemena's revised proposal.

It is also important to note that we understand the AER will largely be accepting Jemena's demand forecast. In our original review we had allowed for a reduction in the demand forecast, based upon advice from the AER. In the discussions below and the revised project probabilities, we have not allowed for any reductions from Jemena's demand forecast. This has resulted in increased project probabilities.

5.2.2.1 Preston / East Preston Conversion

This project involves the establishment of two new zone substations at East Preston (EP) and Preston (P). This project is associated with Jemena's strategy to upgrade to the existing 6.6 kV voltage level in the Preston area to 22 kV. This strategy will result in significant increases in the network capacity in this area to cater for anticipated load growth.

This project was assessed as part of Nuttall Consulting's probabilistic analysis of Jemena's reinforcement needs. Based upon our original review, this project was given a moderate probability (50%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that:

- Jemena's cost estimate was significantly higher than our estimate for the project
- the project timing is primarily related to age/condition of the 6.6 kV assets, but the condition information did not justify the timing.

Jemena's revised proposal considers that capex funding for this project should be considered 100% required. The main issues raised in Jemena's revised proposal relate to the above two matters, namely:

- our view that the cost estimate is too high
- our view that the project is primarily age driven, whereby Jemena considers demand is a significant driver.

With regard to the project cost estimate, Jemena has produced a document[112] in response to our assertion that 'Jemena's cost for the Preston projects is on the high side of a reasonable range'. This document tabulates[113] the costs associated with the entire Preston / East Preston conversion program for each year 2008 to 2019. The total cost stated for the years 2011 to 2015 is $23.7M[114].

[112] Costing Analysis & Comments on Tullamarine & Preston / East Preston Conversion projects – dated 13 August 2010
[113] Table 5-1 page 10.
[114] This value is stated as being in 2009 dollars including 6% overhead and 8% margin.

We have reviewed the material made available by Jemena related to its cost estimate. This has advised us of a number of scope differences to our cost estimate. We have considered the need for this scope and largely accepted the reasoning given by Jemena. Based upon this new material, we do not consider that the difference between our estimate and the Jemena estimate would be material; and as such, have accepted Jemena's estimate.

With regard to the issue of the project driver being demand, we certainly accept that from a strategic point of view, the medium long term needs for the 22 kV upgrade are demand driven. However, we considered that the specific timing of the project is primarily related to the condition of the assets.

Our view is based upon our analysis of Jemena's strategic planning report for these projects. This report makes no mention of transformer loadings being of concern, and forecasts of the value of expected unserved energy is not provided. The strategic plan *does* discuss feeder loading as an issue. On this matter, we note that Jemena's aim is to keep the feeder load below 70% of rating, to allow for switching in the event of an outage. Section 3.2 of the report concludes: "(t)herefore, it is necessary to carry out system augmentation works to allow load to be transferred from P and EP feeders to other nearby feeders that have spare capacity." However, in our view, this is an argument to do more work in the distribution network, rather than the preferred option to establish two zone substations. We do not consider that the strategic plan has sufficient information in it on the forecast feeder overload issues and specific distribution options to address these issues, to justify that the proposed zone substation developments at the proposed time can be reasonably considered the preferred option.

Given additional information has not been provided by Jemena to support its views, we still consider that the project timing is primarily age-driven, and the condition of the asset may allow a 1 to 2 year deferment.

Conclusion

Based upon the above, we have revised our project probability from moderate (50%) to moderate to high (70%)[115]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects our view that the project timing is primarily age-driven and condition information suggest a 1 to 2 year deferment may be possible.

The increase is due the AER's change in its position on Jemena's maximum demand forecast and our acceptance of the Jemena cost estimate.

5.2.2.2 Pascoe Vale Transformer Upgrade

This project involves the replacement of the existing three transformers with two transformers of a higher aggregate capacity.

This project was assessed as part of Nuttall Consulting's probabilistic analysis of Jemena's reinforcement needs. Based upon our original review, this project was given a moderate

[115] Probability based upon: 90% (historical accuracy) x 80% (deferral due to condition)

to high probability (70%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that:

- the project timing is primarily related to age/condition of the assets at Pascoe Vale, but the condition information did not justify the timing
- the project may be reduced in scope, due to the relatively better condition of the transformers compared to the switchgear.

Jemena's revised proposal considers that capex funding for this project should be considered 100% required. The main issues raised in Jemena's revised proposal relate to the above two matters, namely:

- our view that the project is primarily age driven, whereby Jemena considers energy at risk is sufficient to justify the project
- our view of alternative lower cost options.

Nuttall Consulting has considered Jemena's Business case[116] and financial analysis spreadsheet[117] for the refurbishment of the Pascoe Vale Zone Substation, submitted as part of its revised regulatory proposal. A review was subsequently performed, taking into account additional information provided in the business case.

In Jemena's 2009 DSPR, a proposal to replace 2 of the 3 transformers at Pascoe Vale was put forward. In the revised regulatory proposal, a much larger project has been submitted[118] with some assumptions revised (see Table below).

Table 16 Revised scope of project assumptions for Pascoe Vale project

	Original Submission[119]	Revised Submission
Capital Cost ($M)	$4.3 million	$9.0 million
Scope	Replace 2 transformers	Replace 2 transformers, 66kV circuit breakers, 11kV switchboard Protection and control systems Extend the switchroom
Value of expected unserved energy (EUE)	$138K in 2012	$1,981K in 2012
EUE Based on	$55,000 / MWh N-1 rating only	$40,000 / MWh N-1 rating and N rating at nameplate only

[116] Appendix 8.10 to the Revised Regulatory Proposal
[117] C444-08 Financial analysis - Refurbishment of PV ZSS - Final.xls
[118] It is our understanding that some of this project is allocated to RQM
[119] As detailed in DSPR 2009 (Section 8.1.19)

The business case seeks to argue that the project is prudent, based on the increased value of EUE i.e. it is demand driven. However, we do not believe that the calculated value of EUE in 2012 in the revised proposal is reasonable.

In section 3.1.1 of the business case, the N rating of the substation is given as 33MVA, based on 3 transformers with 11 MVA nameplate ratings. It is good electricity industry practice to allow some cyclic overloading of transformers as described in the Australian Standard, *AS 2374.7 1997 Loading Guide for oil-immersed power transformers*. Long term cyclic ratings of between 110% and 120% of nameplate ratings are common and it is standard practice to allow for these when calculating energy at risk. Use of the cyclic ratings in the energy at risk calculations would result in a reduced value of expected unserved energy, and so delay the need for the project. Based upon our assumption of a relatively modest cyclic rating of 110% of nameplate rating, we estimate that a value of expected unserved energy of $137K in 2012, which is considerably less than that required to justify the project. We consider that an allowance for cyclic rating may result in around a 2-year deferral of the project.

With regard to the option considered by Jemena, we still have some concerns that alternative lower cost options may exist. The business case indicates that only two of the substations adjacent to Pascoe Vale operate at 11kV, Essendon (ES) and North Essendon (NS). The current transfer capacities listed to these two stations are 0.7 and 2.1 MVA respectively. Switching constraints mean that only the 2.1 MVA to NS can be used. We consider it reasonable to assume that lower cost options involving 11kV network reinforcement to provide more switching capacity or off-load PV substation may exist; however, they have not been addressed in the business case.

Furthermore, another option, which may delay the need for the investment proposed at Pascoe Vale is the installation of additional capacitors on the 11kV busbar. This would reduce the MVA load on the transformers, and thus reduce the energy at risk. We note that the installation of an 8 MVAr capacitor bank at PV in 2015 has been proposed in the 2009 DSPR. Advancing this project may delay the need for the major substation refurbishment recommended in the business case.

Conclusion

Based upon the above, we have maintained our project probability at moderate to high (70%)[120]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects our view that:

- the project timing may be deferred 1 to 2 years, given our assessment of the energy at risk and the condition of the aging assets
- the possibility that a lower cost alternative option may be found to be the preferred solution.

[120] Probability based upon: 90% (historical accuracy) x 85% (deferral – cyclic ratings/condition) x 88% (alternative options)

5.2.2.3 Tullamarine Substation Establishment

This project involves the establishment of a new zone substation at Tullamarine. This project is driven by load at risk at the exiting Airport West zone substation (AW) and various issues with distribution feeder loading.

This project was assessed as part of Nuttall Consulting's probabilistic analysis of Jemena's reinforcement needs. Based upon our original review, this project was given a moderate probability (50%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that optimisation of the project scope may result in further deferral.

Jemena's revised proposal considers that capex funding for this project should be considered 100% required. The main issue raised in Jemena's revised proposal is that energy at risk is sufficient to justify the project.

Nuttall Consulting has considered Jemena's Business case[121] for the Establishment of Tullamarine Zone Substation, submitted as part of its revised regulatory proposal. A review was subsequently performed, taking into account additional information provided in the business case.

The table below indicates the main changes to the project cost and underlying assumption in the revised proposal.

Table 17 Revised scope of project assumptions for the Tullamarine project

	Original Submission[122]	Revised Submission
Capital Cost ($M)	10.3	9.9
Completion	2012	2012
Scope	New Zone Substation 1 Tx	New Zone Substation 1 Tx
Value of expected unserved energy	$490K in 2016[123]	$872K[124] in 2016/17
Value of expected unserved energy (inc feeder outages)		$1,245K[125] in 2011/12

The economic justification for the project is laid out in the business case attached to the revised proposal, and is largely justified on the basis of expected unserved energy (EUE) due to overloaded distribution feeders. Some of this energy is due to feeders being overloaded in normal system conditions, and some is due to EUE in the event of feeder outages.

121 Appendix 08.11 of the Revised Regulatory proposal
122 As detailed in DSPR 2009 (Section 8.1.1)
123 C459-8 G3 Planning paper - TMA zone substation v6.pdf sent to Hill Michael on 11 March 2010
124 A08.11 - Business Case - Tullamarine (TMA) Zone Substation - CONFIDENTIAL.pdf. July 2010, Table 4.
125 A08.11 - Business Case - Tullamarine (TMA) Zone Substation - CONFIDENTIAL.pdf. July 2010, Table 4 and 6

We still have a number of concerns with the assumptions Jemena has made in the calculation of the feeder EUE.

Firstly, the distribution feeder repair time (MTTR) of 4 days is much higher than we would expect. Published values of actual SAIDI performance of the AW feeders obtained from the ESC Victoria website[126] show that the annual average total minutes off supply never exceed 400 minutes on any AW feeders in the period 2005-2007. In the same period, none of the AW feeders exceeded a SAIFI of 4.0. These figures are not directly comparable, but they do indicate that a MTTR of 4 days is higher than actual experience. In our view, a figure of less than 1 day is expected. Allowing for this adjustment in Jemena's economic analysis spreadsheet results in a delay in the economic timing of the project by approximately 1 year.

Secondly, we note that the forecast growth rate on feeder AW8 is very high. We have calculated the growth rate implied for AW8 in Jemena's economic evaluation spreadsheet[127]. The table below shows Jemena's forecast 50% PoE load forecast on AW8 and our calculated annual growth rate.

Table 18 Growth rates for AW8 feeder

Year	2010	2011	2012	2013	2014	2015	2016
Load (MVA)	12.3	14.1	15.6	16.9	17.5	18.1	18.7
Growth (pa%)		15%	10%	8%	3%	3%	4%

These figures are different to figure 2 in the business case which is copied below.

Figure 20 Copy of Figure 2 in Tullamarine business case

Figure 2 – The Airport West and Tullamarine Areas

[126] Electricity Distribution Businesses – Comparative Performance Report 2007, Feeder Performance 2005–07 for Alinta AE October 2008

[127] A08.11 Airport West (New Tullamarine Zone Substation) v0_1.xls (EAR tab, cells EG8:EP8)

If annual growth rates, similar to those in the figure, are assumed on feeder AW8, the need for the project can be delayed by 1-2 years. Alternatively, if the growth rate on the feeder is as high as suggested then it may be that a HV augmentation, specifically focused on addressing this feeder's loading, may result in the larger project being deferred. We do not consider that this specific issue has been addressed in Jemena's business case.

Finally, it is also important to note that as the new zone substation will address the high utilisation on the HV feeders by splitting a number of existing feeders then it is likely that reliability benefits will occur due to improvements in reliability. As such, it is likely that at least part of this project would be funded through the reliability incentive scheme.

Conclusion

Based upon the above, we have revised our project probability from moderate (50%) to moderate to high (70%)[128]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects our view that:

- the project timing may be deferred by 1 to 2 years, given our assessment of the conservatism in the energy at risk calculations
- the possibility that a lower cost alternative option may be found to be the preferred solution to manage the forecast growth on the AW8 feeder
- the project will be part funded through the reliability incentive scheme.

The increase largely reflects the AER's change in its position on the Jemena's maximum demand forecast, but also our removal of the reduction due to the load profile assumptions.

5.2.2.4 TTS-CN-CS-TTS 66 kV line re-conductor

This project involves the re-conductoring of sections of the existing TTS-CN-CS-TTS 66 kV line. This project is driven by load at risk due to an outage of a section of the existing line.

Nuttall Consulting assigned the project a moderate to high probability (70%) of occurring as planned, based upon the load profile used by Jemena in its energy at risk calculations, and the AER's findings on Jemena's load forecast.

Jemena's revised proposal requests the full reinstatement of this project. However, the basis appears to be Jemena's view that we considered energy at risk to be sufficient and therefore assigned a 90% probability to this project. Although this does not reflect Nuttall Consulting's view at that time, given the AER's acceptance of the Jemena demand forecast and Jemena's subsequent change to its load profile assumption, we are satisfied that energy at risk should be sufficient, and therefore, this project can be assigned a high probability of occurrence as planned (90%).

We do not consider that a 100% probability is appropriate in these circumstances for the reasoning discussed in section 3.1.

[128] Probability based upon: 90% (historical accuracy) x 90% (deferral – energy at risk calculations) x 90% (alternative options) x 88% (reliability improvement funding)

5.2.2.5 KTS-MAT-AW-PV-KTS 66 kV Loop Upgrade

This project involves the re-conductoring of sections of the existing KTS-MAT-AW-PV-KTS 66 kV line followed by a later project to split the loop. This project is driven by load at risk due to an outage of a section of the existing line.

This project was assessed as part of Nuttall Consulting's probabilistic analysis of Jemena's reinforcement needs. Based upon our original review, this project was given a low probability (33%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that the risks were not sufficient to justify the timing of the project.

Jemena's revised proposal considers that capex funding for this project should be considered 100% required. The main issue raised in Jemena's revised proposal is that energy at risk is sufficient to justify the project.

Nuttall Consulting has considered Jemena's Strategic Planning paper[129] and economic analysis spreadsheet[130] for the KTS-MAT-AW-PV-KTS sub-transmission loop submitted as part of its revised regulatory proposal. A review was subsequently performed, taking into account the additional information provided in the strategic planning paper.

The proposed staging is as shown in the table below.

Table 19 KTS-MAT-AW-PV-KTS sub-transmission loop project staging

Year	Description	Capital Cost
2010/11	Install post contingent load shedding scheme	$0.1M
2011	Reconductor 1 existing line	$0.5M
2015	Build additional 66kV line and split existing 66kV loop	$1.8M

We note that the calculated values of expected unserved energy have increased significantly from those in the original regulatory proposal, and so our view on the prudent timing has changed. These values are tabulated below.

Table 20 revision to value of unserved energy - KTS-MAT-AW-PV-KTS sub-transmission loop project

	Value of Expected Unserved Energy (EUE) ($K)						
	2010	2011	2012	2013	2014	2015	2016
DSPR 2009	17	22	34	49	77	110	154
Strategic Planning Paper	15	20	155	1,486	7,234	15,298	28,256

[129] Appendix 08.12 of the revised regulatory proposal

[130] '(A08.12) KTS-MAT-AW-PV-KTS loop v0_5.xls' dated 3 Aug 2010

The difference in values, shown in the table above, can be explained by the fact that the Strategic Planning Paper submitted with the revised proposal considers the value of unserved energy associated with pre-contingent load shedding, which was not included in the original analysis. In the revised paper, Jemena argues that it would be necessary to shed load in the event that post contingent load on a 66kV line would be more than 130% of rating[131]. This policy is implemented to avoid the possibility of cascade trips or plant damage. In the network in question, tripping of KTS-MAT sub-transmission lines at peak load causes the KTS-AW sub-transmission line to be loaded beyond 130% of rating in 2012 and beyond. This accounts for the large difference in EUE in the 2009 DSPR and the Strategic Planning paper, as shown in the table above, for years 2012 and later.

We consider that further risk analysis of this load criteria and the proposed control scheme may well result in a loading criteria being accepted above the 130% indicated. However, given the low materiality of this project, we have accepted Jemena's criteria and consider that the revised values of expected unserved energy justify the proposed staged project recommended in the Strategic Planning paper.

It is worth noting that, based upon the revised information, we have noted some inconsistencies with the growth rates that Jemena has used to calculate the expected unserved energy. In the strategic planning document for the project[132] an expected annual average growth rate of 3.5% is stated. However, the economic evaluation spreadsheet provided by Jemena to support the project appears to use higher growth rates[133]. The growth rates calculated by Nuttall Consulting for the 50th percentile summer MD in MVA on the critical KTS-AW line with KTS-MAT out of service are as shown in the following table.

Table 21 maximum demand growth rates - KTS-AW line with KTS-MAT out of service

	2010	2011	2012	2013	2014	2015	2016
Summer MD (MVA)	127	130	135	140	147	153	159
Annual Growth %		2.3%	3.8%	4.2%	5.2%	3.9%	3.7%

Since the value of expected unserved energy is very sensitive to forecast maximum demand, the higher than average growth rates forecast from 2012 onwards are a cause of some concern to us. If actual growth in maximum demand is not as high as the figures in the table above, it may be that the final stage of the proposed project, the construction of a new 66kV line in 2015 at a cost of $1.8M, would be able to be prudently deferred.

All that said, as we have not been involved in the demand forecasting review, we have not adjusted our probabilities with respect to this issue. However, the AER may need to consider this in the broader context of its demand forecast review.

[131] The 130% limits appears to be the amount of overloading that Jemena considers its planned control scheme can allow for.

[132] Page 7

[133] (A08.12) KTS-MAT-AW-PV-KTS loop v0_5.xls' dated 3 Aug 2010. Tab '66kV Lines N', row 22.

Conclusion

Based upon the above, we have revised our project probability to high (90%).

5.2.2.6 Distribution substations

Jemena is forecasting a large increase in the level of distribution transformer augmentations compared to that which had occurred historically. The main reason for the increase was a change from a "reactive" replacement program, mainly associated with a "replace on fail" approach, to a "proactive" replacement program, based upon the replacement of overloaded transformers in order to reduce the failure rates. The need for this change was broadly explained to be due to increasing failure rates and the resulting increases in reliability and safety risks. In this regard, the recent heatwave (2008/09) appears to have resulted in a high number of transformer failures.

Nuttall Consulting's view was that the DNSPs had not demonstrated that the large increase in expenditure could be considered prudent and efficient. The main issue forming this view was the lack of evidence to demonstrate that the transformers can be adequately targeted, such that sufficient benefits would be realized through the reduction in the failure rate.

The important point here was that determining when a distribution transformer may fail is more problematic than simply knowing how overloaded it is. Furthermore, the DNSPs do not meter the maximum demand at individual distribution transformers; it has to estimate the loading at a particular transformer via customer metering data that is associated with transformers.

We also noted that:

- it may be more economic to defer the program until the AMI rollout in order to use the information from these smart meters to more accurately estimate transformer maximum demands and load profiles, and in turn determine empirical relationships between the level of overloading and the probability of failure
- the STIPS may provide some funding for the reliability gains predicted through the change to a proactive program.

The Jemena revised proposal has raised a number of criticisms of our position, and provided a revised strategic plan to support its forecast. The following discusses the main points raised by Jemena.

Jemena considers that Nuttall Consulting's assertion that load management systems cannot sufficiently identify transformers to be replaced is not valid. It notes that transformers are measured to confirm loading before being replaced, and the field experience confirms that the load management system provides reliable data.

We consider that this largely misses our fundamental concerns with the methodology. Our issue is not so much how accurately the loading of the transformers can be estimated, but how well this estimate helps target the transformers such that the failure rate can be economically reduced. This matter is not dealt with in the Jemena response. We have reviewed the strategic plan and do not consider that it has been adequately shown that this has been considered in the economic analysis presented in this document. The main concern we have is that Jemena's analysis appears to assume that the planned program is very well targeted and as such is very effective in removing risks. However, the paper provides little evidence to support this view. Given the scale of the expenditure increase, and the opinions we expressed in our original report, we would have expected some form of statistical analysis of historical failures; for example, to attempt to develop probability distribution that models the relationship between the failure probability to factors such as loading (and possibly age) and show the typical consequences. This could then be used to undertake a more robust form of probabilistic economic analysis, in order to determine the optimum scale of a planned replacement program (i.e. the program that will most likely maximise the net benefits). We still have significant concerns that if this form of analysis was undertaken it may not support the proposed program.

On this matter we note that Jemena is proposing to reduce the distribution transformer utilisation to 100% of normal cyclic rating over a 10 year period. This reduction appears excessive compared to the two other DNSPs proposing programs of this type (United Energy and SP AusNet). This also has to be considered in the context that many older transformers may have significant design redundancy, and as such, may be able to withstand far higher levels of overloading without risking failure. Furthermore, it is clear that historically Jemena and other Victorian DNSPs have been willing to allow transformers to breach this limit by a significant margin i.e. although the recent heatwave may have resulted in an increased number of failed transformers, information on the extent of overloaded transformers was available beforehand, and as such, these risks appear to have been accepted.

On balance, we do accept that there appears to be evidence that a planned replacement of the most heavily loaded transformers may be required. However, we do not consider that Jemena has adequately addressed our concerns with the scale of this proposed program.

We consider it reasonable to assume that the transformers over 140% of rating may be planned for replacement. Furthermore, given current utilisation levels, we also consider it reasonable to assume that this program will occur over a 5 to 10 year period. We consider that this program would result in a risk profile that is more in line with a trending down of currently accepted risks, rather than the step down over a short period that appears to be being proposed.

We also consider that further optimisation to the program may occur that may reduce or defer the number of transformer augmentations. This may occur when opportunities arise with other needs, such as the existing supply improvement program or the age related replacement program. They may also arise following further investigations Jemena may undertake prior to the upgrade, which may find that the condition of some transformers is acceptable, or at least, sufficient to optimise the upgrade with other later plans.

It is also worth noting that we consider that the STIPS should also allow for additional expenditure that will improve reliability. We still consider that this should have some relevance to this program as the reliability benefits Jemena has determined appear to be largely due to existing reliability levels, rather than only the incremental levels due to load growth in the next period.

Based upon the above we consider it reasonable to assume that a probability of 45% can be applied to this program. This assumes that the portion of recurrent expenditure occurs at historical levels (average 2006-2009), but the programmed replacement is reduced by 70%. This reduction is largely based upon the higher utilisation criteria and the spreading of the program over a longer period, but also allows for the other efficiency and funding points noted above.

5.2.2.7 Summary findings

Based upon the above, we have revised our project probabilities as indicated in the Table below.

Table 22 Jemena reinforcement project summary

Project	original probability	revised probability
Preston area voltage conversions	Moderate (50%)	Moderate/High (70%)
Pascoe vale transformer upgrade	Moderate/high (70%)	Moderate/high (70%)
Tullamarine new zone substation	Moderate (50%)	Moderate/High (70%)
Craigieburn new zone substation	Low (33%)	Low (33%)
TTS-CN-CS-TTS 66 kV line re-conductor	Moderate/high (70%)	High (90%)
KTS-MAT-AW-PV-KTS 66kV loop	Low (33%)	High (90%)
Distribution substation upgrades.	Low (30%)	Moderate (45%)
Weighted average	**38%**	**53%**

The project probabilities largely reflect the concerns we raised in our original review:

- energy at risk is insufficient to justify the timing
- part funding through the reliability incentive scheme
- alternative lower cost options
- conservative load profile assumptions
- previous forecasting accuracy.

The increases are largely due to the increased demand forecast and updates or clarification on the DNSPs project justifications.

5.3 Reliability and quality maintained

Our original review considered Jemena's RQM forecast based upon the DNSP's internal activity codes. This break-down was used as it was considered to be the most consistent between the historical and forecast allocation of expenditure. This breakdown largely reflects various asset classes, but is slightly different to the AER's revised RIN asset categories. This review lead to various parts of the forecast being accepted, and others being rejected, with the substitute forecast based upon the calibrated repex model for those categories.

Jemena has not agreed with Nuttall Consulting's rejection of these categories. Jemena has provided updated strategic asset management plans for most of its categories.

For a number of categories, the revised proposal provides comments on the specific concerns we expressed in our original report. However, for a number of other categories, the revised proposal does not provide any specific comments or criticisms. Furthermore, for a number of categories, the proposed volumes have been reviewed and recommended by ESV.

The table below list the various categories and indicates whether Jemena has rejected the draft decision. It also indicates where volumes for that category have been reviewed and recommended by the ESV.

Table 23 Jemena RQM category summary

Category	Original finding	DNSP revised proposal
Poles	Reject	Rejected – reviewed and accepted by the ESV
Pole Top Structure	Reject	Rejected – reviewed and accepted by the ESV
Conductor	Reject	Rejected – reviewed and accepted by the ESV
Distribution Transformers	Reject	Rejected – no specific comments in the revised proposal
Underground Cable	Reject	Rejected - no specific comments in the revised proposal
Zone Substation	Reject	Rejected
Protection	Reject	Rejected - no specific comments in the revised proposal
Distribution Switchgear	Accepted (partial)	Rejected - no specific comments in the revised proposal
Services	Accept	Accepted
Reliability Maintained (performance)	Reject	Rejected

General criticisms of Nuttall Consulting's approach to assessing RQM expenditure and determining substitute allowances, which are similar between DNSPs, are discussed in Section 3.2. For the categories where the ESV has accepted the volumes or made an alternative allowance, we have only considered the unit costs. This review of unit costs is discussed in Appendix G of this report.

This section discusses the remaining categories where specific criticisms or new information has been provided in the revised proposal.

5.3.1 Categories without specific criticisms in the revised proposal

As noted in Table 23, for a number of asset categories, Jemena's revised proposal does not provide any specific comments or criticisms of the matters we raised in our original report. These asset categories cover:

- distribution transformers
- underground cables
- protection
- distribution switchgear.

These categories represent 24% of Jemena's RQM forecast for the next period.

5.3.1.1 Distribution transformers

In our original report, we did not consider that Jemena had adequately demonstrated that its forecast expenditure associated with distribution transformers was reasonable. The forecast was made from two main components: an age/condition based component that was in line with the historical trend and a performance component that appeared to indicate a significant increase in expenditure. We accepted that the age/condition based forecast appeared reasonable, but did not consider there was sufficient information to justify the increase, which appeared to be due to the performance component.

We used the expenditure growth rates, suggested by the repex model, to determine the recommended allowance for this category. This resulted in an increase above the age/condition based component, but was less than the total expenditure proposed by Jemena for this category.

As noted above, Jemena's revised proposal does not provide any specific criticisms of our position. It also does not provide any new information. However, Jemena's revised proposal has significantly reduced the proposed expenditure for this category from the level we reviewed. The proposed expenditure is more in line with the previous age/condition component. This level of expenditure is below the level indicated by the calibrated repex model. This supports this proposed amount being accepted.

However, as we have significantly reduced Jemena's proposed proactive distribution transformer upgrade program, which is allocated to the reinforcement category (see section 5.2.2.6), we consider it reasonable to still allow for the additional expenditure supported by the repex model.

As such, we still consider that the allowance for distribution transformers should be based upon the average historical level between 2006 and 2009, escalated by the growth rates suggested by the repex model. For the avoidance of doubt this has resulted in a small increase above the amount proposed by Jemena.

Based upon these adjustments, the table below provides our revised estimate for this allowance (estimate exclusive of overheads and escalations).

Table 24 Jemena distribution transformers

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	0.3	0.3	0.4	0.3	0.9
Recommended	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**

5.3.1.2 Underground cables

In our original report, we did not consider that Jemena had adequately demonstrated that its forecast expenditure associated with underground cables was reasonable. The Jemena forecast indicated a very significant increase in expenditure from recent historical levels. This asset category covered two main components: cable joint and termination replacements, and cable replacements.

For the joints and terminations, the Jemena's documents indicated that forecast replacement volumes were based upon historical levels. As such, this did not appear to be a basis for the increase.

For the cables, there was a significant increase in forecast volumes from 2013 to 2015, which appeared to be driven by LV paper replacements. However, we did not consider that Jemena's documentation adequately justified that this scale of replacement was required.

Nuttall Consulting's recommended allowance was based upon the average historical level of expenditure in this category (2006-2008) with an additional component based upon the annual expenditure increase predicted by the calibrated repex model.

As noted above, Jemena's revised proposal did not provide any specific criticism of our review of this category; however, it did provide a revised strategic plan for underground cables. The underground cable volumes were also discussed in an expert report provided with the revised proposal (the PB report)[134].

[134] Jemena revised proposal, Appendix 8.2

Both documents note that PB's replacement model was used by Jemena to forecast the volumes for underground cables. The PB report includes a review of the model inputs and considers them reasonable.

Both documents cover the same matters associated with the need for the increases. These are as follows:

- It is considered that an increasing volume of assets are entering the 'wear-out' phase, with two distinct age profiles: paper insulated cable with a 70-year life of which the oldest assets are 73 years old[135]; and early XLPE cable with a life of 40 years[136] and none older than 40 years. Jemena considers that these proportions will increase if historical replacement rates are maintained.
- An increasing trend in the number of cable faults is discussed. This includes information on historical cable fault rates (1999-2008), indicating a 5% annual increase, which Jemena considers supports the view that assets are nearing their end of life and replacement needs are increasing.
- Three specific cable integrity issues are discussed. These are:
  - 8.4 km of very old cable was installed between 1908 and 1937; the majority is 73 years old; this cable has poorer reliability than new cable;
  - an aging type of paper insulated HV cable, which is now over 50 years, has experienced a number of failures;
  - Jemena has experienced an "excessive" number of joint failures on XLPE cables; it notes that this is currently being investigated and supports the view that increased volumes of replacement are required.
- It is also considered that there are increasing risks resulting from changing weather patterns (climate change) and the increased incentive rates that are proposed for the reliability incentive scheme.
- It is also noted that the historical replacement rate is significantly below the required long-term replacement rate. Jemena considers that, given it has 2,852 km of cable, maintaining the existing replacement rate over the current period (0.9km per annum) would require lives over the long-term in excess of 1000s of years. Even allowing for the rate proposed for the next period (5.7km per annum) suggests further significant increases will be required.
- Jemena has also undertaken an evaluation of three options: do nothing, maintain investment levels, and the proposed program. Jemena considers that this supports its proposed program, indicating that reliability and public safety risks will degrade if current levels of investment are maintained.

[135] We note it also indicates the oldest is 90 years in places, but based upon the age profile, this appears to be a very small amount.
[136] We note it also states 35 years in places.

Nuttall Consulting has reviewed the new information provided. We consider it important to note that with regard to the reasons for the increase, both the Jemena paper and the PB report provide the same arguments. In many places, they actually have the same text. However, there is no referencing between documents; and as such, it is not clear which party has copied the others material. We find this strange in this regulatory context, where it would be normal practice to reference others material and provide some form of critique of it.

Setting this matter aside, we still consider that the new information does not adequately demonstrate that the scale of the proposed increase is required. On this matter, we do not disagree, in principle, with the matters raised and we consider that this justifies increasing replacement levels. This position is in line with our original recommendation, where we allowed for an increase of approximately 10% per annum. However, we do not consider that this new information provides compelling evidence that the further increases proposed by Jemena are reasonable.

With regard to the proportion of assets entering the wear out phase, the increasing failure rates, the integrity issues, and the historical replacement rate, there is no analysis to suggest that Jemena's proposed increase is the required amount other than the Jemena's analysis using to PB replacement model which we will discuss below.

With regard to the integrity issues, we do not disagree that these are real. However, given a lack of analysis to the contrary, it seems reasonable to assume that reliability may not degrade much further in the next period than already accepted by Jemena in this period, and so Jemena may not need to replace the level it is proposing.

On the need for increases in historical replacement rates, this view is supported by our repex modelling, which indicates rates will continue to increase for a significant period into the future. However, our modelling does not support the view that the increase needs to be as dramatic in the next period as proposed by Jemena; rather, it indicates a more gradual and sustained ramping up.

Finally, with regard to the increasing risks, we do not consider that Jemena has provided sufficient evidence to demonstrate that these increases will be material. For example, we understand that the AER is not excepting that climate change will cause a material difference in the next period. Furthermore, with respect to reliability incentive rates, we consider it reasonable to assume that if they give some downside risk for failure, they must also give a greater reward for actions; therefore, there should be additional funding through this scheme.

Ultimately, the basis for the proposed increase rests with Jemena's replacement model, and in particular, the lives it has assumed for this model. We do not consider that there is sufficient evidence to say that Jemena's assumed lives are reasonable – noting its use of 70 years for paper and 40 years for XLPE.

We note that PB's only real comment on this matter is to say that the lives "*appear to be typical of asset lives typically used by electricity distribution businesses in replacement* *modelling"*[137]. But there is nothing else to clarify the basis of this statement. For example, are the comparative lives that PB refers to, used and validated by businesses that are current seeing significant levels of replacement; or are these lives those that PB has historically used for replacement modelling.

Based upon lives benchmarked to past expenditure, we consider there is evidence that significantly longer lives can and are being achieved. For example, typical benchmark lives determined by the UK regulator, Ofgem, for HV and LV cables are greater than 80 years[138]. Based upon our benchmarking of CitiPower cable replacement volumes, we found that average lives for CitiPower must be considerably longer than 70 years.

Based upon the above, we still consider it reasonable to reject Jemena's forecast. We also consider it reasonable to substitute an allowance based upon the historical replacement levels (2006-2009), with the growth rate set by the repex model benchmarked to historical volumes.

It is worth noting that based upon our revised analysis, this still provides for an increase in expenditure of approximately 11% per annum.

Based upon these adjustments, the table below provides our revised estimate for this allowance (estimate exclusive of overheads and escalations).

Table 25 Jemena underground cables

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	0.7	0.8	1.4	2.1	2.3
Recommended	**0.6**	**0.6**	**0.7**	**0.8**	**0.9**

5.3.1.3 Protection

In Jemena's original proposal, the forecast for the protection category was made from two main components: an age/condition based component that was below the historical trend and a performance component that appeared to indicate a small increase in expenditure.

In our original report, we noted that the methodology applied by Jemena to produce the forecast for this category was not clear. We used the expenditure growth rates suggested by the repex model to determine the recommended allowance for this category. This resulted in an increase above the age/condition based component, but was less than the total expenditure proposed by Jemena for this category.

As noted above, Jemena's revised proposal does not provide any specific criticisms of our position. It also does not provide any new information. However, Jemena's revised proposal has significantly altered the historical and forecast expenditure for this category from the level we reviewed. We understand that this is partly due to the performance

[137] Jemena revised proposal, Appendix 8.2, pg 27
[138] http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/May_doc_appx_results.xls

component being allocated to the reliability category in the revised proposal. However, the remaining expenditure is still showing an increase from historical levels.

The majority of the revised forecast for this category is associated with the replacement of aged relays; however, based upon the asset volume information provided in the revised RIN, replacement volumes do not appear to be increasing. Given the above, and the lack of detail in Jemena's documents to justify the forecast, we consider that the allowance for this category should be based upon the average historical level between 2006 and 2009, escalated by the growth rates suggested by the repex model.

Given the link with the reliability category, to ensure consistency with our original review, we have assessed the increase as a composite of the protection and reliability categories. This composite allowance is discussed further below, in our review of the reliability category.

5.3.2 Distribution switchgear

In Jemena's original proposal, the forecast for distribution switchgear was made from two main components: age/condition based replacements and a performance enhancement component.

In our original report, we did not review this category in detail. However, given the findings repex model, we considered the age/condition component to be reasonable.

As noted above, Jemena's revised proposal did not provide any specific comment on our review of this category; however, Jemena's revised proposal has significantly altered the forecast expenditure for this category from the level we reviewed, which now shows a more significant increase over the next period. The revised proposal also provides a revised strategic plan for distribution switchgear.

The strategic plan covers the matters Jemena considered most relevant to the need for the increases. These are as follows:

- It is considered that an increasing volume of assets are entering the 'wear-out' phase, resulting in the need for an increase in replacement levels.
- Asset inspection information supports increasing rates of replacement.
- Known specific defects of a number of types of switchgear – the paper summarises a number of issues.
- A brief discussion of three options is provided covering a "do nothing" option, switchgear refurbishment, and the proposed program. Jemena considers the proposed program is the only feasible option.

Nuttall Consulting has reviewed the new information provided. Based upon this review, we consider that the new information does not adequately demonstrate that the scale of the proposed increase is required. On this matter, we do not disagree, in principle, with the matters raised and we consider that this justifies increasing replacement levels. This position is in line with our original repex modelling, were we determined an increase of 5%

per annum. However, we do not consider that this new information provides compelling evidence that the further increases proposed by Jemena are reasonable.

With regard to the proportion of assets entering the wear out phase, there is no analysis to suggest that Jemena's assumptions on asset lives are reasonable. In this regard, the strategic plan notes that Jemena does not have sufficient information to determine a relationship between age and condition; however, it considers there is evidence that the nominal life (35 years) it has assigned to this group is consistent with the wear-out phase[139].

We dispute this position as we do not consider that Jemena has presented any compelling evidence to support this view. If we applied its 35 year life in our repex model, we would predict much higher levels of replacement than have occurred. Without Jemena discussing this type of analysis, it is not clear how it can claim that its lives are reasonable when they appear not to reconcile with its own history. It is also noted that, other than United Energy, our benchmark lives for distribution switchgear of the other DNSPs was well above 35 years. Furthermore, Ofgems analysis of UK DNSPs lives found lives well above 35 years for distribution switchgear, other than pole mounted circuit breakers[140].

With regard to the inspection information and stated asset issues supporting its forecasts, we do not disagree that these support a need for increasing replacement levels. However, we do not consider that Jemena's paper has provided any meaningful information to support the scale of its forecast. The information is largely qualitative and does not provide any information that demonstrates how risks will change in the next period from those accepted in the current, and consequently, how the scale of the increase can be considered prudent and efficient. This is particularly important given expenditure was reducing in the current period. It is also noted that many of the issues raised are safety related; however, the ESV assessed this category in its review and did not consider that safety was the primary factor driving the need to replace.

Based upon the above, we consider it reasonable to reject Jemena's forecast. We also consider it reasonable to substitute an allowance based upon the historical replacement levels (2006-2009), with the growth rate set by the repex model benchmarked to historical volumes.

It is worth noting that based upon our modelling, this still provides for an increase in expenditure of approximately 5% per annum.

Based upon these adjustments, the table below provides our revised estimate for this allowance (estimate exclusive of overheads and escalations).

Table 26 Jemena distribution switchgear

	$millions (2010)				
	2011	2012	2013	2014	2015

[139] Jemena revised proposal, Appendix 8.23, pg 9

[140] http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/May_doc_appx_results.xls

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	2.1	2.5	3.2	3.3	3.4
Recommended	**2.2**	**2.4**	**2.5**	**2.6**	**2.7**

5.3.3 Zone substation

The zone substation plant category covers the replacement of power transformers, zone substation switchgear, and associated primary plant.

This category represents 13% of Jemena's RQM forecast for the next period. Jemena has forecast this category to have a very significant increase in expenditure from recent levels.

It is important to note that Jemena's revised proposal has reduced the number of transformer replacements from those indicated in its original proposal - from 6 to 3. It has stated that this is due to new test data that indicated previously planned transformers were in better than expected condition[141].

5.3.3.1 Summary of Nuttall Consulting original review

Nuttall Consulting did not consider that Jemena had adequately demonstrated that its forecast expenditure associated with this RQM category was reasonable (i.e. it could be considered a disaggregated component of the overall prudent and efficient capex[142]).

The key matters we raised to support this view were:

- Nuttall Consulting's assessment of the transformer condition information (polymerization estimate results), which we considered did not reasonably justify the number of transformers Jemena was predicting would need to be replaced in the next period. We also considered that this view appeared to be supported by Jemena's asset management plan, which had dates for replacement later than its proposed dates.[143]
- Lack of evidence that other issues noted in the asset management plans were sufficient to advance the replacement[144].
- Lack of justification and detail of the comparability, management, and past and future changes in the risks assessed for the CBs[145].
- Nuttall Consulting's views that switchgear test results for a specific location suggest some flexibility in timing[146].

[141] Jemena revised proposal, Pg 163
[142] Nuttall Consulting report, pg 153
[143] Ibid, Pg 153
[144] Ibid, Pg 153
[145] Ibid, Pg 153
[146] Ibid, Pg 153

- CB volume information that suggested the level of CB replacement in the next period would be below 2009/2010 levels[147].

Nuttall Consulting's recommended allowance was based upon the average historical level of expenditure in this category (2006-2008) with an additional component based upon the expenditure annual increase predicted by the calibrated repex model.

It is our understanding that the AER accepted our view in forming its overall capex allowance for Jemena.

5.3.3.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The Jemena revised proposal details a number of criticisms associated with our views. They broadly relate to transformers and CBs.

With regard to transformers, Jemena considers that we have misinterpreted the dates presented in the asset management plan by suggesting that these indicated that replacement could be deferred[148]. On this matter, Jemena notes that these dates were simple age based figures and did not reflect test data. Jemena has also provided a strategic planning paper on its transformer replacements[149].

Nuttall Consulting accepts that it misinterpreted the dates and has reviewed the strategic paper. Although we do not consider that this has added greatly to what we had already received during the course of our previous review, given Jemena's revised number of transformer replacements, we do not consider that our modelling is significantly different to Jemena's plan. We do however consider that an adjustment should be made to our original allowance to account for this, and discuss this further at the conclusion to this section.

With regard to the CBs, Jemena's revised proposal includes a strategic planning paper to address our concerns associated with the transparency of the risk assessments[150]. Jemena also noted that the level of CB replacement was in line with the historical trend.

Nuttall Consulting has reviewed the strategic plan, and we still do not consider that this has adequately addressed our original concerns. There is still limited detail on risks including (a) how they are quantified (rather than qualitatively discussed), and (b) how they will change over time, in order that we can assess the need for the scale of the proposed plan. We do note that there is some analysis of the reliability impact of a reduction to the proposed plan (i.e. 11.7 minute degradation in SAIDI). We have reviewed the model provided by Jemena to the AER to support the reliability impact, but do not consider that there is sufficient justification of the model inputs to support this position. Jemena would need to provide and justify its reliability models/assumptions to justify that such a significant increase would occur.

[147] Ibid, pg 153
[148] Jemena revised proposal, pg 159
[149] Jemena revised proposal, A8.24
[150] Jemena revised proposal, pg 160 and A8.25

Based upon the above, we still consider that Jemena's forecast for this category should be rejected.

Turning now to our recommended allowance, we still consider that our approach of using the repex model is the most appropriate. However, we do consider that this needs to be adjusted to reflect:

- the transformer replacements, which we consider are not appropriately accounted for in our original forecast as Jemena had not undertaken any transformer replacements in the current period[151]
- 2009 expenditure and volumes, which were not allowed for in our original calibration exercise
- a 15% increase to account for more costly components, including retirements, which are not reflected in the cost base of the current period.

Based upon these adjustments, the table below provides our revised estimate for this allowance (estimate exclusive of overheads and escalation). This represents a 65% increase in expenditure over the current period.

Table 27 Jemena zone substation

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	2.3	2.5	2.9	3.5	5.5
Recommended	**1.7**	**1.8**	**1.8**	**3.3**	**4.6**

5.3.4 Reliability and performance

The reliability category covers a number of programs to address reliability and network performance. Jemena considers that this is only to maintain reliability levels and comply with quality of supply obligations.

This category represents approximately 22% of Jemena's RQM expenditure. This represents over a two-fold increase in annual expenditure in this category during the 2006 to 2009 period.

Significant factors Jemena had raised in support of the need for this expenditure to maintain reliability and performance levels were the degradation in asset performance in the current period and the worsening impact of the environment in the next period due to "climate change".

[151] We have used the amount indicated by Jemena in its revised RIN for zone substation asset category in 2014 and 2015 to represent this amount.

5.3.4.1 Summary of Nuttall Consulting's original review

Nuttall Consulting rejected Jemena's proposed expenditure on reliability and performance[152]. This rejection was based upon:

- advice from the AER that it did not accept the climate change argument
- a lack of substantive analysis by Jemena that demonstrated the large increase was required to only maintain reliability – rather than improve it. This was particularly relevant given the significant increase in expenditure over historical levels that was being allowed for in our recommendation.

We considered that the allowance should be based on historical levels with some allowance for the ageing of the network. The repex model was used to determine the aging effect.

5.3.4.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The Jemena revised proposal requests the reinstatement of the reliability expenditure[153] and reasserts the need for this to address worsening reliability due to climate change and the historical degradation of assets.

To support this view, the revised proposal notes that performance in 2009 is much worse than the average over the current period and considers that the 2009 performance is more likely to represent future performance, due to climate change.

It also notes the rising trend in asset failure rates, which it considers is increasing at a rate of 3.7% per annum. It notes that there is no related increase in SAIDI during this time, but considers that this is due to it using reliability improvement measures to mask this affect. It does not consider that these types of program can be maintained into the future.

It considers that its proposal will allow it to address a predicted 5 minutes-per-annum degradation in SAIDI over the next period due to these factors.

The revised proposal also provides a number of strategic planning papers to supports it position[154].

Nuttall Consulting has considered the arguments presented by Jemena and the revised strategic papers and still does not consider that it has justified that such a significant increase in this category is required.

In forming this view, we understand the AER is still not accepting that climate change will so significantly impact reliability in the next period. However, possibly equally importantly, we still do not consider that Jemena has adequately demonstrated that the large increases in RQM (and expenditure in other categories) will not be sufficient to address the existing degradation due to ageing – or even climate change.

---

[152] Nuttall Consulting original report, Pg 159 and Pg 163
[153] Jemena revised proposal, pg 160
[154] Jemena revised proposal, Appendices 8.27, 8.28 and 8.32

We considered this was the case with our original recommendation, which still allowed for a significant increase over historical levels. Since then, the findings of the ESV review of volumes have allowed for a very large increase over historical levels. These increases are shown in the two figures below – note: these are estimates only and do not allow for unit costs changes resulting from the ESV unit cost review (Appendix G). This shows the trend in overall RQM and the trend in “line” related RQM. These show significant increase in expenditure levels over the first half of the current period. Most notably for the lines categories (poles, pole tops, conductors and cables), this is indicating a very significant increase in expenditure over historical levels.

Figure 21 RQM expenditure increase

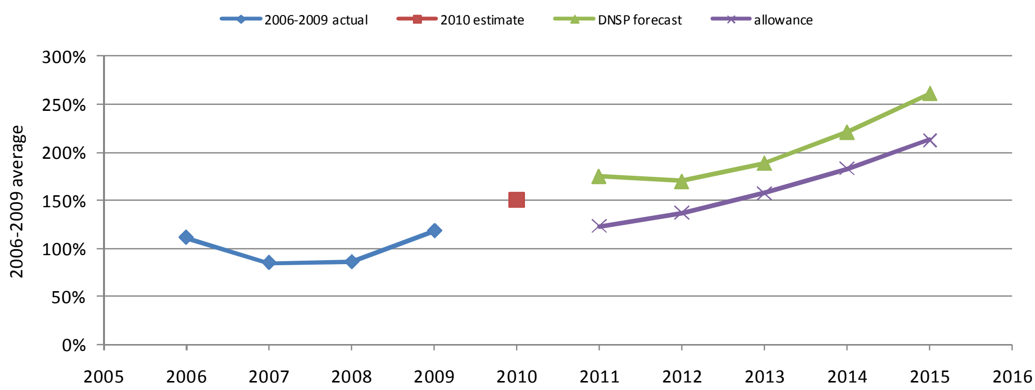
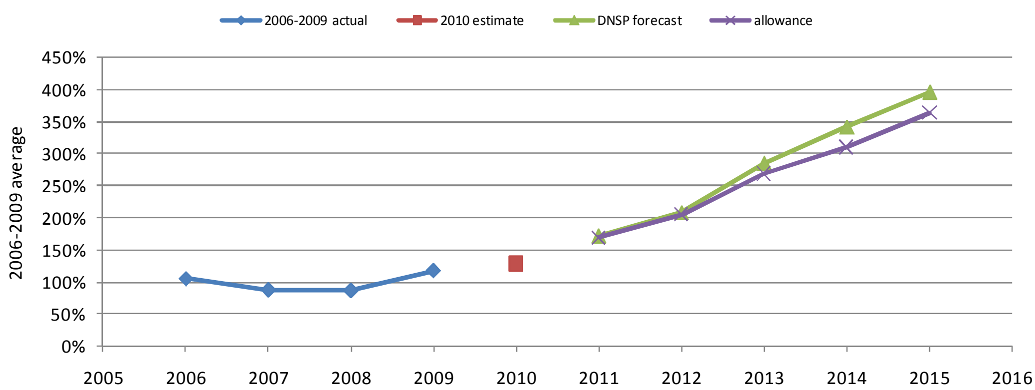


Figure 22 RQM line category (poles, pole tops, conductor, cable) expenditure increase



Given the scale of these increases, we consider that Jemena would need to provide detailed reliability and economic analysis to justify its proposal. We have not been provided with such modelling. On this point, we do not disagree that the programs may realise the benefits discussed in the strategic papers. However, we do not consider that, in light of the above, the analysis in these papers clearly justifies that they need to be funded purely to maintain reliability, rather than funded through the reliability incentive scheme.

With regard to the power quality component, we note that the associated strategic paper discusses the need for these works. However, we do not consider that this paper adequately justifies the scale of the increase or the timing of the programs, particularly in the context of how Jemena has managed these matters in the current period.

As such, we still maintain that the allowance should be set to reflect historical levels and consider our previous recommendation to still be appropriate with an adjustment to allow for 2009 actuals.

Important note on revised allowance

We note that since our original review, Jemena has revised its allocation associated with reliability. This has resulted in a significant change in historical expenditure between the protection and reliability categories. To reconcile this change to our previous modelling results, we have recast our numbers using both categories and the 2009 actuals.

Based upon this analysis, the table below provides our revised estimate for the **combined protection and reliability category** (estimate exclusive of overheads and escalation).

Table 28 Jemena combined protection and reliability

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	10.0	7.1	5.5	6.8	6.9
Recommended	**3.4**	**3.4**	**3.4**	**3.5**	**3.5**

5.4 Environmental, Safety and Legal

Jemena has proposed additional and new activities in response to changed safety and line clearance regulations, the Victorian Bushfires of 2009 and the Royal Bushfire Commission's final report. The proposed expenditures have been reviewed by Energy Safe Victoria (ESV) and recommendations made as to the future volumes of work required. The AER has requested Nuttall Consulting to review the unit costs associated with the ESV recommended volumes. This assessment is provided in Appendix G – Unit cost review of this report.

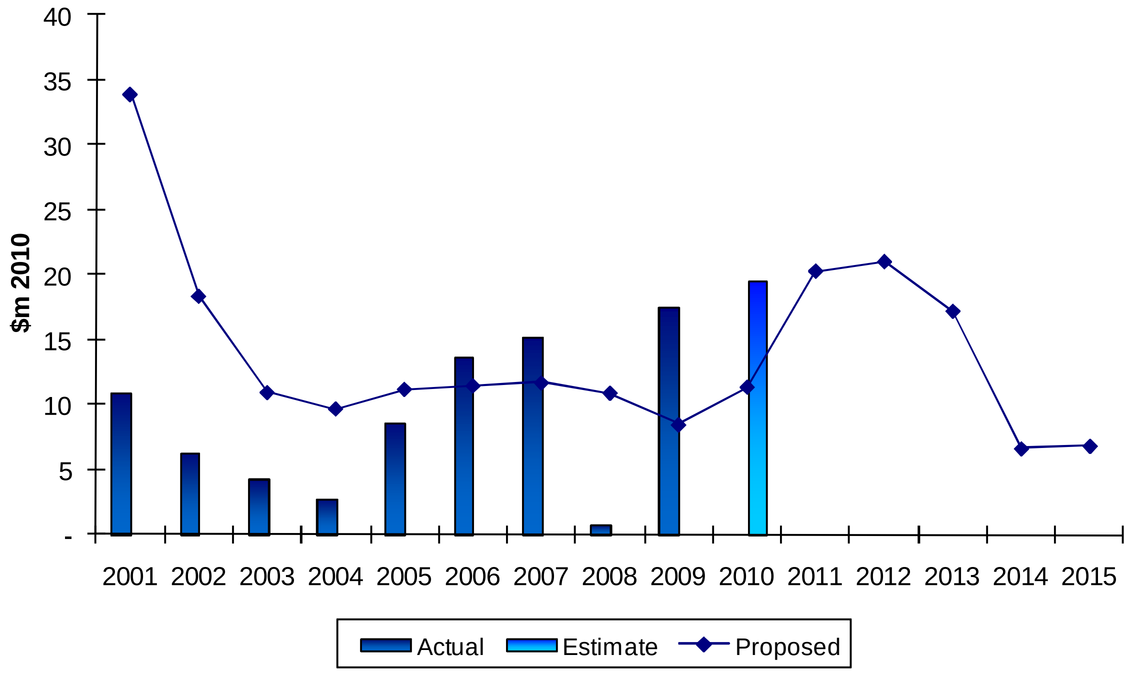
Nuttall Consulting has not been requested to assess any other proposed Jemena expenditures in this category.

5.5 SCADA and Network Control

Nuttall Consulting has not been requested to assess this category.

5.6 Non-network general – IT

In its revised proposal, Jemena submitted forecast IT capital expenditure of $72.0 million over the forthcoming regulatory control period, which represents an increase of 22% in capital expenditure from current period expenditure ($67.0 million). Major proposed IT capital projects include replacing its SAP enterprise asset management system and building a disaster recovery data centre, and establishing a geographical information system (GIS).



During 2004-2009, Jemena overspent their IT capital expenditure from a proposed $54.0 million to actual and estimated expenditure of $67 million including deferrals of project like DMS, VMS and some SAP models which were impacted by AMI.

In the original report Nuttall Consulting rejected the IT capital program for Jemena and substituted a new IT capital amount based upon audited historical expenditure. As a result, Jemena has provided a revised proposal and additional material in response to the AEC's Draft Determination.

In their response to the Draft Determination, Jemena states that it does not agree with the AER's determination or Nuttall Consulting's opinion that Jemena is not capable of delivering its proposed IT capex program for 2011-2015 and that its IT architecture is not sufficiently agile. Jemena considers that Nuttall Consulting's conclusion is based upon the fact that Jemena has historically underspent relative to its own forecasts by deferring projects. Nuttall Consulting believes that the underspend was due to poor forecasting and lack of agility, specifically a lack of IT Infrastructure agility.

In their response to the Draft Determination, Jemena states that its IT program is not ambitious or large compared to the Jemena Group total IT program. Jemena note that Nuttall Consulting has only reviewed the Jemena IT spend and has formed its conclusion based upon the information submitted.

In their response to the Draft Determination, Jemena states that any deferral of spend over 2006-2010 has been driven by external events and vendors' product replacement and not due to capability or IT architecture. Nuttall Consulting believes that Jemena would have been better able to accommodate external events if the IT infrastructure was more agile. Jemena should maintain relationship with vendors to ensure that product replacement announcement or change to support arrangements be planned well in advance.

The Jemena statement that deferral of spend over 2006-2010 has been driven by external events and vendors' product replacement provides evidence that the Jemena forecasting of IT capex is not adequate to determine prudent and efficient allowances. External delays to IT projects are relatively common, as highlighted by Jemena. The Jemena forecast for the next control period does not make allowances for a reasonable level of external delays and therefore may represent an optimistic forecast, not a forecast that reasonably reflects the likely level of future expenditure.

In counter to this position, Nuttall Consulting notes that Jemena has actually overspent against its current period forecasts. In their November proposal, Jemena estimated 2009 expenditures of $8 million in IT capex. The actual expenditures for 2009 were $18 million. This means that estimated expenditures in the November proposal were 54% less than the actual level of expenditure for that period. This again highlights significant errors in the forecasting process. However, Jemena is unusual in that the errors in forecasting are not consistently biased to over or underspend.

In their response to the Draft Determination, Jemena states that new IT Infrastructure was implemented as value for money based on competitive tender and the use of contemporary technologies. Based upon the review of the material provided by Jemena, Nuttall Consulting concludes that the design of the infrastructure may not be agile, regardless of how cost-effective or well market-tested it was.

In their response to the Draft Determination, Jemena states that its program delivers proven application and technologies currently in place in Australian energy companies. Nuttall Consulting considers that the Jemena requirements are common to other DNSPs, but also unique to its requirements and based upon technology decisions made in the past. Nuttall Consulting does not recommend any particular system, but that the systems be delivered in an agile way, to accommodate the inevitable level of change that will occur.

In their response to the Draft Determination, Jemena states that the AER's draft decision considered the record of IT delivery from 2004-2008 as indicative of IT capex and delivery trends for Jemena. Jemena state that this period was a time of great disruption for Jemena because of two changes of ownership. Nuttall Consulting considers, that the change of ownership would have been much less disruptive to the IT systems, if the IT systems were implemented in an agile way. For example, Jemena has undertaken a virtualisation program of work that delivered the relatively average result of 65% systems virtualised with planning now commencing towards 95% virtualisation[155]. Nuttall Consulting believes Jemena has been overly conservative in its virtualisation effort and that as a result too many of its system are not yet sufficiently agile.

[155] Appendix 8.9 JEN's IT Program, p8.

Although Nuttall Consulting considers that Jemena's IT infrastructure is not sufficiently agile, we also note the forecast IT expenditure is relatively consistent with the historical IT expenditure and that Jemena has not shown a systemic bias in IT capex forecasting. On this basis we recommend that the revised IT capex proposed by Jemena be accepted.

Table 29 – Recommended Jemena non-network general IT capex

Jemena	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
Proposed Expenditure	20.3	21.0	17.2	6.6	6.8
Recommended Expenditure	20.3	21.0	17.2	6.6	6.8

5.7 Non-network general other

5.7.1 Zone substation land purchases

In the draft determination, the AER identified that zone substation property purchases proposed by Jemena should be considered within the reinforcement category. The reinforcement category includes expenditure for the construction of zone substations to meet general demand growth.

In their revised proposal Jemena has stated that they consider it more appropriate to include zone substation property purchase in 'Non-network-Other' category. Jemena notes that while property purchase is related to the future requirement for a new zone substation, property purchase would need to be ahead of time, especially in the general built-up area that Jemena serves due to scarcity of suitable land parcels.

Nuttall Consulting notes the comments made by Jemena. However, to consider whether it is prudent and efficient to purchase the land for a zone substation requires Nuttall Consulting to consider the timing and location of load growth in the area, as well as the loading of adjacent zone substations. This information is already reviewed as part of the reinforcement capex category. As such, Nuttall Consulting has considered the proposed expenditures for zone substation land purchase in the reinforcement sections of this review.

5.7.2 Broadmeadows depot

The AER has requested Nuttall Consulting to review the proposed capex for Jemena's proposed Broadmeadows depot relocation project (Broadmeadows depot) as detailed in Jemena's revised proposal[156].

This project includes the development of a new office and depot to accommodate staff currently working from Broadmeadows and Sunshine depots, and to cater for the projected increase in the capex program.

[156] Jemena Electricity Networks (Vic) Ltd - Revised regulatory proposal - 20 July 2010, page 171.

In the original Nuttall Consulting report, the review of this project highlighted a deficit of information and supporting evidence to justify the proposed capex.

Jemena states that the Broadmeadows relocation project is required because the depot currently fails to meet a range of legislation and codes. Jemena identifies that there are serious problems associated with safety, asbestos, oil containment and access, and that the buildings do not comply with major sections of the Building Code of Australia or with recent amendments to the Disability Discrimination Act 1992.

Table 30 – Jemena Broadmeadows depot relocation capex

Jemena	Costs (2010 $M)				
	2011	2012	2013	2014	2015
Proposed Expenditure	15.1	-	-	-	-

Accompanying its revised proposal, Jemena has provided a significant level of detail supporting the proposed relocation. This information addresses many of the information gaps identified by Nuttall Consulting. The areas of concern that remain for Nuttall Consulting are as follows:

- the timing of the works and related expenditures
- the costing of the works
- the recognition of the operating benefits associated with the project.

Each of the above concerns are detailed in the following sections.

5.7.2.1 Timing of expenditure

Nuttall Consulting considers that the project timing proposed by Jemena is optimistic and is not likely to eventuate.

In its 2006 proposal to the ORG, Jemena's predecessor (AGLE) proposed expenditure in the non-network general - other category that included "rebuilding of the Broadmeadows depot". The total expenditure proposed in the non-network general – other category was $26.3 million, while actual expenditures are estimated by Jemena to be $21.9 million, or 17% less than predicted.

Given the negative commentary provided by Jemena[157] and its consultants[158] about the state of the current Broadmeadows facility, it would appear that this investment was either not undertaken, or was only partially completed.

In addition, Jemena's proposed workplan for the Broadmeadows relocation is already behind schedule. The Jemena business case for this project identifies that Board approval

[157] Jemena: "there are serious problems associated with safety, asbestos, oil containment and access risks" – Revised proposal, page 173

[158] Woodhead et al, JEN Feasibility Study, July 2010, section 2.1.1.

will be completed by June 2010. Updated timing information from Jemena[159] indicates that this paper will not be presented to the board until at least October 2010. This represents a delay of 4 or more months on a workplan that is only 6 months old.

The updated information from Jemena notes that "Jemena's Property Group are continuing to explore alternative greenfield site options prior to establishing a project office contract (engineering, design and procurement) with professional building consultants"[160]. This also indicates that the project is still in the early stages of definition and that the costs and timings cannot be fully understood.

5.7.2.2 Costing of works

The cost information submitted to the AER in November 2009 identified $15.3 million associated with the Broadmeadows & Sunshine depot merger & relocation in the next regulatory period. The revised submission from Jemena in July 2010 identified $30 million in expenditure for the same project over the same period.

As of the date of writing this report, Nuttall Consulting had not received any information that identified the reasons for the doubling of the costs in the next regulatory period.

Nuttall Consulting considers that the proposed increases between the original and revised proposals is significant and that the lack of supporting information does not satisfy the capital expenditure objectives. On this basis, Nuttall Consulting cannot recommend the proposed increases contained in the revised proposal.

Nuttall Consulting notes that the assessment of land values and office/depot construction costs are beyond the skillset of this consultant.

5.7.2.3 Recognition of operating benefits

In the original Nuttall Consulting report, we noted comments from GHD Australia Pty Ltd ("GHD"), who were appointed by Jemena to review the Jemena Network Asset Management Plan (NAMP) and associated capex forecasts prepared by Jemena. The purpose of the review was for GHD to provide an opinion as to the compliance of Jemena's capex proposal with the requirements of the National Electricity Law and Rules. This review identified that the depot merger project was not sufficiently justified: "*The Broadmeadows – Sunshine Depot Relocation/Merger project, while having an established need, has not sufficiently demonstrated the benefits of the specific proposal through identifying Opex efficiencies and potential performance improvements from the consolidation.*"[161]

Jemena has identified operating cost savings of $161,400 per annum in reduced lease payments for the Sunshine depot. In addition to these operating cost reductions, Jemena has identified, but not quantified, the following operating benefits:

[159] Letter from Jemena to AER. Subject: JEN 2011-15 regulatory proposal: Capital expenditure, 30 August 2010, page 3

[160] Ibid

[161] GHD: Independent Review of Jemena Electricity Networks (Vic) capital expenditure forecasts - 30 November 2009, P2.

- Reduction in operating and maintenance costs of plant and equipment in old facilities (most of which is at the end of its useful life) vs. equipment at a new facility which will be warranted and at the start of its life cycle.
- The new facility will integrate Environmental Sustainable Development (ESD) initiatives and features inclusive of Building Automation Systems (BAS), Solar HWS, Energy/Lighting conservation systems, Water and Waste Management systems. These Initiatives will seek to achieve a minimum Green Star rating of 4, thereby maximising asset performance and realising operating cost savings in the order of 20-30% (source: www.abgr.com.au).
- Reduction in multiple site security costs, rates and taxes, insurance premiums, telecommunications and MFB line rentals.
- Reduced operating costs due to optimal design of the new facility, e.g. use of overhead crane vs. forklift lease and running costs, etc.
- Reduced inefficiencies by integrating pole storage into the consolidated site and eliminating the need to utilise the Somerton site for this purpose.
- Improved workplace synergies and communications by having all Jemena related resources at one site maximising productivity and output.
- Improved network response times and resource utilisation through efficient scheduling of labour and plant.
- Improved OHS & E initiatives through effective design of the new facility adopting improvements implemented and learned from the Clayton facility.
- Improved access to network assets through optimal site location and proximity to key arterial roads.

Nuttall Consulting considers that the above benefits are real and material. Nuttall Consulting considers that the majority of these benefits will be operational.

5.7.2.4 Summary

Based on the Nuttall Consulting findings above relating to the timing and associated costs of this project, Nuttall Consulting recommends the following capex allowances in relation to the Broadmeadows depot relocation.

Table 31 – Recommended Jemena depot relocation capex

Jemena	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
Proposed Expenditure	15.0	15.0	-	-	-
Recommended Expenditure	7.1	7.0	-	-	-

The recommended capex represents the full capex amount for this project identified by Jemena in its original RIN submission for the next regulatory period. This amount is split over two years consistent with the delays identified by Jemena.

The additional expenditure contained in the revised proposal is not recommended due to the absence of supporting information.

6 Appendix C - Powercor

The CitiPower and Powercor franchises are both owned by the same investment group and share management and executive services. The CitiPower and Powercor proposals share a great deal in common including structure and significant areas of content. There are also areas of differentiation between the proposals; specifically in relation to individual projects and programs.

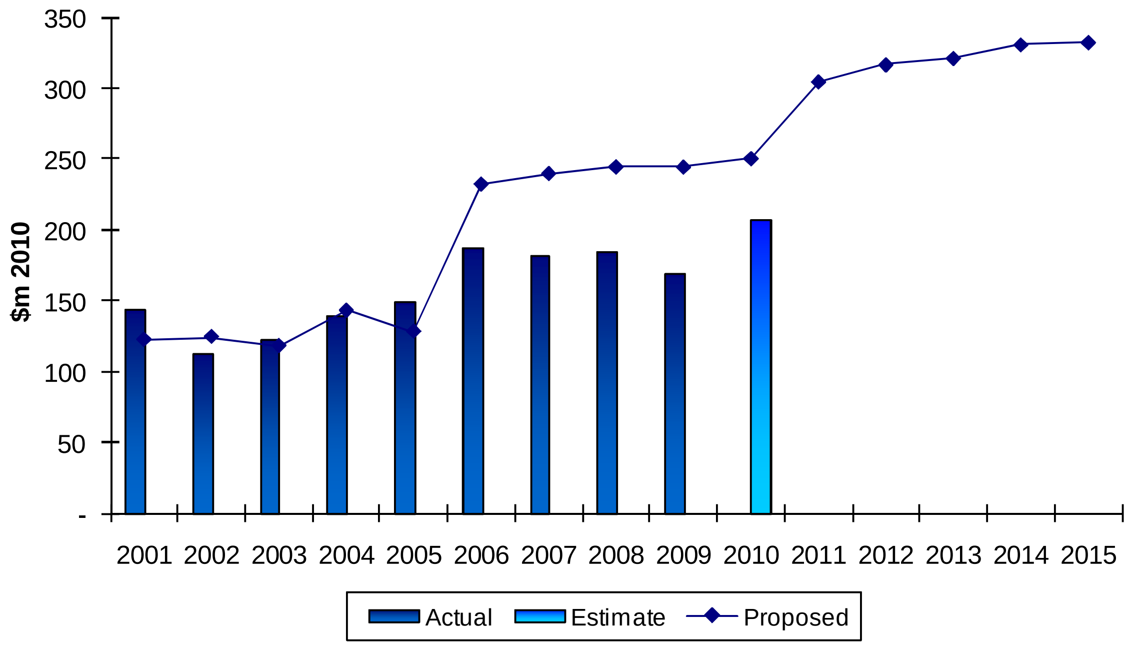
6.1 Overall capex

Overall capex is forecast to increase by 78% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement, reliability and quality maintained, new connections, and non-network IT.

The following chart provides a summary of the overall capex figures for Powercor. Key aspects of this chart include:

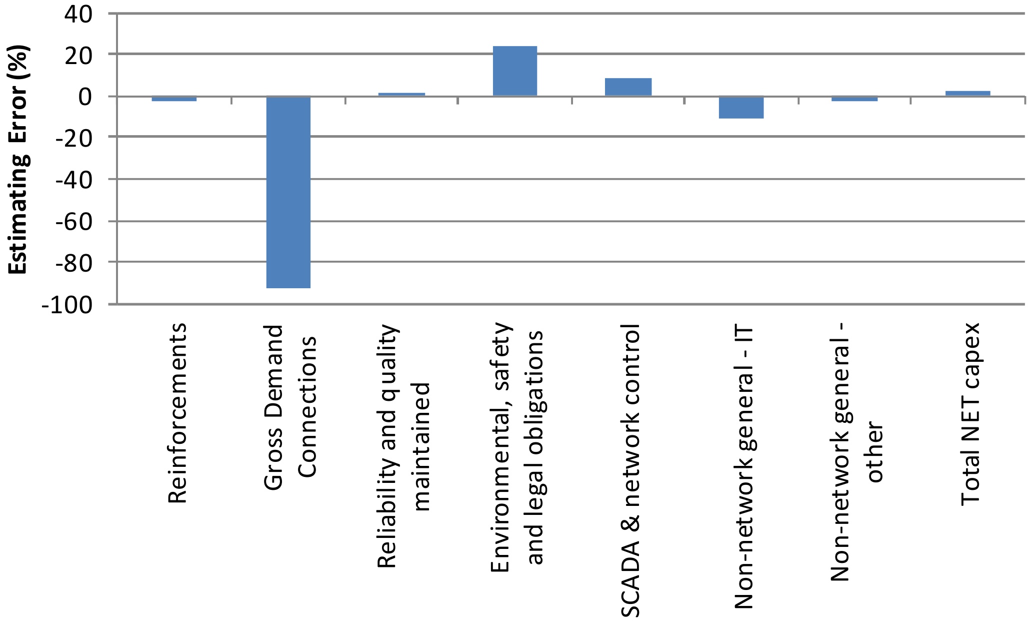
- Powercor has consistently spent less than they proposed in the 2006 EDPR
- Powercor is proposing a future level of capex that is significantly higher than the historical levels of expenditure and is not consistent with the historical trend in capex.

Figure 23 - Powercor Capex Summary



The following chart considers the accuracy of the November 2009 Powercor proposal compared with the actual 2009 audited data.

Figure 24 – 2009 estimating accuracy



The estimated figures for 2009 were provided by the DNSPs in November 2009; two months prior to the completion of the financial period. The actual figures for 2009 have been subject to audit and were provided to the AER in early 2010.

The overall accuracy of the 2009 Powercor forecasts was relatively good with actual net capex varying by 3% from that estimated. However, the above chart highlights that the DNSP forecasts at the individual capex category show significant levels of variation from the actual 2009 capex. This highlights a concern with the forecasting processes utilised by Powercor and calls into question the veracity of the forecasts for 2010 and the next regulatory control period of 2011 to 2015.

When considered in conjunction with the historical levels of forecasting inaccuracy as described in section 2.2, Nuttall Consulting observes that the processes used by Powercor to forecast expenditure in this category have not produced reliable forecasts.

Nuttall Consulting requested Powercor to provide an explanation of the methodology applied to determine the 2009 and 2010 estimates and to explain the relationship of this methodology to the methodology used to produce the 2011-2015 forecasts[162]. Powercor did not identify any changes or variations between the forecasting methodologies.

This raises a concern relating to the accuracy of the DNSP forecasts for the next control period as the methodologies used to create these forecasts are the same methodologies that have produced the previous inaccurate estimates and forecasts.

To be clear, although the above information provides sound reason to question the accuracy of the DNSP forecasts, Nuttall Consulting has not taken this as proof that the forecasts do not meet the capital expenditure objectives. The Nuttall Consulting review of

[162] Nuttall Consulting information request (email) – 18 January 2010.

the forecasts has been undertaken on a case-by-case basis with due consideration of the information provided by the DNSPs.

6.2 Reinforcement

Powercor's revised proposal makes a number of criticisms of the process and findings of Nuttall Consulting's original review of Powercor's reinforcement expenditure.

General criticisms of the process we applied, which are similar between DNSPs, have been discussed in Section 3.1 above. This section deals with matters more specific to our findings on Powercor's reinforcement forecasting methodology and our review of a number of reinforcement projects. Importantly, this section includes revised project probabilities, which will be important for the AER in its considerations of the appropriate reinforcement allowance.

6.2.1 Load duration curve assumptions

Nuttall Consulting considered that the need for the reinforcement projects may be overstated due to assumptions associated with the energy at risk calculations that supported the need and timing for projects, and specifically the load profile assumed in these calculations. In this regard, Powercor is using a load profile based upon the 2008/09 year.

This view relates to the fact that the Victorian load is becoming more "peaky" as demand growth outstrips energy growth. This peakiness may tend to reduce the energy at risk (and associated value of the expected energy at risk) as the load at risk increases in the future. Nuttall Consulting undertook some trend analysis of historical load profiles that it considered justified this position. We also considered that the 2008/09 year may not be representative of typical conditions due to the untypical extreme weather conditions that year.

Powercor has disagreed with Nuttall Consulting's view and has supplied a report by SKM to support its position. The following discusses the matters raised in the SKM report.

The SKM report considered Powercor's assumptions to be reasonable, based upon analysis of the sensitivity of a notional project timing with different historical load profiles.

Nuttall Consulting has reviewed this analysis and disagrees that it shows that our views are not valid. The SKM analysis only assesses project timing against four years 2003/04, 07/08, 08/09, 09/10 and, importantly, assumes a 5% growth rate. We have a number of concerns with this analysis.

We consider that the results support our view that project timing will be sensitive to load profile assumptions, with results showing a variation of 3 years depending on the profile assumed. Moreover, we consider that SKM's assumption of a load growth of 5% will reduce timing sensitivity over lower growth rates. On this matter, it is noted that 5% is higher than CitiPower's forecast growth. As such, it is clear why this has been chosen and why the sensitivity of the load growth assumption is not discussed.

Furthermore, while we can see that the SKM results show a sensitivity in timing, they do not clearly show whether a trend is up or down or immaterial. This was the important point in our analysis.

We also note that this report indicates that our findings are fundamentally flawed as our analysis places great weight on the top 1%. But this is not the case; our analysis considered scenarios from 1% to 20%, with all showing a material trending decline in energy at risk (see Fig 144 in the original report).

All that said, based upon the results presented and other confirming studies undertaken by SP AusNet, we do accept that using the 2008/09 load profile is unlikely to overstate expected energy at risk in the future. Although, it is worth noting that in Nuttall Consulting's probabilistic assessment, our view on the load profile assumptions had a low sensitivity on the project probabilities.

We do note that the SKM report also reviewed Powercor's assumptions underpinning its expected energy at risk (EEAR) calculations, and considered these to understate actual expected energy at risk. This view is based upon:

- 50% PoE – which may understate risks associated with worse temp conditions – accept this may be the case, but not clear how material
- not allowing for other equipment failures
- not allowing for more minor transformer failures.

While we do not disagree with the points above, we do not consider that this means that the overall process is understating risks. For example, although SKM has undertaken some benchmarking that shows the major failure rates and repair times are in accordance with industry levels, it has not undertaken any analysis of historical data to see whether there is any case that these may still overstate risks. We do not consider that there is anything that the industry is not aware of in the matters noted by SKM, and as such, it seems reasonable to assume that the industry is satisfied that these risks are either immaterial or allowed for in the existing assumptions.

This is different from the load profile issue, where the load profile assumption should be being made to reasonably reflect the most likely conditions in the future i.e. the assumptions on the PoE, failure rate, and repair time may be relatively static in the medium term, but the load profile assumptions would be dynamic (undergoing an annual review and updating).

6.2.2 Updated project assessments

The following projects were assessed as part of Nuttall Consulting's review of Powercor's reinforcement expenditure:

1. The Eagle Hawk zone substation upgrade
2. The Gisborne new zone substation
3. The BETS-CTN 66 kV line upgrade

4 The GLE upgrade

5 GTS 66 kV lines upgrade

6 NKA-CBE 66 kV line upgrade.

The following sections discuss our reassessment of these specific projects, based upon Powercor's revised proposal.

It is also important to note that we understand that the AER will largely be accepting Powercor's demand forecast. In our original review we had allowed for a reduction in the demand forecast, based upon advice from the AER. In the discussions below and the revised project probabilities, we have not allowed for any reductions from Powercor's demand forecast. This has resulted in increased project probabilities.

6.2.2.1 Eaglehawk substation upgrade

The Eaglehawk substation establishment project involves the upgrade of the existing substation to install a 3rd 66/22 kV transformer and a 3rd 22 kV bus. The key driver for this project is the projected loading at the existing substation and the internal planning criteria to upgrade to a fully switched substation when loading exceeds 20 MVA.

This project was assessed as part of Nuttall Consulting's probabilistic analysis of Powercor's reinforcement needs. Based upon our original review, this project was given a moderate to high probability (70%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology, this probability reflected the AER's position on the demand forecast and our views on the load profile assumption.

The Powercor revised proposal does not accept our views and considers that the project should be viewed as 100% required as originally proposed[163]. This view largely reflected its position that its demand forecast and load profile are appropriate.

Given our further considerations of the load profile assumptions, discussed above, where we have accepted them to be reasonable, and assuming the AER is accepting the Powercor demand forecast, we consider that this project should be revised to have a high probability (90%). We do not accept however that it should be considered 100% for the reasoning discussed in Section 3.1.

6.2.2.2 Gisborne Substation Establishment

The Gisborne substation establishment project is drive by energy at risk considerations due to the projected loading at the existing Woodend zone substation (WND) and an associated 66 kV sub-transmission line.

This project was assessed as part of Nuttall Consulting's probabilistic analysis of Powercor's reinforcement needs. Based upon our original review, this project was given a low probability (33%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that:

[163] Table 9.5 of CitiPower's Revised Proposal

- Powercor had not clearly demonstrated that energy at risk was sufficient to justify the timing of the project – of particular note here was our uncertainty over the risks associated with line outages
- We also considered that there was a reasonable possibility that a lower cost alternative may be found to be the preferred option – we noted the option of a staged development, involving a switching station at Gisborne as the first stage.

The Powercor revised proposal does not accept our views and considers that the project should be viewed as 100% required as originally proposed. Additional information has been provided by Powercor to support its position[164].

We have considered Powercor's contention in its revised regulatory proposal that the project is 100% required in the forthcoming regulatory period. A review has subsequently been performed of the additional information.

We note that the project cost has increased from $9.7 million to $12.2 million in the revised proposal. We reviewed the basis for this cost increase, and are, on balance, satisfied with Powercor's justification of the higher cost.

With regard to energy at risk, Powercor considers that this is sufficient to justify the project and has provided analysis showing its forecast of energy at risk for both the loss of a transformer at WND and the loss of the line. This supports Powercor's timing of the project, indicating that the value of unserved energy by 2013 is sufficient to justify the project just prior to this date. It also indicates that energy at risk due to loss of the transformer at WND is the most significant, being approximately 78% of the risk. Powercor has also noted that an important consideration in assessing the risks is that the WND load is winter peaking.

We have considered Powercor's analysis, and accept that the forecast energy at risk is sufficient to justify Powercor's preferred project. It is worth noting that the value of customer reliability (VCR) used by Powercor to justify the project had increased significantly from the value indicated in our original review[165]. Powercor has clarified[166] that this was due to an error in the original VCR, which used the number of customers rather than their energy to develop the weighted average VCR. Although, we are not in a position to audit Powercor's revised calculation of the VCR, we do not consider that the revised VCR is unreasonable, and as such, have accepted Powercor's position.

With regard to the option considered, Powercor argues that there are no lower cost options for the project. On the matter of a stage project, involving only a switching station at Gisborne as the initial stage, Powercor considers that this will not result in lower costs as the project will be more expensive (by $300,000) to allow for working in a live

[164] Table 9.5 of Powercor's Revised Proposal and the revised Material Project template (Attachment 161)

[165] In its attached Gisborne Substation Establishment Material Project Template, a VCR value of $45,353/MW.h[165] was used to economically justify the project. This VCR is significantly higher than the original $28,876/MW.h value as specified in energy at risk spreadsheet provided to the AER by Powercor on the 19th of February 2010.

[166] Powercor email reply to the AER on the 20th of August 2010.

substation in the later stages, but it would not be economically to defer the later stages as the switching station would not remove the risks.

We have considered Powercor's reasoning on this matter, and broadly accept that it is unlikely that our example is likely to be found to be a lower cost option. In forming this view, we note that the proposed timing appears optimal based upon Powercor's forecast energy at risk at WND, which this option would not relieve. It is worth noting however that for the other options that Powercor has considered, the capex required in the next period is much lower than the preferred option. For these other options, the higher NPV results from high-cost augmentations that Powercor considers to be subsequently required from around 2019. Although we consider that this still suggests that there may be some possibility that a lower cost solution may exist (i.e. if other lower-cost solutions to the future need are found), given it is not possible for us to assess this issue in detail, we have no longer explicitly accounted for alternatives in our project probability.

However, assuming that the preferred option is the new substation as proposed by Powercor, it seems reasonable to assume that the four new feeders from this substation will split a number of existing feeders. As such, it is likely that reliability benefits will occur due to improvements in reliability. This matter has been noted for other DNSPs proposing new substations, particularly SP AusNet who provided economic analysis on this issue. Therefore, it is likely that at least part of this project would be funded through the reliability incentive scheme.

Conclusions

Based upon the above, we have revised our project probability from low (33%) to moderate to high (70%)[167]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this revised probability reflects our view that the project will be partly funded through the reliability incentive scheme.

The increase is largely due to the AER's change in its position on the Powercor's maximum demand forecast, and our view that energy at risk is sufficient and it is unlikely a lower cost alternative exists. To a lesser degree, this also reflects our revised view that the Powercor's load profile assumptions are reasonable.

6.2.2.3 Bendigo to Charlton (BETS-CTN) Sub-transmission Line Upgrade

This project involves the staged upgrade of the existing radial 66 kV line from BETS to CTN. The key drivers for this project are loading and voltage stability issues on the existing line, and Powercor's internal criteria to only allow loading up to 20 MVA on radial lines.

This project was assessed as part of Nuttall Consulting's probabilistic analysis of Powercor's reinforcement needs. Based upon our original review, this project was given a moderate probability (50%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that other lower cost alternatives may be found. On

[167] Probability based upon: 90% (historical accuracy) x 80% (part funding through reliability incentive scheme)

this matter, we noted two possibilities: a staged development involving reactive support or an alternative line from KGTS to CTN.

The Powercor revised proposal does not accept our views and considers that the project should be viewed as 100% required as originally proposed. Additional information has been provided by Powercor to support its position[168]. With regard to the possibility of a lower cost alternative option, Powercor argues their preferred option to gradually upgrade the Bendigo-Charlton feeder has the cheapest net present value of the options considered and that there are no lower cost options for the project.

We have considered CitiPower's contention in its revised regulatory proposal that this project is 100% required in the forthcoming regulatory period. A review has subsequently been performed of the additional information. Based upon this review, we still have concerns with the reasonableness and inclusiveness of the options analysis performed by Powercor to justify the project.

Powercor has considered a number of alternative options in their revised material project template including the examples we suggested in our original report. With regard to an alternative 66 kV line from KGTS, Powercor considers that this option will have a much higher NPV cost because it will require the installation of the entire 100km line from KGTS to CTN without any staging possible, plus it requires additional works at KGTS, including a new transformer. Based upon these clarifications, we accept that it is unlikely this would be a preferred option.

With regard to a staged development with reactive support, Powercor has considered these as two separate options. For the staged development, it considered that this will have the same NPV as its preferred option. For reactive support, it considers that capacitor banks will not address the stability issue, and more costly dynamic voltage compensation (i.e. a STATCOM) will be required, resulting in a higher-cost overall project.

Based upon the information presented, we still do not consider that Powercor has adequately demonstrated a stage development in combination with some reactive support may not be a lower cost alternative. We are not fully convinced that Powercor's preferred options and our suggestion should have the same NPV, given that this reconductoring approach may result in less work in the next period, even if the overall project is still completed near Powercor's proposed timing (i.e. in 10 years time). Furthermore, there appears to be another potential alternative to at least partly address the voltage issue that has not been fully considered by Powercor. This involves installing reactive compensation at an intermediate location on the feeder, such as the future Bridgewater zone substation site (located roughly between CTN and BETS). This is not considered in the options analysis presented. As such, we still consider that some stages of the project may be able to be economically deferred, such that the voltage issue is optimally managed and the security of supply issue is addressed at the same time as presently proposed.

Conclusion

[168] Table 9.5 of Powercor's Revised Proposal and in the revised Material Project Template (Attachment 161)

Based upon the above, we have revised our project probability to moderate to high (70%). In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects the possibility that an alternative lower cost option may be found[169].

The increase is largely due the AER's change in its position on the Powercor's maximum demand forecast, but also reflects our revised view that the Powercor's load profile assumptions are reasonable and it is less likely an alternative option will be found.

6.2.2.4 The GLE upgrade

This project involves the upgrade of the existing GLE zone substation by replacing the existing transformers with higher rated units. The key driver for this project is the energy at risk at the existing GLE zone substations.

Nuttall Consulting assigned this project a moderate probability (50%), based upon our views that:

- the level of energy at risk in Powercor's Distribution Planning Report did not clearly demonstrate the need for the project at the proposed time
- the load profile assumption may overstate the level of energy at risk near the end of the next period.

The Powercor revised proposal considers that project costs should be viewed as 100% required as originally proposed. Powercor has provided a revised material project template and energy at risk spreadsheet to support this view.

With regard to our main concern, sufficient energy at risk, Powercor has provided revised analysis that it considers indicates that energy at risk will be sufficient in 2016 to support the need for the project to be completed in 2014/15. This analysis allows for available load transfers. However, due to uncertainty as to whether this level of transfer will be available by that time, Powercor has suggested that the project may be required earlier.

We have reviewed the Powercor document and have a number of concerns with Powercor's analysis.

- It is marginal that the project will be needed by 2016. If a higher discount rate (Powercor has assumed 7.2%) is applied then this may change to 2017. It is our understanding that the AER may have WACC set closer to 8%; if this is the case then the project may be deferred by 1 year.
- The growth in energy at risk is largely driven by the growth in demand during the winter, which Powercor has forecast will be approximately double that of the summer. The Powercor material does not explain why this growth in winter only should be so large.

Based upon the above, we still consider there is a reasonable possibility that this project may be deferred by 1 to 2 years.

[169] Probability based upon: 90% (historical accuracy) x 88% (lower cost alternative)

With regard to the load profile, as noted above, we have accepted that the load profile assumptions applied by Powercor are unlikely to result in a material understatement of future energy at risk.

Conclusions

Based upon the above, we have revised our project probability to moderate to high (70%). In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects the possibility that the risks can be prudently and efficiently managed for another 1 or 2 years[170].

The increase is largely due our revised view of the energy at risk and associated economic timing, and to a lesser degree, our revised view that the Powercor's load profile assumptions are reasonable.

6.2.2.5 GTS 66 kV lines upgrade

This project involves the upgrade of various lines that connect GTS to various zone substations. The key driver for this project is the projected loading at GTS and various existing lines.

Nuttall Consulting assigned this project a high probability (90%), but we did note that due to the load profile and the AER's reductions to Powercor's maximum demand this project may be deferred.

The Powercor revised proposal considers that project costs should be viewed as 100% required as originally proposed. Powercor has provided a revised material project template and energy at risk spreadsheet to support this view.

Although we have accepted that Powercor's load profile is appropriate, and the AER has accepted Powercor's maximum demand forecast, we are not proposing to adjust the probability for this project as these matters did not directly affect the original project probability.

For the reasons discussed in section 3.1, we consider that this probability should remain at 90%.

6.2.2.6 NKA-CME 66 kV line upgrade.

This project involves the establishment of a second line to the Cobram East zone substation (CME) from the Numurkah zone substation (NKA). Presently, CME is supplied by a radial line from NKA. The key drivers for this project are the energy at risk at CBE, and Powercor's internal criteria to only allow loading up to 20 MVA on radial lines.

Nuttall Consulting assigned this project a moderate to high probability (70%), based upon our views on:

- the lack of sufficient demonstration that the energy at risk justified the project, noting the impact of available load transfers and emergency generation indicated in the 2009 DSPR

[170] Probability based upon: 90% (historical accuracy) x 80% (energy at risk)

- the possibility that a lower cost 22 kV feeder option may economically defer the larger sub-transmission project.

The Powercor revised proposal considers that project costs should be viewed as 100% required as originally proposed. Powercor has provided a revised material project template and energy at risk spreadsheets to support this view.

With regard to our main concern, sufficient energy at risk, Powercor has provided revised analysis that it considers indicates that energy at risk will be sufficient to support the need for the project to be completed in 2014/15. This analysis indicates that the value of expected unserved energy due to an outage of the existing line is already $12m this year and will rise to $13.5m by 2014. On the matter of load transfers and emergency generation, Powercor considers that there is no back-up available at peak load times and emergency generation would only have a minor impact on unserved load (i.e. 2-4 MVA of generation compared to over 40 MVA of load).

We have reviewed the Powercor document and although we cannot find fault with Powercor's claims, we do consider that these appear anomalous to the statements in the 2009 DSPR and the proposed timing of the project. In this regard, Powercor's value of the annual expected unserved energy is extremely high compared to the capital cost of removing this. Given Powercor's comments on load transfers and emergency generation it is not clear how Powercor can presently prudently and efficiently manage this situation, never mind continue to manage this until the end of the next period – the avoided costs now would appear to justify a $160m development. Assuming Powercor are not accepting these risks – which are effectively covered by its customers – it does suggest that Powercor is able to manage the load in a way not clearly explained in its documents.

If on the other hand the expected unserved energy is as indicated then it strongly suggests that this circuit will be having a material impact on existing SAIDI levels – noting Powercor assumes one outage per annum with a duration of 8 hours[171]. As such, a significant part of the project could be funded through the reliability incentive scheme.

Based upon the above, we still consider there is a reasonable possibility that the project may be either deferred or partly funded through another incentive mechanism.

With regard to the alternative 22 kV option, Powercor has provided further details on an option involving three 22 kV feeders, which is significantly more expensive than the 66 kV option. This discussion has not addressed our specific point that fewer feeders may allow the 66 kV option to be deferred while accepting some remaining risk, such that the 66 kV option can be economically deferred. Nonetheless, based upon the information provided, we are satisfied that it is very unlikely such an option would be optimal. As such, we accept that Powercor's preferred option is reasonable.

Conclusions

[171] Indicated on the material project template.

Based upon the above, we have maintained our project probability to moderate to high (70%)[172]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects:

- the possibility that the risks can be prudently and efficiently managed for another 1 or 2 years
- or the project will be partly funded through the reliability incentive scheme.

6.2.2.7 Summary findings

Based upon the above, we have revised our project probabilities as indicated in the Table below.

Table 32 Powercor reinforcement project summary

Project	original probability	revised probability
The Eagle Hawk zone substation upgrade	Moderate/high (70%)	High (90%)
The Gisborne new zone substation	Moderate (50%)	Moderate/high (70%)
The BETS-CTN 66 kV line upgrade	Moderate (50%)	Moderate/High (70%)
The GLE upgrade	Moderate (50%)	Moderate/High (70%)
GTS 66 kV lines upgrade	High (90%)	High (90%)
NKA-CME 66 kV line upgrade.	Moderate/High (70%)	Moderate/High (70%)
Weighted average	**62%**	**75%**

The project probabilities largely reflect the concerns we raised in our original review:

- energy at risk is insufficient to justify the timing
- part funding through the reliability incentive scheme
- alternative lower cost options
- conservative load profile assumptions
- previous forecasting accuracy.

The increases are largely due to the increased demand forecast and updates or clarification on the DNSPs project justifications.

6.3 Reliability and quality maintained

Our original review considered Powercor's RQM forecast based upon the DNSP's internal activity codes. This break-down was used as it was considered to be the most consistent

[172] Probability based upon: 90% (historical accuracy) x 80% (energy at risk adjustment OR reliability improvement funding)

between the historical and forecast allocation of expenditure. This break-down largely reflects various asset classes, but is slightly different to the AER's revised RIN asset categories. This review lead to various parts of the forecast being accepted, and others being rejected, with the substitute forecast based upon the calibrated repex model for those asset categories.

Powercor has not agreed with Nuttall Consulting's rejection of a number of categories. For these categories, the revised Powercor proposal provided further discussion and information to support these categories and address Nuttall Consulting's concerns expressed in our original report.

The table below lists the various categories and indicates where additional information has been reviewed by us and is discussed in the section below.

Table 33 Powercor RQM category summary

Category	Original finding	DNSP revised proposal
Cross-arm Replacement	Accept	Accepted
Fault related	Accept	Accepted
HV Fuse Unit & Surge Divert. Repl.	Accept	Accepted
HV Switch Replacement	Reject	Accepted
OH/UG Line Replacement	Reject	Accepted
Other	Accept	Accepted
Pole	Accept	Accepted
Reliability Improvement	Reject	Rejected – additional information provided
Services	Accept	Accepted
Transformer Replacement	Accept	Accepted
Zone Substation Plant Replacement	Reject	Rejected – additional information provided
ZSS - Secondary Systems Replacement	Reject	Rejected – additional information provided
Conductor	Reject	Rejected – additional information provided

General criticisms of Nuttall Consulting's approach to assessing RQM expenditure and determining substitute allowances, which are similar between DNSPs, are discussed in Section 3.2.

This section discusses the specific categories where specific criticisms or new information has been provided in the revised proposal.

6.3.1 Zone substation plant replacement

The zone substation plant category covers the replacement of power transformers, zone substation switchgear, and associated primary plant.

This category represents 14% of Powercor's RQM forecast for the next period. Powercor has forecast this category to have a very significant increase in expenditure from recent levels.

6.3.1.1 Summary of Nuttall Consulting original review

Nuttall Consulting did not consider that Powercor had adequately demonstrated that its forecast expenditure associated with this RQM category was reasonable (i.e. it could be considered a disaggregated component of the overall prudent and efficient capex)[173].

In rejecting the forecast, we considered Powercor had not adequately demonstrated that the models it used to predict the level of replacement were "fit for purpose" in the regulatory context. This specifically related to our view that Powercor had not adequately shown that the models had been calibrated and validated[174]. The key matters we raised to support this view were:

- our assessment of the transformer condition information (polymerization test results), which we considered did not reasonably justify the number of transformers Powercor was predicting would need to be replaced in the next period[175]
- a number of inconsistencies between assumptions inherent in the models with regard to asset failure probabilities and historical failure rates, particularly those that we considered important to predicting replacement needs[176].

During the course of the review, Nuttall Consulting had requested information on these concerns but considered Powercor's response did not adequately address these matters[177].

Nuttall Consulting's recommended allowance was based upon the average historical level of expenditure in this category (2006-2008) with an additional component based upon the expenditure annual increase predicted by the calibrated repex model.

It is our understanding that the AER accepted our view in forming its overall capex allowance for Powercor.

6.3.1.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The Powercor revised proposal details a number of criticisms associated with our view that the models had not been demonstrated to be "fit for purpose". These largely relate

[173] Nuttall Consulting report, pg 191
[174] Ibid, Pg 191
[175] Ibid, Pg 189
[176] Ibid, Pg 190
[177] Ibid, Pg 191

to further advice Powercor has sought from EA Technology (the consultancy that prepared the models for Powercor)[178]. The main matters discussed in the revised proposal cover:

- The validity of Nuttall Consulting's rejection of the health index (HI) of the transformers[179], where it notes EA's views that the combination of condition factors (rather than only the polymerization test results) must be considered to determine remaining life[180].
- The validity of Nuttall Consulting's concerns that the failure rates indicated by the model were too high[181], where it notes that EA considered that these were well below typical industry rates and rates it had seen elsewhere.

Nuttall Consulting has considered the information presented by Powercor, including the EA Technology report; however, we do not consider that this has adequately addressed the concerns we expressed in our original report.

We do not disagree with EA's views noted above. However, we still do not consider that this justifies that the models used by Powercor are fit for purpose. With regard to the polymerisation test results, we still consider that these are very important results in determining the end of life of transformers – it is noted that this is the main test result used in United Energy and Jemena's modelling of transformer replacements. With regard to the failure probabilities, we still consider that Powercor has not adequately explained why the probabilities predicted by the model appear to be below historical levels – even if these are below other benchmarks. Given (a) the apparent reasonable condition of the transformers, (b) the apparent overstating of the failure probabilities, and (c) the relatively complex formulation within the model for calculating the failure probability (and health Index) from the numerous factors, we still consider it reasonable that Powercor should more clearly demonstrate that the replacement predictions made by the models are "fit for purpose".

In our original report we provided some guidance on this matter, stating:

> "*this would require a far more substantial and quantitative analysis to appropriately and transparently demonstrate their suitability. This would require network level and sample asset level analysis that shows that the number of failures, probability of failure, the aging relationship, and the consequences, derived through the model are reasonable unbiased estimates of the replacement needs. Such an evaluation would need to take into account Powercor's historical information, including failure statistics, asset condition monitoring results and risk mitigation measures.*"[182]

On this matter it is noted that Powercor has stated that it does not consider that this requirement is legally permissible[183]. Although we consider that the AER will need to address this legality issue, we consider that we have adequately justified the basis for our

[178] Attachment 163, to Powercor revised proposal.
[179] Powercor revised proposal, Pg 284
[180] We note the example given in revised proposal concerning the specific example we raised in our report.
[181] Powercor revised proposal, Pg 285
[182] Nuttall Consulting original report, pg 191
[183] Powercor revised proposal, pg 287

rejection of the forecast proposed by Powercor. As further guidance here on our requirement, we do not see any reason why Powercor could not run the model, at least for a subset of the transformers and CBs, using 2005 condition data. In this way, it could be shown whether or not the model does overstate needs by comparing the model outputs (and associated predicted replacement requirements) against those that have actually occurred. We consider that this is a standard model validation process.

We do note that Powercor has raised the fact that the AER has accepted the use of this modelling approach in its recent Energex decision[184]. The AER will need to consider this from a legal perspective; however, we do not consider from a practical point of view that this is a demonstration that the Powercor model is calibrated correctly.

Based upon the above, we still consider that Powercor's forecast for this category should be rejected. Turning now to our recommended allowance, we note that Powercor does not consider that our use of the repex model is valid[185].

We also note that Powercor's revised proposal includes additional expenditure to rebuild the existing Sunshine zone substation. We have reviewed the material presented to support this re-build. Based upon this review, we do not disagree that the rebuild may be required as proposed. However, we do not consider that Powercor has fully justified why this could not be undertaken within the existing allowance.

In appreciating our allowance recommended in the original report, we consider that it is important to note that this allowance still represents a 22% increase over the expenditure in this category in the current period. Based upon the historical volume and cost base, this should allow approximately 53% of Powercor's proposed transformer replacements and 76% of its proposed CB replacements.

That said, we do accept that for the zone substation category in particular, there may be a need for some additional uplift to cover more costly work in the next period (i.e. assume many of the lower cost replacements may have been targeted in the current period). However, we consider that a 15% uplift factor is appropriate for this. As also noted in Section 3.2, we accept that 2009 data should be used in the calibration process.

Based upon the above, we recommend that our original allowance for this category is increased to cover these two matters. The table below provides our revised estimate for this allowance (estimate exclusive of overheads and escalation).

Table 34 Powercor substation primary plant

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	9.3	14.5	12.1	7.0	6.6
Recommended	**4.3**	**4.7**	**5.0**	**5.4**	**5.8**

[184] Powercor revised proposal, pg 285
[185] Powercor revised proposal, pg 285

6.3.2 Zone substation Secondary Systems Replacement

The zone substation secondary systems category covers a large number of separate programs. The most significant is an ongoing aged-relay replacement program, which covers approximately 30% of the expenditure. There are a number of much smaller ongoing programs covering another 30%, with the remainder being due to a significant number of new programs.

This category represents 8% of Powercor's RQM forecast for the next period. Powercor has forecast this category to have a very significant increase in expenditure from recent levels.

6.3.2.1 Summary of Nuttall Consulting original review

Nuttall Consulting did not consider that Powercor had adequately demonstrated that its forecast expenditure associated with this RQM category was reasonable (i.e. it could be considered a disaggregated component of the overall prudent and efficient capex[186]).

The key matters we raised to support this view were:

- with regard to the aged relay programs, it appeared that the volume of replacement proposed in the next period was below those replaced in the current[187]
- for the other ongoing and new programs there was no economic analysis that demonstrated the prudency and efficiency of the proposed increases[188]
- with regard to the new programs, we considered that there was no evidence that such a significant step increase would not result in a step reduction in risks.

Nuttall Consulting's recommended allowance was based upon the average historical level of expenditure in this category (2006-2008) with an additional component based upon the expenditure annual increase predicted by the calibrated repex model.

It is our understanding that the AER accepted our view in forming its overall capex allowance for Powercor.

6.3.2.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The Powercor revised proposal details a number of criticisms associated with this category. These broadly fall into the following matters:

- aged relay replacement program
- other programs
- our allowance.

These matters are discussed in turn below.

[186] Nuttall Consulting report, pg 193
[187] Ibid, Pg 193
[188] Ibid, PG 190

With regard to the aged relay program (approximately 30% of the category), Powercor considers that Nuttall Consulting was in error in thinking that the quantity of relay replacement is proposed to be lower in the next period than in the current – Powercor noted that this is due to the difference between figures being quoted as the number of relays for the current period but number of schemes in the next.

Nuttall Consulting accepts that it was in error on this matter (although we do not accept that this was because we "misunderstood the difference between relays and protection schemes" as stated in Powercor's revised proposal. We do however note that there still appears to be some confusion over the replacement volumes given in Powercor's revised RIN template (Schedule 2.7), which still appears to indicate lower volumes in the next period compared to the current.

Nonetheless, accepting that the number of schemes to be replaced is as given by Powercor in its revised proposal (55 per annum in the next versus 38 in the current), we still do not consider that Powercor adequately demonstrated that its proposed volume and associated expenditure is reasonable.

On this matter, Powercor has provided a revised asset management plan[189]. In addition, it has also provided some commentary on the number of relays in various risk categories and how these volumes change through the next period, based upon various replacement scenarios[190]. Nuttall Consulting has reviewed this information, but still considers that it is lacking in clearly demonstrating the validity of the modelling that underpins these results, both in terms of the estimation of end-of-life associated with the risk scores and the algorithm used to predict the changes in risk levels with time. This in turn relates to our concern that the need for a significant increase from historical levels has not been shown.

Turning now to the other programs (which constitute about 70% of the expenditure), the Powercor revised proposal includes a Table that provides some commentary on the assets and risks associated with some of these programs[191]. Powercor has also provided a number of attachments on a selection of these programs[192]. Nuttall Consulting has reviewed this material; however, we do not consider that it has addressed the concerns we expressed in our original report. Although the material provides some information (generally in a qualitative way) on the risks and obligations associated with the programs, it does not provide meaningful information that can inform a review of this form. Such information would include explanations of how the risks have been management in the current period, how they have changed in the current period, and how they are predicted to change in the next period. This in turn would allow us to evaluate whether we could expect a step change in the risk position of the business associated with such an increase in replacement. Based upon the information made available to us, it is not clear why expenditure showing a more gradual increase from historical levels, would not more reasonably reflect a prudent and efficient continuation of risks.

[189] Attachment 255, to Powercor revised proposal
[190] Powercor proposal, Pg 288 and Pg 290
[191] Powercor proposal, Pg 291
[192] Attachment 164, to Powercor revised proposal

Based upon the above, we still do not consider that Powercor has justified the need for such a significant increase in expenditure in this category.

With regard to our allowance, we have reviewed our approach in light of the new information, and do accept that a significant increase from our original allowance is warranted. In this regard, we do not consider that our original allowance will be sufficient to allow for the likely increases in the ongoing programs, and still allow for a modest increase to address new needs.

We do note that Powercor considers it is inappropriate to use the repex model to determine the allowance as many needs are not related to aging factors[193]. While we do not disagree entirely with this view (we accept that many of the programs are not directly related to age factors), in the absence of any other more appropriate guidance, we still consider that the rate of increase suggested by the repex model can be considered the most reasonable guide.

That said, in the case of the secondary systems, we consider that the actual expenditure in 2009 is the appropriate base-line to increment expenditure from. This year captures the commencement of a significant number of the ongoing programs, and so should better reflect the ongoing needs. We have also re-calibrated the growth rates to allow for historical replacement volumes – this has resulted in increases in the expenditure growth rates from the base-line.

The table below provides our revised estimate for this allowance (estimate exclusive of overheads and escalation). This represents a 24% increase in expenditure over the current period (2006-2009).

Table 35 Powercor substation secondary systems

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	6.3	6.2	6.0	6.1	6.0
Recommended	**2.9**	**3.0**	**3.2**	**3.4**	**3.6**

6.3.3 Conductor

In Nuttall Consulting's original report, we did not consider that Powercor had adequately demonstrated that its forecast step increase in expenditure associated with its conductor replacement program was reasonable[194]. This position effectively assumed that the risks accepted by Powercor in the current period were appropriate and there would be a step reduction in risks if the proposed program was undertaken.

[193] Powercor revised proposal, Pg 288

[194] Nuttall Consulting report, pg 187

However, we did note that due to the relationship of this program with bushfire risks, and the impending findings from the Royal Bushfire Commission, this program may need to be "ring-fenced" and considered further by the AER.

Subsequent to this advice, the AER undertook further analysis and in its draft decision it accepted the need for a significant step increase in the conductor replacement program, but reduced the allowance proposed by Powercor. We understand that the reduction was based upon:

- a lower unit cost applied by the AER
- an "accuracy factor" related to the ability to target conductors.

In Powercor's revised proposal it has disagreed with the AER's position. We note that in places, Powercor has associated Nuttall Consulting with its criticisms of the AER's basis for its allowance. However, this view is incorrect as we did not recommend or approve the AER's position.

Nuttall Consulting understands that the AER does not disagree with Powercor's view of the volume of conductor replacement. However, the AER has requested Nuttall Consulting to consider Powercor's proposed unit costs.

On this matter, we understand that the AER reduced the Powercor unit cost based upon the unit cost supplied by SP AusNet, which was considerably lower.

Powercor has disagreed with this adjustment. To support this view, it has noted the following:

- It was inappropriate to use the SP AusNet cost as a benchmark, as this unit cost is not directly comparable with the Powercor unit cost. The Powercor cost allows for the line replacement, including pole and pole top assets, whereas the SP AusNet unit cost only allowed for the conductor replacement, with the pole and pole top cost allocated elsewhere[195].
- PB has undertaken a benchmarking exercise that supports Powercor's unit cost. PB found the unit cost to be reasonable as it fell within the bounds of typical industry values[196].

In addition to this, the AER has requested further information to support the Powercor unit cost[197]. Importantly, this included analysis of historical conductor replacement costs. In response to this, Powercor has provided further information[198], including analysis of the costs of the conductor replacement project it has undertaken in the current period. Powercor also considers that this analysis supports its unit cost as this found the average historical unit cost of these projects to be slightly higher than the unit cost it has assumed (i.e. $43,000 per route km (historical) versus $41,000 assumed).

[195] Powercor revised proposal, Pg 282
[196] Powercor revised proposal, Pg 282, Attachment 252 – PB Report
[197] AER email, dated 31 August 2010
[198] Powercor email, dated 7 September 2010

Nuttall Consulting has reviewed the material provided by Powercor and considered its reasoning.

With regard to the incompatibility of the SP AusNet and Powercor unit costs, based upon the variation in the unit costs and the low cost for SP AusNet compared to other DNSPs, Nuttall Consulting agrees with Powercor. As such, we accept that there is a reasonable case that the Powercor unit cost should be significantly higher than the SP AusNet value.

However, with regard to whether the PB benchmarking alone is sufficient to justify the unit cost, we do not accept this view. There is very little information in the PB report on what its industry costs were based upon and how reflective they are of actual project costs relevant to the circumstances of Powercor. Further, PB did not examine Powercor's unit cost in light of Powercor's actual historical costs in order to determine how these related to PB's industry unit costs. We would expect wide variations in conductor replacement costs between project types and DNSPs. As such, we consider analysis of the Powercor's historical projects to be a better gauge of future unit costs.

With regard to the Powercor analysis of past project costs, we note that Powercor considered that this supported its unit cost as the mean project cost per route km was marginally above the unit cost it has assumed.

We have reviewed this analysis and have a number of concerns. Firstly, as Powercor has used the mean project unit cost, the result is sensitive to a few very high cost projects. In this regard, the distribution of the individual project unit costs is skewed, with a number of very high cost projects – the highest being $289k per route km, which is due to a project covering 212 "route" meters in 2006.

If this single project is removed from the analysis (i.e. it is considered an outlier) then the mean project unit cost is $36k per route km. Alternatively, if we consider the mean cost per km (i.e. total cost / total route km) then the mean unit cost per route km is $33k. This alternative calculation of the mean tends to reduce the significance of high cost projects with low route length. Finally, another alternative – which is possibly more appropriate in these circumstances – is to use the median rather than the mean. This reduces the impact of outliers. The median project unit costs is only $30k per route km.

Based upon above, we consider it reasonable to reduce the Powercor unit cost to $33k per route km. We consider that this better reflects the average cost per km Powercor has historically incurred, and still allows for a 10% increase above the median project unit cost.

6.3.4 Reliability

The reliability category covers a number of programs to address worst served customer and other reliability related issues.

This category only represents approximately 2.5% of RQM capex. The expenditure is broadly in line with Powercor's 2009 actual and 2010 estimate, but is a significant increase over historical levels, where Powercor had allocated zero expenditure to this category over 2006-2008.

6.3.4.1 Summary of Nuttall Consulting's original review

Nuttall Consulting did not consider that Powercor had provided sufficient information to justify any expenditure in this category[199]. We considered that, given there was zero expenditure in this category between 2006 and 2008, expenditure we allowed in other categories should be sufficient (i.e. to maintain reliability) noting these allowances were largely based upon an extrapolation of these costs.

6.3.4.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The Powercor revised proposal requests the reinstatement of the reliability expenditure[200]. It considers that these should be considered prudent and efficient, and are necessary to "meet reasonable expectations of reliability of supply" as required by Clause 5.2 of the Distribution Code.

Powercor also noted that PB reviewed this category[201] and noted that we did not reject this category based upon any fundamental analysis. Furthermore, Powercor noted that PB considered that the expenditure should be accepted as it was in line with our overall repex model findings.

Powercor also provided further details of the individual programs that made up the reliability expenditure.

Nuttall Consulting has reviewed the material provided by Powercor and considered its position. We still maintain that there is insufficient information to justify that any capex allowance is required to allow for these programs.

Importantly, in forming this view, we have considered the information provided on the individual programs advised by Powercor, and note that many of these programs appear to be reliability improvement programs targeted at the worst served customers. There are others that appear to be targeted at other matters, but these also appear to be largely related to improving reliability.

As such, it is reasonable to consider that these programs would be funded through the reliability incentive scheme. On this view, we note that these types of programs were rejected on these grounds by the ESC in its decision for the current period[202].

We do note that it could be that the costs outweigh the funding through the reliability incentive scheme. However, in this case, we would expect Powercor to provide some analysis to justify the prudency and efficiency of the incremental capex requirement. This type of information has not been provided. On this matter, we note PB's comment that we have not undertaken any fundamental analysis to support our rejection. However, we consider that the onus is on Powercor to provide this analysis for us to review. We do not consider it is reasonable that such analysis could be undertaken independently without significant input from Powercor.

[199] Nuttall Consulting original report, Pg
[200] Powercor revised proposal, pg 306
[201] Powercor revised proposal, Attachment 171 – PB report
[202] ESC Final Decision Volume 1, Electricity Distribution Price Review 2006-10, pg 297

Based upon the above, we consider that Powercor's forecast for reliability expenditure should be rejected. Further we consider that an allowance of zero should be substituted. It is important to note, this is not to say works should not be undertaken; rather, it will be funded through other mechanisms or already allowed for in other capex allowances.

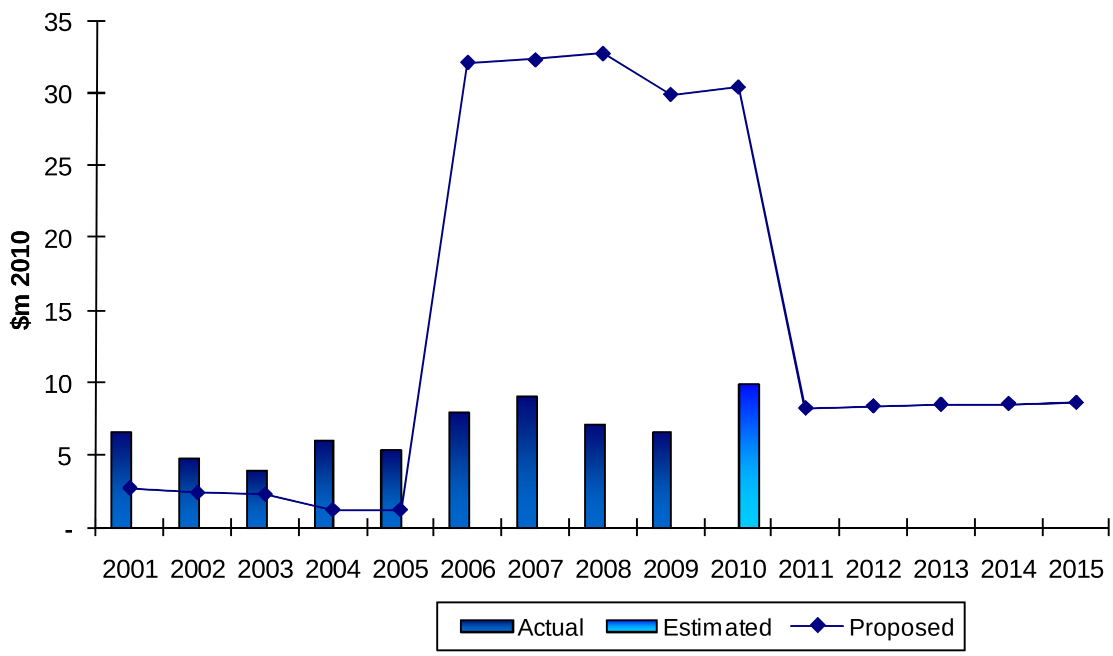
6.4 Environmental, Safety and Legal

Powercor is proposing an increase of 10% in Environmental, Safety and Legal capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. Powercor estimates that its Environmental, Safety and Legal capital expenditure for the 2006-10 regulatory control period will be $40.7 million. It is forecasting that this will increase to $42.1 million in the 2011-15 regulatory control period.

For the 2006 EDPR, Powercor proposed Environmental, Safety and Legal expenditure of $157.3 million. The resultant actual expenditure for this period is forecast to be $40.7 million[203].

The following chart provides a summary of Environmental, Safety and Legal capex for Powercor.

Figure 25 - Powercor Environmental, Safety and Legal capex



In addition to these expenditures, Powercor has proposed additional and new activities in response to the Victorian Bushfires of 2009 and the Royal Bushfire Commission's final report. The proposed expenditures have been reviewed by Energy Safe Victoria (ESV) and recommendations made as to the future volumes of work required. The AER has

[203] Including 2009 and 2010 estimates.

requested Nuttall Consulting to review the unit costs associated with the ESV recommended volumes. This assessment is provided in Appendix G – Unit cost review of this report.

Powercor has stated that it "does not contest the AER's Draft Determination with respect to environmental, safety and legal capex". However, Powercor contends that the AER should include 2009 actual data in its trend analysis and in forecasting the capex required in the next regulatory proposal by reference to historical expenditure."[204]

Powercor also requests that plans submitted under the Electrical Safety Management Regulations should be addressed by the AER as a nominated pass through.

Nuttall Consulting has reviewed the alterations for the trending analysis proposed by Powercor and agrees with the inclusion of the 2009 actual data. This data has now been incorporated into the base information provided to Nuttall Consulting by the AER and has been used, where relevant, in any subsequent trending analysis.

The capex for Environmental, Safety and Legal, as proposed by the AER in the draft determination, is provided in the following table.

Table 36 – Draft determination Powercor ESL capex

Powercor	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Draft determination capex	6.7	6.7	6.7	6.7	6.7

The Powercor revised proposal provides an updated forecast of capex for Environmental, Safety and Legal as per the following table.

Table 37 - Resubmitted Powercor ESL capex

Powercor	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Resubmitted capex	8,211	8,352	8,456	8,527	8,595

The basis for the increased expenditures in the Powercor revised proposal are not evident from the information provided in the Powercor revised proposal or associated documents. Powercor has stated that they do not contest the AER's draft determination in relation to Environmental, Safety and Legal capex and no additional information has been provided to support the changes contained in the Powercor revised proposal. Therefore, Nuttall Consulting recommends that the expenditures for environmental, safety and legal capex provided in the AER's draft determination should be updated to recognise the 2009 actual data as shown below.

[204] Powercor Australia Ltd Revised Regulatory Proposal 2011 to 2015 – July 2010.

Table 38 - Recommended Powercor ESL capex

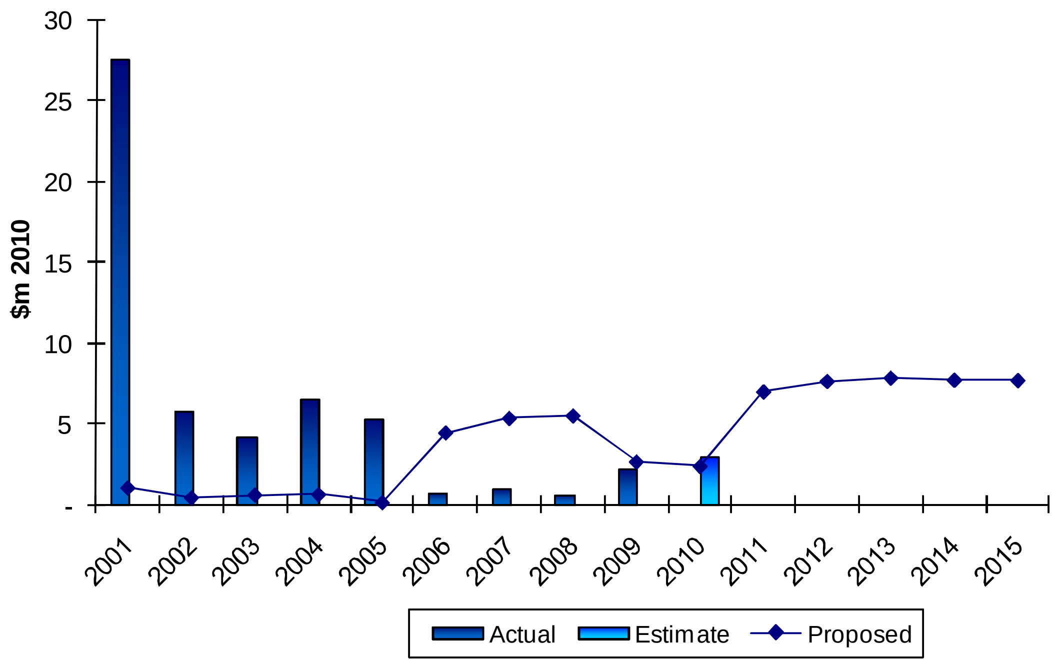
Powercor	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Recommended Expenditure	7.2	7.2	7.2	7.2	7.2

6.5 SCADA and Network Control

Powercor is proposing an increase of over 560% in SCADA and Network Control capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. Powercor estimates that its SCADA and Network Control capital expenditure for the 2006-10 regulatory control period will be $7.4 million. It is forecasting that this will increase to $37.7 million in the 2011-15 regulatory control period.

For the 2006 EDPR, Powercor proposed SCADA and Network Control expenditure of $20.2 million. The resultant actual expenditure for this period is forecast to be $7.4 million .

The following chart provides a summary of SCADA and Network Control capex for Powercor.



In its draft determination, the AER recommended reductions to the Powercor SCADA and Network Control forecast capex. The capex recommended by the AER is described in the following table.

Table 39 – Draft determination Powercor SCADA and Network Control capex

Powercor	Costs (2010 $M)				
SCADA and Network Control	2011	2012	2013	2014	2015
Draft determination capex	2.5	2.5	2.4	2.4	2.3

Powercor's revised proposal states that the "AER has not considered the circumstances of Powercor's network in assessing its proposed SCADA and network control capex. Powercor contends that its SCADA and network control programs in the next regulatory control period are required ..."[205].

The key responses provided by Powercor in relation to the proposed capex are that:

- Nuttall Consulting erred in concluding that the DMS field devices were included in the IT capex (non-network) category
- the AER erred in assuming that the underspend in the current period SCADA and Network Control capex was an efficient outcome
- Powercor maintains that each of its proposed projects link with the Network Protection and Control Communications Strategy 2009-2014[206]
- the programs proposed by Powercor for the next regulatory control period justify forecast expenditure greater than the historical trend.

The above Powercor responses are discussed in detail in the following sections.

On the basis of the above responses, Powercor is proposing SCADA and Network Control capex for the next control period as described in the following table.

Table 40 – Revised proposal Powercor SCADA and Network Control capex

Powercor	Costs (2010 $M)				
SCADA and Network Control	2011	2012	2013	2014	2015
Revised proposal capex	6,959	7,605	7,815	7,684	7,662

The following section considers the information provided by Powercor in its revised proposal.

6.5.1 DMS Field Devices

Powercor states that the DMS field devices are network data collection devices that sit on poles or in substations that provide interface with electrical assets. The revised proposal information provided by Powercor makes it clear that there is a separation between DMS related works that are part of the general – IT capex and DMS field devices.

[205] CitiPower PTY's Revised Regulatory Proposal 2011-2015 – Page 249.
[206] Attachment P0030 to the Initial CitiPower Regulatory Proposal

Nuttall Consulting accepts the position put forward by Powercor that the DMS field devices should therefore be considered as separate and additional to the DMS projects captured in the general –IT capex category.

Powercor has provided an explanation of the capital forecast associated with the implementation of distribution management system (DMS) field devices[207]. This document identifies expenditures[208] of $500,000 for the first two years of the regulatory control period and $800,000 for each remaining year. The project is described by Powercor as a new program that will commence in the next regulatory control period. There is no related expenditure on DMS field devices reported in the current control period.

The reasons provided by Powercor that require the installation of the DMS field devices include the increase in network utilisation and an increase in embedded generation connections. Nuttall Consulting agrees that network utilisation and the incidence of embedded generation will continue to increase in the next regulatory control period. These are not new issues facing the network; both have been referenced as drivers of expenditure in Powercor EDPR proposals from 2001 and 2006.

Powercor has not identified any external obligations or regulations that require the installation of the DMS field devices. Powercor has identified benefits from the field devices. These benefits and the Nuttall Consulting assessment of them are discussed in the following table.

Table 41 – Benefits of DMS field devices

Powercor identified benefit	Nuttall Consulting assessment
Allowing network events to be modelled so that Powercor can plan operational switching requirements that provide the best network performance and reliability	Incremental benefit above current network event information.
Maintaining the reliability of a network that is experiencing increasing utilisation levels and increased levels of embedded generation	Incremental benefit to existing levels
Allowing Powercor to have full control and knowledge of the distribution network	Nuttall Consulting questions the validity of this statement. It does not appear likely that full control and knowledge is possible from the proposed program
Allowing Powercor to avoid any increases in potential health and safety	Powercor does not describe the mechanisms by which the DMS field devices provide this benefit. Nuttall Consulting

[207] PAL 168 - Implementation of DMS field devices.pdf
[208] Excluding overheads and escalation

incidents	considers that the DMS field program will not allow Powercor to avoid "any" increases in potential health and safety incidents, although there are foreseeable mechanisms that it could allow Powercor to avoid "some" increases.

Powercor does not provide any quantified benefits from the DMS field device installations. Powercor does not provide any information to identify or quantify any efficiencies or opex trade-offs from the proposed DMS program.

In the absence of any quantification of benefits it is not possible to assess if the proposed benefits from this program outweigh the identified costs. Therefore it is not possible to assess if the proposed program is prudent and efficient.

The DMS field project is designed to provide capability and functionality, above current levels. Powercor has not shown that these enhancements will provide consumers with a tangible benefit or service improvement.

Nuttall Consulting considers that Powercor has not shown that the proposed expenditure is efficient or that it represents expenditure required to meet the capital expenditure objectives. Nuttall Consulting does not recommend that the expenditure should be included in the next regulatory control period.

Note: the implementation of the DMS project (general – IT capex) is discussed in the general – IT capex section below. The IT project can proceed independent of whether Powercor chooses to proceed with the installation of DMS field devices or not.

6.5.2 Historical underspend

In its revised proposal Powercor states that the AER erred in assuming that the underspend in the current period SCADA and Network Control capex was an efficient outcome[209]. In support of this position, Powercor identified a number of project deferrals that contributed to the resultant underspend. These include:

- delays to "lead-in" projects such as the GIS[210] and OMS[211] migrations and SCADA system replacement
- delays due to the structure, resourcing and management of the service provider's offshore development program
- underestimation of the complexity of the project by the service provider; and
- underestimation of the level of testing required.

Nuttall Consulting accepts that the deferral causes identified by Powercor may reasonably have contributed to actual expenditure being less than that proposed by the DNSP. The

[209] Powercor Australia Ltd's Revised Regulatory Proposal 2011-15 – Page 302
[210] Graphical Information System
[211] Outage Management System

deferral causes identified by Powercor support the Nuttall Consulting view that the proposed SCADA and Network Control capex for the next regulatory control period does not meet the capex objectives.

With the advantage of hindsight, it is possible to assess the prudency and efficiency of the SCADA and Network Control capex that was proposed by Powercor for the current regulatory control period.

In a previous review of NSW DNSP expenditure, prudency was considered as follows: "*Prudence is often best judged by the absence of evidence suggesting a lack of it. In the case of electricity networks, imprudence might be most discernible if there was evidence of failure to invest adequately, accompanied by identified adverse consequences, and is thus best assessed retrospectively*."[212]

Powercor has provided no evidence that the underspend resulted in an imprudent outcome. As there is no discernible evidence of failure to invest adequately and/or adverse consequences we must assume that the level of expenditure was prudent.

The assessment of efficiency is based, in part, on the least cost feasible option to meet the capital expenditure objectives. This requirement would appear to be satisfied by the incurred expenditure.

Based on the above, it is reasonable to accept that the historical levels of SCADA and Network Control capital expenditure incurred by Powercor are both prudent and efficient.

Looking at the forecast SCADA and Network Control capital expenditure proposed by Powercor for the next regulatory control period we see that it is significantly greater than the level of capital expenditure that has actually been incurred in the previous 9 years[213].

When we reconsider the SCADA and Network Control capex that was forecast for the current Regulatory Control Period we can also see that the Powercor forecast for the current period is much higher than the actual level of expenditure.

As noted above, Powercor have identified that their forecast for the current regulatory control period did not take into account the impact of unforeseen project deferrals. Nuttall Consulting consider that this lack of account of project deferrals is a systemic problem with the capex forecasting process.

Capital projects are often complex and require many interactions with third parties. These interactions can include other related projects, resource providers and contractors, councils, planning authorities, health and safety authorities, environmental impacts, etc. While it is not always possible to identify which of these interactions may result in a delay to a project, it is good practice to make allowances for these delays.

The information provided by Powercor in relation to the SCADA and Network Control project delays in the current regulatory control period show that these project delays have not been sufficiently allowed for in the planning processes.

[212] Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1 – Main Report, Final, October 2008 - Wilson Cook & Co, Page 8.

[213] 2001 to 2009 inclusive.

Nuttall Consulting considers that recognition of the potential impacts of project delays in forecasting and planning is good electricity industry practice. A commonly accepted definition of good electricity industry practice is the exercise of that degree of skill, diligence, prudence and foresight to be reasonably expected of a distribution business working under the prevailing conditions consistent with applicable regulatory, service, safety and environmental objectives.

Powercor was requested by the AER to provide details where the policies, strategies and procedures provided to support their submission have changed during the current regulatory period and the effects of these changes[214]. The Powercor response to this request did not identify any changes to the policies, procedures or strategies for expenditure forecasting. On this basis, we must assume that the forecasting processes and procedures utilised by Powercor have not changed and that allowances for delays in capital projects have not been adequately accounted for.

To summarise the above;

- the actual Powercor SCADA and Network Control capex for the current regulatory control period is considered prudent and efficient
- the historical planning processes and procedures used by Powercor do not adequately account for interactions with other projects and third parties and have resulted in forecasts greater than actual expenditure
- Powercor has not identified any changes to the historical planning processes and procedures
- the SCADA and Network Control capex forecast for the next regulatory control period does not adequately account for interactions with other projects and third parties that may result in delays
- if allowances are made for interactions with other projects and third parties, the resultant expenditure would be lower than that proposed by Powercor.

6.5.3 Strategic plan linkages

Powercor "maintains that each of its proposed projects link with the Network Protection and Control Communications Strategy 2009-2014".[215] Nuttall Consulting agrees that there are links between the proposed projects and the Network Protection and Control Communications Strategy 2009-2014. Nuttall Consulting notes that the Network Protection and Control Communications Strategy does not discuss capex forecasting, or identify interactions with other projects and third parties that may result in delays to the identified projects.

Nuttall Consulting considers that the identification and linking of proposed projects with the overall business strategies is only part of a capital governance process to deliver a

[214] Regulatory Information Notice Under Division 4 Of Part 3 Of The National Electricity (Victoria) Law Issued By The Australian Energy Regulator, Section 3.1 – 14/10/2009.

[215] Powercor Australia Ltd's Revised Regulatory Proposal 2011-15, page 315

prudent and efficient outcome. Powercor commissioned PB Power to review Powercor's policies, practices, procedures and governance arrangements[216]. This review provides a number of examples to highlight the processes that impact expenditures as a project moves from strategic intent to physical implementation. The following series of dot points provides examples from the PB Power report.

- *PB identified the significant corporate governance processes involving the capital investment committee, the network planning committee, and financial authorisation.*
- *A strength of the Powercor approach is the senior level of the committee that approves all significant network investments and the inclusion of a technical expert on that committee.*
- *Powercor does not delegate authority for network capital investment to a low level. While this ensures that all expenditure has been appropriately reviewed, this does add some complexity to the approval of expenditure.*
- *Powercor uses an optimisation tool to optimise capital projects in the capital works program each year. The optimisation of the annual capital program results in the deferral of some low-risk projects and our review identified a number of augmentation projects which had been deferred.*
- *PB has identified three significant corporate governance processes that affect system capital expenditure. The three processes are: capital investment committee, network planning committee and financial authorisation.*
- *The process used to approve expenditure is documented in the Authorisation and Payment of Project Expenditure and Services Manual. The effect of these two documents is to require: documentation of all capital expenditure, for any capital expenditure in excess of $50,000, the completion of an Authority to Proceed document and review and approval by the Capital Investment Committee of any material expenditure.*
- *In addition to the formal approval process involving the preparation of an Authority to Proceed and approval of material expenditure by the CIC, Powercor employs a Network Project Committee. This committee provides a forum for review of all network related projects, policies and strategies that have a financial impact of greater than $150,000 in a financial year.*
- *Powercor utilises two committees to review network investments before committing to the expenditure. These committees operate in a hierarchy where the CIC is the peak committee that reviews all material capital expenditure and the NPC reviews expenditure at lower levels. The NPC also ensures that expenditure proposals put to the CIC are appropriate.*

[216] Review of Powercor's policies, practices, procedures and governance arrangements, Parsons Brinckerhoff, October 2009.

- *Powercor generally relies on non-network proponents to respond to identified network constraints though there are cases where Powercor has implemented embedded generation to ease a constraint and therefore defer network augmentation.*

From the above listing it is clear that Powercor has a robust and comprehensive process for the governance of capital expenditure. The information provided by PB Power also highlights the large number of checks and balances that exist to ensure only prudent and efficient investment is undertaken.

The PB Power report provides examples of projects that were deferred as a result of these processes. This report therefore provides clear evidence that the investment proposed within the strategic planning processes will be subject to significant review and assessment prior to implementation. The result of these processes will include the rejection or deferral of some projects.

On this basis, it is reasonable to determine that the summation of projects in the Network Protection and Control Communication Strategy does not represent the efficient level of future capital expenditure.

Nuttall Consulting notes that the PB Power report is focussed on the assessment of demand and non-demand related projects. This assessment did not directly consider the SCADA and Network Control category of costs. It is feasible that Powercor may have lesser capital governance controls on this capex category. If this was the case, it could be argued that this may have resulted in less efficient outcomes. For the purposes of this review Nuttall Consulting has assumed that the controls for SCADA and Network Control are consistent with the controls for the other major capex categories.

6.5.4 Historical trend

The Powercor revised proposal states that the programs proposed by Powercor for the next regulatory control period justify forecast expenditure greater than the historical trend. Powercor also note that “it is difficult to quantify the benefits likely to result from Powercor’s proposed SCADA and network control capex in the next regulatory control period”[217]. Powercor provides a number of qualitative benefits from the SCADA and Network Control proposed program[218]:

- “**improved** data for making operational decisions (e.g. information regarding outages, voltage control, plant and equipment availability, service conditions, operational planning);
- **improved** data for making network planning decisions (e.g. information regarding network load and voltage modelling, contingency scenarios);
- **improved** data for condition monitoring assessments;
- **better** security of network sites;
- **improved** access to data for field technicians working at zone substations;

[217] Powercor Australia Ltd’s Revised Regulatory Proposal 2011-15 – Page 308
[218] Emphasis added

- **improved** ability to analyse network faults; and
- **better** ability to manage the network in relation to the uptake of household generation and electric vehicles, by having access to real time network loading where currently none exists."

The statement by Powercor that "(e)ach of these benefits will allow Powercor to ***maintain*** (emphasis added) reliability and performance of the network and justify the SCADA and network control capex proposed by Powercor in the next regulatory control period"[219] appears inconsistent with the listing of benefits (above) which list improvements and betterments.

However, Nuttall Consulting does agree with Powercor that the benefits of these programs are hard to quantify. On the basis of evidence available it is not possible to state whether the proposed program will "improve", "better" or "maintain" reliability and performance.

6.5.5 Summary

Nuttall Consulting considers that the SCADA and Network Control capex proposed does not meet the capital expenditure objectives.

As Powercor has not identified any changes in obligations or regulations that directly impact expenditure in SCADA and Network Control, the most reasonable substitute for forecast expenditure remains the historical level of expenditure.

Table 42 - Recommended Powercor SCADA and Network Control capex

Powercor	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Recommended Expenditure	1.97	1.97	1.97	1.97	1.97

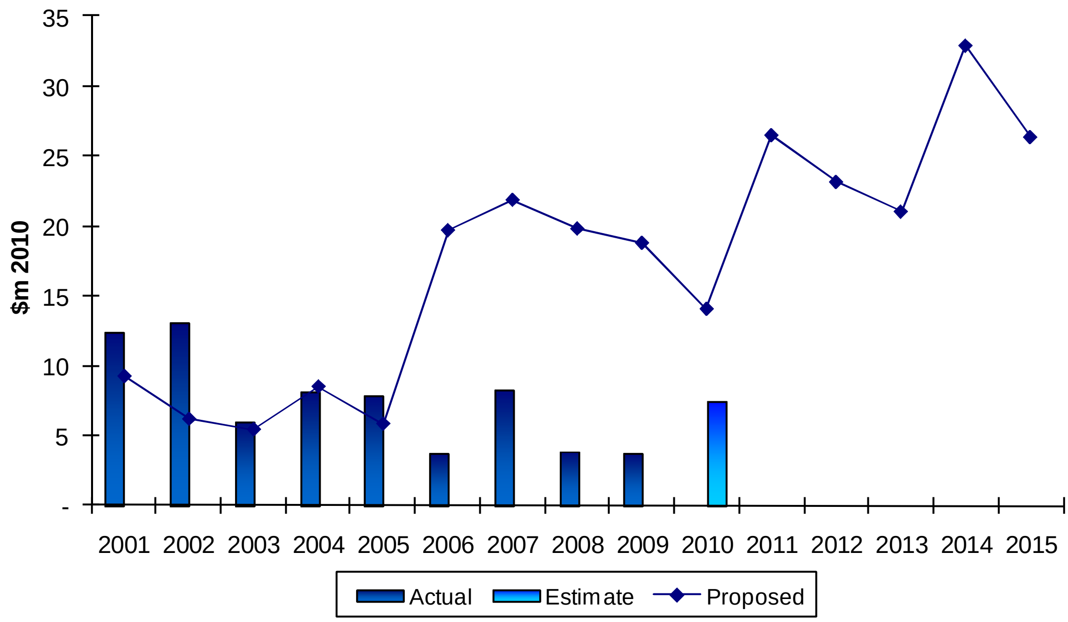
The recommended SCADA and Network Control capex for Powercor is based on the average actual expenditures incurred in the previous 5 years[220] exclusive of indexation and escalation.

6.6 Non-network general – IT

In their revised proposal, Powercor re-submitted IT capital expenditure of $130 million over the forthcoming regulatory control period, which represents an increase of 427% in average annual capital expenditure from that actually incurred in the current period. Major proposed IT capital projects include CIS replacement, leveraging off the AMI project and increasing the utilisation of mobile computing in the field.

[219] Ibid – Page 308
[220] 2005 to 2009 inclusive

Figure 26 – Powercor IT capex



CitiPower and Powercor are related parties and each holds a separate electricity distribution licence for a defined geographical electricity distribution area in Victoria. The Distribution Networks are jointly managed and operated by Powercor Australia and CitiPower personnel and systems. Under the Cost Sharing Agreement, defined overhead costs incurred by Powercor Australia and CitiPower are apportioned between each respective business. CHED Services provides both CitiPower and Powercor with specialist corporate services including: the Chief Executive Officer; Finance; the Company Secretary and Legal; Human Resources; Corporate Affairs; Regulation; Customer Services; Information Technology; and Office Administration; and under the Metering Services Agreement a number of metering services. To assist us with the analysis, we again combined the CitiPower and Powercor submissions to review the actual proposed costs.

Table 43 – CitiPower and Powercor proposed IT capex

CitiPower & Powercor	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
CitiPower – Proposed	9.9	9.0	8.9	14.0	11.1
Powercor – Proposed	26.5	23.1	21.0	32.9	26.3

The original Nuttall Consulting report rejected the IT capital program proposed by CitiPower and substituted a new IT Capital Allowance based upon audited historical expenditure.

In their response to the Draft Determination, Powercor submitted that the AER should include 2009 actual data in its trend analysis and in forecasting the required capex for the next regulatory control period by reference to historical expenditure. Nuttall Consulting has incorporated the 2009 data, however our recommendation does not rely on the 2009 trend.

In their response to the Draft Determination, Powercor submitted that they did not underspend on Non-network-IT capex because it was efficient to do so. They underspent because IT resources were redirected to the implementation of the mandated AMI rollout. Powercor does not accept that this means it will likely defer or modify its proposed Non-network-IT projects in the 2011-15 period. However, the estimate of 2009 IT capex that was provided in the Powercor November proposal was 9% below the actual expenditure for the 2009 year. Although not as high as some DNSPs, this highlights an error in the forecasting process. As the requirements of AMI were known at the time Powercor made the 2009 estimate, this suggests that AMI was not the cause of the overspend in this period.

A review of expenditure and forecasts for the current regulatory period highlights that Powercor has significant underspent on its Non-Network IT forecasts. The Nuttall Consulting analysis highlights that this relates to a systemic problem in the forecasting process, including the lack of recognition of external and internal project delay mechanisms.

On the basis of the lack of IT agility and the forecasting process errors, Nuttall Consulting is unable to rely upon the forecasts as provided.

In their response to the Draft Determination, Powercor submitted that the AER must make its assessment on the basis of a reasonable expectation of future external events. Powercor maintains there is little possibility of a future event on the size and scale necessitated by the AMI rollout. Whilst a single event of the scale of AMI may or may not occur in the next period, Nuttall Consulting believes that Powercor should be expecting and accounting for change. In the dynamic environment in which Powercor operates its IT system should be designed to be sufficiently agile to accommodate change and the potential for change should be better forecast. Whilst Powercor deferred a number of Non-Network IT Capital Projects such as the upgrade of the CIS system due in part to mandated rollout of AMI, Powercor also deferred IT-related SCADA and Network Control capital projects, due to reasons totally unrelated to AMI. The stated reasons[221] include complications arising with essential lead-in projects, vendor issues and an underestimation of the level of testing required. Whilst AMI was a significant requirement, Nuttall Consulting believes that Powercor has over stated this impact and has not sufficiently considered the underlying IT systems not being sufficiently agile.

In their response to the Draft Determination, Powercor rejects Nuttall Consulting's assertions that its IT systems are not agile. Powercor states that Nuttall Consulting's analysis is not DNSP specific and its findings are gross generalisations and do not take into

[221] CitiPower Revised Submission. 9.11.3.2 Reasons for underspend in the current regulatory control period. P302-303.

account the specific circumstances of Powercor. Nuttall Consulting has examined all the information provided by Powercor in reaching its conclusion. Whilst Powercor's circumstances are unique and specific, the fundamental agile technology is largely a commodity, that could be customised for Powercor's specific circumstances.

In their response to the Draft Determination, Powercor considers that the AER appears to be implying that Powercor and CitiPower may defer the CIS replacement project again. Nuttall Consulting believes that the previous deferrals of the CIS project demonstrates a lack of overall IT agility. However, Nuttall Consulting is not recommending the deferral or advancement of any specific project. Nuttall Consulting considers that Powercor will continue to prioritise its capex based on business needs and notes that the allowance that is made by the AER represents an overall estimate of efficient and prudent expenditure that the DNSPs may over or underspend based on their own business needs.

The allowance that is recommended by Nuttall Consulting is not specific to an individual project, but represents the prudent and efficient overall expenditure as recommended by Nuttall Consulting. As we have observed from previous periods, each DNSP will respond to the changing business requirements and resultant expenditures will vary from the recommended allowance.

In their response to the Draft Determination, Powercor requested the AER actively engage in considering the material before it in both the initial and revised regulatory proposals. If it does so, Powercor considers that the AER should be satisfied the proposed expenditure is prudent and efficient and reasonably reflects the capex criteria. Nuttall Consulting has reviewed all the submitted material and this information has been considered in forming our recommendations.

In their response to the Draft Determination, Powercor states that the AER cannot discount the evidentiary value of the external cost benefit analysis Powercor obtained from PwC in respect of its AMI leverage project on the basis that it is not an internal assessment. Nuttall Consulting has reviewed all the submitted material including the PwC opinion and has considered this in forming its recommendations.

In their response to the Draft Determination, Powercor considers that the majority of the costs of the AMI leverage project will not be funded through the S factor. Nuttall consulting believes that if IT capital expenditure improves reliability of the distribution network, then the DNSP will be, at least partially, funded via the S-factor scheme.

In their response to the Draft Determination, Powercor considers that the AER has incorrectly assumed that any reinforcement capex savings associated with the AMI leveraged project would be realised in the 2011-15 regulatory control period. Also, Powercor believes that the AER would be expected to take into account capital deferral benefits likely to be realised in the 2016-20 period as a result of the AMI leveraged projects upfront. As a consequence, Powercor believes that the benefit of any network deferral will be passed immediately through to customers without Powercor obtaining any share of those benefits that could be directed towards partially funding the AMI leveraged project.

Powercor is proposing $18.9m in capex to leverage the information from the AMI new meters. In the original Nuttall Consulting reports we stated that "Whist we agree that there should be benefits through these "AMI leveraging projects", and these benefits may well outweigh the additional costs, we do not consider that the DNSPs have:

- adequately quantified all of the costs and benefits that may accrue through the use of the AMI data, and defined these in terms of those provided for through existing incentive mechanisms (e.g. STPIS, EBSS) and those external to these schemes
- adequately demonstrated that their proposed expenditure represents only the incremental level above that available through the existing incentive mechanisms."

The Powercor responses to the Nuttall Consulting position are provided above. This response provided no additional quantification or estimates to address the concerns raised by Nuttall Consulting, we do not consider that the proposed AMI leverage expenditures are reasonable or meet the capex objectives.

Based on our review of the revised submission, Nuttall Consulting rejects the overall Powercor IT capital forecast and recommends that a new forecast be substituted based upon a proportion of forecast expenditure. In our opinion, Powercor has not fully considered the complexity of the totality of works that they are contemplating and the amount of change they can absorb, given the lack of agility in the IT environment. This is further demonstrated by their historical underspending of proposed IT capital expenditure and systemic errors in the forecasting processes. We consider it more likely that Powercor will take considerably longer to complete many of these projects. Therefore, we recommend that the average forecast capex be reduced by 33%.

Table 44 – Powercor recommended IT capex

Powercor & Powercor	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
Powercor – Proposed	26.5	23.1	21.0	32.9	26.3
Powercor – Recommended	15.6	15.6	15.6	15.6	15.6

6.7 Non-network general other

Powercor's proposed expenditure in the "non-network general – other" category represents 5% of the total net capex in the next period, and is at a level relatively consistent with the current period.

It was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

7 Appendix D - SP AusNet review

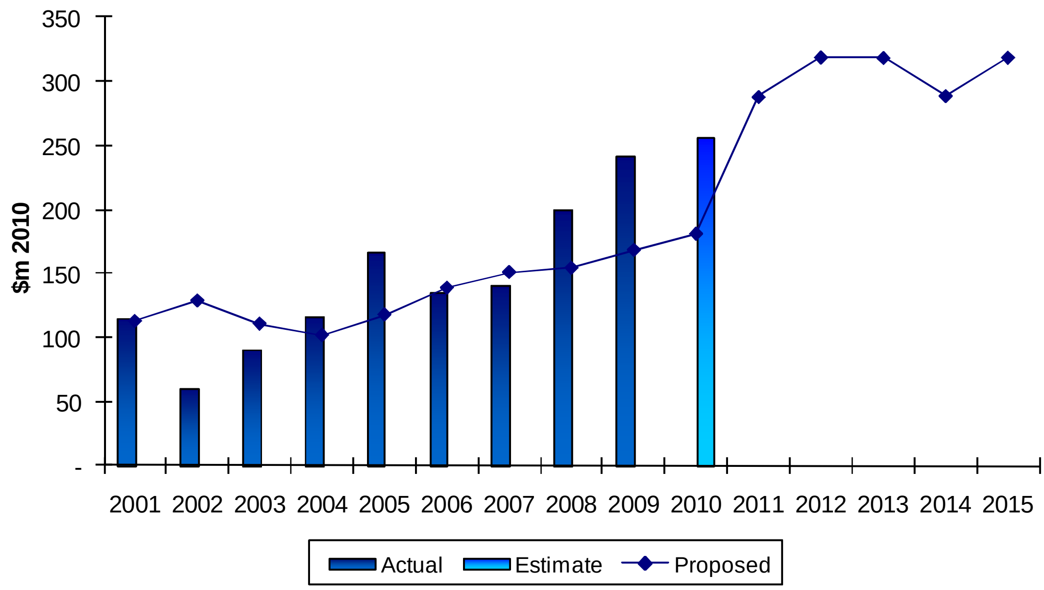
7.1 Overall capex

Overall capex is forecast to increase by 71% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement, reliability and quality maintained and new connections.

The following chart provides a summary of the overall capex figures for SP AusNet. Key aspects of this chart include:

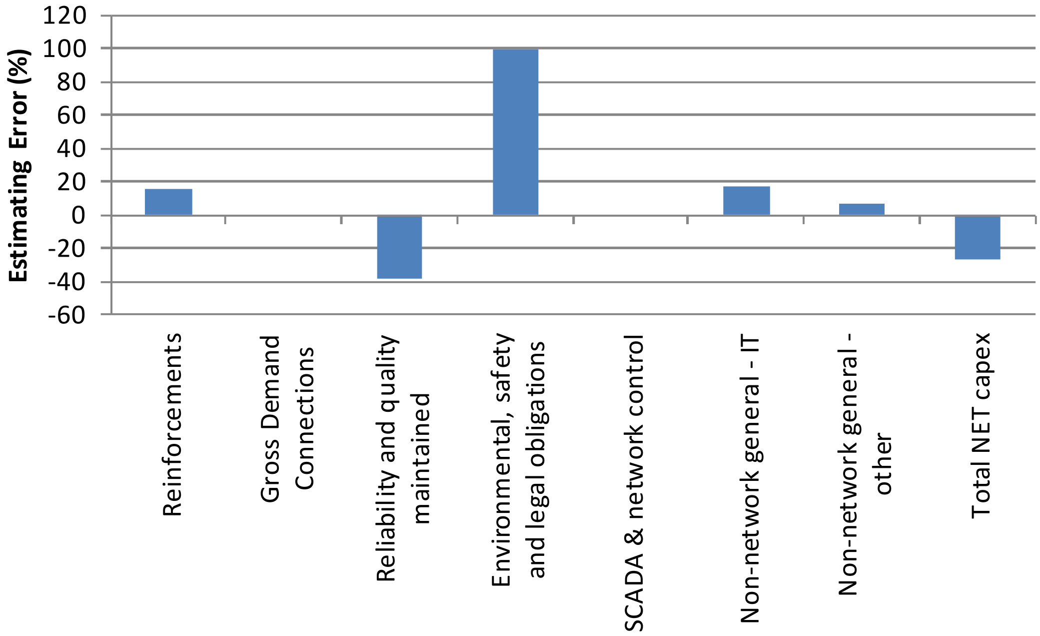
- SP AusNet has on the whole spent less than they proposed in the 2001 and 2006 EDPRs
- SP AusNet is proposing a future level of capex that is generally higher than the historical levels of expenditure and is not consistent with the historical trend in capex.

Figure 27 – SP AusNet Capex Summary



The following chart considers the accuracy of the November 2009 SP AusNet proposal compared with the actual 2009 audited data.

Figure 28 – 2009 estimating accuracy



The estimated figures for 2009 were provided by the DNSPs in November 2009; two months prior to the completion of the financial period. The actual figures for 2009 have been subject to audit and were provided to the AER in early 2010.

The overall accuracy of the 2009 SP AusNet forecasts was relatively poor with actual net capex varying by 26% from that estimated. The above chart also highlights that the DNSP forecasts at the individual capex category show significant levels of variation from the actual 2009 capex. This highlights a concern with the forecasting processes utilised by SP AusNet and calls into question the veracity of the forecasts for 2010 and the next regulatory control period of 2011 to 2015.

When considered in conjunction with the historical levels of forecasting inaccuracy as described in section 2.2, Nuttall Consulting observes that the processes used by SP AusNet to forecast expenditure in this category have not produced reliable forecasts.

Nuttall Consulting requested SP AusNet to provide an explanation of the methodology applied to determine the 2009 and 2010 estimates and to explain the relationship of this methodology to the methodology used to produce the 2011-2015 forecasts[222]. SP AusNet did not identify any changes or variations between the forecasting methodologies.

This raises a concern relating to the accuracy of the DNSP forecasts for the next control period as the methodologies used to create these forecasts are the same methodologies that have produced the previous inaccurate estimates and forecasts.

To be clear, although the above information provides sound reason to question the accuracy of the DNSP forecasts, Nuttall Consulting has not taken this as proof that the forecasts do not meet the capital expenditure objectives. The Nuttall Consulting review of

[222] Nuttall Consulting information request (email) – 18 January 2010.

the forecasts has been undertaken on a case-by-case basis with due consideration of the information provided by the DNSPs.

7.2 Reinforcement

SP AusNet's revised proposal makes a number of criticisms of the process and findings of Nuttall Consulting's original review of SP AusNet's reinforcement expenditure.

General criticisms of the process we applied, which are similar between DNSPs, have been discussed in Section 3.1 above. This section deals with matters more specific to our findings on SP AusNet's reinforcement forecasting methodology and our review of a number of reinforcement projects. Importantly, this section includes revised project probabilities, which will be important for the AER in its considerations of the appropriate reinforcement allowance.

7.2.1 Load profile assumptions

Nuttall Consulting considered that the need for the reinforcement projects may be overstated due to assumptions associated with the energy at risk calculations that supported the need and timing for projects, and specifically the load profile assumed in these calculations. In this regard, SP AusNet is using a load profile based upon the 2007/08 year.

This view related to the fact that the Victorian load is becoming more "peaky" as demand growth outstrips energy growth. This peakiness may tend to reduce the energy at risk (and associated value of the expected energy at risk) as the load at risk increases in the future. Nuttall Consulting undertook some trend analysis of historical load profiles that it considered justified this position.

SP AusNet has disagreed with Nuttall Consulting's view and has supplied some analysis to support its position. The following discusses the matters raised in the SP AusNet revised proposal.

SP AusNet accepts the proposition that load profiles are getting peakier. However, it has assessed the load duration curves and energy at risk for a number of substations (CHTS, Pakenham ZS, and RWTS) over the last three years (2007/08, 2008/09, and 2009/10). SP AusNet considers that this analysis shows the profiles to be variable, but does not indicate a clear trend of increased peakiness such that an assumption based upon the 2007/08 is not valid.

In our view, we consider that by only using three years, SP AusNet's analysis is not sufficient to show any underlying trend. As such, we do not consider that SP AusNet's analysis clearly refutes our claims that the peakiness will be increasing in a material way. We do accept that based upon our analysis, that 2007/08 (that basis of the SP AusNet profile) may be approximately equivalent to a typical 50% PoE for today's conditions, but our trending analysis suggests this may become materially peakier by 2015. We do not consider that SP's more limited analysis refutes this.

SP AusNet considers that the Nuttall Consulting analysis only looked at the top 1% of time and 89% of maximum demand, and as such, this is not reflective of the portion of demand that generates energy at risk, which it considers relates to around 70% of the maximum demand.

We consider that this is an incorrect view of our analysis, where Fig 144 clearly shows our trend analysis considers between 1% to 20% of the maximum demand, with all showing a significant trend down. Although we had not shown the 30% position, our subsequent analysis of this does not indicate that the trend for this position is significantly different to those shown in Fig 144.

Possibly most importantly, SP AusNet considers that even if the peakiness did increase, it would not be sufficient to change project timings.

We do not disagree with this position in most circumstances, particularly when higher load growths are occurring, and therefore, energy at risk could increase substantially from one year to the next. However, we still consider that in some cases, when all factors (i.e. load transfers, etc) are accounted for, this may result in some projects, particularly those in the latter half of the next period, being deferred. On this point, it is important to note that Nuttall Consulting has placed little weight on this load profile issue when developing the project probabilities.

7.2.2 Project review updates

The following projects were assessed as part of Nuttall Consulting's review of SP AusNet's reinforcement expenditure:

1. Mooroolbark new zone substation
2. Wollert new zone substation
3. KMS-SMR 66 kV line establishment
4. Zone substation transformer upgrade program
5. Distribution substation upgrades

The following sections discuss our reassessment of these projects, based upon SP AusNet's revised proposal.

It is also important to note that we understand the AER will largely be accepting SP AusNet's demand forecast. In our original review we had allowed for a reduction in the demand forecast, based upon advice from the AER. In the discussions below and the revised project probabilities, we have not allowed for any reductions from SP AusNet's demand forecast. This has resulted in increased project probabilities.

Finally, SP AusNet has criticised our selection of projects as it largely covered projects in the latter half of the next period. We accept that this may affect our findings and views on the profile of expenditure.

Therefore, we have undertaken a review of a number of additional projects that are proposed for the first half of the next period. The aim of this review is to test the findings from the project noted above and confirm whether they are still applicable across the whole period. The review of the additional projects is also discussed below.

7.2.2.1 Mooroolbark Zone Substation Establishment

This project involves the establishment of a new zone substation at Mooroolbark (MBK) and the associated upgrade of some 66 kV lines. The project is driven by a number of factors: load at risk at the existing LDL and CYN zone substations, 66 kV line overloads associated with the existing 66 kV loop, loss reduction benefits, 22 kV feeder overloads[223].

Based upon our original review, this project was given a moderate probability (50%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that:

- benefits due to the project may be overstated, in particular we noted that SP AusNet's assumptions may overstate the losses due to the existing arrangements
- given the scale of the project and the range of issues being addressed, more extensive economic analysis may result in the project scope and timing being optimised further.

The SP AusNet revised proposal does not accept our views and considers that the project should be viewed as 100% required as originally proposed. Additional information has been provided to support this position[224].

With regard to the project benefits, SP AusNet contends that the proposed Mooroolbark project's benefits justify the project's timing. In their economic justification of the project timing they quantify the benefits due to the establishment of the Mooroolbark substation in terms of the:

1. reduced energy at risk at Lilydale (LDL) and Croydon (CYN) zone substations
2. removal of the risk of overload and collapse of the RWTS-LDL 66kV network
3. reduced losses on the SP AusNet system.

Table 45 below highlights the savings, benefits and costs of the Mooroolbark project presented by SP AusNet in its revised regulatory proposal[225].

[223] It is important to note that these drivers have been determined from the information provided with the revised proposal, and differ slightly from those indicated in our original report.
[224] Section 6.6.5 of SP AusNet's Revised Proposal and in the revised AMS 20-301 Network Augmentation Planning and Project economic evaluation reports attached to SP AusNet's Revised Regulatory Proposal.
[225] In its revised Network Augmentation Planning Report for the Mooroolbark project, SP AusNet indicates that it is using updated NIEIR forecasts. We note that these updated NIEIR forecasts are higher than those presented in the Network Augmentation Planning Report provided to the AER in SP AusNet's initial regulatory proposal. The increased demand has resulted in increases in the energy at risk presented by SP AusNet, but this does not appear to be significant with respect to project timing.

Table 45 - Benefits and Costs of Mooroolbark Substation Establishment [from AMS 20-301]

	Summer 2014/15	Summer 2015/16
Benefits ($'000)		
Reduction of Energy at Risk at LDL and CYN[a]	341	739
Elimination of Overload and Collapse Risk on RWTS-LDL 66kV Network	361[b]	380
Reduction in System Losses	419[b]	441
Total Benefit (inc. losses)	1121	1,560
Total Benefit (excl. losses)	702	1,119
Costs ($'000)		
Total Cost (direct)	15,600	15,600
Estimated Annual Cost (7.5%)	1,170	1,170

a – Nuttall Consulting estimate of reductions, noting not all risk is removed by MBK

b – Nuttall Consulting estimate assuming 5% less than 2015/16 value

SP AusNet considers that its analysis justifies that the project should be completed prior to the summer 2015/16. However, it considers that this should be advanced to ensure it is completed by the end of 2014, for two main reasons:

- to address the 66 kV line overload issue, which it considers is excessive
- to address a number of 22 feeder overloads that it forecasts will occur in the next period.

SP AusNet has provided further economic analysis of a number of options to address the issues.

We have considered SP AusNet's contention in its revised regulatory proposal that the Mooroolbark Substation project is 100% required in the forthcoming regulatory period. A review was subsequently performed of the additional information. Based upon this review, we still have a number of issues with the proposed project and timing.

With regard to SP AusNet's calculation of net benefits (summarised above), we still have concerns with the methodology SP AusNet uses to estimate the loss reduction benefits. To undertake this calculation, SP AusNet performs load flow analyses on the proposed and existing systems to determine the MW reduction in losses at peak conditions and then multiplies this by a "loss load factor" of 0.4 (i.e. the average losses are 0.4 times the peak demand losses). Loss load factors are based on load duration curves, and we note that SP AusNet's use of a standard loss load factor of 0.4 to average the losses in terms of the peak load losses is a simplified approach and does not fully account for the actual load duration characteristic of the substation. For example, a particularly "peaky" load duration characteristic will have a lower average to that of a less peaky duration characteristic. We have studied the load duration curve provided by SP AusNet for the LDL substation, and have determined that a figure around 0.33 would be more appropriate to determine the loss load factor for the substation. This figure is approximately 20% less than the figure used by SP AusNet.

Based upon this, we consider that the need for the project by 2015/16 is more marginal than suggested by the SP AusNet analysis, particularly if the AER determines a WACC more in the order of 8%. Given this, we consider it far more likely that short term measures could be economically applied to defer the main project by another year (i.e. from 2014 to 2016) to ensure energy at risk clearly justifies the timing. We would expect that possibly less than 5 MW of additional relief may be needed to allow this. Such measures to achieve this could include load transfers, demand management, or embedded generation. We do not consider that SP AusNet's evaluation of its various options adequately considers these short term management issues.

With regard to the 66 kV line overload issue, which SP AusNet considers is an important factor in its timing, we accept that SP AusNet's analysis supports the view that this is imposing high risks. Moreover, the value of the removal of these risks certainly supports the sub-transmission line works component of the project ($2 million of the overall project cost).

However, given SP AusNet's economic analysis (summarised above), there is not a clear economic case to remove these risks if this results in the advancement of the zone substation project. Furthermore, it is not clear from the information provided whether other alternatives aimed at only addressing these line risks may be feasible and economic. For example, SP Ausnet's papers do not discuss why the 66 kV line works could not be undertaken prior to the substation development, or alternatively, a fast acting control scheme could not be developed to relieve some of the line risks[226].

With regard to the 22 kV feeder overloads, which SP AusNet also considers is an important factor in its timing, we accept that these impose additional needs not allowed for in its benefits analysis. As such, there will be additional benefits in addressing these overloads. Moreover, based upon SP AusNet's analysis of the reliability improvements due to the project, we accept that these benefits may well justify advancing the proposed project to 2014.

However, given the significance of these 22 kV feeder overloads in now defining the project timing, we do not consider SP AusNet's document sufficiently investigates and discusses alternative options associated with managing these specific overloads. We would expect possible short terms measures to manage these overloads may be similar to those noted above i.e. load transfers, demand management, or embedded generation.

Possibly more importantly, we note that the additional reliability benefits to a large extent appear to represent the reliability improvement that will occur due to the feeder works included in this project. This is as we would expect, given that the new HV feeders,

[226] Such a control scheme would be armed during times of high demand, and set to shed load rapidly following the critical contingency, such that the full loop load is not lost.

developed with the new substation, will result in existing feeders being split. Therefore, even if the project occurs as proposed, we do not consider that a capex allowance is clearly required to fund the overall project. SP AusNet has valued the reliability improvement at approximately $600k per annum – via an s-factor type calculation. This would suggest that this reliability incentive scheme may fund up to $6 million of the project over the next period[227].

It is also worth noting that we consider that these types of reliability improvements will occur for any project where new HV feeders are developed with new substations or extra transformers, which result in existing feeders being split.

Conclusions

Based upon the above, we have revised our project probability from moderate (50%) to moderate to high (70%)[228]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects:

- the project will be partly funded through the reliability incentive scheme
- the risks may be prudently managed allowing a 1 to 2 year deferment.

The increase is largely due the AER's change in its position on the SP AusNet maximum demand forecast, but also allows for the reduced impact of the load profile assumptions.

7.2.2.2 Wollert Zone Substation Establishment

This project involves the establishment of a new zone substation at Wollert (W). The project is driven by load at risk at the existing Epping zone substation (EPG), loss reduction benefits, and 22 kV feeder overloads.

Based upon our original review, this project was given a moderate probability (50%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that energy at risk could be managed further, where we noted that further load transfers away from EPG may be possible.

The SP AusNet revised proposal does not accept our views and considers that the project should be viewed as 100% required as originally proposed. Additional information has been provided to support this position[229].

It is important to note that SP AusNet have increased the scope and cost of its preferred project since their initial regulatory proposal and are now recommending the installation of two transformers at Wollert rather than the originally proposed one transformer. The project cost has increased from $6.3 million to $10.8 million (including overheads). SP AusNet considers that this revised scope is justified, due to additional demand that is

[227] Noting actual capex will be rolled into the asset based at the end of the period, and then this will then generate a return on and of this capital in subsequent periods.
[228] Probability based upon: 90% (historical accuracy) x 90% (deferral potential) x 80% (part funding through reliability incentive scheme) x 98% (load profile assumptions)
[229] Section 6.6.5 of SP AusNet's Revised Proposal and in the revised AMS 20-314 Network Augmentation Planning and Project economic evaluation reports attached to SP AusNet's Revised Regulatory Proposal.

forecast at Epping that was not allowed for in its original proposal[230], and the ability to remove all load at risk at EPG with the increased scope.

With regard to the project benefits, SP AusNet contends that the proposed Wollert project's benefits justify the project's timing. In their economic justification of the project timing they quantify the benefits due to the establishment of the Wollert substation in terms of the:

1 reduced energy at risk at Epping zone substations

2 reduced losses on the SP AusNet system.

Table 46 below highlight the savings, benefits and costs of the Wollert project presented by SP AusNet in its revised regulatory proposal for summer 2013/14, 2014/15 and summer 2015/16 respectively[231].

Table 46 - Benefits and Costs of Wollert Substation Establishment [from AMS 20-314]

	Summer 2013/14	Summer 2014/15	Summer 2015/16
Benefits ($'000)			
Reduction of Energy at Risk at EPG	432	1,016	2,734
Reduction in System Losses	57[a]	60[a]	63
Total Benefit (inc. losses)	489	1,076	2,797
Costs ($'000)			
Total Cost (direct)	9,300	9,300	9,300
Estimated Annual Cost (7.5%)	698	698	698

a – Nuttall Consulting estimate assuming 5% less than 2015/16 value

SP AusNet's considers that its analysis justifies that the project should be completed prior to the summer 2014/15. However, it considers that this should be advanced to ensure it is completed by the end of 2013, to address a number of 22 feeder overloads that it forecasts will occur in the next period. SP AusNet has provided further economic analysis of a number of options to address the issues.

We have considered SP AusNet's contention in its revised regulatory proposal that the Wollert Substation project is 100% required in the forthcoming regulatory period. A review was subsequently performed of the additional information. Based upon this review, we still have a number of issues with the proposed project and timing.

[230] This demand is related to the planned relocation of the Victorian wholesale fruit and vegetable market, which we understand the AER is accepting this additional demand as reasonable.

[231] In its revised Network Augmentation Planning Report for the Wollert project, SP AusNet indicates that it is using updated NIEIR forecasts. We note that these updated NIEIR forecasts are higher than those presented in the Network Augmentation Planning Report provided to the AER in SP AusNet's initial regulatory proposal. The increased demand has resulted in increases in the energy at risk presented by SP AusNet.

With regard to SP AusNet's calculation of net benefits (summarised above), we accept that this does indicate that the proposed project is justified to be in place just prior to summer 2014/15. However, we still consider that this analysis suggest that there is a reasonable possibility that energy at risk could be managed for at least another year. Based upon this analysis, it appear that if around 5 MW a further load relief can be found for 2014/15 then the optimal timing would be just prior to 2015/2016. We consider that there are a number of reasons that this may be possible.

Firstly, SP AusNet, in its Network Augmentation Planning Report for the project, indicates that there is up to 10 MVA of available load transfer from Epping to surrounding substations[232]. This appears to be in addition to an assumed 10 MVA transfer to the proposed new South Morang zone substation. It may be possible to use some of these transfers, at least temporarily, in 2014/15.

Secondly, SP AusNet claims that further transfers to the new South Morang zone substation are not possible as this will place this new zone substation above its N-1 rating. However, we consider that it may well be economic to place a small amount of load at risk at South Morang via a transfer from Epping if this allows the project to be deferred, at least temporarily.

Finally, given only a small level of load relief is required then this may be able to be achieved by demand management or embedded generation for one or two years.

We do not consider that SP AusNet's evaluation of its various options adequately considers these short term management issues.

It is also worth noting that for the reasons discussed above on the Mooroolbark new zone substation project, we consider that SP AusNet may be over stating the loss benefits. However, in the context of the Wollert project, this issue is less likely to be material.

With regard to the 22 kV feeder overloads, which SP AusNet considers is an important factor in its timing, we accept that these impose additional needs not allowed for in its benefits analysis. As such, there will be additional benefits in addressing these overloads. Moreover, based upon SP AusNet's analysis of the reliability improvements due to the project, we accept that these benefits may well justify advancing the proposed project to 2014.

However, given the significance of these 22 kV feeder overloads in defining the project timing, we do not consider SP AusNet's planning report sufficiently investigates and discusses alternative options associated with managing these specific overloads. We would expect possible short term measures to manage these overloads may be similar to those noted above i.e. load transfers, demand management, or embedded generation.

Possibly more importantly, as noted above for the Mooroolbark project, reliability improvements should occur due to the proposed feeder works included in this project. Therefore, even if the project occurs as proposed, we do not consider that a capex allowance is clearly required to fund the overall project. SP AusNet has valued the

[232] AMS 30-314, pg 7

reliability improvement at approximately $745k per annum – via an s-factor type calculation. This would suggest that this reliability incentive scheme may fund up to $7 million of the project over the next period.

Conclusions

Based upon the above, we have maintained our project probability at moderate (50%)[233]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects:

- the project will be partly funded through the reliability incentive scheme
- the risks may be prudently managed allowing a 1 to 2 year deferment.

7.2.2.3 KMS-SMR No.2 66kV line Establishment

This project involves the establishment of a 2nd 66 kV line between KMS and SMR. The project is driven by energy at risk and loss reduction benefits.

Based upon our original review, this project was given a moderate probability (50%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that:

- given the scale of the project and the range of issues being addressed, more extensive economic analysis may result in the project scope and timing being optimised further - we noted that possible alternatives, including reactive compensation or a line from MDI to YEA
- benefits due to the project may be overstated, in particular we noted that:
  - SP AusNet's assumptions may overstate the losses due to the existing arrangements
  - the line outage probability had not been adequately justified and options considered to reduce this.

The SP AusNet revised proposal does not accept our views and considers that the project should be viewed as 100% required as originally proposed. Additional information has been provided to support this position[234].

With regard to the project benefits, SP AusNet contends that the proposed project's benefits justify the timing. In their economic justification of the project timing they quantify the benefits due to the establishment of the new line in terms of the following:

1. eliminate the risk (expected unserved energy) of collapse of the SMTS-DRN-KLK-MDI-RubA-YEA-KMS-SMTS 66 kV network
2. reduced losses on the SP AusNet system.

[233] Probability based upon: 90% (historical accuracy) x 90% (deferral potential) x 70% (part funding through reliability incentive scheme) x 98% (load profile assumptions)
[234] Section 6.6.5 of SP AusNet's Revised Proposal and in the revised AMS 20-302 Network Augmentation Planning and Project economic evaluation reports attached to SP AusNet's Revised Regulatory Proposal.

Table 47 below highlights the savings, benefits and costs of the KMS-SMR No.2 66kV line project presented by SP AusNet in its revised regulatory proposal[235].

Table 47 - Benefits and Costs of KMS-SMR No.2 66kV line establishment [from AMS 20-302]

	Summer 2014/15	Summer 2015/16
Benefits ($'000)		
Elimination of loop collapse risk	744	907
Reduction in system losses	297	315
Total Benefit (inc. losses)	1,041	1,222
Costs ($'000)		
Total Cost (direct)	14,500	14,500
Estimated Annual Cost (7.5%)	1,086	1,086

SP AusNet's considers that its analysis justifies that the project should be completed prior to the summer of 2015/16. SP AusNet has also provided further analysis of a number of options to address the issues that it considers demonstrate its has selected the most appropriate project.

We have considered SP AusNet's contention in its revised regulatory proposal that the project is 100% required in the forthcoming regulatory period. A review was subsequently performed of the additional information. Based upon this review, we still have a number of issues with the proposed project and timing.

With regard to SP AusNet's benefits calculations (summarised above), we still have a number of concerns that there may not be a net benefit in undertaking the proposed project in 2015. This view relates to three matters.

Firstly, as discussed for the Mooroolbark zone substation development, we consider that SP AusNet's methodology for calculating losses may overstate the losses by as much as 20%.

Secondly, with regard to the line outage probabilities, we still maintain that SP AusNet's assumptions may overstate the risks. In this regard, we note that SP AusNet has based the outage rate on historical outage data and the outage restore and repair duration appears to be assumed values. Moreover, SP Ausnet's revised proposal has provided the historical outage data that these assumptions are based upon[236].

[235] In its revised Network Augmentation Planning Report for the Mooroolbark project, SP AusNet indicates that it is using updated NIEIR forecasts. We note that these updated NIEIR forecasts are lower than those presented in the Network Augmentation Planning Report provided to the AER in SP AusNet's initial regulatory proposal. The reduced demand has resulted in reductions in the energy at risk presented by SP AusNet, but this does not appear to be significant with respect to project timing.

[236] Appendix 2, SP AusNet reinforcement capex – response to draft decision

We have reviewed this new information, and agree that SP AusNet's calculation of the mean outage rate corresponds to the assumptions applied in its analysis ,and we accept that it appears reasonable. However, with regard to the outage duration assumptions, based upon the historical data, we still consider that SP AusNet's assumptions will most likely overstate risks.

In this regard, SP AusNet assumes that the line outage duration is 2.5 hours. The average historical duration for this line is 3 hours. Therefore, this appears reasonable. However, if only the duration due to the line faults that resulting in customer outages is considered then the mean is only 1.6 hours. This reduction in time is as we may expect, given that outages affecting customers will be responded to with much greater urgency than those not affecting customers. If it is assumed that 2 hours, rather than 2.5 hours, is a reasonable outage duration the loop collapse risks are reduced by 30%.

Finally, it is also worth noting that should the AER decide upon a WACC resulting in a discount rate significantly greater than SP AusNet's assumption of 7.5% then this will also reduce the net benefits.

Allowing for these factors, particularly the first two, we consider it reasonable to assume that the project timing will not be economically justified until just prior to 2016/17 i.e. a one year deferment.

We do note that the SP AusNet document also notes that the 66 kV loop will be close to a voltage collapse limit under normal conditions by 2015/16. However, there is no significant detail provided on this matter; as such, we consider it reasonable to assume that it should be able to be managed for at least for another year or two.

With regard to alternative options, SP Ausnet has provided specific comments[237] on the two options noted in our original report.

With regard to the MDI-YEA alternative 66 kV line, SP AusNet has provided further information clarifying the likely costs associated with this line. This shows that the line will be a similar cost, but has some greater risks associated with its development. SP AusNet also considers that its preferred solution has greater loss reduction benefits.

We have considered SP AusNet's reasoning, and although it is difficult in a review of this form to assess potential line route issues, we see no clear reason to disagree with SP AusNet's views. As such, we accept that, even if this option was undertaken, it is unlikely to result in a significantly different capex requirement.

With regard to the addition reactive compensation, SP AusNet considers that this is not an appropriate option. The basis for this view appears to be that this form of compensation is already applied and it would not be possible to install sufficient additional quantities to address the risk.

We have considered SP AusNet's reasoning, but note that no additional information has been provided to support SP AusNet's claims on this matter, particularly with regard to the upper limit on possible reactive support. Moreover, SP AusNet's response does not make

[237] SP AusNet revised proposal, Reinforcement Capex – Response to draft decision, pg 31

it clear whether its view relates only to the appropriateness of this option as a long term solution. The important point here is that we are only suggesting this option as a short term measure to allow the project to be deferred for a short period i.e. 1 to 2 years. Therefore, only a small amount of additional reactive support may be required to achieve this. We do not consider that the SP AusNet information is sufficient to justify that this would not be feasible.

As such, we still consider it reasonable to assume that a small amount of further reactive support may allow the risks to reduce such that the project could be deferred 1 to 2 years. This however has to be viewed in the context of the discussion above on the marginal net benefit.

Conclusions

Based upon the above, we have revised our project probability from moderate (50%) to moderate to high (70%)[238]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects our view that the risks may be prudently managed allowing a 1 to 2 year deferment of the project.

The increase is largely due the AER's change in its position on the SP AusNet maximum demand forecast, but also allows for the reduced impact of the load profile assumptions and removal of the likelihood of alternative lower cost options.

7.2.2.4 Zone substation transformers

This project covers a proposed program of work that involves the installation of a number of additional transformers at a number of existing zone substations. The need for the new transformers is generally driven by energy at risk considerations at each zone substation, based upon the existing transformers capacity and forecast load growth.

Nuttall Consulting's original view was based upon a detailed review of 4 projects within this program (at FGY, KMS, MOE and CLN). Based upon this review, we considered that the projects only had a moderate probability (50%) of occurring as planned. The main matters we noted in support of this view were:

- The availability of temporary load transfers that had been noted in SP AusNet's planning documents, but were not explicitly allowed for in its economic analysis of the load at risk, and therefore, the allowance for these may defer the need for some of the works.
- Given the scale of the program, the possibility that more effective management of the existing transformer fleet (e.g. through the use of spares, contracting, etc) may be able to reduce the risks associated with transformer failure, and therefore, defer the need for some of the works.

[238] Probability based upon: 90% (historical accuracy) x 85% (deferral – over stating net benefits) x 98% (load profile assumptions)

Although not explicitly stated in the specific project review, our views on the conservatism in the load profile assumed by SP AusNet and the slight reduction in SP AusNet's demand forecast determined by the AER also impacted the project probability.

SP AusNet's revised proposal disagrees with Nuttall Consulting's view and considers that the full program is required. SP AusNet considers that our focus on the two points noted above has not taken a balanced view of the differing matters that can result in an over or understatement of energy at risk. In this regard, SP considers that when all matters are considered then SP AusNet's energy at risk calculation is more likely to be an underestimate, rather than an over estimate of the risk.

In support of this view, SP AusNet notes that temporary transfers are not very significant, and cannot be guaranteed to be available when needed. Furthermore, it considers that its assumption that the cyclic rating can be applied following a failure is very optimistic, and would most likely overstate the available capacity – i.e. in worst case conditions the available capacity would be the continuous rating, which is much lower than the cyclic rating. Moreover, it considers that any additional benefits available through transfers will be more than offset by the actual reduction in available rating.

In addition, it also notes that the actual ambient temperature at the time of high demand will most likely reduce the transformers capacity further, and its assumptions on the transformer failure rates are most likely too optimistic for older transformers.

SP Ausnet has also provided revised planning reports and economic evaluations for a number of the projects. It is our understanding that these have only been revised to account for the revised forecast from NIEIR.

Nuttall Consulting has reviewed SP AusNet's revised documents for the 4 projects previously reviewed; it has also carefully considered SP AusNet's views noted above.

Our review of the revised planning reports indicates that most projects could be delayed by 1 to 2 years if the stated load transfers are allowed for. We do not consider that SP AusNet has presented sufficient information to demonstrate that it is not reasonable to assume that a significant proportion of these transfers will not be available if required.

Further, we note comments in TCPR on load transfers, which appears to suggest that although such transfers are not normally included in energy at risk calculations of this form, they would be allowed for in later risk assessments that will be applied when undertaking a more rigorous evaluation of the project.

We also note SP AusNet's acceptance that temporary transfers may reduce risks but will be outweighed by other factors, particularly the assumed availability of the full cyclic rating. We do not disagree with the worst case scenario presented by SP AusNet on the matter of the unavailability of cyclic rating, and the impact of matters such as ambient temperature and the fact that temporary transfers may not necessarily be available when required. However, with regard to a balanced view on this matter, we do not consider that SP AusNet's discussion is recognising the use of "emergency" cyclic ratings (both long terms and short term) and how these can be used to increase capacity under low probability contingency conditions. This essentially trades off the risk of a small reduction in the life of the transformers (remaining in service) against the additional capacity that can be made available by these transformers for a period of time following the failure of another transformer.

On better transformer management, we also accept that there may only be limited circumstances when this may be able to reduce the need for the upgrade. However, given the scale of the proposed transformer replacements, we still consider that there is a good possibility that this factor will result in some limited deferral of some projects.

Conclusions

Based upon the above, we still consider it reasonable that some deferral will occur, but, given the further information provided by SP AusNet and the revision to the load forecast, we have accepted that our original probability was too low. As such, we have revised our probability to moderate (70%) to reflect our views above, and the other general matters[239].

7.2.2.5 Distribution transformers

SP AusNet is forecasting a large increase in the level of distribution transformer augmentations compared to that which had occurred historically. The main reason for the increase was a change from a "reactive" replacement program, mainly associated with a "replace on fail" approach, to a "proactive" replacement program, based upon the replacement of overloaded transformers in order to reduce the failure rates. The need for this change was broadly explained to be due to increasing failure rates and the resulting increases in reliability and safety risks. In this regard, the recent heatwave (2008/09) appears to have resulted in a high number of transformer failures.

Nuttall Consulting's view was that the DNSPs had not demonstrated that the large increase in expenditure could be considered prudent and efficient. The main issue forming this view was the lack of evidence to demonstrate that the transformers can be adequately targeted, such that sufficient benefits would be realized through the reduction in the failure rate.

The important point here was that determining when a distribution transformer may fail is more problematic than simply knowing how overloaded it is. Furthermore, the DNSPs do not meter the maximum demand at individual distribution transformers; it has to estimate the loading at a particular transformer via customer metering data that is associated with transformers.

We also noted the following:

- It may be more economic to defer the program until the AMI rollout in order to use the information from these smart meters to more accurately estimate transformer maximum demands and load profiles, and in turn determine empirical relationships between the level of overloading and the probability of failure.

[239] Probability based upon: 90% (historical accuracy) x 90% (deferral – load transfers) x 94% (transformer management)

- The STIPS may provide some funding for the reliability gains predicted through the change to a proactive program.

The SP AusNet revised proposal has raised a number of criticisms of our position, and provided further information to support its forecast. The following discusses the main points raised by SP AusNet.

SP AusNet's response considers that the Nuttall Consulting allowance fails to consider an underlying recurrent spend of $20m (of the $42m) within its 60% reduction. This amount is in line with historical levels of approximately $4m per annum, which is required to address supply improvement issues.

We agree with this point, and accept that the recurrent expenditure would not have been appropriately allowed for in our allowance.

With regard to the pro-active replacement program, SP AusNet states that this is already approved and is planned to be completed by 2012. To address Nuttall Consulting's concerns over the ability to target the appropriate transformers, SP AusNet has provided further information on this matter (appendix 3 – Reinforcement response). This provides further information to support its view that its load estimates can be relied upon, including a discussion on its previous testing and measurements, and details of the investigations it plans to undertake on each transformer identified for replacement, prior to the replacement.

We have reviewed this revised information. We do not disagree that this supports the view that the loading can be reliably estimated. However, this does not address Nuttall Consulting's main concern, which is whether this will efficiently address failure risks (i.e. targeting those transformers that will most likely fail). SP AusNet has not provided any analysis that supports the scale of the proposed programs. Given the scale of the expenditure and the significant change to past practices, and the opinions we expressed in our paper, we would have expected:

- utilisation profiles of the transformer fleet, indicating the proportion of transformers by type at various utilisation levels (it is noted that utilisation information is provided in AMS 20-58, but appear to be average, and so the proportion of heavily loaded transformers is not provided)
- some form of statistical analysis of historical failures; for example, to attempt to develop probability distribution that models the relationship between the failure probability to factors such as loading (and possibly age) and show the typical consequences
- some form of probabilistic economic analysis, in order to determine the optimum scale of a planned replacement program (i.e. the program that will most likely maximise the net benefits) – or at least demonstrate the proposed is clearly not overstated.

All that said, it is noted that SP AusNet's information on this program indicates that transformers have been targeted based upon a loading of 150% at 10% PoE maximum demand conditions (based upon AS2374.7). This criterion does not appear to be overly pessimistic (i.e. it does not appear that SP AusNet is attempting to remove all overloaded transformer). However, counter to this is the fact that many older transformers may have significant design redundancy, and as such, may be able to withstand far higher levels of overloading without risking failure. Furthermore, it is clear that historically SP AusNet and other Victorian DNSPs have been willing to allow transformers to breach this limit i.e. although the recent heatwave may have resulted in an increased number of failed transformers, information on the extent of overloaded transformers was available beforehand.

On balance, we do accept that there appears to be evidence that a planned replacement of the most heavily loaded transformers may be required. However, we do not consider that SP AusNet has adequately addressed our concerns with the scale of this proposed program, particularly with the short time frame it is proposing to undertake the program.

We consider it reasonable to assume that the proposed expenditure will occur over a longer timeframe i.e. the program will be spread over a longer period. We consider that this would result in a risk profile that is more in line with a trending down of currently accepted risks, rather than the step down over a short period that appears to be being proposed. We consider it reasonable to assume that the remaining program can be spread over at least the next period.

Furthermore, it is not clear whether SP AusNet has allowed for further optimisation to occur that may reduce the number of transformer augmentations. This may occur when opportunities arise with other needs, such as the existing supply improvement program or the age related replacement program. They may also arise following further investigations SP AusNet intends to undertake, which may find that the condition of some transformers is acceptable, or at least, sufficient to optimise the upgrade with other later plans.

It is also worth noting that we consider that the STIPS should also allow for additional expenditure that will improve reliability. We still consider that this should have some relevance to this program as the reliability benefits determined through United Energy and Jemena's economic analysis appear to be largely due to existing reliability levels, rather than only the incremental levels due to load growth in the next period.

Based upon the above we consider it reasonable to assume that a probability of 80% can be applied to this program. This assumes that the portion of recurrent expenditure occurs as proposed, but the programmed replacement is reduced by 40% due to spreading the program over a longer period and the other efficiency and funding points noted above.

7.2.2.6 Other projects reviewed to test findings

As discussed in the introduction, a criticism of SP AusNet was that our project selection did not adequately consider projects in the early period. We have accepted that this could have affected our original findings. Therefore, to address this possibility we have undertaken a review of a number of additional projects that occur in the first half of the next period. These are taken from SP AusNet's 66 kV line upgrade program and HV feeder upgrade programs, which constitute a large portion of the proposed reinforcement expenditure in the early part of the next period.

The projects reviewed were as indicated in the Table below.

Table 48 Additional reinforcement projects reviewed for SP AusNet[240]

Project	Cost	Project timing
66 kV line projects		
Thermal uprate to MOE/YPS-WGL	$2.3 million	2012
LGA-WGI and MWTS-LGA 66 kV line upgrades and reconductoring	$12.2 million	2011
KLO-DRN new 66 kV line	$11.6 million	2012
HV feeders		
Ferntree Gully	$2.1 million	2012 and 2015
Lilydale	$3.3 million	2012 and 2015
Clyde North	$0.9 million	2013
Epping	$0.6 million	2013
Wangaratta	$2.0 million	2013

Where we considered suitable information to review was lacking for these projects, the AER requested further information from SP AusNet. In these cases, SP AusNet has provided additional information[241].

We have reviewed the information SP AusNet has provided to support these projects, including the additional information provided by SP AusNet. Based upon this review, we consider that our general findings from the main project reviews should still be applicable in the first half of the next period.

In this regard, our overall probability from the main project reviews is moderate to high (70%). Our general finding for the additional projects reviewed is also moderate to high.

This position generally reflects our view that there is insufficient energy at risk to justify some of the 66 kV line projects, which may result in a 1 to 2 year deferment. In addition, we considered that some of the 66 kV line projects and the HV feeder projects would have some material reliability improvement benefit, of which some funding for the project would be available through the reliability incentive scheme.

Furthermore, as noted in our original report, we consider that SP AusNet's forecasting accuracy for the current period (i.e. the comparison of its reinforcement forecast it prepared for its 2006-2010 submission to the ESC compared against its actual expenditure) overstated needs, particularly in the first half of the period.

[240] Cost and timing taken from SP AusNet AMS 20-12.
[241] SP AusNet email dated, 24 August 2010

The section below provides summaries of the findings of the project reviews.

Thermal uprate to MOE/YPS-WGL

The need for this project relates to energy at risk due to a thermal overload of an existing 66 kV circuit supply Warragul ZS and voltage collapse, following the outage of the other 66 kV circuits. SP AusNet's documentation provides a brief discussion of the need, including energy at risk calculations, and options and costings.

Based upon our review, we do not consider that SP AusNet has adequately demonstrated that energy at risk is sufficient to justify the timing of the project.

Energy at risk results have been provided for 2015/16, but it is not clear from these how SP AusNet's calculation addresses both the thermal and voltage issues. In this regard, it appears to not allow for the thermal overload, but assumes a high probability of voltage collapse.

Setting this uncertainty aside, given SP AusNet's load forecast for Warragul, we do not consider that the energy at risk results would support a $ 2.3 million project before 2013/14 or 2014/15. Furthermore, based upon our assessment of the energy at risk due to the thermal overload it does not appear that this would be sufficient to justify a project until 2014/15. This suggests a 2 year deferment in timing may be possible.

Based upon the above, we consider that this project may only have moderate to high likelihood of occurring as planned.

LGA-WGI and MWTS-LGA 66 kV line upgrades and reconductoring

The need for this project relates to energy at risk due to the voltage collapse of system supplied by the existing 66 kV loops, following an outage of various 66 kV lines in system at times of high demand.

This system has been subject to a number of load shedding events since 2003. The project was originally planned for the current period (around 2007). However, the project was deferred due to a possible opportunity provided by the proposed desalination plant development, whereby one connection option may have allowed load to be transferred to a new terminal station. This connection option has not been selected, and therefore, the original project is now planned for 2011. The planning report indicates that demand management has been used to manage load to allow the deferment until 2011.

We have reviewed the SP AusNet planning report and associated analysis for this project. Given the deferment of the project, the need appears to be clearly justified based upon the value of the expected energy at risk. However, we do have some minor concerns with the transparency of the energy at risk calculation. Firstly, we do note that it is not clear from the information provided how assumptions associated with the demand management scheme are affecting the existing and projected energy at risk. We also noted that, although a number of events resulting in a major loss of supply to customers appear to have occurred from 2003 to 2006, none are discussed after this date. As such, it is not clear whether something significant has changed, that is not accounted for in the calculations.

All that said, given the scale of the value of energy at risk by 2011 ($66 million) we accept that it is very likely that the need will exist at 2011. Furthermore, based upon the range of options considered, we are satisfied that the proposed option will be the most likely option and the costs of this option appear reasonable.

However, it does appear that this portion of the 66 kV network has contributed to SAIDI during the current period (i.e. a 2006 incident amounted to 1.8 minute contribution). As such, it seems reasonable to assume that there will be some incremental improvement in overall reliability by undertaking this project, and as such, this project may be at least partly funded through the reliability incentive scheme.

Based upon the above, we consider that there is a moderate to high probability of funds being required as proposed.

KLO-DRN new 66 kV line

The need for this project is related to energy at risk due to the radial supply to KLO and WLT from SMTS. WLT (Wollert) is a new zone substation planned for the next period.

We have reviewed the planning report and associated analysis provided by SP AusNet. We have a number of concerns with the economic analysis associated with this project.

Firstly, the timing assumption used for the Wollert development for this project (indicated in service for 2012/13) appears to be earlier than the planned timing for Wollert in its planning report and the RIN (in service for 2013/14). It is not clear to us that the project is justified until the Wollert development occurs.

Secondly, the line from SMTS to WLT is much shorter than the line from WLT to KLO; however, both have the same probability of failure in the energy at risk calculations, with the level of load at risk due to the SMTS-WLT outage being much higher. If the probability of failure for this line is reduced then the energy at risk may be reduced such that the timing may be deferred.

Finally, the short distance from SMTS to WLT may also support a staged option to upgrade from SMTS to KLO, with the upgrade from SMTS to WLT being the first stage. We note that the options analysis indicates that this may be a higher cost option than the preferred KLO to DRN, but we consider there is some possibility that this could result in a lower cost option following further analysis – albeit, we accept this possibility is low.

Based upon the above, we consider that this project may have moderate to high likelihood of occurring as planned.

HV feeder projects

These works involve new feeders and some lower cost thermal upgrades of existing feeders. The need for these works relates to forecast overloads of existing feeders supplied by the substations.

We have reviewed the information provided by SP AusNet to support these projects. For all the substations reviewed, we agree that the feeders indicated and the overall feeder loadings at the substations support that some HV feeder augmentation will most likely be required and the options proposed by SP AusNet appear reasonable. However, in some cases we consider that there appears that there may be some opportunities to defer some of the later stages as other developments that are planned occur. These developments and their associated feeder works may allow additional load transfers to occur to offload existing heavily loaded feeders. Although, we accept that these opportunities may be limited.

More importantly, we consider that the planned new feeders should involve reliability improvement benefits. This is due to the fact that these new feeders should split a number of presently very heavily loaded feeders that are contributing to existing SAIDI levels. The benefits realised through these augmentation should be above any small degradation that may occur due to the load growth alone in the next period.

Based upon the methodology SP AusNet has applied to assess these benefits for its new substation developments discussed above, we have estimated the benefits due to the new feeder projects. Using a conservative estimate of a 10% improvement in existing SAIDI for feeders being relieved, in most cases we found that the majority of the projects would be funded through the reliability incentive scheme.

Based upon the above, we consider that there is a low to moderate probability of funds being required as proposed for the HV feeder upgrades.

7.2.2.7 Summary findings

Based upon the above, we have revised our project probabilities as indicated in the Table below.

Table 49 SP AusNet reinforcement project summary

Project	original probability	revised probability
Mooroolbark new zone substation	Moderate (50%)	Moderate (50%)
Wollert new zone substation	Moderate (50%)	Moderate (50%)
KMS-SMR 66 kV line establishment	Moderate (50%)	Moderate/High (70%)
Zone substation transformer upgrade program	Moderate (50%)	Moderate/High (70%)
Distribution substation upgrades	Moderate (60%)	Moderate/High (80%)
Weighted average	**53%**	**71%**

The project probabilities largely reflect the concerns we raised in our original review:

- energy at risk is insufficient to justify the timing
- part funding through the reliability incentive scheme
- alternative lower cost options
- conservative load profile assumptions

- previous forecasting accuracy.

The increases are largely due to the increased demand forecast and updates or clarification on the DNSPs project justifications.

7.3 Reliability and quality maintained

Our original review considered SP AusNet's RQM forecast based upon the DNSP's internal activity codes. This break-down was used as it was considered to be the most consistent between the historical and forecast allocation of expenditure. This breakdown largely reflects various asset classes, but is different to the AER's revised RIN asset categories. This review lead to various parts of the forecast being accepted, and others being rejected with the substitute forecast based upon the calibrated repex model for that category (except for the zone substation category).

SP AusNet has not agreed with Nuttall Consulting's rejection of a number of categories. For the majority of these categories, the revised proposal provided further discussion and information to support these categories and address Nuttall Consulting's concerns expressed in our original report.

SP AusNet has also proposed some additional programs. It considered that these are enhanced programs to address bushfire risk. The proposed volumes for this category have been reviewed by ESV.

The table below list the various categories and indicates where additional information has been reviewed by us and is discussed in the section below. It also indicates where volumes in the category have been reviewed and accepted by the ESV.

Table 50 SP AusNet RQM category summary

Category	Original finding	DNSP revised proposal
poles	Accept	Accepted
OH line reps	Rejected, but with caveat on bushfire risks	Rejected Conductors accepted by the ESV Cross-arms additional information provided
services	Accept	Accepted
UG cable	Accept	Accepted
HV installation	Accept	Accepted
Zone substation plant	Reject	Rejected – additional information provided.
Enhanced programs	Not applicable	accepted by the ESV
Recoverable works	Reject	Rejected – no additional information provided – see comment below.

General criticisms of Nuttall Consulting's approach to assessing RQM expenditure and determining substitute allowances, which are similar between DNSPs, are discussed in Section 3.2. For the categories where the ESV has accepted the volumes or made an alternative allowance, we have only considered the unit costs. This review of unit costs is discussed in Appendix G of this report.

This section discusses the specific categories where specific criticisms or new information has been provided in the revised proposal.

It is important to note that although SP AusNet has not accepted our rejection of its allowance for the recoverable works category, it has not provided any new information to support its views. As such, we consider that the recommendation provided in our original report is still valid. This matters is not discussed further in this report.

7.3.1 Zone substation plant

The zone substation plant category covers the replacement of power transformers, zones substation switchgear, and zone substation secondary equipment, and a number of rebuilds of specific zone substation.

This category represents 32% of SP AusNet's RQM forecast for the next period. SP AusNet has forecast this category to have a very significant increase in expenditure from recent levels.

7.3.1.1 Summary of Nuttall Consulting original review

Nuttall Consulting did not consider that SP AusNet had adequately demonstrated that its forecast expenditure associated with this RQM category was reasonable (i.e. it could be considered a disaggregated component of the overall prudent and efficient capex[242].

In rejecting the forecast, we considered SP AusNet had not adequately demonstrated that the models it used to predict the level of replacement were "fit for purpose" in the regulatory context. This specifically related to our view that SP AusNet had not adequately shown that the models had been calibrated and validated[243]. The key matters we raised to support this view were:

- Nuttall Consulting's assessment of the transformer condition information, which we considered did not reasonably justify the number of transformers SP AusNet were predicting would need to be replaced in the next period[244]
- the age modelling in SP's circuit breaker replacement model, which assumed asset lives were lower than those we derived through the repex model calibration process[245]

[242] Nuttall Consulting report, pg 234
[243] Ibid, Pg 234
[244] Ibid, Pg 232
[245] Ibid, Pg 232

- a number of inconsistencies between assumptions inherent in the SP AusNet models with regard to asset failure probabilities and historical failure rates, particularly those that we considered important to predicting replacement needs[246]
- lack of evidence that assumed consequence and risks in the model reflect those that have occurred[247]
- lack of detailed discussion in the substation rebuild project reports on the make-up of the risks and possible risk control measures, linking with the economic analysis provided[248].

During the course of the review, Nuttall Consulting had requested information to address these concerns but considered SP AusNet's response did not adequately address these matters[249].

Although Nuttall Consulting rejected SP AusNet's forecast in this category, we did consider that there was sufficient evidence that SP would require an allowance for this category that was well above its recent historical level[250]. We recommended an allowance that was based upon a "notional" 2011 figure of $8 million and an annual increase from this amount, which was set at the rate of expenditure increase suggested by the calibrated repex model for this asset category[251].

It is our understanding that the AER accepted our view in forming its overall capex allowance for SP AusNet.

7.3.1.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

SP AusNet's revised proposal has raised a number of issues associated with Nuttall Consulting's findings on this asset category and provided additional information to support its claims. The matters cover:

- the review process followed by Nuttall Consulting
- the use of the repex model
- Nuttall Consulting's views on the condition of transformers and circuit breakers
- Nuttall Consulting's view on the calibration of the models
- Nuttall Consulting's view on the allowance.

These matters are discussed in turn below.

Criticisms of Nuttall Consulting's process

The SP AusNet proposal details two main criticisms of the process it considers that Nuttall Consulting applied in forming its view on zone substation plant expenditure, namely:

[246] Ibid, Pg 233
[247] Ibid, Pg 233
[248] Ibid, Pg 233
[249] Ibid, Pg 233
[250] Ibid, Pg 234
[251] Ibid, Pg 234

- Nuttall Consulting and the AER resisted offers from SP AusNet to explain its model, and as such, the concerns expressed cannot be relied upon[252].
- SP AusNet also questions whether all relevant information has been reviewed by Nuttall Consulting (and the AER)[253].

We do not consider that these criticisms are materially relevant.

In support of our view, it important to note that during the course of our original review, a meeting was held with SP AusNet personnel[254] with AER staff in attendance. This meeting involved a demonstration and discussion on the models used by SP AusNet.

Nuttall Consulting also reviewed the spreadsheet models and the information provided by SP AusNet to support these models in the original proposal. Subsequently, Nuttall Consulting has reviewed the information provided in the revised proposal.

Some of the revised information has resulted in alterations to our original recommended allowance for this category, which is discussed further below. However, we do not consider that this information shows that we had or still have a fundamental misunderstanding of the modelling performed by SP AusNet, such that it is inappropriate to reject SP AusNet's forecast.

Criticisms of Nuttall Consulting's use of the repex model

The SP AusNet proposal details a number of criticisms of the use of the repex model for the zone substation category. These broadly cover the following concerns:

- the model fails to consider economic as opposed to technical considerations (i.e. it is a failure model not a risk model) [255] [256]
- the lives suggested by the calibrated repex model are much longer than allowed elsewhere[257].

These criticisms are broadly in line with the general procedural criticisms that many of the DNSPs have made, which we have discussed in Section 3.2 and for the most part we do not accept.

Specifically with regard to our review of SP AusNet's zone substation category, we do not consider that SP AusNet's criticism on this matter is valid for two main reasons.

Firstly, as noted above our rejection of SP AusNet's forecast was largely based upon concerns we had with SP AusNet's modelling and detailed asset management information provided by SP AusNet, including asset condition – not the findings of the repex modelling.

Secondly, as also noted above, based upon this review of asset management information, it was accepted that an allowance based upon historical expenditure levels would most

[252] SP AusNet revised proposal, Pg 125
[253] SP AusNet, RQM response to draft decision, S7.1, pg 33
[254] Ref to date
[255] Ibid, Pg 126
[256] SP RQM response, S7.2.5, S7.2.9, S7.2.10
[257] Ibid

likely significantly underestimate expenditure requirements. As such, an allowance was recommended based upon a "notional" 2011 amount that was **not** determined from the calibrated repex model output. The notional amount was based upon expenditure levels for similar asset replacements for Powercor, which we considered was a reasonable proxy given its similar number of zone substations and age[258]. We then scaled this amount, to account for further aging of the network, by using the rate of increase given by the calibrated repex model. However, it is important to appreciate that we consider that this is a conservative estimate of the annual increase from the notional amount (i.e. it is most likely to overstate the rate of increase from the notional amount) specifically due to the long lives assumed in the calibrated repex model (i.e. shorter lives would have predicted a lower rate of increase of expenditure).

Finally, with regard to the criticisms that the repex model is a failure model not a risk model, in additional to the lack of relevance of this criticism as discussed in the above two points, we do not consider that this view is factually correct. As the asset lives have been calibrated to historical replacement levels, the lives should reflect the historical replacement driver. If this was due to a "replace on fail" strategy then this may reflect a failure life. However, if replacements were based upon economic or other considerations then this should be intrinsically allowed for in the deduced life.

Criticisms of Nuttall Consulting views of asset condition

The SP AusNet revised proposal details a number of criticisms of Nuttall Consulting's views of the condition of the zone substation assets, and how these views related to our rejection of the forecast. The criticisms mainly concern our comments on transformer condition, most notably:

- our reliance on the estimated condition of the transformer winding insulation (i.e. the estimated degree of polymerisation (DPv))[259] [260]
- our lack of consideration of the other factors affecting overall transformer condition.

There is less specific critique of our views of the circuit breaker condition, but further information detailed the risk modelling and determination of the associated condition scores has been provided[261]. SP AusNet has also provided a revised version of its transformer refurbishment and replacement program, which includes details of the transformer condition assessments[262], and further details of specific transformer condition information[263].

Nuttall Consulting has considered SP AusNet's criticisms and reviewed the information SP AusNet has referred to in support of its views. From our review of this information, we are

258 Nuttall Consulting report, Pg 234
259 SP AusNet revised proposal, pg 26
260 SP AusNet RQM response, S7.4.3
261 Most notably, SP AusNet RQM response appendices, AMS 20-128 (transformer risk model report) and AMS 2-129 (CB risk model report)
262 AMS 20-120
263 SP AusNet RQM response, S7.4.7-10

not convinced that this shows that we erred in rejecting SP AusNet's forecasts, for the following reasons.

With regard to our views on the estimated DPv of the transformer windings, in our original report, we considered that this was the most critical indicator of the need to replace the transformer, but noted that test data did not indicate that all transformers were near to a level that indicated an impending failure[264].

SP AusNet has criticised this view as it considers we have relied too heavily on this estimate[265] and a holistic approach allowing for all measures is more appropriate[266]. It considers the actual DPv value will be highly variable and the worst-case actual value can be much lower (i.e. the transformer is in poorer condition) than the estimate[267]. It also noted that the rate of change of this parameter can be just as informative as to the condition as the relative value[268]. To aid in its discussion it also provides information on:

- the derivation of the estimate[269]
- SP AusNet's use of this estimate[270]
- the effect of transformer age on DPv[271].

To a large extent we consider that SP AusNet's discussions on this matter are redundant, as Nuttall Consulting does not disagree with the theory or the general views that SP AusNet has expressed on this matter.

Nonetheless, we still regard the DPv estimate as one of the most informative measures for appreciating the condition of the windings and the remaining life of the transformer[272], and do not consider that the transformer DPv estimates clearly demonstrate that the scale of the proposed replacement program is required. We do not consider that SP AusNet has provided any meaningful evidence that would allow us to adjust the estimates to better reflect the "most likely" actual winding condition or remaining life.

We certainly do not disagree that other measures may also be important in determining the optimum course of action. However, given such a large step in replacement volumes is proposed, we consider that it is important that this is analysed and the options assessed - as SP AusNet is attempting in its risk modelling approach (i.e. in the absence of this type of economic evaluation, we do not consider the condition information alone justifies the scale of the proposed program).

[264] Nuttall Consulting original report, Pg 232
[265] SP AusNet RQM response, S7.4.3.6
[266] SP AusNet RQM response, S7.4.1 and S7.4.5-6
[267] SP AusNet RQM response, S7.4.3.4
[268] SP AusNet RQM response, S7.4.3.5
[269] SP AusNet RQM response, S7.4.3.1
[270] SP AusNet RQM response, S7.4.3.2
[271] SP AusNet RQM response, S7.4.3.3
[272] On this matter, it is noted that both JEN and UED use the DPv estimates as the primary parameter in developing their transformer replacement forecasts.

Although, there is less additional information provided on the circuit breaker replacement program, we still consider that the above view on the need for robust economic analysis is valid.

Finally, we note that SP AusNet has provided further details of recent condition test results for two transformers[273], which show they are in poor condition, and has provided some historical examples of the catastrophic failure of other components of the transformer[274]. However, given that we have already accepted that some of the transformers are in poor condition and a number most likely will need to be replaced in the next period, we do not consider that this additional information supports the need to accept the overall program.

Criticisms of Nuttall Consulting views of the lack of calibration/validation of the SP AusNet models

The Nuttall Consulting original report defined the type of analysis we would expect SP AusNet to undertake to show that the models were calibrated appropriately, stating:

> "*(i)n our opinion, this would require a far more substantial and quantitative analysis to appropriately and transparently demonstrate their suitability. This would require network level and sample asset level analysis that shows that the number of failures, probability of failure, the aging relationship, and the consequences, derived through the model are reasonable unbiased estimates of the replacement needs. Such an evaluation would need to take into account SP AusNet's historical information, including failure statistics and reliability consequences, asset condition monitoring results and risk mitigation measures.*"[275]

The SP AusNet revised proposal disagrees that the models are not calibrated appropriately. SP AusNet's main contention with Nuttall Consulting appears to be that, as transformers (and circuit breakers) are not managed under a "run to fail" policy, there is not the available historical data to undertake the type of calibration suggested by Nuttall Consulting[276]. SP AusNet has provided further information that it considers shows that the models are calibrated, covering the failure probability, consequence calculations, and NPV analysis of options[277].

Nuttall Consulting has reviewed this information, including the revised asset management documents and associated spreadsheets, and does not consider that this has adequately addressed our concerns expressed in our original report.

We consider that SP AusNet's main reasoning regarding insufficient data is not valid. We see no reason that SP AusNet would need to operate a "run to fail" policy to obtain useful data, and consider this argument to be missing the main issue. The risk models make predictions from 2005 of failure probabilities, consequences, and risks. We see no reason why the predictions over the current period cannot be assessed in light of the actual

[273] SP AusNet RQM response, S7.4.7.1-2
[274] SP AusNet RQM response, S7.4.8-10
[275] Ibid, Pg 234
[276] SP AusNet RQM response, S7.2.3, S7.2.4, S7.2.7, S7.4.4.
[277] SP AusNet RQM response, S7.2.2, S7.2.6, S7.2.8, S7.6

outcomes. As discussed in our original report, there appears to be very high probabilities of failures for certain assets that would suggest failures would have been expected. These matters have not been assessed.

On this matter, it is noted that the revised proposal suggests we have misunderstood the probabilities given by the model[278], and our view of how high the probability of failure has been over the current period is overstated. This relates to a comment in our original report that the probability of failure of the RUBA No 1 transformer (20% per annum) suggested we may have expected 1 failure to have occurred in the current period.

Once again, we consider that this is not a valid position to reject our view. It is certainly correct that the probability of failure across a number of years is not the simple sum of the predicted probabilities in each year, and the simple sum will overstate the probability. However, the probability over the period is still high (we estimate about 70% of the simple sum), and therefore, we consider that our concerns of the high probabilities suggested by the models remain valid. In this regard, if such a model is suggesting a high probability of failure over the current period – and we are agreed that it would not be prudent to operate a "run to failure" policy – then it seems reasonable to consider that the probability of failure may be overstated.

We consider that this issue is due to the age of the transformer having such a significant influence on the probability of failure, over condition information. This issue is also evident in SP AusNet's revised NPV analysis of its transformer replacement plans[279], which is discussed further below.

SP AusNet considers that its revised NPV analysis demonstrates that the replace option in the next period for all transformers has the lowest NPV. This considers costs covering planned and unplanned replacement costs, refurbishment costs, opex costs, and community costs.

Nuttall Consulting has reviewed the analysis and has significant concerns that the modelling may be biasing the analysis to selecting replacement options. In understanding this concern it is important to recognise that the NPV difference between the two options for all cases is relatively small, generally between 0 and 9%. This means the results can be sensitive to assumptions inherent in the modelling.

Of most concern on this matter is the probabilistic modelling that predicts the likelihood of failure of the transformer, which in turn produces an expected unplanned replacement cost – this modelling is similar to that applied in the risk models. SP AusNet assumes a normal distribution that it considers is typical for transformers. This is then used to predict the probability of failure through the study period.

However, we consider that SP AusNet's assumptions are conservative as they tend to result in the greatest probability of failure in the first years of the study with this generally reducing through the study period. This increases the relative NPV difference between

[278] SP AusNet RQM response, S7.4.11

[279] AMS20-130 - note, also includes analysis of substation rebuild transformers

the replace and refurbish options. It also means the optimal timing of the replacement is generally at the beginning of the study period.

In our view, SP AusNet's assumptions would be appropriate if we were considering a population of transformers of which their condition is unknown. In these circumstances this could be considered the best estimate. However, in the case of SP's analysis, SP does have an estimate of the condition of the specific transformers, and therefore, the failure distribution should be set to reflect this knowledge. Our view is that, assuming the transformers are in poor condition (which we do not disagree given SP AusNet's condition data), then this would tend to place the mean life *for that specific transformer* some time after the current age of the transformer (assuming test data does not suggest we are at or past its end of life).

Based upon our analysis of SP AusNet's model with parameters such as these, in most cases, the least cost option was either the refurbishments option or a delay in the replacement option.

For example, in the case of the CL 1 and CL 2 transformers, which are 74 years old, SP assumes the failure probability is based upon a normal distribution with a mean life of 60 years and standard deviation of 12 years. However, in our analysis we have assumed that condition information suggests that the transformers will most likely fail in 4 years (i.e. the life can be considered to be 78 years) with a standard deviation of 3 years. Based upon these parameters, the least cost option would be to refurbish in 2011 and replace in the next period.

Based upon the above, we still do not consider that SP AusNet has adequately demonstrated that its modelling is calibrated correctly, and on balance consider that it would most likely overstate replacement needs.

Criticisms of allowance

Based upon the above, we still do not consider that there is sufficient case to change our recommendation to reject the proposed allowance.

With regard to the substitute allowance, consistent with our views in our original report, we do not consider that, within our review process, we could reasonably define a specific program. With this in mind, we still consider it reasonable to use the Powercor allowance as a guide to SP AusNet's needs.

However, as we have raised the Powercor allowance by 15% in this review of the revised proposal, we also consider it reasonable to raise the SP AusNet allowance by 15%. We have also allowed for a further 15% to allow for SP AusNet's older transformer fleet. This should provide SP AusNet with sufficient funds to undertake approximately 40% of its proposed program, which we consider a conservative estimate given the condition information presented and the issues we have raised with the modelling provided. It is worth noting that this allowance represents a very significant increase from the recent level of expenditure in this category.

We do note that SP AusNet has criticised our original allowance as it considered the lives required to achieve this were well in excess of industry benchmarks. We do not disagree with this, and we would expect that this increased allowance would still suggest longer lives than some benchmarks. Nonetheless, given the benchmarks quoted by SP AusNet would have over-forecast historical replacement levels by a considerable margin, we do not consider that these benchmarks can be considered a reasonable gauge of the prudency of the future requirements.

The table below provides our revised estimate for this allowance (estimate inclusive of overheads).

Table 51 SP AusNet substation plant

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	24.7	39.5	30.8	27.5	17.9
Recommended	**10.0**	**10.5**	**11.1**	**11.7**	**12.3**

7.3.2 Cross arm replacements

This section discusses what could be considered the "business as usual" cross-arm replacement. This does not include additional cross arm replacements that have been assessed by the ESV and are discussed in Appendix G.

SP AusNet has forecast this category to have a significant increase in expenditure from recent levels.

7.3.2.1 Summary of Nuttall Consulting original review

Nuttall Consulting did not consider that SP AusNet had adequately demonstrated that its forecast expenditure associated with this RQM category was reasonable (i.e. it could be considered a disaggregated component of the overall prudent and efficient capex[280]).

In rejecting the forecast, we considered SP AusNet had not adequately demonstrated that the step increase in cross arm volumes from historical levels was justified. The key matters we raised to support this view were:

- SP AusNet's assumption that replacement volumes would be at approximately the 2009 level was too conservative as 2009 was overstating the historical trend.
- We considered this to be the case given changes to SP AusNet's management of cross-arms in the current and preceding periods, which we considered had resulted in a reduction in replacement volumes from around 2001 to around 2006, and an increase after this period.
- We considered that the increases seen from 2005 to 2009 were partly catch-up from the preceding low levels, and these recent higher levels would most likely reduce back to the historical trend by 2011.

[280] Nuttall Consulting report, pg 237

We recommended an allowance that was based upon the 2006-2008 historical levels with an increase as suggested by the calibrated repex model.

It is our understanding that the AER accepted our view in forming its overall capex allowance for SP AusNet.

7.3.2.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

SP AusNet's revised proposal has raised a number of issues associated with Nuttall Consulting's findings on this asset category and provided additional information to support its claims.

The key matters raised by SP AusNet to support its forecast include further trending analysis[281]. This considers both 2009 actual and estimated 2010 data, and the longer-term historical trend in replacement rates. SP AusNet considers that these show that its estimates are in accordance with these – if anything, the SP AusNet forecast is below the trend.

SP AusNet has also provided some details of its estimated replacement quantities for 2011 and 2012, which also indicates that replacement rates may be above the forecast level[282]. It is also noted that SP AusNet has discussed enhanced inspection techniques that have been employed recently (since 2008) that are determining higher rates of replacement[283].

Nuttall Consulting has considered the information provided by SP AusNet, particularly its revised trend analysis. Based upon this review, we are satisfied that this information does support the forecast proposed by SP AusNet. In forming this view, it is important to appreciate that our previous allowance was not significantly different to the SP AusNet forecast, with our recommendations resulting in a small reduction in 2011 but an increase over the end of the period. Given this small difference and the further information provided by SP AusNet, we do not consider there is sufficient reason to reject the SP AusNet forecast.

It is important to note however that this acceptance does not extend to some of the criticisms of the use of the repex model that SP AusNet has associated with its response on cross-arm[284]. We still consider that the use was appropriate for the information available – these matters are discussed further in Section 3.2.

7.4 Environmental, Safety and Legal

SP AusNet has accepted the relocation of some expenditure categories that were originally proposed within the Environmental, Safety and Legal category. These expenditures have been considered within the reliability and quality maintained capex category in this report.

281 SP AusNet RQM response, S5.2.3
282 SP AusNet RQM response, S5.2.3
283 SP AusNet RQM response, S5.2.2
284 SP AusNet RQM response, S5.3

SP AusNet considers that the expenditure recommended in the draft determination is consistent with its requirements for the next regulatory control period. On this basis, SP AusNet has adopted the allowance set out in the draft determination for the four Environmental, Safety and Legal activities that remain in this category.

- Environmental, bunding, security;
- OH & S - Replace CTs;
- OH & S - Replace disconnectors; and
- OH & S - Replace silicon carbide gap arrestors.

In addition to these expenditures, SP AusNet has proposed additional and new activities in response to changed safety and line clearance regulations, the Victorian Bushfires of 2009 and the Royal Bushfire Commission's final report. The proposed expenditures have been reviewed by Energy Safe Victoria (ESV) and recommendations made as to the future volumes of work required. The AER has requested Nuttall Consulting to review the unit costs associated with the ESV recommended volumes. This assessment is provided in Appendix G – Unit cost review of this report.

7.5 SCADA and Network Control

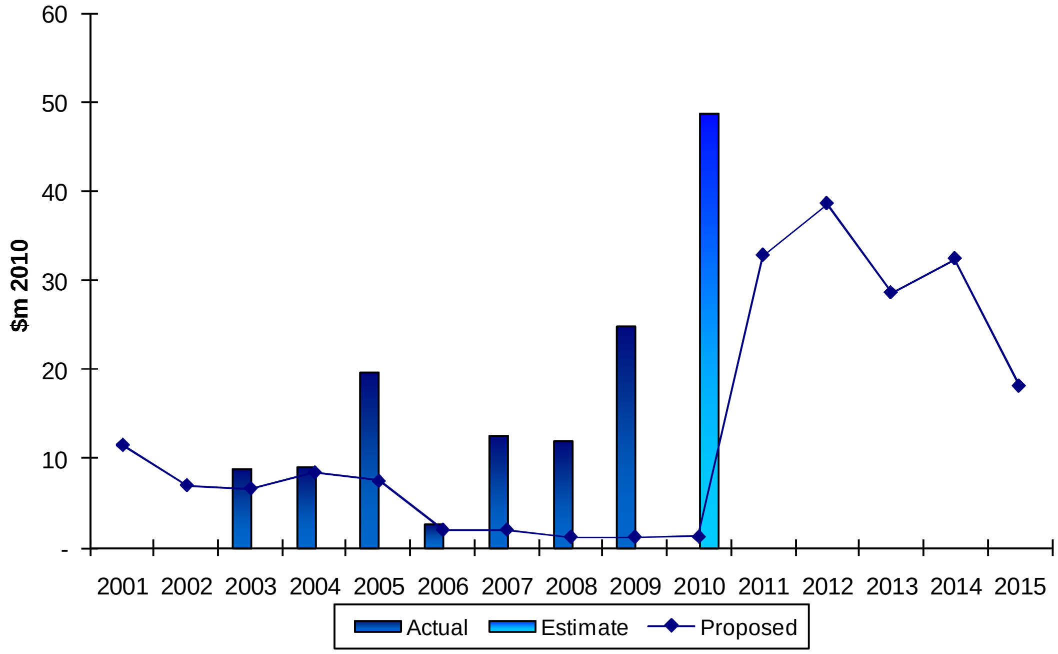
SP AusNet's proposed expenditure in the "SCADA and Network Control" category represents less than 1% of the total net capex in the next period, and is at a lower level than that in the current period.

It was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

7.6 Non-network general – IT

In its revised proposal, SP AusNet submitted forecast IT capital expenditure of $150 million over the forthcoming regulatory control period, which represents an increase of 130% on average annual expenditure incurred in the current period. Major proposed IT capital projects include IT infrastructure asset replacements, IT application replacements and application investments with new functionality.

Figure 29 – SP AusNet proposed and actual IT capex



During the current regulatory period, SP AusNet substantially overspent their IT capital expenditure from a proposed $8 million compared to an estimated $101 million. Noting that $29 million of that overspend is proposed to occur in the 2010 period, this still represents a significant overspend from that based on actual incurred expenditure.

In the original report Nuttall Consulting rejected the IT capital program for SP AusNet and substituted a new IT Capital Allowance based upon audited historical expenditure. As a result, SP AusNet has submitted a revised proposal and additional material in response to the AER's Draft Determination.

As part of their response to the Draft Determination, SP AusNet engaged Deloitte to provide advice on specific recommendations in the Nuttall Consulting report as well as the AER's approach to its draft decision. The Deloitte Report was critical of the approach described in the Nuttall Consulting first report, stating in part that whilst "cloud computing is superficially attractive due to potential cost savings, the journey to adopting cloud computing is complex"[285]. Nuttall Consulting concurs with the statement that the transition to cloud computing is complex, but notes that the existing IT infrastructure is equally complex. Nuttall Consulting believes that based upon a review of all the material supplied, SP AusNet is not moving towards Cloud Computing in a manner that is fast enough, despite the potential cost savings.

The Deloitte Report was also critical of the Nuttall Consulting approach, by stating that it appeared "not to recognise that the electricity distribution industry in Victoria is undergoing fundamental change with the advent of AMI." Whilst the adoption of interval

[285] Deloitte: SP AusNet Review of non-system IT capital expenditure, p7

metering for the millions of households throughout Victoria generates more interval data that must be processed, the processing of that data is comparable to how the data was processed prior to AMI. Therefore, Nuttall Consulting believes that change would have less impact on SP AusNet, had their IT systems be sufficiently agile.

The Deloitte Report states that the reduction in non-system IT capex proposed by the AER may jeopardise the ESC's desire to improve communications of supply outage details to consumers in the event of significant and widespread energy supply events. SP AusNet considers the AER's decision appears to conflict with the ESC's 'implicit assumption' that upgraded communications will occur. Nuttall Consulting is not making any recommendation or opinions on which projects SP AusNet should or should not complete.

In their response to the Draft Determination, SP AusNet states that it does not agree with the AER's forecasting approach for IT capex. A forecasting methodology that reflects historic capex is likely to produce allowances that systematically understate the requirements of the business. Rule 6.4.7(c)(2) provides that a business should be able to recover the costs that a prudent operator would in its particular circumstances to achieve the capex objectives. Nuttall Consulting notes that SP AusNet has historically over-spent on IT capital suggesting that the forecasting processes used to develop these forecasts are flawed.

In their response to the Draft Determination, SP AusNet states that the flaw in the AER's approach to determining historical spend is that it has excluded 2009 and 2010 data from its analysis. Nuttall Consulting will incorporate the audited 2009 regulatory accounts in its new forecast, but regards the inclusion of 2010 data as not appropriate since this data has not be audited.

In the November 2009 proposal to the AER, SP AusNet estimated that actual IT capex spend in 2009 would be $30 million. The actual IT capex expenditure reported to the AER was $25 million. The estimating error of 20% is quite significant given the very short proportion of the 2009 year that remained. Nuttall Consulting considers that this highlights a significant flaw in the forecasting process. Based on this analysis, it would be inappropriate to assume that the 2010 forecast IT capex should be relied upon.

In their response to the Draft Determination, SP AusNet noted that the AER has applied a different method to determining SP AusNet's forecast expenditure compared to the other DNSPs. The draft determination the AER allowed the first three years of capital programs spread across the five year period, whereas it has used an annual historical average for SP AusNet that disadvantages SP AusNet by $24.1 million. Nuttall Consulting has reviewed this position and revised the forecast allowances for the other DNSPs. This has resulted in a more consistent treatment of the IT capex forecasts.

In their response to the Draft Determination, SP AusNet considers that Nuttall Consulting's review was far from comprehensive and as such should not be heavily relied upon to determine SP AusNet's non-network IT capex forecast. Nuttall Consulting has reviewed all the material provided and has made its recommendation based upon the material provided.

In their response to the Draft Determination, SP AusNet states that the AER should seek to understand an appropriate level of virtualisation for the utilities sector. The AER also needs to take into account the limitation on the scale of virtualisation possible due to the obsolete applications still used by SP AusNet that are not supported in a virtualised environment. Nuttall Consulting notes these comments and re-iterates that it considers that the SP AusNet IT systems are not as sufficiently agile as would be efficient for a DNSP.

In their response to the Draft Determination, SP AusNet states that the AER's review has not engaged in understanding and meaningfully reviewing SP AusNet's IT Strategy and IT capex forecast. Nuttall Consulting has reviewed all the material, including the IT strategy. Nuttall Consulting considers that the individual projects proposed by SP AusNet are reasonable[286], but that SP AusNet has not properly accounted for the impact of internal and external project delays and deferrals and does not have an agile IT infrastructure.

In their response to the Draft Determination, SP AusNet states that there is a lack of evidence to support Nuttall Consulting's assessment that SP AusNet will be unable to deliver the IT programs. The Nuttall Consulting recommended IT capex is based on our assessment of the prudent and efficient expenditure required to meet the capex objectives, not what volume of work SP AusNet is able to have undertaken in a given period.

In their response to the Draft Determination, SP AusNet believes that Nuttall Consulting suggests that SP AusNet should move to a lease model for its IT infrastructure. Nuttall Consulting does not advocate if SP AusNet purchase or leases its IT infrastructure. However, Nuttall Consulting does highlight that the move towards Cloud Computing does offer the opportunity to "rent" additional capability during peak periods as a way of more economically handling peak loads.

In their response to the Draft Determination, SP AusNet believes that there is a lack of rigour in the AER's decision and Nuttall Consulting's review was incomplete. SP AusNet considers this was evidenced by "a failure to consider [its] industry expert-validated and clearly costed IT strategy and to engage in the detail of the proposed programs". Nuttall Consulting restates that it did review and consider all the materials provided.

In their response to the Draft Determination, SP AusNet believes that the AER's capex efficiency incentives that operate within period mean SP AusNet will be penalised disproportionately if it overspends its IT capex allowance. SP AusNet proposes that the capex efficiency regime to be applied to its IT capex excludes a return of capital component and retains only the return on capital component. Nuttall Consulting does not provide comment on this issue as it pertains to the regulatory structure and framework.

Based on our review of the revised proposal, Nuttall Consulting considers that the IT capex proposed by SP AusNet for the next regulatory period is not prudent and efficient for the reasons described above. Noting the historical levels of inaccuracy derived from the SP AusNet forecasting processes, we consider that a substitute amount of 67% of the

[286] Noting the previous discussions on agility

proposed capex represents a prudent and efficient level of overall expenditure. This represents a 38% increase on actual IT expenditure incurred in the current period.

Table 52 – SP AusNet recommended IT capex

SP AusNet	Costs (2010 $million)				
Non-network general – IT	2011	2012	2013	2014	2015
Proposed Expenditure	32.8	38.5	28.6	32.4	18.1
Recommended Expenditure	18.0	18.0	18.0	18.0	18.0

7.7 Non-network general - other

With agreement from the AER, non-network other capex was not considered by Nuttall Consulting in its original report.

The AER has requested Nuttall Consulting to consider an aspect of the SP AusNet revised proposal that deals with non-network other capex. This aspect relates to the adjustment of these figures to deal with network growth and increases in customer numbers.

SP AusNet has accepted the draft determination forecast as the starting point for its revised proposal. However, SP AusNet considered that the non-network other capex allowance is related to the size and scale of the network in manner similar to the opex allowance. On this basis SP AusNet considers that the allowance needs to be adjusted to be consistent with network growth and increased customer numbers.

Table 53 - Proposed SP AusNet non-network other capex

SP AusNet	Costs (2010 $M)				
Non-network other	2011	2012	2013	2014	2015
Recommended Expenditure	3.7	3.7	3.8	3.9	3.9

The SP AusNet regulatory proposal[287] identifies that the cost inputs to this category include minor tools, equipment, fleet, etc. This suggests that the most direct driver of these costs is the number of employees of SP AusNet who are provided with these facilities.

However, the use of employees as a proxy for growth is problematic; as demonstrated by SP AusNet in the current control period. Following the development of the 2006 EDPR SP AusNet moved from an outsourced (alliance) style service delivery model to an in-house model. Under the alliance arrangement expenditure for minor tools, equipment, fleet, etc were bundled in with the service provider charges. When this alliance was discontinued, SP AusNet became responsible for the purchase of these items. This resulted in a very

[287] SPI Electricity Pty Ltd Electricity Distribution Price Review 2011-2015 Regulatory Proposal - November 2009

high level of expenditure in this category compared with the levels originally proposed by SP AusNet. Presumably, there was a commensurate reduction in alliance contract payments.

The problems with the use of employees as a proxy for growth is twofold:

- the difficulty in assessing the equivalent number of employees for services that are provided via contract
- the potential for theses capital costs to be amortised through a unit rate style contract fee (and therefore appear as an opex cost item, rather than capex).

Nuttall Consulting considers that the use of network growth and customer numbers as a proxy for growth in non-network other capex represents a more viable alternative due to the availability and consistency of the input measures.

SP AusNet state in their revised proposal that the AER's capex efficiency incentives that operate within period mean that SP AusNet will be penalised disproportionately if it overspends its non-network other allowance.

Nuttall Consulting does not provide an opinion on the operation of the capex efficiency incentive program. However, we note that the use of network growth and customer numbers as proxies for growth in the non-network other capex category does not make allowance for any productive or dynamic efficiencies. Nuttall Consulting considers that productive efficiencies would be applicable to the non-network other capex category. No modification has been made to the recommended non-network other capex to account for productive or dynamic efficiencies.

Table 54 - Recommended SP AusNet non-network other capex

SP AusNet	Costs (2010 $M)				
Non-network other	2011	2012	2013	2014	2015
Recommended Expenditure	3.7	3.7	3.8	3.9	3.9

8 Appendix E - United Energy review

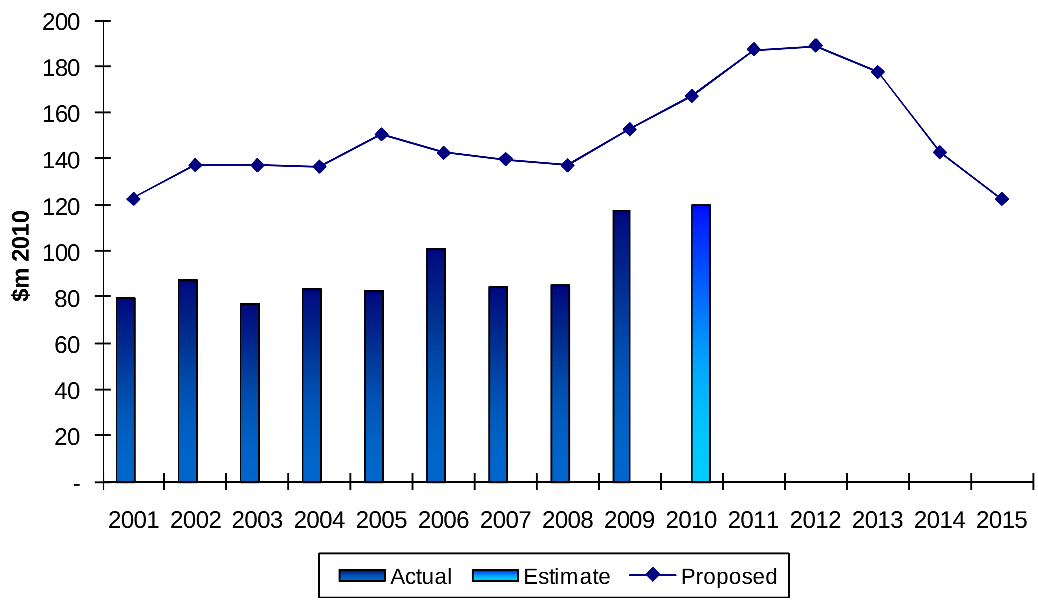
8.1 Overall capex

Overall capex is forecast to increase by 68% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement, reliability and quality maintained, and non-network - IT.

The following chart provides a summary of the overall capex figures for United Energy. Key aspects of this chart include:

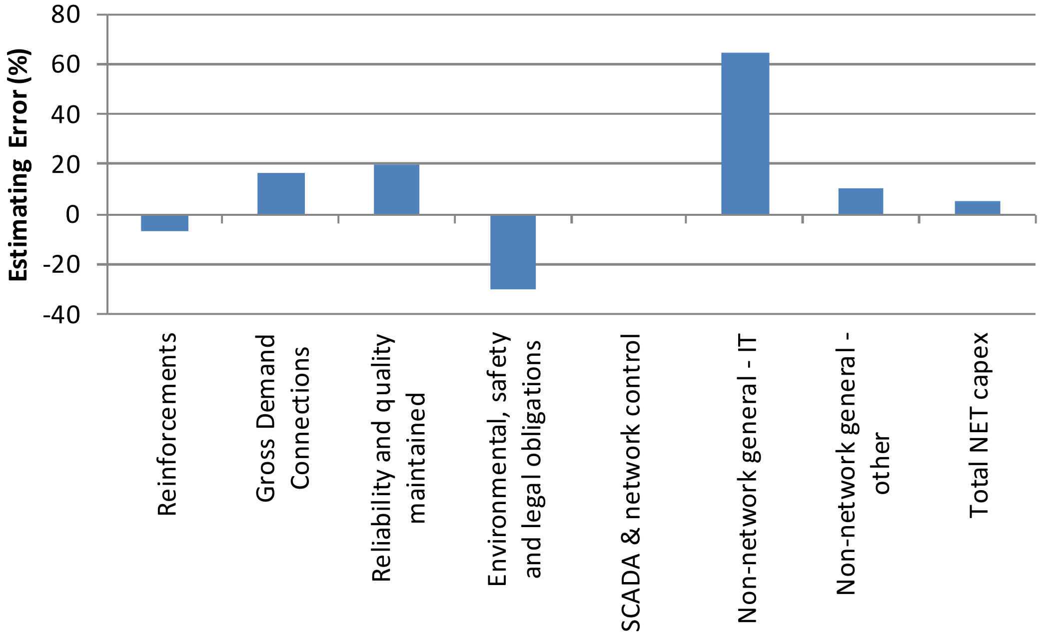
- United Energy has consistently spent significantly less than they proposed in the 2001 and 2006 EDPRs
- United Energy is proposing a future level of capex that is significantly higher than the historical levels of expenditure and is not consistent with the historical trend in capex. It is also noted that it steps up in 2011 and reduces during the period.

Figure 30 – United Energy Capex Summary



The following chart considers the accuracy of the November 2009 United Energy proposal compared with the actual 2009 audited data.

Figure 31 – 2009 estimating accuracy



The estimated figures for 2009 were provided by the DNSPs in November 2009; two months prior to the completion of the financial period. The actual figures for 2009 have been subject to audit and were provided to the AER in early 2010.

The overall accuracy of the 2009 United Energy forecasts was relatively good with actual net capex varying by 5% from that estimated. However, the above chart highlights that the DNSP forecasts at the individual capex category show significant levels of variation from the actual 2009 capex. This highlights a concern with the forecasting processes utilised by United Energy and calls into question the veracity of the forecasts for 2010 and the next regulatory control period of 2011 to 2015.

When considered in conjunction with the historical levels of forecasting inaccuracy as described in section 2.2, Nuttall Consulting observes that the processes used by United Energy to forecast expenditure in this category have not produced reliable forecasts.

Nuttall Consulting requested United Energy to provide an explanation of the methodology applied to determine the 2009 and 2010 estimates and to explain the relationship of this methodology to the methodology used to produce the 2011-2015 forecasts[288]. United Energy did not identify any changes or variations between the forecasting methodologies.

This raises a concern relating to the accuracy of the DNSP forecasts for the next control period as the methodologies used to create these forecasts are the same methodologies that have produced the previous inaccurate estimates and forecasts.

To be clear, although the above information provides sound reason to question the accuracy of the DNSP forecasts, Nuttall Consulting has not taken this as proof that the forecasts do not meet the capital expenditure objectives. The Nuttall Consulting review of

[288] Nuttall Consulting request (email) – 18 January 2010.

the forecasts has been undertaken on a case-by-case basis with due consideration of the information provided by the DNSPs.

8.2 Reinforcement

United Energy's revised proposal makes a number of criticisms of the process and findings of Nuttall Consulting's original review of United Energy's reinforcement expenditure.

General criticisms of the process we applied, which are similar between DNSPs, have been discussed in Section 3.1 above. This section deals with matters more specific to our findings on United Energy's reinforcement forecasting methodology and our review of a number of reinforcement projects. Importantly, this section includes revised project probabilities, which will be important for the AER in its considerations of the appropriate reinforcement allowance.

8.2.1 Maximum Demand assumption

United Energy was the only DNSP to use 10 PoE maximum demand conditions for planning its network. Nuttall Consulting considered that this would overstate its energy at risk and adjusted our project probabilities to account for this matter.

In United Energy's revised proposal, United Energy has disagreed with our view. The basis for United Energy's position is:

- its view that, at the time of augmentation, the energy at risk for the 10% PoE condition should not be materially different to the 50% PoE condition
- its view that it has traditionally used this condition; it is consistent with forecasts accepted by ESC/ORG in the previous decisions; and if it was conservative then it could be expected that United Energy would have a lower utilisation than other DNSPs, which is not the case.

Nuttall Consulting does not accept United Energy's views and still considers the use of the 10% PoE will have some affect on project timing. In understanding our position, it is important to appreciate our view in the context of our assessments of the forecast energy at risk for each DNSP and each project reviewed. For all other DNSPs, this assessment is based upon the 50% PoE and the timing when energy at risk justifies the project cost. In this regard, we do not accept that United Energy had adequately justified that the 10% and 50% POE should result in similar energy at risk. Our experience of reviewing projects, particularly those of the Victorian transmission planner, which also undertakes detailed probabilistic planning, is that the 10% PoE case generally produces considerably more energy at risk than the 50% case.

It is important to appreciate that our view only relates to our assessment of the likely project timing and does not relate to the reasonableness of United Energy's use of the 10% PoE in its broader internal planning process. On this point, we note that United Energy states that the 10% condition is used as the trigger for further investigation. As such, it is not clear if it directly defines the project timing as assumed in our assessments. It may be that these further investigations often defer projects, and as such, may be why there appears to be some anomaly between the use of the conservative 10% PoE and the high utilisation of the United Energy network.

Finally with regard to acceptance by ESC, we do not consider that ESC has accepted this in the context of our review. The fact that ESC reduced the allowance from that proposed by United Energy for the current period, would suggest that ESC had some concerns that the United Energy forecasting process did not reflect actual outcomes.

8.2.2 Load profile

In our original report, we considered that United Energy's load profile assumptions, which are based upon the 2007/08 load profile would overstate energy at risk in the next period. This was based upon our analysis of historical load profiles, which indicated that the increasing peakiness of the load profile may result in future energy at risk being overestimated if a historical load profile is assumed.

We note that United Energy does not appear to have changed its profile, and as such, we still consider that this may affect the project timings. However, it is worth noting that the load profile assumptions have only a minor affect on our project probabilities.

8.2.3 Project review updates

The following projects were assessed as part of Nuttall Consulting's review of United Energy's reinforcement expenditure:

1. Templestowe new zone substation
2. Keysborough new zone substation
3. Mentone transformer upgrade
4. MTS-BW-MTS 66 kV line upgrade
5. TBTS-DMA-RBD-STO 66 kV line
6. Distribution substation upgrades.

The following sections discuss our reassessment of these specific projects, based upon United Energy's revised proposal.

It is also important to note that we understand the AER will largely be accepting United Energy's demand forecast. In our original review we had allowed for a reduction in the demand forecast, based upon advice from the AER. In the discussions below and the revised project probabilities, we have not allowed for any reductions from United Energy's demand forecast. This has resulted in increased project probabilities.

8.2.3.1 Templestowe (TSE) Zone Substation Establishment

This project involves the establishment of a new zone substation at Templestowe. This project is driven by load at risk at the exiting Doncaster zone substation.

Based upon our original review, this project was given a low probability (33%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that energy at risk was not sufficient to justify the timing.

United Energy's revised proposal considers that capex funding for this project should be considered 100% required. The main issue raised in United Energy's revised proposal is that energy at risk is sufficient to justify the project.

Nuttall Consulting has considered United Energy's contention in its revised regulatory proposal that the Templestowe Substation project is required in the forthcoming regulatory period. A review was subsequently performed, taking into account additional information provided in Section 6.5.3 of United Energy's Revised Proposal and in the Templestowe Strategic Planning Paper attached to United Energy's Revised Regulatory Proposal.

United Energy contends that the economic timing of its preferred option is the end of 2015 (pg 4). However, it also states the economic timing of this option is the end of 2016 (pg 3). We note that the United Energy capital plan indicates it is planned to be commissioned by the 2014/15 summer i.e. the end 2014. This timing appears to be the basis of its regulatory proposal.

With regard to this project timing, we still have a number of concerns with United Energy's project justification. In particular, we have concerns that energy at risk is not sufficient to justify the timing of the project and the options to address related feeder overload issues have not been adequately explored.

Energy at risk

Table 55 below highlights the savings, benefits and costs of the Templestowe project presented by United Energy in their revised regulatory proposal for summer 2015/16, 2016/17 and summer 2017/18 respectively. The estimated annual cost of the project based on 8.49% costs of capital is also provided in the table.

Table 55 - Benefits and Costs of Templestowe Substation Establishment

	Summer 2015/16	Summer 2016/17	Summer 2017/18
Benefits ($'000)			
Reduction of Energy at Risk at DC and NW	218	240	277
Reduction of Energy at Risk on DC distribution feeders	591	666	746
Total Benefit	809	906	1023
Costs ($'000)			
Total Cost	10,000	10,000	10,000
Estimated Annual Cost	849	849	849

With regard to these results, we note that the benefits of reduction in energy at risk at DC and NW substations have decreased from the initial proposal to the revised proposal. No specific information has been provided by United Energy to explain the decrease but we do, however, note that the overall benefits have ultimately increased through the addition of benefits from the reduction of energy at risk on the distribution feeders supplied by DC as a part of the proposed works, which were not allowed for in the original review.

We accept the inclusion of distribution feeder energy at risk to justify the project timing; however, as indicated above, United Energy's analysis suggests the optimal timing is 2016 – just prior to the summer 2016/17 period.

Furthermore, we have some concerns as to the manner in which the reduction in energy at risk has been determined. In this regard, we note that while United Energy has provided detailed information on its calculation of substation energy at risk reduction benefit it has not provided any detailed information on its calculation of the feeder energy at risk reduction benefit. Although we cannot confirm the significance of this matter with certainty, given the high value of feeder energy at risk, we are concerned that United Energy has assumed that the majority of feeder energy at risk can be avoided. If, for example, a feeder is split in half with half of the feeder transferred to a different substation the energy at risk will be only halved[289] - rather than completely eliminated. It may be that the additional feeder capacity will allow a further reduction via transfers, but this may still result in a significant portion of energy at risk.

Possibly more importantly, it is also important to note that as the new zone substation will address the high utilisation on the HV feeders by splitting the existing feeders then it is likely that reliability benefits will occur due to improvements in reliability. As such, it is likely that at least part of this project would be funded through the reliability incentive scheme.

Options

With regard to the options considered, it is also noted that United Energy has not, as yet, undertaken a detailed net present value (NPV) analysis of the project options. As a result, we are concerned that when a detailed NPV analysis is undertaken it may not be found to be the preferred option from a NPV perspective.

This is based upon our understanding that it is the high utilisation of a select number of HV feeders that is the primary driver of the timing of the project. In this regard, we accept United Energy's argument that DC1, DC2 and DC3 feeders to the north of DC will be heavily utilised (i.e. greater than 100% utilisation) in 2014 and that establishing new feeders from DC to offload the DC1, DC2 and DC3 will be practically difficult because these feeders cross the freeway from DC. However, we note that United Energy states that the establishment of new feeders to the north is only practically difficult and not practically

[289] Assuming that the length of the original and new feeders are half the original length and assuming that number of faults per annum can be correlated to feeder length the number of faults on each feeder will be halved. The load at risk in the event of a feeder outage will also be halved; assuming load is evenly distributed on the original feeder such that physically splitting the original feeder in half will also split the loading in half. Consider that for the two feeders 0.5x0.5x2=0.5.

impossible. We therefore consider it reasonable that given that the only real driver for the project in the forthcoming regulatory period may be the utilisation of these 22 kV feeders, the option of installing new feeders from DC should be considered and the NPV of this option compared to the proposed option. Without United Energy fully investigating this option, it is not clear to us that this option will not be feasible and still the lowest cost option.

Furthermore, given these feeders appear to play such a prominent role in defining the project timing, it may be that short term solution, such as demand management, may be able to be applied to minimise risk associated with these feeders such that the project can be deferred.

Conclusions

Based upon the above, we have revised our project probability from low (33%) to moderate to high (70%)[290]. In addition to the general concerns of historical over-forecasting of reinforcement needs and the use of a 10% PoE in the analysis, this reflects:

- energy at risk can be managed for a further 1-2 years
- an alternative lower cost option may be used to defer the larger project further
- the project will be partly funded through the reliability incentive scheme.

The increase largely reflects the AER's change in its position on the United Energy's maximum demand forecast, but also reflects our reduction on the impact of the 10% PoE conditions and the load profile.

8.2.3.2 Keysborough (KBH) Zone Substation Establishment

This project involves the establishment of a new zone substation at Keysborough. This project is driven by load at risk at the exiting Dandenong South and Nobel Park zone substation.

Based upon our original review, this project was given a moderate to high probability (70%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology and the AER's position on the demand forecast, this probability reflected our views that the scope may be further optimised.

United Energy's revised proposal considers that capex funding for this project should be considered 100% required. The main issues raised in United Energy's revised proposal is that energy at risk is sufficient to justify the project and it has considered all reasonable options.

Nuttall Consulting has considered United Energy's contention in its revised regulatory proposal that the Keysborough Substation project is required in the forthcoming regulatory period. A review was subsequently performed, taking into account additional information provided in Section 6.5.3 of United Energy's Revised Proposal and in the

[290] Probability based upon: 90% (historical accuracy) x 80% (deferral – energy at risk calculations) x 82% (distribution options / reliability incentive funding) x 93% (10% PoE) x 98% (load profile)

Keysborough Strategic Planning Paper attached to United Energy's Revised Regulatory Proposal.

United Energy contends that the energy at risk justifies a substation timing of 2015 and that to achieve this timing work must commence in 2012. However, we note that the United Energy capital plan indicates it is planned to be commissioned by the 2013/14 summer i.e. the end 2013. This timing appears to be the basis of its regulatory proposal.

With regard to this project timing, we still have a number of concerns with United Energy's project justification. In particular, we have concerns that energy at risk is not sufficient to justify the timing of the project.

Table 56 below highlights the 2015/16 and 2016/17 benefits of the Keysborough project presented by United Energy in its revised regulatory proposal. The estimated annual cost of the project based on 8.49% costs of capital is also provided in the tables.

Table 56 - Benefits and Costs of Keysborough Substation Establishment

	Summer 2015/16	Summer 2016/17
Benefits ($'000)		
Reduction of Energy at Risk at DSH	332	419
Reduction of Energy at Risk at NP	146	163
Reduction of Energy at Risk on SVTS-SS-NP-SVTS loop	76	82
Reduction of Energy at Risk on distribution feeders	594	669
Total Benefit (inc. losses)	1,148	1,333
Costs ($'000)		
Total Cost	12,000	12,000
Estimated Annual Cost	1,019	1,091

We note that the benefits of the reduction in energy at risk at DSH and NW substations have decreased and slightly increased respectively from the initial proposal to the revised proposal. No specific information has been provided by United Energy to explain the changes but we do, however, note that the overall benefits have ultimately increased through the addition of benefits from reduction of distribution feeder energy at risk as a part of the proposed works, which were not allowed for in the original review.

We accept the inclusion of distribution feeder energy at risk to justify the project timing; however, as indicated above, United Energy's analysis suggests the optimal timing is 2015 – just prior to the summer 2015/16 period.

Furthermore, as discussed above for Templestowe, we have concerns as to the manner in which the reduction in energy at risk has been determined for feeders, where it is assumed that all energy at risk is removed. In this regard, we consider that United Energy may be overstating the reduction as it is likely that some portion of energy at risk will remain. Therefore, it may be that the project can be deferred further. Moreover, if feeder overloads are the primary driver for the project timing then distribution focused options (e.g. transfers, demand management) may be a suitable short term option to allow the main project to be deferred.

As also noted for Templestowe, as the new zone substation will address the high utilisation on the HV feeders by splitting the existing feeders then it is likely that the reliability benefits will occur due to improvements in reliability. As such, it is likely that at least part of this project would be funded through the reliability incentive scheme.

Conclusions

Based upon the above, we have revised our project probability to moderate (50%)[291]. In addition to the general concerns of historical over-forecasting of reinforcement needs and the use of the 10% PoE in the analysis, this reflects:

- energy at risk can be managed for a further 1 to 2 years
- the project will be partly funded through the reliability incentive scheme.

The revised probability reflects the AER's change in its position on the United Energy's maximum demand forecast and also reflects our reduction on the impact of the 10% PoE conditions and the load profile. However, the increase is due to United Energy's revised information and the point noted above.

8.2.3.3 Mentone (M) Zone Substation Upgrade

This project involves the installation of a 3rd transformer at the existing Mentone substation. This project is driven by load at risk at the exiting Mentone zone substation.

Based upon our original review, this project was given a high probability (90%) of proceeding as proposed.

Nuttall Consulting has considered United Energy's contention in its revised regulatory proposal that the Mentone Transformer Replacement project is required in the forthcoming regulatory period. A review was subsequently performed, taking into account additional information provided in Section 6.5.3 of United Energy's Revised Proposal and in the Mentone Strategic Planning Paper attached to United Energy's Revised Regulatory Proposal.

In keeping with our findings from the original review, the energy at risk calculated by United Energy supports its proposed timing, which is indicated as 2012/13 in United Energy's capital plan.

We do note however that the energy at risk calculation in the forthcoming regulatory period presented by United Energy is highly dependent on an elevated transformer probability of failure due to its view of the relatively poor condition of the existing transformers at Mentone. According to United Energy, the failure rate for the transformers will increase from 1 in 100 years to 1 in 15 years in 2012 and that the

[291] Probability based upon: 90% (historical accuracy) x 80% (deferral – energy at risk calculations) x 82% (distribution options / reliability incentive funding) x 93% (10% PoE) x 98% (load profile)

probability of failure will continue to increase to 1 in 7 years in 2018 at which point United Energy recommends replacement of the existing transformers.

If the more typical probability was applied then it does not appear to us that energy at risk would be sufficient to justify this project in the next period. We have reviewed the condition information associated with these transformers in the strategic plan. While we do not disagree with the condition information, we still consider that United Energy's assumption on the probability of failure used in this energy at risk analysis appears conservative (i.e. overstate risks).

Nonetheless, accepting that the probability of failure may be above typical levels – even if not as onerous as assumed by United energy – we accept that there is a high probability that the risks will be sufficient to justify the project timing.

Conclusions

Although we have noted concerns with United Energy's assumptions in its energy at risk calculations, we have maintained our project probability at high (90%).

8.2.3.4 MTS-BW-MTS 66kV line upgrade

This project involves the conversion of the existing MTS-BW-MTS 22 kV loop to 66 kV. This project is related to the longer term need to upgrade the capacity of the lines. However, the timing is opportunistic, and driven by the plans to replace the three existing 22/11 kV transformers at BW with two 66/11 kV units. The BW upgrade is driven by the condition of the transformers and is included in the RQM category.

Based upon our original review, this project was given a moderate to high probability (70%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology, this probability reflected our views that the replacement of the aged transformers may be deferred.

United Energy's revised proposal considers that capex funding for this project should be considered 100% required. The main issue raised in United Energy's revised proposal is that the asset condition justifies the timing.

Nuttall Consulting has considered United Energy's contention in its revised regulatory proposal that the MTS-BW-MTS 66kV line upgrade project is required in the forthcoming regulatory period. A review was subsequently performed, taking into account additional information provided in Section 6.5.3 of United Energy's Revised Proposal and in the Strategic Planning Paper attached to United Energy's Revised Regulatory Proposal.

As noted above, and discussed in our original report, this project appears to be primarily driven by the condition of the existing transformers at BW. We have reviewed the strategic paper provided by United Energy that discusses the condition of these transformers. Given our views on United Energy's predictions of transformer condition discussed in the RQM section, we only consider that one transformer will be at a condition requiring replacement around the timing of this project. While we accept that the replacements will most likely need to be undertaken together, given that the other two could be delayed, we consider it reasonable to assume that there is some reasonable possibility that the project could be deferred a modest amount (e.g. 1 or 2 years).

Conclusions

Based upon the above, we have maintained our project probability to moderate to high (70%)[292]. In addition to the general concerns of historical over-forecasting of reinforcement needs, this reflects our view that the project may be deferred by 1 to 2 years due to the condition of the aged assets.

8.2.3.5 TBTS-DMA-RBD-STO 66kV Network Reinforcement

The project involves the establishment of a new 66 kV line from Hastings to Rosebud. This project is driven by a number of issues including load at risk due to an outage of a section of the existing line and Code compliance issues associated with an excessive voltage drop.

Based upon our original review, this project was given a moderate to high probability (70%) of proceeding as proposed. In addition to our general concerns on the forecasting methodology, this probability reflected our views that:

- energy at risk was sufficient to justify the timing of the project
- the voltage issue may be able to managed via load shedding
- lower cost alternatives may exist, where we noted a staged upgrade involving an initial 22 kV development.

United Energy’s revised proposal considers that capex funding for this project should be considered 100% required. The main issues raised in United Energy’s revised proposal are:

- the issues and risks are sufficient to justify the timing
- the alternative options we suggested is not sufficient to address the issues.

Nuttall Consulting has considered United Energy’s contention in its revised regulatory proposal that the TBTS-DMA-RBD-STO 66kV Network Reinforcement project is required in the forthcoming regulatory period. A review was subsequently performed, taking into account additional information provided in Section 6.5.3 of United Energy’s Revised Proposal and in the TBTS-DMA-RBD-STO 66kV Network Reinforcement Strategic Planning Paper attached to United Energy’s Revised Regulatory Proposal.

With regard to the risks, United Energy appears to accept the argument that the energy at risk does not fully justify project timing in the forthcoming regulatory period. In this regard, it is noted that United Energy is justifying their project on the basis of voltage profiles (code compliance) and “reputational risk”. We do not consider that we can take a position on reputational risk; we also question whether this could be allowed for under the definition of cost and benefits in the regulatory test. As such, we do not consider that this risk can be a primary factor in driving the project.

[292] Probability based upon: 90% (historical accuracy) x 80% (deferral – condition of assets)

With regard to the voltage issue, it is not clear from the paper whether this could be economically managed for another year or so, possibly via additional reactive support or even an automated load shedding scheme.

With regard to alternative options, we note that United Energy has indicated in its Strategic Planning Paper that should the proposed project be assessed as unacceptable on economic grounds they would be able to install a 66kV feeder, energised at 22kV, from Hastings (HGS) substation to support DMA substation's 22kV feeders in emergency conditions. This alternative is estimated by United Energy to cost approximately $5 million. We note that this is significantly cheaper than the proposed $18 million project and is very similar to the alternative 22kV option noted in our original report (other than that the line from running from HGS to RBD rather than DMA). We also note United Energy's argument that this is a viable risk management option and considers it reasonable that this option could also potentially address the voltage profile issues on the network.

Given this, we consider it is still reasonable to assume that a lower cost option may well be the preferred option following further analysis.

Conclusions

Based upon the above, we have maintained our project probability at moderate to high (70%)[293]. In addition to the general concerns of historical over-forecasting of reinforcement needs and the use of the 10% PoE in the analysis, this reflects:

- energy at risk can be managed for a further 1 to 2 years
- or an alternative lower cost option will be used to defer the main project.

8.2.3.6 Distribution substations

United Energy is forecasting a large increase in the level of distribution transformer augmentations compared to that which had occurred historically. The main reason for the increase was a change from a "reactive" replacement program, mainly associated with a "replace on fail" approach, to a "proactive" replacement program, based upon the replacement of overloaded transformers in order to reduce the failure rates. The need for this change was broadly explained to be due to increasing failure rates and the resulting increases in reliability and safety risks. In this regard, the recent heatwave (2008/09) appears to have resulted in a high number of transformer failures.

Nuttall Consulting's view was that the DNSPs had not demonstrated that the large increase in expenditure could be considered prudent and efficient. The main issue forming this view was the lack of evidence to demonstrate that the transformers can be adequately targeted, such that sufficient benefits would be realized through the reduction in the failure rate.

[293] Probability based upon: 90% (historical accuracy) x 80% (deferral/lower cost alternative) x 93% (10% PoE condition) x 98% (load profile)

The important point here was that determining when a distribution transformer may fail is more problematic than simply knowing how overloaded it is. Furthermore, the DNSP does not meter the maximum demand at individual distribution transformers; it has to estimate the loading at a particular transformer via customer metering data that is associated with transformers.

We also noted that:

- it may be more economic to defer the program until the AMI rollout in order to use the information from these smart meters to more accurately estimate transformer maximum demands and load profiles, and in turn determine empirical relationships between the level of overloading and the probability of failure
- the STIPS may provide some funding for the reliability gains predicted through the change to a proactive program.

The United Energy revised proposal has raised a number of criticisms of our position, and provided a revised strategic plan to support its forecast. The following discusses the main point raised by United Energy.

United Energy considers that Nuttall Consulting's assertion that its load management systems cannot sufficiently identify transformers to be replaced is not valid. It notes that transformers are measured to confirm loading before being replaced, and the field experience confirms that the load management system provides reliable data.

We consider that this largely misses our fundamental concerns with the methodology. Our issue is not so much how accurately the loading of the transformers can be estimated, but how well this estimate helps target the transformers such that the failure rate can be economically reduced. This matter is not dealt with in the United Energy response. We have reviewed the strategic plan and do not consider that it adequately shows that this has been considered in the economic analysis presented in this document. The main concern we have is that United Energy's analysis appears to assume that the planned program is very well targeted and as such if very effective in removing risks. However, the paper provides little evidence to support this view. Given the scale of the expenditure and the significant change, and the opinions we expressed in our original report, we would have expected some form of statistical analysis of historical failures; for example, to attempt to develop probability distribution that models the relationship between the failure probability to factors such as loading (and possibly age) and show the typical consequences. This could then be used to undertake a more robust form of probabilistic economic analysis, in order to determine the optimum scale of a planned replacement program (i.e. the program that will most likely maximise the net benefits). We still have significant concerns that if this form of analysis was undertaken it may not support the proposed program.

On this matter we note that United Energy is proposing to reduce the distribution transformer utilisation to 140% of normal cyclic rating over the next period. This utilisation does not appear too unreasonable and is broadly in line with SP AusNet's criteria. This however has to be considered in the context that many older transformers may have significant design redundancy, and as such, may be able to withstand far higher levels of overloading without risking failure. Furthermore, it is clear that historically United Energy and other Victorian DNSPs have been willing to allow transformers to breach this limit by a significant margin i.e. although the recent heatwave may have resulted in an increased number of failed transformers, information on the extent of overloaded transformers was available beforehand, and a such, these risks appear to have been accepted.

On balance, we do accept that there appears to be evidence that a planned replacement of the most heavily loaded transformers may be required. However, we do not consider that United Energy has adequately addressed our concerns with the scale of this proposed program.

We consider it reasonable to assume that the transformers over 140% of rating may be planned for replacement. However, given current utilisation levels, we also consider it reasonable to assume that this program will occur over a 5 to 10 year period. We consider that this program would result in a risk profile that is more in line with a trending down of currently accepted risks, rather than the step down over a short period that appears to be being proposed by United Energy.

We also consider that further optimisation of the program may occur that may reduce or defer the number of transformer augmentations. This may occur when opportunities arise with other needs, such as the existing supply improvement program or the age related replacement program. They may also arise following further investigations United Energy may undertake prior to the upgrade, which may find that the condition of some transformers is acceptable, or at least, sufficient to optimise the upgrade with other later plans.

It is also worth noting that we consider that the STIPS should also allow for additional expenditure that will improve reliability. We still consider that this should have some relevance to this program as the reliability benefits United Energy has determined appear to be largely due to existing reliability levels, rather than only the incremental levels due to load growth in the next period.

Based upon the above, we consider it reasonable to assume that a probability of 75% can be applied to this program. This assumes that the portion of recurrent expenditure occurs at historical levels (average 2006-2009), but the programmed replacement is reduced by 50%. This reduction is largely based upon our spreading of the program over a longer period, but also allows for the other efficiency and funding points noted above.

Finally, we also note that United Energy has claimed the following:

- As this project has already commenced, the business case has already been approved. Therefore, our view that it should only have a moderate probability of occurring is “totally irrational”.

  In the context of our probabilistic assessment, we do not consider that it would be appropriate to assume that, just because a project has business approval and has commenced in the current period, we should consider the proposed expenditure for the next period to be prudent and efficient. Our probability is set to reflect the most likely funding requirement for only prudent and efficient capex. As discussed above, we do not consider that this has been demonstrated.

- Nuttall Consulting's contention that the 2008/09 heatwave would have identified all overloaded transformers and therefore there is no need for the program to continue is not valid.

  We are not sure where this contention has been made. While we do not disagree with United Energy, in principle, we do not consider that this is particularly relevant to our discussion above.

8.2.3.7 Summary findings

Based upon the above, we have revised our project probabilities as indicated in the Table below.

Table 57 United Energy reinforcement project summary

Project	original probability	revised probability
Templestowe new zone substation	Low (33%)	Moderate (50%)
Keysborough new zone substation	Moderate/High (70%)	Moderate (50%)
Mentone transformer upgrade	High (90%)	High (90%)
MTS-BW-MTS 66 kV line upgrade	Moderate/high (70%)	Moderate/high (70%)
TBTS-DMA-RBD-STO 66 kV line	Moderate/high (70%)	Moderate/high (70%)
Distribution substation upgrades.	Moderate (60%)	Moderate/high (75%)
Weighted average	63%	70%

The project probabilities largely reflect the concerns we raised in our original review:

- energy at risk is insufficient to justify the timing
- part funding through the reliability incentive scheme
- alternative lower cost options
- conservative maximum demand and load profile assumptions
- previous forecasting accuracy.

The increases are largely due to the increased demand forecast and updates or clarification on the DNSPs project justifications.

8.3 Reliability and quality maintained

Our original review considered United Energy's RQM forecast based upon the DNSP's internal activity codes. This break-down was used as it was considered to be the most consistent between the historical and forecast allocation of expenditure. This breakdown largely reflects various asset classes, but is slightly different to the AER's revised RIN asset categories. This review lead to various parts of the forecast being accepted, and others being rejected, with the substitute forecast based upon the calibrated repex model for those asset categories.

United Energy has not agreed with Nuttall Consulting's rejection of a number of categories. For some categories, the revised proposal provided further discussion and information to support these categories and address Nuttall Consulting's concerns expressed in our original report. The additional information includes revised strategic planning papers for specific asset categories. Furthermore, for a number of categories, the proposed volumes have been reviewed by ESV.

The table below list the various categories and indicates where additional information has been reviewed by us and is discussed in the section below. It also indicates where volumes in the category have been reviewed and accepted by the ESV.

Table 58 United Energy RQM category summary

Category	Original finding	DNSP revised proposal
Sub T. comms and protection replacement	Accept	Accepted
Network HV replacement	Accept	Accepted
Services replacement	Accept	Rejected – accepted by the ESV
OH line replacement	Reject	Rejected – accepted by the ESV
Pole replacement	Accept	Rejected – accepted by the ESV
Sub T installation replacement	Reject	Rejected – additional information provided.
UG replacement	Accept	Accepted
Pole top replacement	Reject	Rejected – accepted by the ESV
Performance	Reject	Rejected – additional information provided.

General criticisms of Nuttall Consulting's approach to assessing RQM expenditure and determining substitute allowances, which are similar between DNSPs, are discussed in Section 3.2. For the categories where the ESV has accepted the volumes or made an alternative allowance, we have only considered the unit costs. This review of unit costs is discussed in Appendix G of this report.

This section discusses the specific categories where specific criticisms or new information has been provided in the revised proposal.

8.3.1 Zone substation

The zone substation plant category covers the replacement of power transformers, zones substation switchgear, and associated primary plant.

This category represents 11% of United Energy's RQM forecast for the next period. United Energy has forecast this category to have a very significant increase in expenditure from recent levels.

8.3.1.1 Summary of Nuttall Consulting original review

Nuttall Consulting did not consider that United Energy had adequately demonstrated that its forecast expenditure associated with this RQM category was reasonable (i.e. it could be considered a disaggregated component of the overall prudent and efficient capex[294].

The key matters we raised to support this view were:

- Nuttall Consulting's assessment of the transformer condition information (polymerization estimate results), which we considered did not reasonably justify the number of transformers United Energy was predicting would need to be replaced in the next period[295]
- Nuttall Consulting's views that the United Energy model used to predict the end-of-life of transformers may overstate the forecast deterioration[296]
- a lack of justification and detail of the comparability, management and past and future change of the risks assessed for the CBs[297].

Nuttall Consulting's recommended allowance was based upon the average historical level of expenditure in this category (2006-2008) with an additional component based upon the expenditure annual increase predicted by the calibrated repex model.

It is our understanding that the AER accepted our view in forming its overall capex allowance for United Energy.

8.3.1.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The United Energy revised proposal details a number of criticisms associated with our views. These broadly relate to transformers and CBs.

With regard to transformers, United Energy considers that we were incorrect to conclude that most of the transformers planned for replacement had sufficient remaining life to see them in service beyond the next period[298]. United Energy considers that all transformers

[294] Nuttall Consulting report, pg 167
[295] Ibid, Pg 267
[296] Ibid, Pg 267
[297] Ibid, Pg 267
[298] UED revised proposal, pg 133

have been subject to “extensive testing” to determine that the degree of polymerisation (DP) will be below the industry standard of 200 (which is considered to represent the point at which replacement is required). United Energy also noted advice from UES that supported the replacement of the transformers[299]. United Energy also provided a strategic planning paper to support its transformer replacements[300].

Nuttall Consulting has reviewed the information provided by the United Energy, particularly the strategic planning paper, which includes more detailed discussion of specific transformer test data. Based upon this review, we accept that 4 to 5 transformers have condition data that support the need to replace these in the next period. However, we still note that United Energy appears to plan to replace transformers when the modelled DP is well beyond 200. As such, we still do not consider that United Energy has clearly shown that its models do not “on average” overstate the degradation. Given this view, we still consider that for the remaining four transformers it is far more likely that United Energy will manage the risks and not replace these in the next period. We do accept that our original allowance would not have been sufficient to address the transformers that we have accepted will need to be replaced. This matter will be discussed further at the conclusion to this section.

With regard to the CBs, United Energy’s revised proposal includes a strategic planning paper to address our concerns associated with the transparency of the risk assessments[301]. United Energy also noted that the level of CB replacement was in line with the historical trend.

Nuttall Consulting has reviewed the strategic plan, and we still do not consider that this has adequately addressed our original concerns. There is still limited detail on risks - including (a) how they are quantified (rather than qualitatively discussed), and (b) how they will change over time - in order that we can assess the need for the scale of the proposed plan. We do note that there is some analysis of the reliability impact of a reduction to the proposed plan (i.e. 5.2 minute degradation in SAIDI). We have reviewed the model provided by United Energy to the AER to support the reliability impact, but do not consider that there is sufficient justification of the model inputs to support this position. United Energy would need to provide and justify its reliability models/assumptions to justify that such a significant increase would occur.

It is also important to note that our original and revised allowance includes a substantial increase in expenditure from historical levels for switchgear and other zone substation primary replacements. Therefore, setting aside our revised transformer requirements noted above, we consider that there is not a clear reason why our allowance should not be sufficient to address the CB needs, given United Energy considers these are in line with the trend.

Based upon the above, we still consider that United Energy’s forecast for this category should be rejected.

[299] UED revised proposal, C-22
[300] UED revised proposal, D-28
[301] UED revised proposal, D2-27

Turning now to our recommended allowance, we still consider that our approach of using the repex model is the most appropriate. However, we accept that this needs to be adjusted to reflect:

- the transformers replacements, which we consider are not appropriately accounted for in our original forecast[302]
- 2009 expenditure and volumes, which were not allowed for in our original calibration exercise[303].

Based upon these adjustments, the table below provides our revised estimate for this allowance (estimate exclusive of overheads and escalation). This represents a 88% increase in expenditure over the current period.

Table 59 United Energy zone substation

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed[304]	6.4	6.7	7.3	6.7	5.6
Recommended	**3.7**	**4.0**	**4.3**	**4.6**	**5.0**

8.3.2 Reliability and performance

The reliability category covers a number of programs to address reliability and network performance. United Energy considers that this is only to maintain reliability levels and comply with quality of supply obligations.

This category represents approximately 21% of United Energy's RQM expenditure. This represents over a two-fold increase in annual expenditure in this category from the 2006 to 2009 period.

Significant factors United Energy had raised in support of the need for this expenditure to maintain reliability and performance levels were the degradation in asset performance in the current period and the worsening impact of the environment in the next period due to "climate change".

8.3.2.1 Summary of Nuttall Consulting's original review

Nuttall Consulting rejected United Energy's proposed expenditure on reliability and performance[305]. This rejection was based upon:

- advice from the AER that it did not accept the climate change argument

[302] We have excluded transformer costs from our repex modelling, and have allowed for 5 transformers to be replaced during the next period (at $1.5 million per transformer).
[303] We have assumed approximately 20% of the historical costs was associated with the transformer replacement in the current period, and have removed this from our repex modelling.
[304] This figures should be considered estimates only.
[305] Nuttall Consulting original report, Pg 159 and Pg 163

- a lack of substantive analysis by United Energy that demonstrated the large increase was required to only maintain reliability and performance – rather than improve it. This was particularly relevant given the significant increase in expenditure over historical levels that was being allowed for in our recommendation.

We considered that the allowance should be based upon historical levels with some allowance for the ageing of the network. The repex model was used to determine the aging effect.

8.3.2.2 Nuttall Consulting's discussion of matters raised in DNSP revised proposal

The United Energy revised proposal requests the reinstatement of the reliability expenditure[306] and reasserts the need to address worsening reliability due to the historical degradation of assets, and to comply with quality of supply obligations. It notes two of the most significant programs it is proposing to address these matters:

- HV ABC program to address reliability
- installation of harmonic filters to address quality of supply.

To support this view with regard to reliability, the revised proposal notes that the reliability of its network has been historically degrading at an average rate of 6.5 minutes of SAIDI. Its proposed programs are to address this degradation.

With regard to the quality of supply obligations, it considers that presently 19 zone substation do not comply with harmonic requirement. United Energy is proposing to address the 10 worst performing locations. The revised proposal also notes that harmonic tuning reactors are proposed for 8 capacitor banks.

The revised proposal also provides a number of strategic planning papers to supports it position[307].

Nuttall Consulting has considered the arguments presented by United Energy and the revised strategic papers and still does not consider that it has justified that such a significant increase in this category is required.

In forming this view, we still consider that United Energy has not adequately demonstrated that the large increases in age/condition related RQM expenditure that it is proposing (and expenditure in other categories) will not be sufficient to address the recent degradation of the network due to ageing – or even climate change.

We considered this was the case with our original recommendation, which still allowed for a significant increase over historical levels. Since then, the findings of the ESV review of volumes have allowed for a very large increase over historical levels. These increases are shown in the two figures below[308] – note: these do not include unit cost adjustments due

---

[306] UED revised proposal, pg 135

[307] United Energy revised proposal, Appendices D4, D17 and D20

[308] These charts should be considered as estimates only. It is our understanding that some figures used to produce these chart may have changed due to further discussions between the AER and United Energy. We do not consider that these changes are likely to be material to the our overall views expressed here.

to ESV unit cost review (Appendix G). This shows the trend in overall RQM and the trend in "line" related RQM. These figures show significant increases in expenditure levels from those incurred over the current period. Most notably for the lines categories (poles, pole tops, conductors and cables), this figure is indicating over a two-fold increase.

Figure 32 RQM expenditure increase

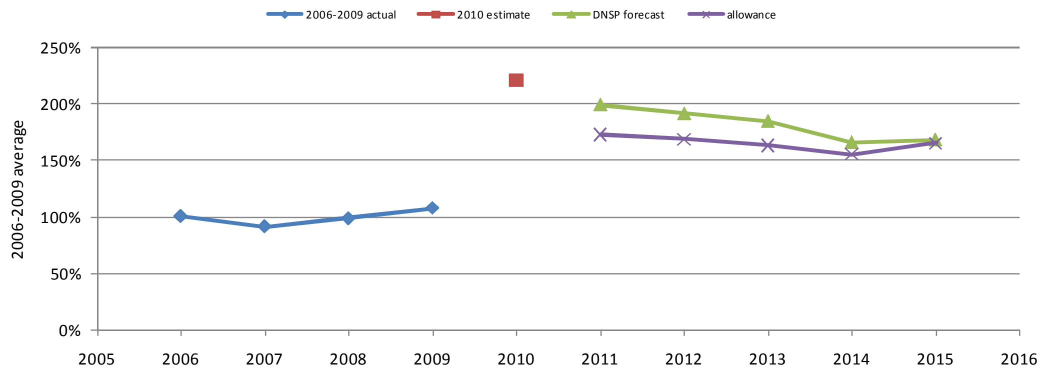
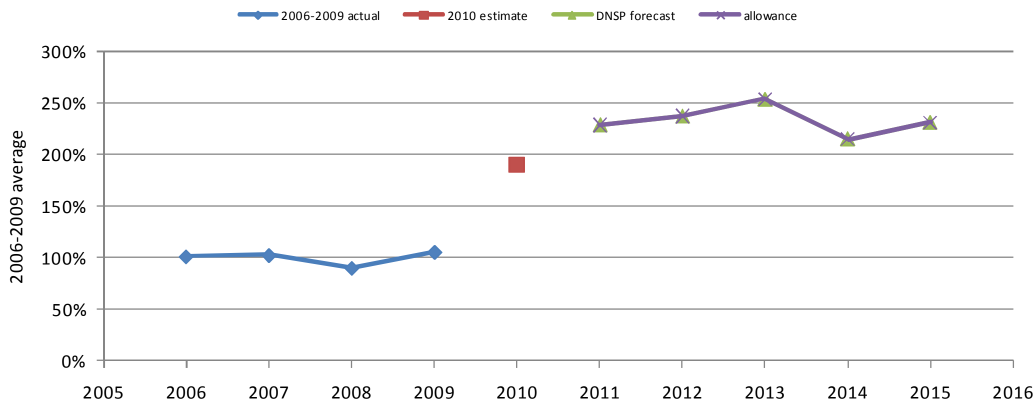


Figure 33 RQM line category (poles, pole tops, conductor, cable) expenditure increase



Given the scale of these increases, we consider that United Energy would need to provide detailed reliability and economic analysis to justify its proposal. We have not been provided with such modelling. On this point, we do not disagree that the programs may realise the benefits discussed in the strategic papers. However, we do not consider that, in light of the above, the analysis in these papers clearly justifies that they need to be funded purely to maintain reliability, rather than funded through the reliability incentive scheme.

With regard to the quality of supply issues, the associated strategic paper does not provide a detailed analysis and discussion that clearly shows how United Energy has identified and profiled its quality of supply projects. Given that it is suggesting that compliance issues presently exist and it is only proposing to address a proportion of these, it seems reasonable to consider that it can manage these risks with expenditure that is in line with the historical trend.

As such, we still maintain that United Energy's proposal should be rejected and the allowance should be set to reflect historical levels of expenditure.

Important note on revised allowance

We note that since our original review, United Energy has revised its expenditure associated with reliability and performance – we understand this is due to a portion being reallocated to ESL.

The table below provides our revised estimate for the reliability and performance category (estimate exclusive of overheads and escalation) allowing for this change. It is worth noting that the use of the repex model for the trend in quality of supply programs is not strictly correct – i.e. they should not be driven by age factors. However, the expenditure growth rate from the repex model is around 8%, which we consider a conservative estimate for other drivers. As such, in the absence of evidence to the contrary, we do not consider that this is unreasonable.

Table 60 United Energy reliability and performance

	$millions (2010)				
	2011	2012	2013	2014	2015
Proposed	11.0	10.1	9.9	8.2	7.7
Recommended	5.6	6.1	6.6	7.1	7.5

8.4 Environmental, Safety and Legal

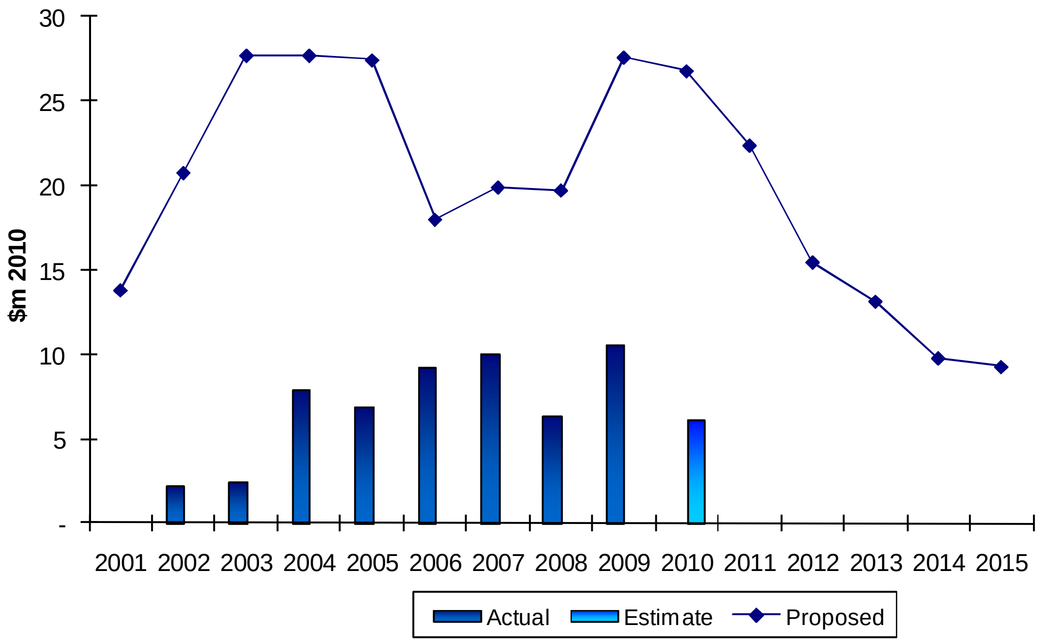
United Energy is proposing an increase of over 55% in Environmental, Safety and Legal capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. United Energy estimates that its Environmental, Safety and Legal capital expenditure for the 2006-10 regulatory control period will be $42.4 million. It is forecasting that this will increase to $70.0 million in the 2011-15 regulatory control period.

For the 2006 EDPR, United Energy proposed Environmental, Safety and Legal expenditure of $112.0 million. The resultant actual expenditure for this period is forecast to be $42.4 million[309].

The following chart provides a summary of Environmental, Safety and Legal capex for United Energy.

[309] Including 2009 and 2010 estimates.

Figure 34 – United Energy Environmental, Safety and Legal capex



The Environmental, Safety and Legal expenditures proposed by United Energy have been reviewed by Energy Safe Victoria (ESV) and recommendations made as to the future volumes of work required. The AER has requested Nuttall Consulting to review the unit costs associated with the ESV recommended volumes. This assessment is provided in Appendix G – Unit cost review of this report.

8.5 SCADA and Network Control

United Energy's proposed expenditure in the "SCADA and Network Control" category represents less than 1% of the total net capex in the next period, and only a very small portion of the proposed expenditure increase (2%).

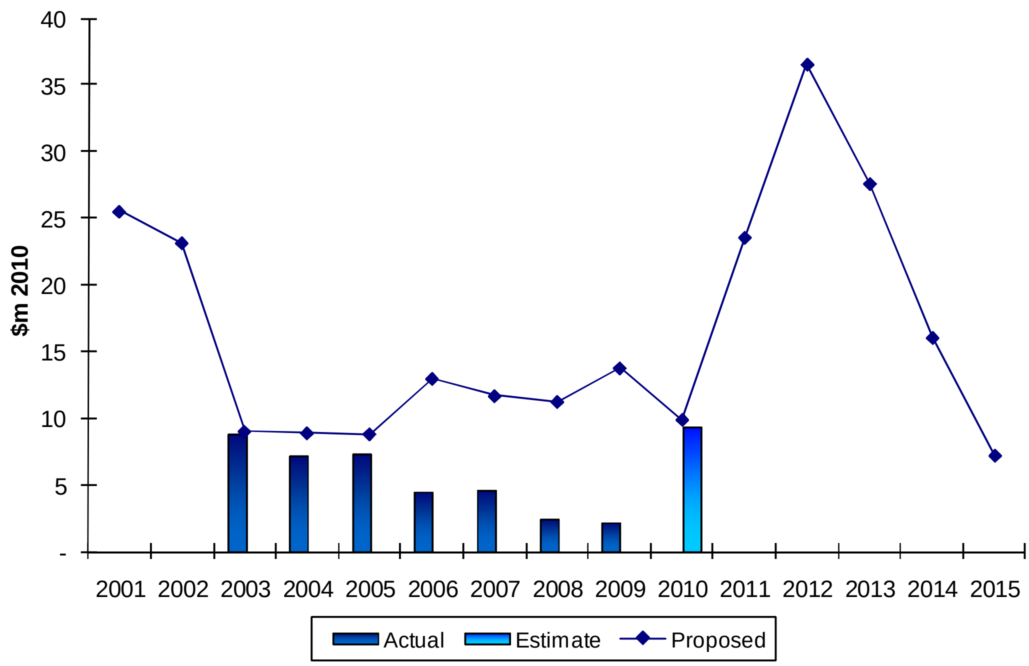
It was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

8.6 Non-network general – IT

In its revised proposal, United Energy submitted forecast IT capital expenditure of $111 million over the forthcoming regulatory control period, which represents an increase of 548% from average expenditures incurred in the current regulatory period. Major proposed IT capital projects include ERP –SAP Consolidation, CIS Migration of Legacy Meters, SCADA Replacement, DMS Upgrade, Identity and Access Management System, Market System Upgrade (CATS/B2B), System Rationalisation and Consolidation, Enterprise

Content Management, Management (CMS) and the fit out of New Production & Disaster Recovery Data Centres.

Figure 35 – United Energy IT capex



During the current regulatory period United Energy underspent their proposed IT capital expenditure of $60 million against an estimated expenditure of $23 million. This includes an estimated expenditure of 9 million in 2010 which is more than double any other year in the current period.

In its November 2009 proposal, United Energy estimated that total IT capex for 2009 would be $6 million. The actual expenditure for this period was only $2 million. This represents a forecasting error of 183% and is considered significant given that most of the year was complete when the forecast was made.

Nuttall Consulting considers that the historical inaccuracy in forecasting and the 2009 estimation errors represent a systemic error in the United Energy forecasting processes.

United Energy currently has four data centres, two of which are recent additions funded under AMI. The long term plan is to consolidate into 2 data centres and United Energy have submitted capital costs to complete as part of their submission.

In our original report Nuttall Consulting rejected the IT capital program for United Energy and substituted a new IT Capital Allowance based upon audited historical expenditure. As a result, United Energy has provided a revised proposal in response to the AEC's Draft Determination.

United Energy states that its approach to its IT strategy is "structured" and intended to "takes into account inputs from the business, the state of the current IT environment and emerging IT trends to develop an IT roadmap that delivers the necessary IT systems to support the business objectives."[310] United Energy has reassessed its ability to implement its IT Strategy, the accuracy of cost estimates and the mix of capex/opex. United Energy accepts that the program is "large in comparison to previous years and presents a delivery challenge for United Energy over the next 5 years." As a result, United Energy believes it still has the capability to deliver "the program in full". In addition United Energy stated that the failure to complete capital projects will result in United Energy failing to achieve efficiency savings in Opex. United Energy is also undertaking a business transformation program to deliver a new business model aimed at providing a better value, sustainable proposition to its customers. The new business model is intended to take effect from July 2011.

United Energy has continued to refine cost estimates associated with key projects such as the GIS upgrade, DMS upgrade and CIS Type 1-4 consolidation. Nuttall Consulting has considered the revised forecasts.

In their response to the Draft Determination, United Energy has stated that the AER cannot simply dismiss the IT program on the basis that Nuttall Consulting believes the program is large and therefore there is a possibility that 40 per cent of the program can be deferred. Nuttall Consulting has formed its opinion based upon the review of all of the submitted information and the audited expenditure of the DNSP during the previous regulatory period. To be clear, Nuttall Consulting has not formed its opinion based on a perception of a "large" IT program.

In their response to the Draft Determination, United Energy has stated that Accenture have been recently engaged by United Energy to assist with the large ERP – SAP consolidation project and as a result, the project has been divided into three phases. Based upon our review of the submitted information, Nuttall Consulting believes that the discussion to split the project into three phases, mitigates some of the risks that are due to the lack of agility in the IT environment.

In their response to the Draft Determination, United Energy has stated that the AER's approach to revising forecast fails to recognise important strategic projects in the final two years that must be completed in order to achieve the efficiency savings identified in United Energy's opex forecast. Nuttall Consulting makes no recommendation as to which individual project United Energy should complete. Nuttall Consulting's recommendation is based on an overall level of prudent and efficient capex, and each DNSP remains able to undertaken the programs that it considers best meets the business' need.

In their response to the Draft Determination, United Energy has stated that it believes the position presented by the AER and Nuttall Consulting is incorrect and does not accurately portray information that United Energy provided during the process and has failed to understand the future IT strategy. Nuttall Consulting has reviewed all the information provided including the IT strategy.

United Energy's revised submission detailed a number of guiding principles to direct IT investment decisions. Nuttall Consulting believes most of these are reasonable principles,

[310] United Energy Revised Regulatory Proposal 6.10.3 p146-147

including a preference for use of COTS (Commercial Off the Shelf Software), Outsource commodity / Insource strategic, Open not proprietary standards and Mature products over 'bleeding' edge. However Nuttall Consulting considers that United Energy has been too conservative in the adoption of virtualisation and consolidation of its IT environment. Nuttall Consulting believes that based upon a review of the material provided, United Energy could have a more agile IT environment. Adoption of the approaches above may have permitted to either defer data centre relocations/expansions or permit relocation to much more compact environments.

In 6.10.10.2 of the revised submission, United Energy states that cloud computing "provides organisations with access to almost limitless IT computing power and capability". Nuttall Consulting believes that this statement shows that United Energy does not have a thorough understanding of cloud computing. The move towards agile pools of compute and storage, allows better utilisation of available resources and the ability to plan to provide additional capacities at a lower cost, but certainly does not provide limitless computing resources.

In their response to the Draft Determination, United Energy stated that it has an Agile Application Architecture, because it has Service Oriented Architecture (SOA) and the N-Tier so that the presentation, application processing and data management processes are separated from each other. Nuttall Consulting makes no comment on the application architecture, but only on the underlying supporting infrastructure.

In its revised proposal, United Energy agrees with the AER that IT architecture should be flexible and agile. United Energy also considered that the view presented in the AER's draft decision does not take into account the significant level of change that the AMI mandate brought to Victorian distributors. Nuttall Consulting reviewed all the material provided by United Energy and believes that whilst the AMI project significantly increases data flows and storage requirements, that these impacts are over-stated.

In their response to the Draft Determination, United Energy stated that it is unrealistic of the AER to expect United Energy to be able to anticipate and therefore cost the implementation of new applications for requirements that were undefined before the completion of the last EDPR process and that it is unrealistic of the AER to expect United Energy to build an IT environment in the future that is able to completely adapt and absorb major industry changes such as AMI. To be clear, Nuttall Consulting is not making any ex-post expenditure recommendations and the cost recovery processes for AMI are provided via a completely separate exercise to this review. Consistent with the arguments in the original Nuttall Consulting report, and following the review of the revised information provided by United Energy, Nuttall Consulting believes that United Energy should have an agile IT environment, that is better able to adjust to challenges of the future.

United Energy's forecasts of IT capex have proven to be highly inaccurate. United Energy has identified the AMI project as contributing to changes to the IT capex program in the current period. Nuttall Consulting notes that this does not explain all of the underspend in the current period or in the previous regulatory period. AMI's requirements were well understood when the 2009 estimate was made and were therefore not a factor in the 183% forecasting error for this year.

Nuttall Consulting notes that there have historically been a number of factors that have contributed to the delay or deferral of IT projects and accepts that the deferral causes identified by the DNSPs may reasonably have contributed to actual expenditure being less than was originally proposed. This supports the Nuttall Consulting view that the forecasting processes do not adequately recognise or account for external and internal project delay mechanisms that may impact the ability to deliver the forecast IT capex amounts.

United Energy has provided no evidence to suggest that the historical IT expenditures resulted in an imprudent outcome. As there is no discernible evidence of failure to invest adequately and/or adverse consequences we must assume that the resultant levels of expenditure were prudent.

Looking at the forecast IT capital expenditure proposed by United Energy for the next regulatory control period we see that it is significantly greater than the level of capital expenditure that has actually been incurred in the previous 9 years .

When we consider the IT capex that was forecast for the current Regulatory Control Period we can also see that the overall United Energy forecast for the current period is much higher than the actual level of expenditure.

Nuttall Consulting considers that this is a systemic problem with the capex forecasting process and that the United Energy forecasting processes fail to consider the delays and deferrals that occur from internal and external factors.

Capital projects, particularly IT projects, are often complex and require many interactions with third parties. These interactions can include other related projects, resources providers and contractors, hardware and software vendors, system wide impacts, etc. While it is not always possible to identify which of these interactions may result in a delay to a project, it is good practice to make a reasonable allowance for these delays.

Nuttall Consulting considers that recognition of the potential impacts of project delays in forecasting and planning is good electricity industry practice. A commonly accepted definition of good electricity industry practice is the exercise of that degree of skill, diligence, prudence and foresight reasonably to be expected of a distribution business working under the prevailing conditions consistent with applicable regulatory, service, safety and environmental objectives.

United Energy was requested by the AER to provide details where the policies, strategies and procedures provided to support their submission have changed during the current regulatory period and the effects of these changes. United Energy did not identify any changes to the policies, procedures or strategies for expenditure forecasting. On this basis, we must assume that the forecasting processes and procedures utilised by United Energy has not changed and that allowances for delays in capital projects have not been adequately accounted for.

Based on the above considerations, Nuttall Consulting recommends that the forecast expenditure for the next regulatory period should be $66 million. This represents a 289% increase on current levels of IT capex.

Table 61 – United Energy recommended non-network general IT capex

United Energy	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
Proposed Expenditure	23.5	36.5	27.6	16.0	7.2
Recommended Expenditure	13.3	13.3	13.3	13.3	13.3

8.7 Non-network general other

United Energy's proposed expenditure in the "non-network general – other" category represents only a small percentage of the total net capex in the next period, and only 1% of the proposed expenditure increase.

It was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

9 Appendix F – Opex Step Changes

This appendix addresses specific areas of review that Nuttall Consulting has been requested to undertake by the AER. The review items in this section relate to step changes in operating expenditure proposed by the DNSPs for the next regulatory control period.

Where a step change has been identified by more than one DNSP, the step change is reviewed for all DNSPs. Individual opex step change requests are considered for each DNSP.

Step changes relating to changed safety and line clearance regulations, the 2009 Bushfires and the Bushfire Royal Commission report are discussed in Appendix G – Unit cost review.

9.1 CitiPower

9.1.1 West Melbourne Demand Management

Nuttall Consulting rejected CitiPower's costs for the proposed demand management project to relieve an emerging constraint at the West Melbourne Terminal Station. Although we accepted that an emerging constraint most likely would exist and that a demand management option may be the best approach to manage this, we did not consider that CitiPower had provided sufficient information to justify that the additional funds were necessary.

Our main concerns with CitiPower's proposal were:

- the limited justification for the demand management costs, which were only sourced from one demand management supplier
- the lack of analysis of alternate options (as identified in the Transmission Connection Planning Report)
- a significant discrepancy between the proposed demand reduction and the forecast load at risk, including the fact that demand management had not been contracted for the expected load at risk of 10MVA for 2009/10.

CitiPower has raised a number of criticisms of our view and provided further commentary on the concerns we raised[311].

With regard to the costs, we note that only Energy Response has provided a cost estimate. Given the limited market, and the role Energy Response play as an aggregator of smaller demand management proponents, we consider it reasonable to use these costs as the best estimate at this time.

[311] CitiPower revised proposal, pg 198

With regard to the alternative options, CitiPower has provided more discussion on these matters. Based upon this information, we are satisfied that it is unlikely that a complete alternative to the demand management option will be found to be the most prudent and efficient option. However, as discussed further below, we consider a combination of options, involving some demand management and other measures, may still be the preferred solution.

Finally, and most importantly, with regard to the discrepancy in the load at risk, CitiPower has provided further information to reconcile the load at risk and demand management forecast. This information indicates its estimate of the short fall between the load at risk and the level demand management available. This shortfall is zero up to 2010/11, rising to 32 MVA by 2012/13. However, CitiPower also states that it will manage this shortfall via other contingency actions, the majority of which it indicates will be managed by distribution load transfers.

Given this view, it is not clear to us why it would not be more efficient to make use of at least some of this transfer capacity to offset the need for the level of demand management proposed. We accept that it could be considered this would expose the network to greater energy at risk. However, in CitiPower's discussion on contingency options, it indicates that the distribution transfers will "*reduce or even nullify any network exposure*"[312] to energy at risk.

Therefore, in the absence of information to the contrary, we consider it reasonable to assume that 20 MVA of the distribution transfers may be found to be a more efficient option than the equivalent amount of the demand management – this represents 2/3 of the shortfall in 2012/13.

Based upon this and CitiPower's cost model, we have estimated the demand management cost to be as indicated in the table below.

Table 62 CitiPower WMTS demand management recommendation

	2011	2012	2013	Total
Demand management	0 MVA	13 MVA	25 MVA	
Cost ($'000)	**$176.8**	**$1,888.7**	**$2,677.5**	**$4,743.0**

9.2 Jemena

Jemena engaged UMS (the UMS Group) to benchmark Jemena's historic and forecast operating expenditure against comparable network utilities and provide an opinion on the efficiency of Jemena's operating expenditure by comparative reference to Jemena's network peers.

[312] CitiPower revised proposal, pg 200

UMS analysed Jemena's historical, base year and forecast operating expenditure using a number of methods. The costs analysed were inclusive of the commercial margin paid by Jemena to JAM. UMS used both publicly available information and proprietary UMS databases to benchmark Jemena's opex costs using a range of key indicators.

The UMS report concluded that: "*Based on our benchmarking of Jemena Electricity Networks' (JEN) historic, base and forecast operating expenditure (Opex), we believe that JEN's spend levels are efficient based upon better than industry average performance along a wide array of key performance and benchmark indicators*."[313]

The UMS report is relatively consistent with analysis undertaken by the AER with respect to the current levels of operating expenditure for Jemena. The rationale for the use of trendlines and "predicted" opex is not clearly explained in the UMS report. However, the general position of Jemena relative to its industry peers is consistent with the results of the AER analysis.

On this basis, it is reasonable to conclude that the current levels of opex incurred by Jemena are relatively efficient.

The UMS report has also sought to assess the relative efficiency of Jemena's forecast opex. The assessment of forecast expenditures is problematic and the certainty that can be obtained from this sort of assessment is questionable. The following issues are noted in the comparative assessment of forecast capex:

- The assessment utilises opex allowances for each of the DNSPs in NSW, Queensland, South Australia and the ACT. As we have seen historically, these allowances are often significantly different from actual expenditures incurred by the DNSPs. The DNSPs are under no obligation to constrain themselves to these allowances.
- The assessment does not consider the impact of changing regulations on forecast expenditures for each of the jurisdictions.
- The report identifies that variances in the data have been identified and that the data has been normalised[314]. The means by which the data has been adjusted or normalised is not evident from the report. On this basis, it is not possible to assess the impact of the normalisation or the appropriateness of the data manipulation.
- The forecast assessment undertaken by UMS only utilises two of the three measures used for opex in the other sections of the report. The omission of opex per km of network (length) is not explained. On this basis it is not clear if this measure was omitted in error, or deliberately.
- The report focussed on opex only, and therefore does not allow for consideration of the capex-opex tradeoff. That is, analysis of the trade-offs between operating and capital expenditure are not able to be assessed.

[313] UMS, Jemena Electricity Networks (JEN) – Victoria AUS, Operating Expenditure Efficiency Review, 15 July 2010, p. 4 (Appendix 6.11).
[314] Ibid P11.

- Forecast performance levels are not considered in the assessment of the forecast opex. This means that it is not possible to determine from the UMS benchmarks whether the relative expenditures are comparable in terms of changing levels of service and performance.

On the basis of the above, Nuttall Consulting considers that it is not possible to conclude that the opex that is forecast by Jemena is efficient.

9.2.1 IT Opex

The AER has requested Nuttall Consulting to address a number of specific items relating to operating expenditure step changes. The Jemena opex step changes being assessed by Nuttall Consulting are as follows:

- the introduction of new systems dealing with emergency, risk and safety management
- the increased support of current systems including the SAS tool, the BRIO tool and an asset defects database
- new data centre facilities.

9.2.1.1 Introduction of new systems

In its original regulatory proposal, Jemena proposed an opex step change for the introduction of a new IT system to deal with emergency, risk and safety management. The step change was based on increasing IT staff levels "required to maintain and support the provision of the relevant information to customers"[315].

Nuttall Consulting was unable to recommend that the step change associated with the emergency, risk and safety management system be accepted, on the basis that the system step change was consistent with the number of extreme events forecast by AECOM, and the AER had not accepted AECOM climate change modelling as part of its draft decision.

In its revised proposal, Jemena accepts the AER's decision on climate change[316]. The AER decision was based, in part, on the projection that the number of extreme weather events is not likely to be greater in 2015 than in 2009. Jemena argues that the step change is in part driven by a permanent increase in the number of extreme weather events.

Jemena is proposing to introduce this new system to improve its emergency response management. Jemena state that their awareness of this need became more acute following the April 2008 storm events and 2009 heatwave. As this is a new system, Jemena considers that the proposed costs are not already included in the base year.

The Jemena revised proposal also refers to "state government recommendations to improve the use of technology for emergency response and management capabilities"[317].

[315] Appendix 7.2 JEN Step changes—20 July 2010, Page 65
[316] Ibid.
[317] Appendix 7.2 JEN Step changes—20 July 2010, page 66.

Jemena also considers that customers will benefit from Jemena's improved emergency response management, as reliability and safety of supply will be improved. Jemena also considers that opex objectives (1), (3) and (4) will be met by this step change.

With respect to the "state government recommendations" identified above, Jemena has not provided any link or reference to these. In addition, Jemena has specifically omitted reference to opex objective 2[318] when describing the relationship of the step change to the opex objectives. On this basis, it is reasonable to assume that the step change is not required to meet a new or changed obligation or regulation.

Opex objectives 3 and 4 specifically deal with maintaining the services and the network themselves. As Jemena appears to accept that the "number of extreme weather events is not likely to be greater in 2015 than in 2009"[319], then current expenditures already reflect the manner in which Jemena has responded to this matter in the past. Therefore, the step change expenditure does not satisfy items 3 and 4 of the opex objectives.

Jemena does identify that reliability and safety of supply will be improved through this additional opex. This would appear to specifically relate the opex step change to opex objective 1 – "meet or manage the expected demand for standard control services over the relevant regulatory control period". In assessing Jemena's proposed step change against this criteria, there are two issues:

1 the Jemena revised proposal does not provide any quantification of the proposed benefit or improvement that will be provided to customers

2 the revised proposal does not identify any customer demand for this improved service.

While it could be argued that expenditure associated with safety and health should be prioritised above other expenditures, the lack of a clear need and the absence of any quantification of benefits makes it difficult to see how the proposed expenditures could be considered either prudent or efficient. Nuttall Consulting considers that this proposed expenditure does not meet any of the opex objectives.

Table 63 - Recommended Jemena IT opex step changes ($000s)

Introduction of new systems	2011	2012	2013	2014	2015	Total
IT opex step changes	0	0	0	0	0	0

9.2.1.2 Increased support of current systems

In its original regulatory proposal, Jemena proposed step changes associated with:

- replacement of its unsupported SAS system
- replacement of its unsupported BRIO Query Replacement system

[318] comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.
[319] Appendix 7.2 JEN Step changes—20 July 2010, page 65.

- implementation of support for its asset defects database.

In the Draft Determination, the AER stated that Jemena had not demonstrated to the AER's satisfaction that these costs represent an increase to the replacement of existing systems or support costs, and that Jemena had not quantified the benefits from this step change.

In its revised proposal[320], Jemena states that there are currently no costs associated with maintaining the following systems, as they have no support or maintenance agreements, and Jemena is not able to provide IT support for them internally.

- SAS, which is a financial management and decision support tool that also generates accruals for accounting. The system vendor no longer offers a maintenance agreement due to the age of the software. As such, in recent years, there have been no support costs at all. Jemena proposes to replace the product and put a vendor maintenance agreement in place.
- BRIO query tool, which is a business intelligence and reporting tool which has been discontinued by the vendor. Therefore, there is no current maintenance agreement or support, and no current in-house support. As such, there are no current support costs.
- The Assets Defects Data Base, the current version of which is a software application that has been developed in-house and has no current IT support. As demand for this software increases (due to the permanent increase in extreme weather conditions), the software will be replaced by a new market product, or enhanced to become a product supported by EB Services.

Jemena argues that as it replaces these systems, the costs associated with securing maintenance of these systems will necessarily represent an increase in costs.

The information provided by Jemena in its revised proposal does not provide any new or additional quantification for the proposed step change expenditures. However, as this item is being resubmitted by Jemena, Nuttall Consulting has reviewed the proposed expenditure information. In reviewing our original position, we note that Jemena is arguing that there are no support costs for the "unsupported" SAS, BRIO and defect management systems, but that there are substantial costs for other older systems:

- SAP - *The system is over 12 years old and is on extended support which is costly – there are approximately 200 patches which have not been implemented on SAP 4.6c. The SAP 4.6c system is not aligned with the business and many workarounds are executed by staff (e.g. to support finance and works management). In addition there are business initiatives and operational changes which are impeded by the current system. These include compliance to legislation, business process reengineering initiatives, configuration of new industrial relations and enterprise agreements (including safety*

[320] Appendix 7.2 JEN Step changes—20 July 2010, page 67.

and privacy regulations), and configuration of the complex JEN organisational structure accurately.[321]

- SAS tool – *in recent years, there have been no support costs at all*[322]
- BRIO tool - *there is no current maintenance agreement or support, and no current in-house support. As such, there are no current support costs*[323]
- Assets Defects Data Base - *the current version of which is a software application that has been developed in-house and has no current IT support*[324].

The above points highlight the difference between direct support costs and the overall costs of unsupported or aging systems. Jemena has highlighted the costs to the business of an out-of-date SAP system to include security costs/risks, work-arounds, impediments to other business processes, etc. While there remains extended support for SAP 4.6c, the additional costs of the out of date system are not immaterial.

This contrasts with the Jemena position of "no support costs" for the older SAS, BRIO and defect management systems. While there may be no direct support costs for these systems, Jemena has not identified the associated security costs/risks, work-arounds, and impediments to other business processes that would result from these unsupported systems.

With reference to the above discussion and the original considerations in the Nuttall Consulting report for the draft determination[325] the Jemena proposed step change costs associated with the SAS, BRIO and defect management systems do not represent a prudent and efficient forecast. The following section considers what alternate amount should be substituted in place of that proposed by Jemena.

Nuttall Consulting considers that the information put forward by Jemena is factually correct for the three systems that have been identified, but that the focus on the three systems without reference to the overall IT environment is misleading.

DNSPs are large and complex businesses - the IT environments of the DNSPs are equally large and complex. IT assets, like poles and wires, have a typical lifecycle with operating and capital expenditures varying depending on the asset and its age (among other things).

The Jemena IT Strategy & Asset Management Plan 2011[326] identified 24 functions and applications that are part of the IT environment. The SAS and BRIO tools and defects database discussed above are each a part of these 24 functions and applications. Of the hundreds of systems and tools that form part of the IT environments, there will be systems and tools at all stages of the IT asset lifecycle.

[321] Jemena Electricity Networks (Vic) Ltd Regulatory Proposal 2011-15, Appendix 9.2, JEN IT Strategy Asset Management Plan 2011-15, 30 November 2009.
[322] Appendix 7.2 JEN Step changes—20 July 2010
[323] ibid
[324] ibid
[325] Nuttall Consulting, Victorian Electricity Distribution Revenue Review, May 2010.
[326] Appendix 9.2 - JEN IT Strategy & Asset Management Plan 2011 - CONFIDENTIAL.pdf

To separate and identify only the systems and tools that are moving from low or no-cost support to a higher level of support would be biased. A balanced approach would require consideration of all systems and their changing level of support. In a large and complex IT environment, there are also likely to be systems that are moving from a high-cost support level to a low or no-cost support level. With no evidence to contrary, it is not reasonable to assume that overall IT support costs should be changing.

Nuttall Consulting does not recommend the proposed step change costs for the SAS and BRIO tools and defects database.

Table 64 - Recommended Jemena IT opex step changes ($000s)

Increased support of current systems	2011	2012	2013	2014	2015	Total
IT opex step changes	0	0	0	0	0	0

9.2.1.3 New data centre facilities

It its original submission Jemena proposed the replacement of the current data centres due to the existing facilities reaching capacity, with no scope to further expand that capacity. Jemena considered that it must find new facilities and had been given notice to do so by the owner of the production data centre facility.

Proposed data centre facility projects included:

- Production DC - Facility Costs
- Production DC - Racks Costs
- Disaster Recover DC
- Disaster Recovery DC - Racks Costs

Jemena provided indicative costs for the new data centre facilities. These costs were reviewed by Nuttall Consulting and recommended for recovery. Jemena now has data on its actual expenditure for 2009 and has therefore revised its forecast opex in respect of the two production data centre step changes.

The production data centre has been operating since 1 July 2009 (and the relevant opex is therefore accounted for in Jemena's base year opex).

Jemena has also been able to determine more precisely the commencement date for operation of the disaster recovery centre, which is six months later than originally advised (1 July 2011). Nuttall Consulting has reviewed the revised proposal costs and notes that the revised forecasts and substantially less than those originally proposed and less than previously recommended by Nuttall Consulting.

Nuttall Consulting recommends the additional step change costs as proposed in the Jemena revised proposal.

Table 65 - Recommended Jemena IT opex step changes ($000s)

New data facilities	2011	2012	2013	2014	2015
Disaster Recovery Data Centre	160.0	193.9	217.0	240.1	263.2
Disaster Recovery Data Centre - Racks Costs	254.0	577.2	669.5	761.9	854.2

9.2.2 Additional maintenance arising from capex step changes

In its original submission, Jemena proposed a number of additional operating expenditure areas that it considered would require addition expenditure to achieve a "capex/opex" balance. The AER rejected all of these step changes, noting that the proposal was driven by economic benefits, rather than a new or changed regulatory obligation, or a change in Jemena's operating environment. The proposed step changes are:

- ZS pot VT/CT testing
- ZA transformer dryouts (Trojan)
- DP testing
- ZS transformer condition testing
- ZS power quality metering maintenance
- ZS secondary spares maintenance
- Cable testing.

In its revised proposal Jemena stated that it considers that these step changes are linked to a change in the operating environment. Jemena considers that the proposed expenditures reasonably reflect the opex criteria (particularly having regard to opex factor (7)).

The AER's approach as identified in the draft determination[327] was to allow step changes only where triggered by a changed regulatory obligation or a change in Jemena's operating environment.

The application of either of these narrow definitions clearly conflicts with the NER, which states that, if the AER is satisfied that forecast opex reasonably reflects the opex criteria, the AER must accept the forecast. Jemena considers that this definition is unduly limiting and has adopted a 'step change' definition to describe all changes relative to current costs and scope (except for input cost and growth escalation).

Nuttall Consulting considers that the issue of a definition for step changes and interpretations of the rules is best addressed by the AER. The following review of the proposed Jemena expenditure to achieve capex / opex balance is undertaken with specific reference to the opex objectives, criteria and factors.

[327] Draft decision, Victorian electricity distribution network service providers, Distribution determination 2011–2015, June 2010, Page 257.

As discussed in the previous Nuttall Consulting report[328], we do not consider that Jemena has provided adequate information to support the proposed increases associated with the PQ meter maintenance and spares maintenance programs.

With regard to the other programs, we considered that the maintenance practices were reasonably well defined. In this regard, it may well be prudent to implement these practices in the next period. Jemena's views on the need for these practices are not driven from changes to regulatory obligations, but from its views on the economic benefits – the relevant section in the Jemena revised proposal is titled "*Expenditure to achieve capex / opex balance*". It is clear from the information provided by Jemena that the proposed additional opex should realise net benefits through avoided capex and reduced risks. The previous Nuttall Consulting report identified that Jemena had not provided economic analysis that clearly justified the scale and timing of the proposed increases.

In response, Jemena has identified that aging assets are a significant factor in driving the proposed opex increases. Jemena identified that:

- approximately 61% of zone substation transformers are over 40 years old
- approximately 30% of zone substation transformers are over 50 years old
- approximately 54% of zone substation circuit breakers are over 40 years old.

Jemena states that as this plant ages, increased maintenance becomes necessary and that Jemena is no longer operating in an environment where its primary plant is new, but in an environment where primary plant is ageing.

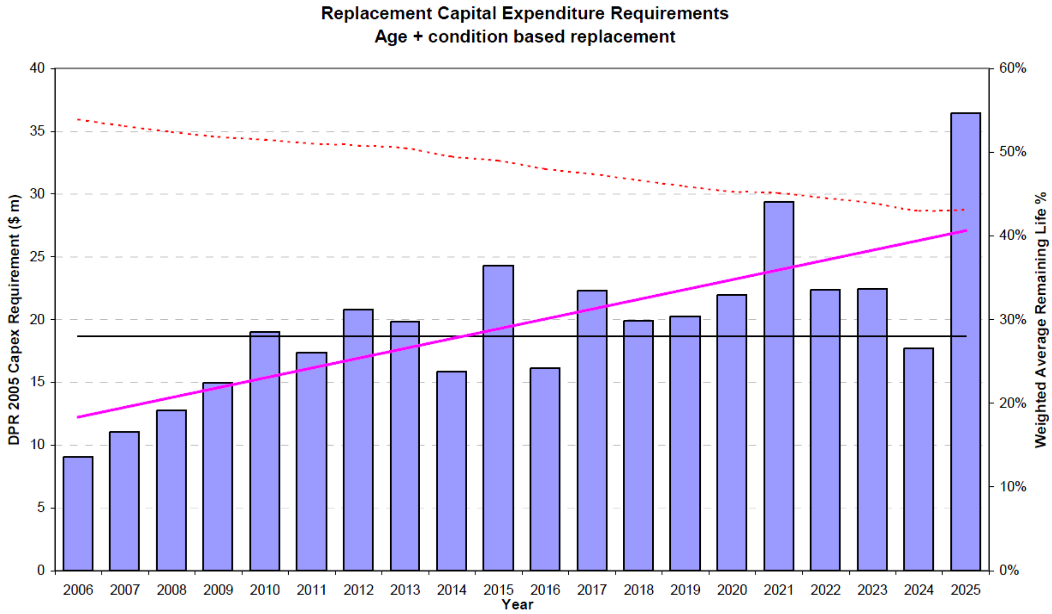
Nuttall Consulting agrees that the electricity networks are generally aging. This effect has been noted and commented on for many years. The following are excerpts from previous EDPR submissions for the Jemena franchise area:

- 1999 - Asset Replacement expenditure increases over time due to the aging of the network. This is a trend that is already evident and continues beyond the period 2001 to 2005.[329]
- 1999 - The PB Power model of non-load related capital expenditure forecasts that, due to the aging of assets, there is a requirement for increased capital expenditure to replace assets both during the period 2001 to 2005 and beyond
- 2000 - AGLE has an aging asset base, and although AGLE will be replacing assets as they come to the end of their lives and installing new assets to meet growth, the average age of the assets is increasing over the period[330]
- 2004 - The PB Associates model of non-load related capital expenditure forecasts that, due to the aging of assets, there is a requirement for increased capital expenditure during the 2006 to 2010 period and beyond.[331]

[328] Nuttall Consulting Report – Capital Expenditure, Victorian Electricity Distribution Revenue Review, 26 May 2010, page 352.
[329] 2001 Electricity Distribution Pricing Review Submission By AGL Electricity Limited, December 1999
[330] 2001 Electricity Distribution Price Review Supplementary Submission By AGL Electricity Limited, April 2000.

In the 2004 submission, AGLE, the then owners of the Jemena franchise area, highlighted aging assets as a significant contributor to a requirement for increased capex[332]. The following chart highlights the proposed capex increases and the aging assets. The proposed capex increase is highlighted in blue and the aging assets via the "Weighted Average Remaining Life (WARL) in dotted red.

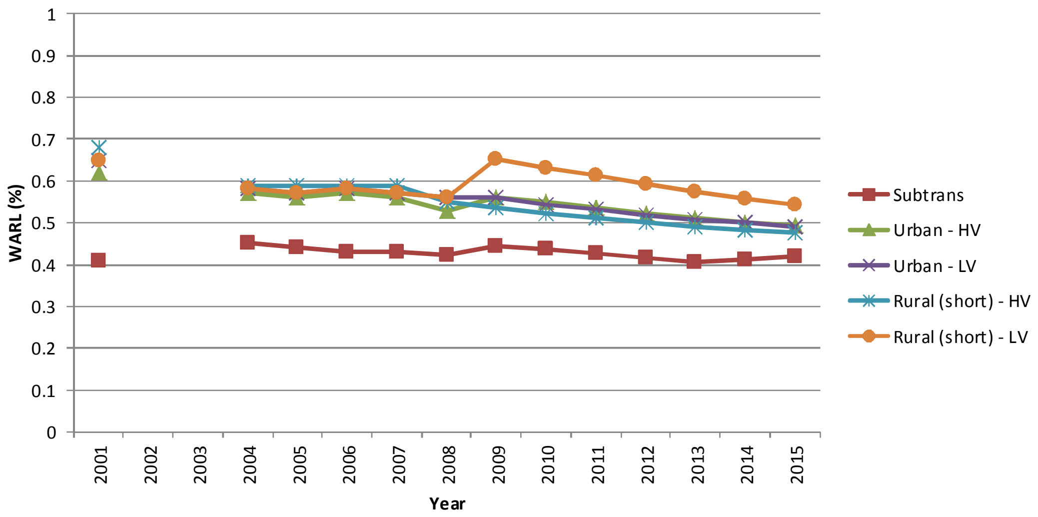
Figure 36 - 2004 Weighted Average Remaining Life projection



The weighted average remaining life predictions identified in the above chart are reasonably consistent with those that are being seen in the current period data. The following chart provides the WARL for major Jemena assets as provided in the Jemena Regulatory Information Notice.

331 2006 Electricity Distribution Price Review Submission By AGL Electricity Limited, October 2004.
332 Ibid.

Figure 37 - 2010 Weighted Average Remaining Life historical and projection



The above information highlights two important aspects; the average age of the network is gradually increasing, and this has been a recognised concern of the DNSPs for the last decade. These two aspects suggest that any action to address aging assets should be known well in advance and be incremental or gradual in a manner consistent with the gradual aging of the assets.

The Jemena proposed step changes that all commence on a specific date are at odds with this understanding. On this basis, we conclude that the opex step change amounts proposed by Jemena do not meet the prudent and efficient criteria.

In order to determine an appropriate substitute amount for the proposed capex-opex balance step change, Nuttall Consulting identified that a higher degree of justification and supporting information would be required. In our previous report, Nuttall Consulting indicated that this should include some sort of cost-benefit analysis that included recognition of the benefits of the program and the attendant risk reductions[333].

The Jemena revised proposal did not address the information gaps identified in the previous Nuttall Consulting report with the exception of the following:

- failure rate information for feeder and ACR outages
- feeder or ACR faults due to underground asset failure
- discounted cash flow analysis for ZS secondary spares maintenance.

Nuttall Consulting has reviewed the additional information provided by Jemena. The outage rate information confirms a trend of failures that is broadly consistent with the aging of asset information. The highlighted trends are informative, but do not provide any justification for a step change, rather the 11 year history provided reinforces the gradual/

[333] Nuttall Consulting Report – Capital Expenditure, Victorian Electricity Distribution Revenue Review, 26 May 2010, page 352.

incremental discussion from above. No additional quantitative information is provided to suggest the prudent timing of any additional expenditure.

The discounted cash flow analysis provided for ZS secondary spares maintenance highlights the net benefits of undertaking this program. We consider that the incentive mechanisms in the existing regulatory regime should inherently allow for these types of changes to routine maintenance practices. On this basis, we do not recommend that the forward opex forecasts for Jemena should be reduced to reflect the net benefits of this program, but that Jemena should be able to implement the program and retain the benefits of the program through the incentive framework.

It is accepted that the incentive mechanisms do not inherently allow for reductions in certain risks, such as those associated with safety and environmental matters. It is also accepted that we would expect that the proposed practices may reduce these types of risk. However, we would also expect that the benefits captured through the existing incentive mechanisms (i.e. avoided costs and reliability improvement) should form the majority of benefits realised through these programs.

Jemena considers that the capex/opex balance for the proposed expenditures reasonably reflect the opex criteria with specific reference to operating expenditure factor 7. This factor refers to “the substitution possibilities between operating and capital expenditure”. This factor clearly identifies the potential trade-off between capex and opex. The Jemena revised proposal does not provide an analysis or quantification of the capex benefits that may accrue through the additional operating expenditure. On this basis, the Jemena information does not address this factor.

Therefore, given the absence of economic analysis[334] that clearly demonstrates the need for these step increases in the context of its existing incentive mechanisms, we do not consider they are justified.

It is worth noting that Jemena has proposed a significant increase in capex from historical levels. A significant portion of this increase is driven by Jemena’s views of its aging asset base, and this in turn, is related to the proposed opex programs discussed here. We have recommended a reduction to Jemena’s proposed capex, but our recommendation plus the ESV’s recommendation still allows for significantly increasing levels of capex during the next period. In our view, these recommendations on capex should not invalidate our findings discussed here.

Finally, in reviewing for consistency of treatment between the DNSPs, Nuttall Consulting notes that the ZS power quality metering maintenance opex for United Energy is recommended for recovery. Nuttall Consulting has reviewed the information provided by both Jemena and United Energy in relation to ZS power quality metering maintenance. The information provided by United Energy better met the operating expenditure objectives.

Noting that the ZS power quality metering maintenance opex is intended for the same purposes, Nuttall Consulting recommends that the Jemena ZS power quality metering

[334] Noting the exception of the ZS secondary spares maintenance DCF.

maintenance step change opex should also be allowed. The AER may wish to consider the impact of the scale escalation allowance in mitigating the overall step change amount.

9.3 Powercor

Powercor opex step changes associated with the electrical line clearance regulations are discussed in Appendix G – Unit cost review.

9.3.1 At Risk Township Protection Plans

In its Initial Regulatory Proposal, Powercor proposed a $22 million opex step change to undertake measures to reduce the fire risk posed by distribution assets in areas identified in the Victorian Government's 'at risk townships' protection plans initiative.

The Victorian Government announced on 18 August 2009 its intention to establish individual township protection plans for 52 towns and communities within 25 local government areas over and above standard municipal fire prevention plans. Thirty eight of these towns are located in Powercor Australia’s service territory.

Six of those towns are already captured within the areas treated under the existing enhanced bushfire mitigation program. Powercor Australia is working with the communities and fire agencies on a number of initiatives, over and above its existing bushfire mitigation programs targeted at providing even greater protection for the towns identified by the Victorian Government.

The anticipated benefits of the program are to reduce as far as practicable the risk of fires caused by asset failure or vegetation impacting on power lines.

The AER’s draft determination found that Powercor’s at risk townships proposal did not reasonably reflect the opex criteria. The AER did not allow the step change proposed by Powercor on the grounds that:

- the at risk township protection plans did not impose an obligation on Powercor Australia to undertake specific fire mitigation strategies
- Powercor Australia could choose to undertake the at risk townships proposal through self-financing arrangements
- Powercor Australia's proposal pre-empted the recommendations of the Bushfires Royal Commission and the Victorian Government's response to these recommendations. The AER stated that if the Victorian Government imposes new regulatory requirements on the Victorian DNSPs due to the recommendations of the VBRC or other processes, the DNSPs may seek the approval of the AER to pass through to distribution network users a positive pass through amount.

Powercor has provided a slightly modified opex step change in its revised proposal. The requested step change amount is now $19.23 million.

In its revised proposal, Powercor does not contest there is no regulatory obligation to undertake the program. Powercor argues that it has developed its program to complement the Victorian Government's initiatives in that "it is targeted at the towns considered of greatest bushfire risk and it seeks to actively ameliorate the risk faced by the residents of these towns from potential fire risks created by distribution assets"[335].

Powercor believes that a prudent operator would undertake this program and would "consider the risk of ignoring the Victorian Government's initiatives to the community and assess the resultant risk to it of not putting in place a program, including potential legal actions and community backlash"[336].

Powercor has provided additional information as part of its revised proposal. This additional information is discussed below. Nuttall Consulting does not offer comment as to the self-financing comments of Powercor or the AER.

Powercor quote the draft Nuttall Consulting report[337] stating that the "benefits of this program are likely to be material". This is actually a misuse of the Nuttall Consulting comments which identified that the benefits from the programs in terms of operating efficiencies were not recognised by Powercor. This remains a key concern and deficit in the Powercor information provided to support this program.

Powercor has indicated that it intends to extend the current program covering 6 townships to the coverage of 38 townships. Nuttall Consulting considers that this may become a regulatory requirement, but is not aware that corresponding legislation has been enacted at this time.

Powercor is also proposing to expand the scope of the program from that which is required for the existing 6 townships. The activities identified by Powercor as additional to the existing bushfire mitigation and other business obligations include:

- Line Construction Survey
- LIDAR Aerial Imaging
- Independent Asset Audit
- Ground Fuel Reduction
- Broader review of hazardous trees outside the clearance space
- Research into new technologies.

Of the above activities, Powercor has identified in discussions that only 2 activities are currently provided for the 6 at-risk townships and that the other 4 are new initiatives that are proposed by Powercor.

In its draft report, Nuttall Consulting noted that Powercor had previously been requested to "provide analysis (e.g. spreadsheet) that shows how the expenditure increases have been calculated and the proposed benefits/outcomes." The information previously

[335] Powercor revised regulatory proposed, Powercor, page 188.
[336] Ibid
[337] Nuttall Consulting, Capital Expenditure – Victorian Electricity Distribution Revenue Review, 26 May 2010, p346.

provided by Powercor was very high-level and did not provide sufficient detail to reasonably determine how the expenditure increases had been calculated.

Powercor has provided a report[338] that provides the outcomes of a cost-benefit analysis. This report suggests that the proposed works provide a positive Net Present Value (NPV). However, Powercor has not provided the working documents that would have been required to develop these results. Powercor specifically refer to the cost/benefit modelling in this report, but have not provided this modelling despite two requests to do so.

Spreadsheet information that was provided to Nuttall Consulting did contain some input cost information, but was not a Net Present Value analysis as it did not identify or assess the external benefits and did not consider the present value of the costs or benefits.

Nuttall Consulting is particularly concerned that this analysis has been specifically requested twice and sufficient detail has not been provided. In the absence of this supporting analysis, Nuttall Consulting is unable to accept the purported outcomes of the analysis.

In addition to our concerns with the lack of supporting information, Nuttall Consulting notes the following errors or gaps in the Powercor information.

- Powercor is proposing costs for 38 townships. However the 10km radius areas for the protection plans overlap with other protection areas in 24 of the 38 cases[339]. Powercor has not identified any reduction in costs associated with the overlap.
- The Powercor proposal contains a significant number of research and development projects without any associated net benefits.
- Powercor has not responded to the previous Nuttall Consulting concerns regarding the capital and operating expenditure benefits that will accrue from the proposed programs, including:
  - fewer asset losses from fires - requiring fewer capex replacements
  - reduced outages from vegetation contact - resulting in improved reliability outcomes (STPIS impact) and reduced opex associated with fault restoration
  - reduced outages from asset failure - resulting in improved reliability outcomes (STPIS impact) and reduced opex associated with fault restoration.

Based on the above concerns, Nuttall Consulting is unable to recommend a change from the recommendations in our draft report.

[338] Business Case for Enhanced Asset Management of 'At Risk Townships' protection plans, Reliability and Asset Strategy, Powercor, 15 July 2010
[339] Ibid - Figure 14 - Map of Areas to Be Audited.

9.4 SP AusNet

9.4.1 IT opex

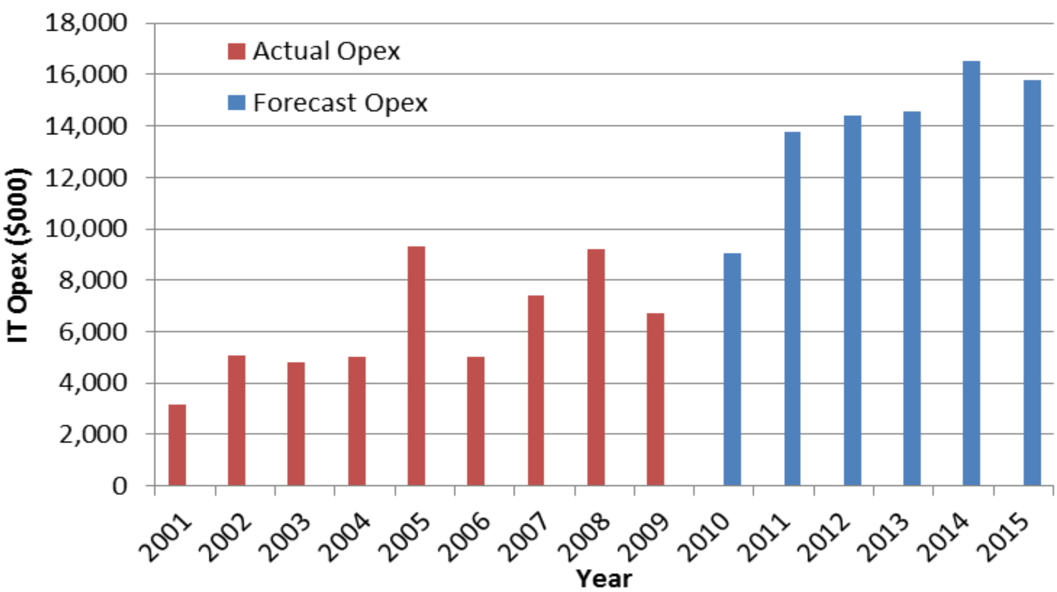
In its original submission SP AusNet noted that the planned replacement of existing IT systems during the forthcoming regulatory control period will have a consequential effect on IT opex. SP AusNet identified that additional operating costs will arise in relation to on-going support; training users of the new systems; and administering and licensing new IT systems.

This expenditure was not reviewed by Nuttall Consulting in its original assessment of the DNSP proposals. The following section provides Nuttall Consulting's assessment of the IT step change opex proposed by SP AusNet. This assessment is based on the information provided in the original SP AusNet proposal – there was very little new information provided in the revised proposal.

SP AusNet is proposing an increase of over 100% in IT opex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. SP AusNet estimates that its' IT operating expenditure for the 2006-10 regulatory control period will be \$7.5 million. It is forecasting that this will increase to \$15 million in the 2011-15 regulatory control period.

The following chart provides a summary of actual and forecast IT opex for SP AusNet.

Figure 38 – SP AusNet IT opex



For the 2006 EDPR, SP AusNet identified incremental operating and maintenance costs including the increased operational costs of the Business Systems function and additional operating costs arising from a larger IT program over the 2006-2010 regulatory period (\$3 million per annum on average)[340]. The actual expenditure for the current period was an average of $2million pa greater than the previous control period.

SP AusNet forecasts IT operating expenditures to increase over the forthcoming regulatory control period. SP AusNet has categorised the step changes in forecast IT operating expenditure into the following categories:

1. **AMI Related** – In February 2009, SP AusNet submitted an updated AMI budget application to the AER. SP AusNet forecasts that IT expenditures necessary to maintain the IT systems and infrastructure to deliver AMI and allocation to the distribution electricity network will total $14.6 million.
2. **Program Related** – Through the delivery of the IT Program of work over the forthcoming regulatory control period, SP AusNet forecasts an increase in operating expenditure of $11.9 million.
3. **Project Delivery** – Through the delivery of the IT Program of work over the forthcoming regulatory control period, SP AusNet will incur project operating expenses for activities such as training, tendering and business case development. SP AusNet forecasts these expenditures to be $5.2 million.
4. **Service Changes** – Service changes forecast for 2010 are anticipated to be recurring and therefore, are forecast to be $5.2 million over the forthcoming regulatory control period.

In forecasting operating expenditure for the forthcoming regulatory control period, SP AusNet states that it has (for each project):

- engaged business units to understand the anticipated efficiency benefits and the material impact those benefits have on forecast operating expenditures
- determined whether the benefits are recurring or once off and apply those benefits to the 2009 base year
- determined whether the project is materially adding IT systems and infrastructure that did not exist in the 2009 base year and for those new IT systems and infrastructure forecast required labour and software and hardware maintenance to support and maintain those IT assets
- applied these costs from the anticipated commission date of the project.

The outcomes of these efficiency assessments are not provided in any qualitative fashion that would enable them to be identified or assessed.

The four IT opex step change areas are considered below.

9.4.1.1 AMI related

SP AusNet has included opex step changes of $14.6 million related to AMI systems and infrastructure.

[340] SPI Networks Electricity Distribution Price Review 2006 Price-Service Proposals for the Period 2006-2010 - 21 October 2004, page 112.

AMI is subject to the Cost Recovery Order in Council, and is therefore separate from EDPR. SP AusNet state that they have recognised the opportunity to efficiently deliver the AMI program by leveraging IT systems and infrastructure.

In forecasting capital expenditure for IT projects necessary to deliver AMI, SP AusNet developed a cost allocation table. SP AusNet engaged Deloitte to review the AMI IT budget application and to provide advice and rationale for the allocation of IT expenditure.

SP AusNet reports that Deloitte adopted five methods to ensure the appropriateness of the AMI IT allocation, as follows:

- Functional Allocation: High level functional requirements were assessed to evaluate alignment of AMI requirements
- Interface Allocation: High level interfaces were evaluated to determine if they were created specifically to support AMI requirements
- Hardware Size Allocation: Hardware was apportioned to each application, and then the application's AMI allocation was applied to the apportioned hardware
- Scope Allocation: The scope of activities was reviewed to evaluate the alignment to AMI requirements
- Other Allocation: Applied to projects with no costs or have inherent business logic to justify the cost allocation.

The outcome of the above approach was to allocate AMI IT expenditure as set out in the table below.

Table 66 – SP AusNet AMI IT Capital and Operating Expenditure Cost Allocation

AMI Project	Elec	Gas	Trans	AMI	Total
Meter Data Management	0%	0%	0%	100%	100%
Network Billing Upgrade	70%	30%	0%	0%	100%
EAI Upgrade	49%	21%	30%	0%	100%
EAI Integration	3%	1%	2%	94%	100%
IT Infrastructure	28%	12%	17%	43%	100%
Customer Information System	60%	26%	0%	15%	100%
PowerOn Separation	50%	0%	0%	50%	100%
Data Warehouse	22%	0%	0%	78%	100%
Document Archive	60%	26%	0%	15%	100%

SP AusNet does not provide reconciliation of the AMI costs to allow the proposed additional $14.6 million to be verified against this allocation process.

Nuttall Consulting understands that the Order in Council (OIC) that applies to AMI expenditures is intended to capture all direct and indirect costs associated with the roll out of the advanced metering infrastructure. On this basis, all increases to expenditure that are related to AMI should be recovered through the Cost Recovery Order in Council.

The NER requires that only expenditures associated with standard control services are included in a building block proposal. AMI related expenditures are not currently included as standard control services.

Approaches that utilise or leverage the AMI infrastructure to delivery improved service may be included in a building block proposal. For example, should the AMI infrastructure be able to be leveraged to deliver improved safety outcomes, this may represent a rationale for considering additional associated expenditures. SP AusNet has not provided any information to suggest that the proposed expenditures will improve the level of services currently being delivered.

The statement by SP AusNet that they have "recognised the opportunity to efficiently deliver the AMI program by leveraging IT systems and infrastructure"[341] is confusing. It is not clear how a "leveraging" of standard control systems and assets to efficiently deliver the AMI program can result in increases in the costs of standard control services.

Based on the requirements of the OIC and the NER, we are unable to recommend the recovery of this proposed expenditure in the next control period.

9.4.1.2 Program related

SP AusNet is forecasting an increase in operating expenditure of $11.9 million over the forthcoming regulatory control period as a result of the delivery of the IT Program of work. SP AusNet stated that forecasts are described in more detail in Section 6 IT Program of Work of the SP AusNet IT Strategy[342].

There is no summary or clear identification of the proposed additional program related IT opex costs. The following table has been put together from various references contained within the chapter 6 of the IT Strategy.

- AMI – to remain constant
- Asset and works management – SP AusNet forecasts a reduction in operating expenditure of $0.58M associated with the support and maintenance of the decommissioned systems
- Network management – to remain constant
- Customer care - as these are materially new IT Systems there is a forecast expenditure of $0.52M per annum recurring from 2015
- Workforce collaboration

[341] Information Technology Strategy (CY2011 - 2015), Electricity Distribution Network, SP AusNet – November 2009, Page 46.

[342] Information Technology Strategy (CY2011 - 2015), Electricity Distribution Network, SP AusNet – November 2009

- Enterprise Content Management projects, as these are materially new IT Systems there is a forecast expenditure of $0.25M per annum recurring from 2013
- Enterprise Portal, as this is a materially new IT System and the forecast expenditure is $0.30M recurring from 2013
- Workforce Mobile Computing, as this is a materially new IT system with a significant number of increased mobile devices. The forecast expenditure is $0.96M recurring from 2013.

- Back office management – to remain consistent
- Analytics and reporting - EDW projects, as these are materially extended and utilised IT Systems there is a forecast expenditure of $0.13M per annum recurring from 2014
- IT infrastructure and operations - SP AusNet forecasts operating expenditures related to IT Infrastructure and Operations to increase over the forthcoming regulatory control period (no figures supplied).

The following table represents the information that Nuttall Consulting was able to determine from chapter 6 of the SP AusNet IT Strategy in relation to program related IT opex step changes. The total of this information is substantially less than the headline amount in the SP AusNet IT Strategy.

Table 67 – SP AusNet program related IT opex step changes ($m)

	2011	2012	2013	2014	2015	Total
Asset and works management	0.00	0.00	-0.58	-0.58	-0.58	-1.74
Customer care	0.00	0.00	0.00	0.00	0.52	0.52
Enterprise content management	0.00	0.00	0.25	0.25	0.25	0.75
Enterprise portal	0.00	0.00	0.30	0.30	0.30	0.90
Workforce mobile computing	0.00	0.00	0.96	0.96	0.96	2.88
Analytics and reporting	0.00	0.00	0.00	0.13	0.13	0.26
Infrastructure and operations	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.93**	**1.06**	**1.58**	**3.57**

The IT Strategy also identifies large numbers of benefits arising from the implementation of the identified programs. In some cases, it appears that these benefits have been taken into account in determining the opex forecast. In other cases it is not at all clear as to whether the benefits have been factored into the opex forecast amounts.

Nuttall Consulting has reviewed the proposed expenditures described above. The descriptive information on each of the above projects is relatively good. However, quantification of the benefits and cost breakdowns are not provided in a manner that allows the timing, efficiency or prudency of the project to be assessed.

Nuttall Consulting notes the linkages between the previous EDPR submission and the current SP AusNet revised proposal. This provides some degree of validation for the proposed projects.

Nuttall Consulting recommends that the values identified in the Table above are considered for inclusion in the opex building blocks. Nuttall Consulting could not locate information that supported the amount of $11.9 million that was referred to in section 7.2.1 of the SP AusNet IT Strategy.

9.4.1.3 Project delivery

SP AusNet applies defined policy that results in that certain “program related”[343] activities not being capitalised. Through the delivery of the IT Program of work over the forthcoming regulatory control period, SP AusNet forecasts that it will incur project operating expenses for activities such as training, tendering and business case development. SP AusNet forecasts these expenditures to be $5.2 million. These forecasts are described in Section 7.2.4 of the SP AusNet IT Strategy.

Examples of these activities provided by SP AusNet include:

- business case preparation
- end user training
- post implementation general expenses
- tendering processes
- system write offs
- manual data quality rectification.

SP AusNet state that the forecast IT Program related operating expenditure has been derived from the historical program related operating expenditure. During the current regulatory control period SP AusNet forecast this to be 5.87% of the actual capital expenditure in IT.

SP AusNet is forecasting increased capital expenditure in the forthcoming regulatory control period. Based on the forecast increase, SP AusNet anticipates economies of scale in program related operating expenditure and has consequently forecast 5% of the forecast capital expenditure for project related activities.

In addition to the non-capitalised IT activities described above, the SP AusNet IT program of work also includes certain supporting activities. These activities encompass the following:

- Manual Data Cleansing – “cleansing” involves the elimination of duplicate, fragmented or redundant / unnecessary data. This typically necessitates the need for targeted field capture of data pertaining to network assets.

[343] Nuttall Consulting notes the possible conflict in terminology. “Program related” is used a number of times in this chapter, although the chapter is clearly titled “Project delivery” and is separate and additional to the expenditures described as “program related”.

- Organisational Change Management – is a process used when significant changes are implemented, that impact roles, responsibilities and cultural aspects of an organisation. It is designed to ensure organisational change is implemented in an orderly, controlled and systematic way.
- Service Management – IT Service Management (ITSM) is an integrated approach to enable an organisation to effectively and efficiently deliver managed IT services which meet business and customer requirements. This program will enable continuous improvement of IT Service Delivery, leveraging the Information Technology Infrastructure Library (ITIL) framework.

The forecast operating expenditures for these operating expenditure projects are as set out in the table below.

Table 68 – SP AusNet Forecast IT Program Related[344] Operating Expenditure ($000)

	2011	2012	2013	2014	2015	Total
Project Delivery	1,623	1,928	1,419	1,713	949	7,633
Manual Data Cleansing	300	300	300	300	300	1,500
Org Change Management	100	100	100	100	100	500
IT Service Management	100	100	100	100	100	500
Total	2,123	2,428	1,919	2,213	1,449	10,133

Nuttall Consulting recognises that there are aspects of information technology delivery that may be classified as operating expenditure. SP AusNet identified an historical level of project delivery IT opex at 5.87% of the IT capex program. SP AusNet has also identified efficiencies associated with this program and used a ratio of 5% for the forecast period.

SP AusNet does not provide any justification for the 5% figure and it is feasible that this is an overstatement or an understatement of the likely relationship. In the absence of information (supporting or contrary), Nuttall Consulting accepts the position put forward by SP AusNet.

Based on the recommendations of the SP AusNet IT capital projects review undertaken by Nuttall Consulting, the project delivery amount has been amended to reflect the recommended changes to the forecast capital expenditure levels.

The areas of data cleansing, change management and IT service management are areas that typically represent business efficiencies or opportunities for business savings.

In the 2006 price-service proposal to the ESC, SPI Networks identified a number of programs that would deliver $3 million in annual savings: "The capital program supports achievement of ongoing operational costs savings in the following areas: Asset data cleansing – provides underpinning data accuracy for Business Reporting Systems," … "SPI

[344] Note: "Program related" title is drawn from SP AusNet IT Strategy document. Possible conflict in terminology as this refers to a different cost category.

Networks estimates that the above programs will deliver approximately $3 million per annum savings by 2010."[345]

Other areas identified by SPI Networks that would deliver the efficiency savings include accessibility and mobility, knowledge management and business reporting systems.

It is not clear how an area that delivered significant efficiency savings in one period (i.e. data cleansing) can become a cost centre in the next. Noting that SP AusNet has already identified small efficiencies in the project delivery forecasts, Nuttall Consulting has not sought to apply additional efficiencies for the data cleansing, change management and IT service management areas. However, we do find that the proposed additional expenditures are not sufficiently supported and are potentially contrary to previous EDPR statements, and therefore, do not satisfy the opex objectives.

SP AusNet has forecast these expenditures to be $5.2 million. This forecast does not appear to reconcile with the cost breakdowns provided in section 7.2.4 of the SP AusNet IT Strategy. The opex step changes assessed by Nuttall Consulting are more closely aligned with the step change request of $5.2 million than the total $10.3 million. On this basis, Nuttall Consulting recommends the step change amount of $5.2 million for recovery.

9.4.1.4 Service changes

SP AusNet has identified service changes that are forecast to commence in 2010 and are anticipated to be recurring. The forecast opex step change for the next regulatory period relating to these service changes is $5.2 million. The SP AusNet IT Strategy states[346] that *"(t)hese service changes are described in more detail in Section 7.1 Historical Operating Expenditure Performance*."

The following is the full set of information provided by SP AusNet to support this increase: "***2009 Service Changes** – In 2009, SP AusNet requested several service changes that are forecast at $1.0M per annum recurring. These service changes included additional 24 x 7 support for the NOC, costs associated with material increase in Service Desk volumes and Maximo Service Requests*."

Nuttall Consulting considers that this information is not sufficient to allow any form of prudency or efficiency assessment. There is no description of the trigger for the step change or any of the benefits that the additional expenditure would provide.

On this basis, Nuttall Consulting is unable to recommend the above amount for recovery in the next regulatory control period.

Nuttall Consulting has considered what an appropriate substitution amount would be in this case. The description of the three service changes (additional 24 x 7 support for the NOC, costs associated with material increase in Service Desk volumes and Maximo Service Requests) all appear to be linked to the natural growth of the network and/or customer

[345] SPI Networks Electricity Distribution Price Review 2006 Price-Service Proposals for the Period 2006-2010 - 21 October 2004, page 113

[346] Information Technology Strategy (CY2011 - 2015) Electricity Distribution Network, SP AusNet, Page 106

base. On these grounds, they should be covered in the trending forecasts that are provided for the base opex, not as a step change.

On the limited information provided, Nuttall Consulting does not recommend that these items are considered as step change expenditures.

9.4.2 Demand management costs

SP AusNet is proposing demand management (DM) and non-network costs for the delivery of specific functions and programs.

The SP AusNet revised proposal clarifies that this additional opex is not a proposed increase to the DMIA under the DMIS but is forecast as ex ante opex.

The proposed projects sum to provide a step change value of $10.84 million in the next control period. The DM opex step change projects identified by SP AusNet are:

- Establishing a non-networks team and attaining the necessary expertise and systems ($3.80 million)
- Deferral of capex ($2.43 million)
- DM programs ($3.29 million)
- Tariffs ($1.32 million)

Each of these projects is discussed in the following sections of this report.

9.4.2.1 Non-networks Team

The $10.84 million of DM opex includes $0.75 million per annum to comply with the National Framework for Distribution Planning and Expansion which imposes additional demand management-related regulatory obligations in the forthcoming regulatory control period including:

- regularly developing and publishing a Demand Side Engagement Facilitation Process Document
- establishing and maintaining a public database of DM proposals/case studies
- establishing and maintaining a Demand Side Engagement Register of all demand side option proponents
- engaging with DM proponents before a regulatory test process commences.

These new obligations are expected to commence by 2011. This expenditure is considered by SP AusNet to represent a “step change” in costs.

SP AusNet states that it must establish effective organisational arrangements to provide a DM and DG knowledge base and enable SP AusNet to develop and deliver non-network programs. SP AusNet considers that a key part of these arrangements will be establishing a team to promote efficient non-network solutions (the non-network planning team).

SP AusNet's non-network planning team is proposed to include four permanent full time equivalent personnel. The proposed team will be led by a Senior Non-network Solutions Engineer, supported by two engineers (focussing on non-network planning and technology development) and a contract and customer officer to manage the commercial and customer arrangements. SP AusNet notes that other role descriptions will be amended to reflect responsibility for administration and planning of DM and DG programs and pilots, and generally to ensure the business actively promotes demand-side alternatives, where it is cost-effective to do so.

The proposed non-network planning team will be responsible for the following functions associated with non-network activities:

- research, evaluation and reporting
- options analysis and assessment
- planning and program design
- document preparation and publication
- contract management
- stakeholder and community engagement.

SP AusNet notes that the group will not be responsible for the day to day project management, administration and implementation of non-network programs. This will be carried out in the relevant line areas and is separately forecast.

The non-network planning team will be established early in the 2011-15 regulatory control period SP AusNet's proposed opex requirement for establishing a non-network planning team and building the necessary expertise and systems totals $3.75 million, spread evenly over the 2011 to 2015 regulatory control period at $0.75 million per annum. The total expenditure consists of:

- $3.25 million for staffing requirements
- $0.25 million for formal training and development
- $0.25 million for the establishment of data, systems and tools to facilitate non-network planning.

The approach proposed by SP AusNet appears consistent with meeting the requirements of the Review of National Framework for Electricity Distribution Network Planning and Expansion[347]. The final report from the AEMC recommends that DNSPs would be required to engage with non-network providers and consider non-network alternatives. DNSPs would also be required to establish and implement a Demand Side Engagement Strategy, encompassing three components:

1 Demand Side Engagement Facilitation Process Document (the facilitation process document)

[347] FINAL REPORT - Review of National Framework for Electricity Distribution Network Planning and Expansion – AEMC, 23 September 2009

2 Public database of proposals/case studies

3 Demand Side Engagement Register.

Nuttall Consulting is unsure of the exact status of the AEMC recommendations and the proposed implementation date. SP AusNet state that these new obligations are expected to commence by 2011. If the AER is satisfied that this meets the requirements of "an applicable regulatory obligation" under clause 6.5.6(a)(2) of the NER, Nuttall Consulting recommends that the proposed step change expenditure be accepted.

9.4.2.2 Deferral of capex

SP AusNet has identified a number of prospective non-network solutions to a range of feeder projects. The identified feeder projects include:

- Benalla (BN1) feeder
- Wangaratta (WN8) feeder
- New Seymour (SMR7) feeder
- New Woori Yallack (WYK13) feeder
- New Bairnsdale (BDL10) feeder
- New Wangaratta (WN9) feeder

SP AusNet has provided a reasonably robust analysis of the options and costs associated with the Benalla feeder augmentation[348]. This analysis shows a likely net benefit from the use of non-network solutions to defer capital expenditure. SP AusNet provides a reasonable analysis of the costs of the likely costs and benefits of the non-network solutions for the Benalla BN1 feeder. The analysis is less detailed for the remaining feeder projects. However, Nuttall Consulting considers that the level of information provided is reasonable given the timeframes and the unknown nature of the actual demand management mechanisms that will be employed.

The SAP analysis is sufficient to suggest that non-network solutions will provide costs efficient deferrals for up to 2 years for the identified projects.

Nuttall Consulting notes that the project estimates provided in table 8.1 of the SP AusNet EDPR proposal are similar, but do not precisely align with the estimates contained in the SP AusNet project estimates sheet[349] as this sheet does not include finance charges and overheads. The projects do appear to be consistently identified in the respective capacity forecasting information[350]. This provides a degree of surety that there is not double counting of the proposed projects in the capex program.

The analysis provided by SP AusNet provides a reasonable level of certainty that opportunities for capex project deferral are likely in the forecast period and that non-

[348] AMS Electricity Distribution Network AMS 20-311. Network Augmentation Planning Report. BN1 22kV feeder upgrade. 2011-2015 EDPR period. Revised.

[349] 28 11 09 EDPR Capacity Projects Indicative Estimate Rev11.doc

[350] AMS – Electricity Distribution Network 20-12 Capacity, SP AusNet.

network solutions may provide the most cost effective options in many of these cases. It is possible ,even likely, that circumstances will change and some non-network solutions will not proceed and new opportunities may also appear.

Despite the level of uncertainty, Nuttall Consulting considers that SP AusNet has provided reasonable evidence that the proposed approach represents an efficient and prudent level of expenditure. Nuttall Consulting recommends that the proposed operating expenditure for the deferral of capex is included in the forecast allowances.

9.4.2.3 DM Programs

SP AusNet proposes to include an amount of $3.29 million in its opex forecast to cover DM programs for load control of hot water systems and air conditioning. SP AusNet identifies that the proposed load control programs:

- meet and manage the expected demand for standard control services over the 2011-15 regulatory control period; and
- meet the National Electricity Objective in that they promote efficient investment in, and efficient operation and use of the network.

The following table details the proposed expenditures and qualifies the potential benefits.

Table 69 – Step change opex costs for DM programs

Program	Activity	Opex ($2010M)	Benefit
Hot water system load control	Set timers on hot water systems in constrained areas of the network	1.26	Load shifting to manage peak demand
Direct Load Control of air conditioning	Pay rebates to participants. Install and access communications device on AC units for homes in target areas.	2.03	Load shifting to manage peak demand
Total		**3.29**	

Hot water system timing

Nuttall Consulting notes that SP AusNet has previously adjusted hot water time clocks and meters to around 8000 customers on its network to permanently shift load and reduce peak demand in constrained areas such as Leongatha, Wonthaggi, Inverloch & Philip Island. SP AusNet also notes that this expenditure of around $320,000 was spread over the current regulatory control period and is not included in SP AusNet's base year opex[351].

SP AusNet plans to adjust hot water system timing to another 90,000 customers on areas of the network experiencing peak demand constraints, such as Cann River, Foster, Kinglake, Moe, Merrijig, Myrtleford and the snowfields areas around Mansfield. It is

[351] Nuttall Consulting has not confirmed whether or not these costs are excluded from the base year calculations.

expected that the roll out of hot water timers will allow for the deferral of a $7.1 million (real $2010) project to reconductor the Wangaratta-Myrtleford line scheduled for 2013.

Direct load control – air conditioning

SP AusNet intends to target Direct Load Control (DLC) air conditioning trials to 2000 customers in the Cranbourne/Pakenham and Epping/Plenty Valley areas because much of the growth in maximum demand is occurring in these residential growth corridors. For planning purposes, SP AusNet forecasts that the maximum peak demand in these areas will increase from 2.3 kW to 4 kW per house in the forthcoming regulatory control period. SP AusNet has forecast $2.2 million to deliver this program.

SP AusNet forecasts peak demand growth to be around 9 per cent per annum in these areas. If this program enables SP AusNet to reduce each customer's peak demand by an average of 0.5-1 kW, this would lead to a reduction in peak demand of 1-2MW across specific locations in these regions and assist in managing expected peak demand.

The proposed budget would be in the form of opex to cover the costs of:

- project management, marketing and administration (approximately $0.10 million)
- technical support and operation (approximately $0.15 million)
- procurement and installation of equipment necessary to facilitate the remote control of air conditioning units (approximately $1.01 million)
- compensation to customers for their participation (the rebates) (approximately $0.76 million).

Nuttall Consulting considers that the above demand management proposals represent non-network solutions of the sort that are intended to be encouraged under the Demand Management Incentive Scheme and as part of the overall incentive framework.

SP AusNet has identified that "(i)f this hot water load shifting expenditure is not approved, SP AusNet forecasts an additional allowance of $7.1 million in capex to undertake reconductoring of the Wangaratta-Myrtleford line in 2013"[352].

SP AusNet does not make clear what the timing of the reconductoring would be if the scheme is put into place. This makes it difficult to determine whether the proposed opex is cost efficient. However, as the reconductoring project does not appear in the forecasts for the next control period, we can assume that it is deferred until at least 2016.

There is even less information relating to the air conditioning demand management solution. SP AusNet has not provided any value for the overall load that expected to be reduced by this program or the capital expenditure that is thereby deferred. That is, there are no quantified benefits or cost deferrals for the proposed works.

The information provided by SP AusNet is sufficient to consider that the hot water program might reasonably represent prudent and efficient expenditure. There is not

[352] SPI Electricity Pty Ltd Electricity Distribution Price Review 2011-2015 Regulatory Proposal - November 2009, page 245.

sufficient supporting evidence in relation to the air conditioning program to support this conclusion. On this basis, Nuttall Consulting recommends that the hot water system timing program is included in the allowed expenditures. SP AusNet has not provided sufficient justification to suggest that the air conditioning program is prudent or efficient.

9.4.2.4 Tariffs

SP AusNet proposes to introduce two new Distribution Use of System tariffs to use the functionality of AMI meters to provide cost reflective price signals to residential and small commercial customers, particularly during peak summer demand periods. These tariffs are:

- time of Use tariff for Residential and Small Commercial Customers
- critical Peak Demand Price for large LV customers, HV customers, and sub-transmission customers.

Key costs associated with delivering these price signals (to residential and small commercial customers) is the cost of the AMI meter, and the communication mechanism associated with that meter; both of which are recovered under the AMI regulatory process.

SP AusNet considers that the cost of making other system and process changes required to facilitate the introduction of the proposed tariffs are not recovered through the AMI process and are therefore applicable to recovery through the 2011-15 price cap determination.

SP AusNet proposes $1.32 million in opex expenditure to implement these tariffs. The proposed expenditures include:

- customer notification systems (SMS, pager, email) and one full time equivalent staff resource at the network operations centre to monitor and manage the notification process (totalling $250,000 per annum)
- resources to update and maintain additional tariff tables (PV2) (totalling approximately $10,000 per annum).

These tariffs are expected to drive reductions in overall energy use and a shift in energy use away from peak periods to 'off peak' periods and reductions in peak demand, which in turn will allow the deferral of some reinforcement capex.

SP AusNet estimates that by the end of 2013 the adoption of the proposed Time of Use tariff is estimated to lead to an:

- 26.5% reduction in energy that SP AusNet classifies as peak energy (2-6pm between December and March on weekdays), relative to the BAU figures provided by NIEIR
- 21.7% reduction in energy that SP AusNet classifies as shoulder energy, relative to the BAU figures provided by NIEIR
- 1.21% increase in the off peak usage, relative to the BAU figures provided by NIEIR.

SP AusNet estimates that the aggregate estimated effect for critical demand pricing is a saving in the peak summer demand of 90.22MVA[353].

Nuttall Consulting has not undertaken the review of SP AusNet's demand forecasts, but has been informed that this summer peak demand reduction has been recognised in the SP AusNet demand forecasts. On this basis, it is reasonable that the program to implement the new Distribution Use of System tariffs is accepted.

9.4.3 Power cable test program

SP AusNet proposes to implement a prioritised cyclic test and monitoring programme for all underground power cables to reduce the risk of failures, and to more accurately forecast long-term asset condition, remaining life and replacement profiles. SP AusNet state that this will improve the safety of both SP AusNet's workers, and the surrounding community. The proposed program is also stated to provide reduced risk of failures from the ageing fleet of assets, by being able to more accurately forecast long-term asset condition, remaining life and replacement profiles, thus leading to more efficient long term replacement / operational decisions.

SP AusNet do not provide any quantification of the proposed benefits of the program.

The SP AusNet asset management strategy for insulated cables identifies that SP AusNet has a relatively young cable network with 66% of the population being 12 years (or less) old[354]. SP AusNet also identifies in this document that the expected average technical life of paper insulated power cables is approximately 60 years, whilst for XLPE-insulated it is approximately 45 years. Less than 0.02% of the SP AusNet underground cable population is reported as being older than 40 years.

The SP AusNet statement that the asset fleet is aging may be technically correct, but does not indicate a population where significant volumes of assets are near or approaching the end of their technical lives.

SP AusNet has identified that the rate of failures is increasing. The SP AusNet total number of cable failures (presumably excluding 3rd party causes) has almost doubled from 2003 to 2009[355]. This statistic is a little misleading as approximately 66% of SP AusNet's underground cable network has been installed in the last 12 years[356]. This means that the rate of failures on a per kilometre basis is increasing, but at a rate that is not much greater than that of the overall population increases.

SP AusNet has identified that more faults are occurring on the older paper-insulated cable network. This would be consistent with the older nature of these cables.

353 However, 76MVA of this reduction pertains to the substation and feeder levels, with the remainder being attributable to the 66KV system

354 AMS – Electricity Distribution Network Insulated Cable Systems, AMS 20-65, 26/11/2009, page 7.

355 AMS – Electricity Distribution Network Insulated Cable Systems, AMS 20-65, 26/11/2009- Based on trendline information from figure 7, page 9.

356 AMS – Electricity Distribution Network Insulated Cable Systems, AMS 20-65, 26/11/2009, page 7.

SP AusNet has provided the results of a net present value (NPV) assessment of the proposed cable test program. These results indicate an overall positive NPV from the program. SP AusNet has not provided the inputs to the analysis, so it is not possible to check the validity of the input measures.

Noting that SP AusNet has only 1439km of installed power cables, and that 0.5% or less of these cables are older than 40 years, it is difficult to understand how the $1.65 million dollar testing program can have a positive NPV. The wording of the SP AusNet NPV analysis appears to indicate that the deferments (benefits) are not available until 2030. If this is the case, an NPV analysis should register this benefit as approaching zero due to the time-value of money.

Nuttall Consulting also notes that 3 of the 5 tests that are proposed as part of the power cable test program require the cable to be de-energised. It is not clear if the customer costs of the de-energisation have been considered.

SP AusNet notes that it is difficult to accurately forecast the specific benefits that are expected to result from such a program. Nonetheless, it is not reasonable to suggest that a program to test cables will not result in a reduction in unplanned outages and their associated costs.

Nuttall Consulting notes that SP AusNet has already purchased the equipment to undertake these tests. SP AusNet has not indicated the dates on which the equipment was purchased or whether any tests have been undertaken to date. SP AusNet has not identified any business case or cost analysis that may have been relied upon by the business in making the purchase decision.

Finally, Nuttall Consulting notes that the proposed step change amount is not linked to any changed or new regulatory obligation or requirement.

In summary, Nuttall Consulting is unable to determine that the proposed expenditure is either prudent or efficient. The relatively young population of assets, the fact that no assets are currently older than the technical life, the lack of defined benefits and questions relating to the NPV analysis contribute to the Nuttall Consulting recommendation. We are unable to recommend that the proposed additional expenditure is allowed for recovery in the next control period.

9.4.4 Condition monitoring and power transformer refurbishment

SP AusNet proposed to enhance its existing programme of condition monitoring and condition assessment of each transformer and regulator. These programs were to enhance asset condition monitoring to improve safety, reduce failure risk and to more reliably forecast timely asset replacement requirements. Nuttall Consulting notes that condition assessment is an essential step in analysing the risk of failure and/or planning for refurbishment or replacement before failure[357]. SP AusNet states that the transformer condition and rankings are used as inputs to the asset planning process, which includes impact of failure; coordination with other projects, customer requirements, risk and

[357] Where economically efficient to do so.

economic analysis models, and development of efficient projects leading to alternative scenarios for management decisions on refurbishment or replacement.

The AER rejected SP AusNet proposed condition monitoring and power transformer refurbishment step changes for reasons including the lack of a link to a "new or changed regulatory obligation or requirement" and the likely self-financing of the programs.

In its revised proposal SP AusNet identified that the returns from the improvements would accrue in later periods and provided additional analysis to highlight the cost/benefit timings.

SP AusNet considers that this analysis clearly demonstrates that even under the most conservative of assumptions, these programs will breakeven, and therefore, it is reasonable to expect the additional opex to enhance its condition monitoring and power transformer refurbishment programs.

Nuttall Consulting has reviewed the additional analysis provided by SP AusNet. This analysis is provided in the form of a present value analysis and covers the areas of transformers, circuit breakers, instrument transformers and cables.

While the structure of the present value analysis is consistent with the typical analysis in this area, Nuttall Consulting has a number of specific areas of concern with the treatment and consistency of the calculations. These are detailed below.

- The present value analysis is not consistent in its treatment of costs between periods. For example, the analysis of power cables utilises different treatment of costs in the next period compared with subsequent years. Costs in the current period are hardcoded into the analysis, whereas subsequent years are formula driven. This has the impact of suggesting that costs in the subsequent period will be 47 times greater than current costs. As the underlying driver of replacement is the expected defect or failures rate, the analysis is suggesting these rates to be 47 times higher than at present. This has the effect of significantly increasing the future costs and benefits and is not representative of a realistic scenario.
- The present value analysis treatment of costs is not consistent. For example; the "transformer only" analysis appears to assume that costs for the program only occur in the next period and not thereafter. If the programs were stopped, it would be reasonable to consider the end of the deferment benefits in the analysis – this is not considered. Nuttall Consulting considers that this is not a reasonable representation of the proposed program and overstates the potential benefits.
- SP AusNet states that the expected service lives for insulating oil and transformer core and coils have been based on normal probability distributions with a mean of 60 years and a standard deviation of 10 years. However, the oldest transformers (at Sub Rub A) are 82 years and 23 power transformers are older than 60 years. SP AusNet has replaced two power transformers in the current period, and none between 2006 and 2008. The proposed condition assessment and transformer refurbishment strategies are aimed at achieving a 6 year mean deferment for transformer replacement. However, based on the current age and replacement

profiles, the proposed condition monitoring and transformer refurbishment strategies would deliver less efficient outcomes than current practice. In other words, the benefits proposed by these programs are already being achieved in terms of life extension.

Nuttall Consulting considers that the framework for the analysis provided by SP AusNet represents good industry practice in the assessment of more efficient business opportunities. However, the application of the framework is flawed and does not represent a viable model of the proposed programs. We note that SP AusNet considers the analysis to be conservative, but deem that the issues with the analysis are significant enough to outweigh the potential conservatism.

Nuttall Consulting considers that the analysis does not support the SP AusNet argument for the reinstatement of these opex step changes.

9.4.5 Substation earthing systems

The AER rejected SP AusNet's proposed step change related to substation earthing systems. This proposed expenditure involved resurfacing being carried out in the switchyards of six substations and the earth grid current injection programme being enhanced in order to complete all zone substations by 2015.

The original SP AusNet proposal stated that the long-term degradation of the switchyard surface can increase the electrocution hazard to unacceptable levels and that 10 year assessments of earthing systems were a regulatory obligation.

The AER considered that the proposed step change regarding substation earthing systems did not represent a change in SP AusNet's operating environment. As such, the AER considered switchyard resurfacing and earth grid testing to be part of the normal ongoing operation of a prudent and efficient DNSP and should already be included in SP AusNet's base opex.

In its revised proposal SP AusNet identified that a substantial component of this step change is a non-recurrent opex item – it reflects the fact that the timing of the expenditure is a function of the underlying degradation in the earthing system. SP AusNet stated that "this degradation does not miraculously coincide with the Base Year of a regulatory period – rather, it occurs over a long period of time – around 30 years".

With respect to the injection testing, SP AusNet restates the original position that "Recently, ESV, through the Blue Book forum, has requested electricity generation, transmission and distribution utilities in Victoria to regularly confirm the integrity of their installed earthing systems with respect to electrical safety.

SP AusNet has stated that it has implemented an earth grid current injection programme to address this requirement and plans to complete this programme in all zone substations by 2015. Five zone substations (including three in 2009) have already had this testing completed and it is planned to do a further three during 2010. As the testing will be included in the proposed rebuild works for seven zone substations, this will leave 40 stations to test between 2011 and 2015.

Nuttall Consulting agrees with the SP AusNet comments regarding the long periodicity of resurfacing requirements. It is feasible that a period of 30 years could exist between remedial action in this area. However, the SP AusNet assumption that all remediation will occur in a designated short period is not supported by the age of the network and, specifically, the age of the substation switchyards themselves. The switchyards have been constructed over the last 80 years in the SP AusNet franchise. This long-term construction program means that degradation will have already occurred on many of the older sites and will continue to occur. This profile does not support a step change, but rather the ongoing process of remediation.

The inspection and testing of substation earths is a critical part of ensuring the health and safety of staff and the public in the vicinity of these assets. SP AusNet identifies that ESV has requested confirmation of the testing program. While confirmation of the program may be requested by ESV, the underlying requirements for a minimum of 10 yearly testing of substation earths has not changed. Testing of substation earths has been industry practice since at least the 1990's and most likely earlier.

After reviewing the information provided by SP AusNet in its revised proposal, Nuttall Consulting considers that the reinstatement of these step change costs is not substantiated.

9.4.6 Substation site cleanup

The AER has rejected SP AusNet's proposed expenditure to retire assets and clean-up sites to maintain adequate environmental and safety standards at zone substations that are expected to be made redundant over the forthcoming regulatory control period.

SP AusNet does not accept the AER's Draft Determination for the following reasons:

- the proposed additional expenditure is a by-product of SP AusNet undertaking its proposed capex program, and as a result, having to comply with existing obligations
- inconsistency with the NER requirements – namely Clause 6.5.6 (c) (1) and Clause 6.5.6 (c) (2) – and the requirements of Section 7A (3) of the NEL
- that it is good industry practice for a DNSP to remediate all sites that it is not proposing to use, or where it will decommission assets
- the remediation of sites was in "the long term interests of consumers of electricity" and moreover, the interests of the general public living in the vicinity of those sites, consistent with the National Electricity Objective.

Nuttall Consulting notes that the remediation of a substation site will improve the capital value of the site. However, as the sale value of any land is treated as a disposal under a building blocks model, it would not be appropriate to recognise the capital benefit of these works.

With reference to the specific sites identified by SP AusNet, Nuttall Consulting considers that the proposed expenditures are reasonable and may reflect an additional level of expenditure above that of the current period. Nuttall Consulting recommends that the proposed step change expenditure is considered for inclusion in for allowances for the next period.

SP AusNet has tens of thousands of items of infrastructure. There will be peaks and troughs in expenditure levels for these assets. Nuttall Consulting considers that it is not consistent with the opex objectives to identify a specific set of items that may be coming into a peak replacement/refurbishment cycle without considering the civil asset base in total. The AER may wish to consider whether the additional costs associated with these specific areas of expenditure are not offset within the overall replacement/refurbishment cycle.

9.4.7 Substation civil infrastructure works

SP AusNet has proposed additional operating expenditure to rectify civil infrastructure issues that have developed in stations. The condition issues address impact on zone substation security, reliability and safety. These expenditure items included:

- cyclical replacement of locks and keys for every station and the installation of padlocks on primary switchyard equipment
- replacement of exterior signage and internal operational signage as signs fade or are vandalised
- re-cladding and restoring asbestos clad buildings where replacement is not economic will enhance security, safety, reliability and extend the life of the building
- rectify switchyard roads, drainage and cable trenches that compromise the reliability, safety and environmental compliance of the station.

The AER did not allow this expenditure in the draft determination. SP AusNet has restated the need for this expenditure in the revised proposal.

Nuttall Consulting agrees with the SP AusNet position that “it is good industry practice, and therefore, ‘prudent’ for a DNSP to maintain its civil infrastructure in and around its zone substations, for the benefit of both its customers (by improving the visual amenity of these sites) and its employees (safety)”[358].

Nuttall Consulting considers that the sort of works identified by SP AusNet are consistent with good industry practice and have historically been identified and previously incurred by SP AusNet.

SP AusNet has thousands of items of civil infrastructure. As discussed above, there will be peaks and troughs in expenditure levels for these assets. Nuttall Consulting considers that it is not consistent with the opex objectives to identify a specific set of items that may be coming into a peak replacement/refurbishment cycle without considering the civil asset base in total.

[358] SP AusNet Revised Regulatory Proposal July 2010, page 231

The following excerpts from previous SP AusNet EDRP proposals are provided to highlight that the above expenditure items are not new and have been previously identified as drivers of expenditure in past periods.

- SPI Networks prioritises its infrastructure security issues in a similar manner to environmental issues - using risk management techniques. This process identifies zone substations, which require additional security measures such as more secure fencing, motion detectors, cameras and rapid response mechanisms.[359]
- SPI Networks assesses its environmental issues using risk management techniques in order to prioritise issues based on their impact on the environment, customers and SPI Networks' reputation as a responsible corporate citizen. Environmental projects identified for the 2006-2010 regulatory period include improving oil spill containment facilities at sites near waterways, installing low oil level alarms at regulator sites, removal of asbestos from sites regularly used by SPI Networks' employees and construction of noise control measures around zone substation transformers which are in close proximity to populated areas.[360]
- Following several fatalities in NSW, … the ESAA established a Working Group with nationwide expertise to develop an appropriate new standard. The resultant draft standard recommends the development of risk assessments and security measures based on defence in depth mechanisms together with … Increased primary security measures – improved fencing, locks etc."[361]

As the proposed expenditures have clearly been considered by SP AusNet as drivers of expenditure in previous price proposals, Nuttall Consulting considers that to identify these costs as opex step changes is not correct. The proposed additional expenditures do not represent the efficient costs of achieving the operating expenditure objectives.

9.4.8 Substation fire systems

In its original proposal SP AusNet proposed to improve its annual fire preparedness at its stations prior to the fire danger period. This programme included cleaning gutters and managing fuel and vegetation within each station and liaising with local fire authorities for each station.

The proposed expenditure also covers the hydrant testing requirements that are required every five years and repairs required after testing discovers defects along with audits of the suitability of the water supplies at each site.

SP AusNet has identified that discussions in late 2009 with SP AusNet's underwriters determined that they must provide appropriate loss mitigation equipment and maintain it more effectively so as not to void their insurance policy.

The AER rejected SP AusNet proposed allowance for the substation fire systems. The draft determination stated that:

[359] SPI Networks Electricity Distribution Price Review 2006, page 89.
[360] SPI Networks Electricity Distribution Price Review 2006, page 89.
[361] SPI Networks Electricity Distribution Price Review 2006, page 120

- the maintenance testing requirements of Australian Standard AS1851-2005, Maintenance of fire protection systems and equipment are not been newly established and that SP AusNet has not demonstrated how any recent changes to this standard have imposed any new or changed obligations on SP AusNet
- SP AusNet has not demonstrated how other aspects of its current fire preparedness program are linked to new or changed regulatory obligations.

SP AusNet does not accept the AER's definition of what constitutes a step change, therefore, it considers that the AER's reason for rejecting its step change has no basis under the NER or the NELs.

Nuttall Consulting has reviewed the information provided by SP AusNet in the original and revised proposals. The activities identified by SP AusNet represent good industry practice and appear consistent with SP AusNet's obligations.

SP AusNet has not described how the proposed activities that are driving the step change expenditures are different from current practice. The statements provided by SP AusNet appear to suggest that they may not have been undertaking these activities in a manner that meets the requirements of their insurance underwriters. However, the information is not clear as to what, if any, activities are required, but have not previously been undertaken.

Nuttall Consulting considers that the information provided by SP AusNet is not sufficient to justify that these expenditures are not already provided for in the base year operating expenditures. Nuttall Consulting does not recommend the addition of these step change expenditure to the opex allowance for the next control period.

9.4.9 Process and configuration management

In its original proposal, SP AusNet identified process and configuration management step change expenditures for the next regulatory control period. These proposed expenditures included the development and maintenance of configuration standards for protection and control schemes and devices, and also the processes and procedures for protection and control setting and database management. Specifically, this included:

- database management
- protection setting review
- maintenance and configuration standards.

Nuttall Consulting considers that SP AusNet already undertakes the proposed activities. Specifically:

- database management – SP AusNet already maintains a database supporting secondary system
- protection setting reviews – SP AusNet has historically undertaken protection setting reviews

- maintenance of configuration standards – configuration standards already exist and are being maintained.

SP AusNet has stated that the costs identified in this category are only incremental costs. As the above services are already being provided, the incremental costs must relate to improvements in these services.

The NER requires the efficient level of expenditure to meet the operating expenditure objectives. As such, the proposed improvements must be assessed for their relative efficiency.

In its original proposal SP AusNet stated that improving database management will have the following long term benefits[362]:

- efficient data storage and asset management
- more appropriate and efficient design and maintenance standards
- savings on engineering time spent on configuration and construction
- reduction in safety- and human error–related incidents
- minimisation of the physical impact of outages on the electricity distribution network.

The benefits associated with protection settings review and maintenance and configuration standards are not specifically identified.

The benefits identified by SP AusNet predominantly relate to operating activities and should therefore directly relate to opex efficiencies. As these efficiencies are not quantified it is not possible to consider whether the proposed expenditures are efficient.

Nuttall Consulting considers that SP AusNet:

- has not provided reasonable evidence that the proposed step change expenditures are not currently undertaken and considered within the base year opex
- has not provided any reasonable level of quantification to support that the proposed step change expenditures are efficient.

On this basis, Nuttall Consulting cannot recommend that the proposed step change expenditures are added to the operating expenditure allowance for the next control period.

9.4.10 Quality of supply

SP AusNet considers that the Advanced Metering Infrastructure (AMI) will provide transparency of network supply quality to a level never experienced before, which in turn is assumed to lead to a higher level of quality of supply complaints. SP AusNet have identified an operating expenditure step change amount of $5.66m associated with meeting this obligation.

[362] Electricity Distribution Network - Incremental Opex impact to 2009 Base Year, Issue 4, 28/10/2009, page

The AER rejected this allowance as part of the draft determination. SP AusNet has resubmitted this amount as part of the revised proposal. The breakdown of the proposed amount is provided in the following table.

Table 70 – Proposed SP AusNet quality of supply opex

SP AusNet	Costs (2010 $M)				
Quality of supply	2011	2012	2013	2014	2015
Proposed Expenditure	$0.52	$0.78	$2.13	$1.14	$1.10

SP AusNet is required to comply with the Victorian Distribution Code (the Code). This Code establishes the voltage requirements for the quality of supply delivered to customer premises. There are a number of voltage requirements established in this code including: Steady State, Less than 1 minute, Less than 10 seconds and Impulse Voltage.

SP AusNet has not identified which voltage variations will be addressed by information from the AMI meters.

The minimum functionality of the AMI meters in relation to under and over-voltage are:

- Under-voltage and overvoltage events shall be recorded. The thresholds shall be remotely and locally settable for under[363]-voltage in the range of at least -5% to -20% in 1 % steps and for overvoltage in the range of at least +5% to +20% in 1 % steps.
- All events of a period equal to or longer than the under-voltage/over-voltage time threshold setting, which may be in the range of 1-60 seconds in I second increments, shall be recorded.
- For each event the minimum voltage that occurred during the period shall be recorded. For each overvoltage event the maximum voltage that occurred during the period shall be recorded. For three phase meters, the phases affected shall also be recorded.

This is a broad ranging requirement and suggests that all voltage variation types will be captured with the exception of impulse voltages. Nuttall Consulting understands that the majority of verified voltage complaints fall within the categories that are measured by the AMI meters.

The DNSPs must maintain a nominal voltage level at the point of supply to the customer's electrical installation in accordance with the voltage ranges established by the Code, although DNSP may seek a written agreement with a customer to expressly vary their respective rights and obligations under the Code. Nuttall Consulting considers that the seeking of written permission for voltage variations is not a safe or likely outcome.

[363] Department of Primary Industries - ADVANCED METERING INFRASTRUCTURE, Minimum AMI functionality Specification (Victoria), September 2008 - Release 1.1.

Once the AMI meter information regarding voltages is received by the DNSP, Nuttall Consulting understands that the DNSP is required to act to rectify the problem. To not act would be contrary to the code requirements.

Voltages outside of the code generally occur over time. New or additional load on a line, general load growth, and altered switching arrangements can contribute to voltages reducing. There are many other mechanisms that can result in voltage variations. Nuttall Consulting considers that voltage variations that are due to poor initial design, construction or energisation are rare and should not be considered as an efficient or prudent outcome (i.e. should not be allowed for recovery as a standard control service).

In Nuttall Consulting's experience, SP AusNet is correct in stating that a percentage of customers may currently be experiencing voltages outside of code requirements and may not be aware of this fact. This means that the implementation of AMI is likely to identify these customers more quickly than current processes.

In the absence of AMI meters, the identification of voltages that are outside of code requirements is not simple. Many consumers may not be aware when code voltages are not being met. If a consumer believes that the voltages are not within code requirements, they may contact the DNSP. Current practice for testing voltages involves the DNSP installing temporary metering at the customer's premises and possibly in adjacent locations.

Once a voltage complaint is verified, the DNSP is required to act to rectify the problem. These works can be relatively simple or complex.

In summary, the SP AusNet argument that AMI will require additional resources to address voltage related quality of supply issues is reasonable.

In terms of the efficiency of the SP AusNet proposal, Nuttall Consulting notes that voltages outside of code occur over time. The AMI roll-out will bring forward the identification of customer's where voltages are outside of Code, but it will not cause new voltage problems. As such, any allowance for costs in this category should only exist for the period of the AMI roll out. After the roll-out the advent of new voltage problems would be expected to continue at current levels[364].

SP AusNet are proposing an average expenditure of $1.2million per annum in this step change for the next regulatory period. In contrast, Jemena are proposing opex of [redacted]. The Jemena submission on this step change is significantly more detailed than the information provided by SP AusNet and also recognises the associated benefits of the AMI program.

The timing of the SP AusNet opex is not explained in the SP AusNet proposal, so Nuttall Consulting is unable to determine why the amounts are phased as they are. Nuttall Consulting notes that the AMI roll-out will complete in 2013 and considers that the required additional expenditures will therefore only be required until 2014.

[364] There may be an argument that AMI data will support better planning and therefore reduced voltage complaints, but this has not been taken into account for this cost assessment.

On the basis of the Jemena submission, Nuttall Consulting considers that the proposed costs of $144k per annum represent a more efficient cost estimate, although allowances should be made for the ratio of customers between the two DNSPs.

Table 71 – Recommended SP AusNet quality of supply opex

SP AusNet	Costs (2010 $M)				
Quality of supply	2011	2012	2013	2014	2015
Proposed Expenditure	$0.29	$0.29	$0.29	$0.29	-

9.5 United Energy

9.5.1 Demand management initiatives

United Energy is proposing a broad range of initiatives relating to demand management. Many of these initiatives are additional to the activities already proposed to fall within the Demand Management Innovation Allowance (DMIA).

United Energy had originally proposed additional demand management activities of $10 million[365]. The United Energy proposal appeared to be suggesting that the DMIA allowance should be increased from $2 to $10 million. This position was rejected by the AER in its draft determination.

In its revised proposal, United Energy has clarified that the proposed $10 million is additional and separate to the $2 million already allowed under the DMIA[366]. The following section reviews this proposed additional $10 million step change in operating expenditure propose for the next regulatory control period.

9.5.1.1 Background

In April 2009, the AER released a Final Decision[367] on the Demand Management Incentive Scheme that is to apply to Jemena, CitiPower, Powercor, SP AusNet and United Energy from 2011 to 2015.

This paper described the framework and operations of the DMIS. The paper also noted that the DMIS is not intended to be the primary source of recovery for demand management expenditure. The AER considered it appropriate that a DNSP recovers demand management costs primarily through forecast opex and capex approved at the time of the AER's distribution determination.

[365] Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015, United Energy Distribution, 30/11/2009 – Page 232.
[366] Revised Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015, United Energy Distribution, Page 320.
[367] Final Decision - Demand Management Incentive Scheme - Jemena, CitiPower, Powercor, SP AusNet and United Energy, 2011–15, April 2009.

Clauses 6.5.6 and 6.5.7 of the NER also require the consideration of non-network alternatives.

In its final determination on AMI costs[368], the AER identified that each DNSP will accrue benefits from the AMI roll out and that any cost savings or reductions will be passed through to customers through lower network prices in the five yearly regulatory price determinations, as well as through lower metering charges.

The AER also noted that the pass through of AMI benefits will be an issue for close consideration in future distribution price reviews, in particular the 2011–15 distribution price review[369].

The AER draft determination for the Victorian DNSPs[370] identified benefits accruing through the AMI rollout including the impact on demand forecasts of the time-of-use information that is provided by the AMI roll out. The lower demand forecasts have resulted in lower capex forecasts based on the deferral of some demand related projects.

The draft determination also notes that " while it is too early to evaluate the precise effect on efficiency from the use of advanced metering infrastructure (AMI – smart meters), the AER expects that such efficiencies will be evident over time and will impact on operating cost trends over time. Through its annual reporting framework, the AER will be monitoring the way AMI impacts on operating costs"[371]. Based on this, Nuttall Consulting understands that the AER has not applied an efficiency factor or other form of assumed opex reduction in relation to the AMI roll out.

9.5.1.2 Summary of proposed activities

United Energy is proposing additional operating expenditure of $10 million over the next regulatory control period to deliver demand management activities. The proposed activities are as follows:

- use of AMI data for demand management
- preparations for critical peak pricing
- systems and data to support RIT-D and demand participation engagement
- broad based demand management initiatives
- demand management team.

The following table provides a breakdown of the proposed operating expenditures.

[368] Final determination - Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications - October 2009, p102

[369] Ibid, page 104.

[370] Draft decision Victorian electricity distribution network service providers, Distribution determination 2011–2015 - June 2010.

[371] Ibid – page 273.

Table 72 - Forecast United Energy operating expenditure on Demand Management activities

Activity/Project	2011 ($m)	2012 ($m)	2013 ($m)	2014 ($m)	2015 ($m)	Total
Use of AMI data for Demand Management	0.00	0.25	0.35	0.35	0.05	1.00
Preparations for Critical Peak Pricing	0.00	0.00	0.00	0.05	0.45	0.50
Systems and Data to support RIT-D and demand participation engagement	0.00	0.10	0.20	0.15	0.05	0.50
Broad Based Demand Management Initiatives	0.50	1.00	1.50	1.50	1.50	6.00
Demand Management Team	0.20	0.45	0.45	0.45	0.45	2.00
Total Baseline Operational Expenditure	**0.70**	**1.80**	**2.50**	**2.50**	**2.50**	**10.00**

In its revised proposal, United Energy has provided brief information regarding each of the above proposed activities. Each activity and the Nuttall Consulting assessment of them are discussed below.

9.5.1.3 Use of AMI data for Demand Management

United Energy notes that the roll-out of advanced metering infrastructure (AMI) will enable the collection of data on peak demand usage from each of its approximately 620,000 customers.

United Energy proposed to undertake activities in this area including integrating the information available from the AMI Rollout on the performance of the network and the incidence and location of peak demand events, and making this information available to network planners for planning purposes, and ultimately more generally to enable industry participants to identify potential non-network alternatives.

Over the next regulatory control period, United Energy proposed to develop an approach to gather demand data and establish the systems and protocols necessary to make it available across the business and to the industry more broadly, as appropriate.

United Energy has estimated that expenditure of $1 million will be required for this project. United Energy states that this estimate of expenditure is based on its own assessment of the costs involved in this process and is supported by analysis undertaken in connection with its Smart Grid, Smart City proposal and advice from Secure Energy and Secure Partners. No supporting information has been provided by United Energy beyond these statements.

United Energy notes that it is difficult to describe the benefits that may be achieved by having greater access to more granular and accurate demand data. However, United Energy state that they are confident that the benefits to customers and the industry will substantially exceed the proposed costs. By way of example, United Energy identifies that access to this data may allow for a delay of major expenditure on one or two reinforcement activities.

United Energy also states that "(i)t is exactly these types of benefits that underpin (in part) the decision to undertake the AMI rollout and to not undertake these benefit realisation activities would place customers at risk of funding the rollout without receiving the full measure of the expected benefits"[372].

Nuttall Consulting concurs with the United Energy position on AMI benefits and considers that it is important that the investment in AMI is allowed to deliver the intended benefits. It is also important to note that the AER's draft determination has not made any assumptions in relation to the efficiencies that may accrue from the AMI roll out.

The expenditure put forward by United Energy for the use of AMI data for demand management provides no quantification of benefits. The operating expenditure criteria require, among other things, that proposed expenditures are prudent and efficient. With no qualified level of benefit to consumers or United Energy, it is not possible to accept that the proposed step change opex meets these criteria.

Nuttall Consulting notes that it is difficult to describe the benefits that may be achieved through this program. However, the lack of any specific quantification of benefits means that Nuttall Consulting cannot be satisfied that the proposed expenditure is either prudent or efficient.

As stated in clause 6.5.6(d) of the NER; "If the AER is not satisfied as referred to in paragraph (c), it must not accept the forecast of required capital expenditure of a Distribution Network Service Provider".

As the proposed expenditure is a step change from the base level of operating expenditure, Nuttall Consulting cannot recommend the proposed additional expenditure.

9.5.1.4 Critical Peak Pricing

United Energy is proposing additional operating expenditure of 0.5 million associated with the development of critical peak pricing.

United Energy states that they have been a "pioneer in implementing innovative tariff structures to address network loading issues"[373]. As evidence of this, United Energy notes that the Summer Demand Incentive Charge introduced by United Energy was in effect the first Critical Peak Pricing tariff of its type in Australia.

United Energy also states that this experience has demonstrated that such tariffs can play a role in ameliorating emerging network constraints, but that full engagement with retailers and customers is required to ensure that the expected behavioural changes can be achieved.

[372] Revised Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015, United Energy Distribution, Page 316.

[373] Revised Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015, United Energy Distribution, Page 316.

United Energy has identified expenditure on collecting data and for the costs of presenting proposals to the industry and to retailers. United Energy notes that this expenditure is also aimed at supporting a more detailed engagement with these parties so as to ensure that solutions are acceptable and workable and therefore more likely to achieve the expected benefits.

In seeking to understand the possible benefits that may result from the proposed step change expenditure, Nuttall Consulting has reviewed the application of the Summer Demand Incentive Charge. This charge has been in place prior to 2006 and is continued in the United Energy 2010 tariff strategy[374]. This information highlights that the Summer Demand Incentive Charge remains a part of the United Energy tariff strategy and that its application is reviewed at least every five years as part of the overall tariff arrangements.

While we may be able to deduce that the longevity of the Summer Demand Incentive Charge suggests it is efficient, it does not provide evidence for the provision of additional opex to further investigate critical peak pricing. On the contrary, the regular review of tariffs (including the Summer Demand Incentive Charge) suggest that some of the cost proposed for investigating critical peak pricing may overlap with the existing costs for tariff review. United Energy has not addressed this consideration in their revised proposal.

Consistent with the position described above for AMI data, Nuttall Consulting finds that the information provided by United Energy for critical peak pricing provides no quantification of benefits. With no qualified level of benefit to consumers or United Energy, it is not possible to accept that the proposed step change opex meets the operating expenditure criteria.

Nuttall Consulting notes that it is difficult to describe the benefits that may be achieved through this program. However, the lack of any specific quantification of benefits means that Nuttall Consulting cannot be satisfied that the proposed expenditure is either prudent or efficient.

As stated in clause 6.5.6(d) of the NER; "If the AER is not satisfied as referred to in paragraph (c), it must not accept the forecast of required capital expenditure of a Distribution Network Service Provider".

As the proposed expenditure is a step change from the base level of operating expenditure, Nuttall Consulting cannot recommend the proposed additional expenditure.

9.5.1.5 Demand Management engagement and the new Regulatory Test

United Energy is proposing $0.75 million in additional operating expenditure to improve the assessment of demand management options.

In its revised submission[375] United Energy notes that "(t)he traditional industry approach to network development has been to fully plan to meet future demand from network solutions and to then pursue non-network solutions". United Energy recognises that non-

[374] United Energy Distribution Tariff Report 2010 - January 2010.

[375] Revised Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015, United Energy Distribution, Page 317.

network solutions should form part of the assessment of possible solutions at a much earlier stage and that bringing forward the assessment of non-network alternatives is a key driver of the regulatory changes being proposed.

United Energy state that, "while electricity distribution businesses have well-developed systems for collecting, assessing and developing network solutions the same is not generally true for non-network solutions"[376]. Whether United Energy is specifically referring to their own processes or not is unclear from this statement.

The expenditures proposed by United Energy are essentially based on the premise that non-network solutions are not adequately considered in the planning process at present and that these expenditures are required to develop new systems, processes and data dissemination approaches over the next regulatory control period.

United Energy has estimated that at least $0.75 million will need to be spent on these particular activities.

Nuttall Consulting notes that the consideration of non-network solutions is not a new obligation on the DNSPs. The current National Electricity Rules specifically identify that the AER must consider the extent the DNSP has considered, and made provision for, efficient non-network alternatives[377].

United Energy has been cognisant of the need to consider non-network solutions for many years:

- **1 December 1999** - A demand side response achieved from customers modifying usage patterns (in response to price signals) can deliver a cost reduction to the industry and hence customers. These benefits come from deferred capital expenditure on new generation, transmission and distribution capacity to meet the peak demands of customers[378].
- **1 December 1999 -** A demand side response can be achieved by customers choosing to use energy at off peak times (ie, load shifting) and or by them making an economic decision not to use it at all at some times[379].
- **21 October 2004** - In the capacity augmentation of transmission connection assets, the (Essential Services Commission) has encouraged the Distributors to consider embedded generations as alternative to traditional network solutions[380].
- **21 October 2004** - An interruptible tariff was introduced for those large customers who are occasionally willing to have some of their load remotely switched off, or to have stand-by generation started by United Energy. The purpose of this initiative was to enable more network capacity to be available when it is otherwise highly

[376] Ibid
[377] NER cl 6.5.6(e)(10)
[378] 2001 Electricity Distribution Price Review Submission, United Energy, 1 December 1999, page 72.
[379] Ibid
[380] 2006 Electricity Distribution Price-Service Offering - United Energy Distribution, page 46.

utilised, by encouraging large customers to delay their usage by a few hours, in doing so, freeing-up capacity for others[381].

The use of non-network solutions is good electricity industry practice and has been widely recognised as so for many years. United Energy has also clearly been aware of the need to consider non-network solutions and has even referred to itself as a "pioneer in implementing innovative tariff structures to address network loading issues"[382].

As the consideration of non-network solutions is an existing regulatory obligation, Nuttall Consulting considers that the United Energy application for additional operating expenditure is not prudent and does not meet the requirements of the operating expenditure objectives.

United Energy has also identified that implementation of the regulatory investment test for distribution (RIT-D) as recommended by the AEMC[383]. The recommendations of this report do not represent a current obligation on the DNSPs, but are reasonably likely to become a binding regulation in the timeframe of 1 to 2 years in the case of Victoria. United Energy has not provided a breakdown or detailed description of the cost build up associated with these proposed step change expenditures.

Nuttall Consulting considers that although United Energy will already be performing at a level that meets many of the recommendations of this final report, it may be necessary to formalise these processes or align them to the new regulatory obligations. On this basis, Nuttall Consulting considers that the proposed expenditures for RIT-D represent a prudent expenditure. It is not possible to determine whether the efficient level of expenditure for this activity.

Nuttall Consulting notes that the AER has already made an allowance of $1.39 million for the implementation of the RIT-D requirements. Nuttall Consulting considers that this additional expenditure should reasonably provide for the issues of formalising or aligning existing processes with the proposed new regulations.

9.5.1.6 Broad Based Demand Management Initiatives

United Energy is proposing to implement "broadly-based demand management initiatives" to replicate schemes that have been put into practice in other jurisdictions and work in conjunction with demand-side aggregators. United Energy has allocated $6 million over the next regulatory control period for these activities.

The United Energy revised proposal notes that the benefits of demand response are now reasonably well established and that there are several businesses in Australia which are dedicated solely to the provision of this service.

[381] Ibid

[382] Revised Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015, United Energy Distribution, Page 316.

[383] Final Report, Review of National Framework for Electricity Distribution Network Planning and Expansion - 23 September 2009

United Energy points to a number of drivers for increasing use of demand-side response including:

- the perceived greenhouse gas benefits of demand response
- the ability of demand response to support and complement renewable energy solutions
- the ability to lower capital expenditure requirements.

United Energy state that they have confirmed with Energy Response and with Secure Energy that a programme of the size envisaged can be implemented and will deliver significant benefits. United Energy considers that these benefits are likely to be greater than the limited deferral benefits set out in the original regulatory proposal.

United Energy also considers that there is anecdotal evidence to suggest that consumers are prepared to fund modest initiatives which produce external or ancillary benefits such as reduced emissions, improved environmental and safety outcomes, and, in some cases, even improved social equality. UER does not provide any evidence to support this statement.

Nuttall Consulting agrees that demand side solutions are an emerging and viable option for deferring capital expenditure. As discussed in the previous chapter, United Energy is obliged to consider non-network solutions and has reportedly been doing so for many years.

A number of other DNSPs have proposed non-network solutions utilising the same providers as described by United Energy. However, in these cases the DNSPs have also identified the capital deferrals that are intended to be achieved. This has enabled consideration of whether the demand-side options are an efficient alternative or not.

United Energy has not identified or quantified the level of capital deferral that is attributable to the "Broad-Based Demand Management initiatives", so it is not possible to determine if the proposed expenditures meet the efficiency requirements of the NER.

In the absence of identified benefits, it would be inconsistent with the operating expenditure objectives to recommend the proposed additional operating expenditures.

9.5.1.7 Demand Management Team

United Energy estimates that the costs of hiring and retaining a team charged with championing demand management solutions would amount to $2 million dollars across the next regulatory control period[384].

United Energy considers that to achieve changes in processes, system and culture requires a dedicated effort and that United Energy is committed to being a leader in providing customers and the industry with the benefits that effective, efficient and prudent demand response activities can deliver.

[384] Revised Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015, United Energy Distribution, Page 320.

United Energy considers that these benefits can only be delivered if there is a dedicated team within the organisation to develop and share the skills and resources necessary for effective demand management processes. The skills and capabilities required are supplementary to the traditional skills required within an electricity distribution business.

The United Energy proposed expenditure related to a senior manager reporting to the Chief Operating Officer and, one senior project manager for a four year period.

Nuttall Consulting agrees that delivering changes in processes, system and culture requires a dedicated effort. However, based on the information provided in the original and revised proposals, United Energy has not proven the need for the step change. As previously discussed, there is no identified change in regulations or obligations that supports this step change.

Nuttall Consulting also notes that United Energy is already obliged to consider non-network solutions and has already stated that it considers non-network solutions when developing options for meeting network demand.

Nuttall Consulting supports United Energy's position of seeking to become a leader in the provision of demand response activities. However, the information provided by United Energy to support this step change does not satisfy the operating expenditure objectives and cannot be recommended by Nuttall Consulting at this time.

9.5.1.8 Summary and conclusion

Nuttall Consulting does not recommend the proposed operating additional expenditure for the:

- use of AMI data for demand management
- preparations for critical peak pricing
- systems and data to support RIT-D and demand participation engagement
- broad based demand management initiatives
- demand management team.

Nuttall Consulting considers that the information provided by United Energy does not satisfy the NER operating expenditure objectives.

9.5.2 ZS power quality metering maintenance

United Energy has proposed a step change of $85k for zone substation power quality metering.

United Energy state that in the 2001-05 EDPR decision United Energy was provided with the capital funds to install power quality meters in every zone substation and at the far end of a distribution feeder from each zone substation[385]. United Energy states that the

[385] Regulatory Proposal for Distribution Prices and Services, January 2011 – December 2015, United Energy Distribution, page 58.

meters were installed as planned and the data collected was reported to the ESC as part of the annual performance reporting requirements.

A routine maintenance policy is now recommended by United Energy for these meters to ensure they remain in reliable service. The maintenance frequency recommended by United Energy for all power quality meters is eight years. This means that routine maintenance is scheduled for the first time on the entire power quality meter population in 2011.

In the draft determination, the AER did not allow this proposed additional expenditure on the basis that the activity did not represent a new or changed regulatory obligation.

In its revised proposal United Energy states that it plans to undertake this work, and that United Energy should be provided with an operating expenditure to enable it to implement its plans. United Energy notes that other DNSPs have received operating expenditure allowances for such activities, but did not provide specific references.

Nuttall Consulting recognises that meter maintenance is required and that the eight year period identified by United Energy is within industry standards. As the power quality meter assets are relatively new, the first maintenance will occur in the next control period and then be ongoing.

On the basis that the meters have been installed in every United Energy zone substation and at the far end of a distribution feeder from each zone substation, Nuttall Consulting considers that the amount proposed for the maintenance is reasonable. Nuttall Consulting notes that travel time to each meter location will be a factor in the proposed costs.

Nuttall Consulting considers that the proposed expenditures meet the operating expenditure objectives in terms of prudent and efficient costs.

Nuttall Consulting notes that the operating expenditure scaling formula that has been used by the AER to adjust future opex requirements may already account for the proposes step change increase. Nuttall Consulting understands that asset volumes were used as a proxy for the scaling factors. This is provided as an observation only. Nuttall Consulting was not involved in the application of these scaling formulas and does not provide a recommendation either way in this matter.

9.5.3 ZS secondary spares maintenance

United Energy is proposing an additional operating expenditure step change of $10k for the next regulatory control period relating to zone substation secondary spare maintenance.

United Energy states that this step change relates to spare secondary equipment, in particular digital microprocessor based protection & control relays[386]. Secondary equipment continues to evolve, in particular within the last 10 years with the development of digital microprocessor technologies. Traditionally, spare secondary

[386] Response to Darren Kearney Questions dated 22 January 2010, Issue 1: 3 February 2010

equipment required no specific maintenance other than storage in a clean and stable environment. This was particularly true for older electro-mechanical type equipment.

United Energy considers that this maintenance practice is no longer considered satisfactory for the newer digital microprocessor technologies as electrolytic capacitors in the relay power supply circuits are subject to "drying out" if not regularly energised. United Energy provided statements that equipment manufacturer's including General Electric (GE) and Schweitzer Engineering (SEL) now recommend that their equipment be routinely energised (that is, cycle power on/off) while in storage.

The maintenance regime proposed by United Energy simply involves cycling the auxiliary power supply of each digital microprocessor protection relay that is held in spare storage for at least one hour every 4 years.

The operating expenditure step change of $10k is based upon United Energy's internal labour rate and an allowance of 2 hours per device.

United Energy considers that the failure to implement this practice increases the risk that the spare equipment will not be serviceable when called upon, that is, during times of emergency. A number of alternative options were considered by United Energy but deemed unsatisfactory, including:

- storage of additional spares; this option is not considered cost effective particularly given the high capital cost of the equipment (e.g. average protection relay cost of $10K) and the ongoing stores costs
- spares kept energised; this option was not considered practical.

Nuttall Consulting agrees that energisation of digital microprocessor equipment may prevent or reduce the likelihood of failure of the stored units. However, the proposed expenditure does not provide sufficient justification for the additional expenditure. Nuttall Consulting has concerns that:

- the risk that a spare unit may not be available has not changed as current practice is not to energise the spare units
- it is not clear how long the manufacturer recommendations have been in place and whether there have been historical failures of spare equipment that have impacted United Energy's performance
- if a spare unit were to fail, whether there is more than one spare or alternate options for interim operations
- as a replacement unit is reported to cost $10k, it is not clear whether it is economically justified to spend $10k every fours years to prevent a possible failure.

In addition to the above concerns, Nuttall Consulting also notes that not all spares will remain in storage for a four year period. Typical stores procedures are to utilise older stock as new stock is purchased. This is referred to as FIFO (first in - first out). It is not clear from the information provided by United Energy as to whether the secondary spares are the current standard for new and replacement installations. If they are the current standard, United Energy does not appear to have considered the impact of new stock moving through the inventory and thereby deferring the need to power up the spares in question.

Based on the above, United Energy has not demonstrated that the proposed expenditure is prudent and meets the requirements of the NER. Nuttall Consulting is therefore unable to recommend the addition of this expenditure to the opex allowance.

In terms of efficiency, United Energy identified a two-hour unit of time to cycle the auxiliary power supplies of all major digital microprocessor protection relays for one hour every 4 years. If this were a single unit that was being powered up, it may be reasonable to assume a two-hour labour requirement. The United Energy information did not identify the exact number of units being energised, although the $10k expenditure suggests that it is a volume of units sufficient to allow for significant synergies in the process. The United Energy proposed additional expenditure is not considered efficient. Nuttall Consulting has not recommended a substitute efficient expenditure as the overall expenditure is not considered prudent and therefore not recommended for recovery.

In addition, Nuttall Consulting notes that the operating expenditure scaling formula that has been used by the AER to adjust future opex requirements may already account for the propose step change increase. Nuttall Consulting understands that asset volumes were used as a proxy for the scaling factors. This is provided as an observation only. Nuttall Consulting was not involved in the application of these scaling formulas and does not provide a recommendation either way in this matter.

9.6 Industry-wide step changes

The following section provides Nuttall Consulting's analysis and recommendations in relation to operating expenditure step changes that have been proposed by two or more DNSPs.

9.6.1 Outcomes monitoring and compliance

The AER has announced that it intends to establish a monitoring framework to monitor the Victorian DNSPs against the AER's 2011–15 Victorian distribution determinations, and the service levels delivered to customers. This framework and approach were described in chapter 21 of the AER's draft determination.

The DNSPs have responded to the AER's intentions and requested additional expenditures to meet these requirements. The exception to this is SP AusNet who has not requested any additional expenditures in this area. The additional opex and capex expenditures requested by the DNSPs are provided in the following tables.

Table 73 – Outcome monitoring and compliance requested expenditures (opex $000)

	2011	2012	2013	2014	2015	Total
CitiPower	665	60	60	60	60	905
Jemena	76.6	76.6	76.6	76.6	76.6	382.8
Powercor	665	60	60	60	60	905
SP AusNet	-	-	-	-	-	
United Energy	80	80	80	80	80	400

Table 74 – Outcome monitoring and compliance requested expenditures (capex $000)

	2011	2012	2013	2014	2015	Total
CitiPower	-	-	-	-	-	-
Jemena	106	-	-	-	-	106
Powercor	-	-	-	-	-	-
SP AusNet	-	-	-	-	-	-
United Energy	130					130

The measures proposed for outcome monitoring and compliance include capital and operating expenditures, service standards, network statistics, incentive and sharing schemes, demand quantities and public lighting information.

The AER has requested Nuttall Consulting to review the expenditures proposed by the DNSPs in relation to this proposed future obligation. Nuttall Consulting has not been requested to comment on the structure or content of the proposed scheme.

The AER is proposing that the monitoring framework will replace the existing annual reporting framework previously established by the Essential Services Commission of Victoria (ESCV) for monitoring a DNSP's regulatory accounts and network performance indicators.

The AER's proposed framework also includes monitoring outcomes of the capex and opex programs proposed by the DNSP. The reporting of actual opex and capex, and volume information by DNSPs is currently required under the Victorian framework. In addition to this, the AER is proposing to also monitor certain outcome measures for material programs and cost categories. The outcome measures proposed will include measures of the effectiveness of opex and capex expenditure through a number of monitoring and performance measures as well as physical volumes of assets such as the number of new connections. The outcomes monitoring framework also includes outcome measures relating to service standard levels, such as the monitoring of low reliability feeders for Victorian DNSPs, which continues the existing ESCV approach.

The information identified by the AER will be collected annually through the issuing of a regulatory information notice. The outcomes monitoring measures described in chapter 21 of the AER's draft determination intended to provide guidance on the framework that the AER intends to implement. The AER has stated that it will undertake further consultation with Victorian DNSPs and other stakeholders to determine the specific form of the outcome measures for Victorian DNSPs to report against as part of a separate RIN process.

9.6.1.1 CitiPower outcomes monitoring and compliance

CitiPower has stated that the information sought by the AER for outcome monitoring is not readily available from within CitiPower's systems[387]. CitiPower notes that the information provided to the AER during the information exchange process was often the result of approximations or assumptions or involved the extensive use of internal resources to prepare. CitiPower considers that this approach is not suitable as a process for the longer term and is unlikely to result in the quality of information the AER expects.

In addition, CitiPower states that it cannot continue to devote up to ten full time resources to collect information not used internally within CitiPower.

CitiPower also notes that the requirement for annual five yearly forecasts for capex appears particularly onerous. CitiPower considers that this equates to an annual price reset process for DNSPs which will require extensive resourcing.

The CitiPower revised proposal states that "(b)ased on CitiPower's previous regulatory experience, it expects that the high level listing of information in the Draft Determination will not be all that is required to satisfy the AER's outcomes monitoring framework. Experience has demonstrated through the RIN process associated with the current price reset that final RINs have deviated substantially from draft RINs and over time, further information has been sought that has not been listed in any RIN".

CitiPower considers that the outcomes monitoring program will require augmentation of CitiPower's existing reporting systems and resourcing.

CitiPower also expects that because information is now being sought through a RIN, the collection and reporting of that information will require greater due diligence than it has exercised under the existing reporting arrangements. Consequentially, CitiPower considers that it will be required to periodically audit the information being provided and subject any information being provided to the AER to legal review.

CitiPower has forecast the costs associated with managing the AER's proposed outcomes monitoring program and provided these forecasts as an attachment to the revised proposal. The total costs have been apportioned evenly between CitiPower and Powercor Australia.

CitiPower proposes the following step change relating to outcomes monitoring and compliance expenditure.

[387] CitiPower Pty Revised Regulatory Proposal: 2011 To 2015 - 21 July 2010, Page 204

Table 75 – CitiPower outcome monitoring and compliance requested expenditures (opex $000)

	2011	2012	2013	2014	2015	Total
CitiPower	665	60	60	60	60	905

The following table provides a summary of the IT cost analysis provided by CitiPower and Powercor. These costs are split 50/50 between each business.

Table 76 – CitiPower/Powercor IT step change – outcomes monitoring

Description	2011 ($000)
1. AER states that it intends to capture information reflecting the health (or condition) of each zone substation transformer and major item of switchgear, and track the changes in health (or condition) over time. This will be used to inform the AER of the effectiveness of the DNSPs' asset replacement investment decisions over the regulatory control period. The exact assets to be covered to be determined through consultation following the final distribution determinations. (AER, Draft Determination, p912)	$400
2. AER states that this outcome measure will monitor the volume of customer connections, the average cost and average level of customer contributions per connection relative to the DNSP's forecasts approved by the AER in its Victorian distribution determinations. This will allow comparisons by the AER of key customer connection metrics against the forecasts by DNSPs approved by the AER in its distribution determinations. (AER, Draft Determination, p913)	$150
3. AER states that failure rates are reflective of a DNSP's asset management outcome, which is a combination of asset replacement expenditure and the effectiveness of their operation and maintenance activities. monitoring will allow the AER to gain a further indication of the impact of the DNSP's investment decisions. This will provide greater transparency and accountability of the performance of a DNSP and will better inform the AER in its assessments of the DNSPs regulatory proposal in the 2016–20 distribution determinations. (AER, Draft Determination, p914)	$600
4. AER state that it is expected that the Advanced Metering Infrastructure (AMI) rollout program will enable DNSPs to improve their operational efficiency, for example faster response time and more accurate response through better network intelligence. (AER, Draft Determination, p915)	$0
5. AER states that this includes guaranteed service level (GSL) payments, call centre performance and customer complaints measures similar to those currently reported under the Information Specification (service performance) for Victorian DNSPs under the existing ESCV framework. (AER, Draft Determination, p915)	$30

Description	2011 ($000)
6. AER states that major event days are currently not subject to a financial incentive scheme. AER intends to develop monitoring measures for major event days in the future, and will consult further with DNSPs on this issue. AER considers it necessary to monitor a DNSP's performance during these days to provide the AER with further information on the adequacy of a DNSP's emergency management system. consistent with the monitoring of services to the worst served customers, and will complement the network average measures reported under the STPIS. (AER Draft Determination, p916)	$0
7. AER states that DNSPs must submit to the AER an annual report on their expenditure under the demand management incentive allowance (DMIA) for each regulatory year of the regulatory control period. (AER, Draft Determination, p917)	$30
Total	**$1,210**

Nuttall Consulting has been requested by the AER to review the proposed step change expenditure for outcomes monitoring and compliance.

To understand the drivers of the changes in operating expenditure, Nuttall Consulting has reviewed the historical levels of expenditure associated with regulatory reporting and compliance.

In its proposal for the 2001-2006 regulatory period CitiPower identified forecast regulatory costs of $20.5 million[388]. Actual expenditure reported by CitiPower for this period was $2.8 million[389]. Nuttall Consulting notes that the definitions of these cost categories have changed over time although the main descriptions remain consistent. The dollar values are from different dates and when corrected for inflation, the differential is even greater. Consistent with other observations of forecast and actual expenditures, there appears to be a consistent error in the way in which CitiPower forecasts costs associated with regulatory obligations.

This observation suggests that the process for building up the forecast step change costs requires closer scrutiny. To be clear; although the above observations suggests that the CitiPower step change forecasts in this category may not be prudent or efficient, Nuttall Consulting has not considered this as proof of an error.

Nuttall Consulting has reviewed each of the step change costs identified by CitiPower in the IT area. As part of this review, we note the AER's statement that "(t)he AER will undertake further consultation with Victorian DNSPs and other stakeholders to determine the specific form of the outcome measures for Victorian DNSPs to report against as part of a separate RIN process"[390]. Nuttall Consulting has assumed that the AER commitment to

[388] 2001 Distribution Price Review Submission, Chapter 3: Operating And Maintenance Expenditure, page 103.
[389] CitiPower Regulatory Information Notice 2010.
[390] AER Draft Determination – Chapter 21, section 21.1.

consultation will include responding to feedback from the DNSPs. The AER is required to consider the economic impact of its decisions and Nuttall Consulting considers that the economic impact will be a consideration of the consultation process.

Table 77 – CitiPower/Powercor IT step change – outcomes monitoring

Nuttall Consulting review of IT step change items (numbering refers to Table 76 – above)
1. CitiPower's existing Asset Management Strategy includes to "Fully implement asset health scores and reporting regime applying Condition Based Risk Management (CBRM) methodology"[391]. Nuttall Consulting considers that good electricity industry practice also requires the collection and recording of this information.
2. CitiPower has already identified a group (called "Customer Projects") who are responsible for connections policies, procedures, standards and guidelines relevant to Customer initiated projects. CitiPower also currently collects and records the information identified by the AER in this category. Nuttall Consulting considers that good electricity industry practice also requires the collection and recording of this information.
3. The CitiPower Asset Management Plans identify and discuss the collection and use of failure rate data. Nuttall Consulting considers that good electricity industry practice also requires the collection and recording of this information.
4. Information on AMI efficiencies is not currently captured or reported. The DNSPs are currently rolling out their AMI programs. Nuttall Consulting agrees with CitiPower that there is not sufficient information available at this time to estimate the potential impact, if any, on the DNSPs.
5. CitiPower already captures, records and reports on guaranteed service level (GSL) payments, call centre performance and customer complaints measures under the Information Specification (service performance) for Victorian DNSPs under the existing ESCV framework.
6. CitiPower already captures and records measures for major event days as these are required to be "netted off" in the current reporting regime. In relation to emergency management systems, Nuttall Consulting notes that CitiPower already operates an emergency management system and considers that it is good electricity industry practice to periodically review such systems.
7. CitiPower currently captures and records information on expenditures under the demand management incentive scheme.

[391] Asset Management Framework, CP-AMF-0001, Issue 1.0 Version 1.0, Nov 2009, page 23.

Based on the above analysis, Nuttall Consulting considers that the information currently being captured by CitiPower is sufficient (or more than sufficient) to meet the likely regulatory requirements. Nuttall Consulting recognises that, in some instances, the requirement to actually report this information may be a new requirement, but that the information is already collected and stored by the business.

This analysis is further supported by the Jemena submission on these new reporting requirements that states that data extraction, review and adjustment, are not additional activities[392].

The actual data requirements and definitions for reporting have not been defined. As previously discussed, Nuttall Consulting considers that the AER will consider the business impacts when consulting on the data requirements.

CitiPower has stated that approximations or assumptions may be suitable for a 'one off' request, but are not suitable as a process for the longer term. Nuttall Consulting notes that much of this information is already provided in the current regulatory proposals provided by CitiPower and will therefore only move from a 5-year reporting requirement to an annual requirement.

CitiPower also states that it cannot continue to devote up to ten full time resources to collect information not used internally within CitiPower. This suggests that any alterations to the IT systems will have significant efficiency benefits to the current CitiPower cost base. For clarity, Nuttall Consulting is not recommending any reductions to the CitiPower cost base on the basis of this CitiPower statement.

The CitiPower submission on step change costs for outcomes monitoring and compliance makes no mention of the potential synergies and efficiencies associated with the existing regulatory costs. Noting the historical inaccuracy of the CitiPower assessments of forecast costs, Nuttall Consulting considers that such synergies and efficiencies will exist and have not been accounted for by CitiPower.

Nuttall Consulting is also required to consider the relative efficiency of the proposed step change expenditures[393]. From a benchmarking perspective, CitiPower/Powercor, United Energy and Jemena are the only businesses to identify an up-front IT related set of expenditures. SP AusNet has not identified any initial IT expenditures.

Based on the above, Nuttall Consulting considers that the proposed IT expenditures for CitiPower do not meet the operating expenditure objectives. Nuttall Consulting considers that the proposed ongoing opex costs will be sufficient to meet the obligations of the proposed reporting requirements.

Nuttall Consulting considers that this recommendation may err in favour of CitiPower as no allowance for synergies or efficiencies with existing regulatory reporting processes has been made.

---

[392] Jemena Electricity Networks, Appendix 7.2 JEN Step changes—20 July 2010, page 72.

[393] NER cl. 6.5.6(e)(4) - benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period.

Nuttall Consulting notes that the proposed reporting requirements relating to outcomes monitoring and compliance are not well defined at this stage. Nuttall Consulting has considered the DNSP proposals against what it considers to be a likely level of reporting requirements – neither overly prescriptive, or overly simplistic.

Table 78 – CitiPower outcomes monitoring and compliance

CitiPower	Costs (2010 $'000)				
	2011	2012	2013	2014	2015
Proposed Expenditure	665	60	60	60	60
Recommended Expenditure	60	60	60	60	60

9.6.1.2 Powercor outcomes monitoring and compliance

Powercor is proposing an outcomes monitoring and compliance step change that is identical to that of CitiPower, described above. On this basis, the recommendations for CitiPower are deemed to equally apply to Powercor. Based on this Nuttall Consulting considers that the proposed IT expenditures for Powercor do not meet the operating expenditure objectives. Nuttall Consulting considers that the proposed ongoing opex costs will be sufficient to meet the obligations of the proposed reporting requirements.

Table 79 – Powercor outcomes monitoring and compliance

Powercor	Costs (2010 $'000)				
	2011	2012	2013	2014	2015
Proposed Expenditure	665	60	60	60	60
Recommended Expenditure	60	60	60	60	60

9.6.1.3 Jemena outcomes monitoring and compliance

Jemena identifies that this step change is linked to a changed regulatory obligation and therefore reasonably reflects the opex criteria[394].

Jemena notes that the DNSPs will be required to monitor certain outcomes that they are not required to monitor under the current framework and has identified the incremental monitoring measures which Jemena considers it will be required to undertake:

- financial reporting
  - actual capex activities according to the building blocks, further separated into different network types (similar to those currently provided under the AER's RINs)

[394] Jemena Electricity Networks, Appendix 7.2 JEN Step changes—20 July 2010, page 72.

  - actual opex activities according to the building blocks, further separated into different network types (or other suitable subcategories), similar to those currently reported in the AER's RINs

- capacity reporting
- annual failure rate forecasts (for each asset category and against each failure rate category)
- annual failure rate reporting
- annual report on expenditure under demand management incentive allowance
- Jemena Board / capital expenditure objectives certification of RIN – approval process.

Jemena notes that the above incremental measures do not include data extraction, review and adjustment, as these are not additional activities.

The Nuttall Consulting review of the Jemena submission on this step change has identified the following issues:

- The Jemena information[395] suggests a requirement for monthly financial reporting. Nuttall Consulting does not consider that this is indicated in the AER draft determination and considers that annual reporting is the most likely requirement.
- The identified information for financial reporting is already required and provided in five year increments. The new requirements simply represent bringing forward this requirement to an annual process. This represents a spreading of expenditure across the period rather than an additional workload.
- Jemena states that a new capacity utilisation process requires it to "calculate capacity utilisation at terminal station, zone substation, aggregated HV feeder and distribution substations". Nuttall Consulting understands that this information is already calculated by Jemena as part of its asset management processes.
- Jemena states that a new process for annual failure rate forecasts requires a "resource for auditing quality of failure and entering the data into the relevant IT system". Nuttall Consulting has reviewed information provided by Jemena and identified that "failure rate" information is already collected. Nuttall Consulting considers that the quality of failure rate information that is necessary to support good asset management will be consistent with the quality required for regulatory reporting.

Nuttall Consulting is also required to consider the relative efficiency of the proposed step change expenditures[396]. From a benchmarking perspective, the CitiPower and Powercor

[395] Jemena Electricity Networks (Vic) Ltd Revised Regulatory Proposal 2011-2015, Appendix 7.2, JEN's reference to AER's concerns raised in its Draft Decision – JEN Step changes - 20 July 2010, page 72.

[396] NER cl. 6.5.6(e)(4) - benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period.

proposed ongoing expenditures for step change outcome monitoring and compliance suggest an annual expenditure that is more efficient than that proposed by Jemena.

Based on above review of the Jemena cost build up, Nuttall Consulting recommends an annual step change requirement similar to that of Powercor and CitiPower. Nuttall Consulting notes that this is slightly greater than the amount that would be calculated from the reductions noted in the above dot points.

Table 80 – Jemena outcomes monitoring and compliance

Jemena	Costs (2010 $'000)				
	2011	2012	2013	2014	2015
Proposed Expenditure	76.6	76.6	76.6	76.6	76.6
Recommended Expenditure	60	60	60	60	60

9.6.1.4 United Energy outcomes monitoring and compliance

United Energy has provided information supporting additional operating and capital expenditure associated with outcomes monitoring and compliance. The information provided by United Energy is, for all intents and purposes, identical to the Jemena information on this topic. As such, Nuttall Consulting is recommending the same levels of expenditure as for Jemena.

Based on the Jemena review (above), Nuttall Consulting recommends an annual step change requirement similar to that of Powercor and CitiPower. Nuttall Consulting notes that this is slightly greater than the amount that would be calculated from the reductions noted in the above dot points.

Table 81 – United Energy outcomes monitoring and compliance

United Energy	Costs (2010 $'000)				
	2011	2012	2013	2014	2015
Proposed Expenditure	80	80	80	80	80
Recommended Expenditure	60	60	60	60	60

10 Appendix G – Unit cost review

This appendix addresses the review of unit costs for works that have been recommended by Energy Safe Victoria (ESV).

In response to regulatory changes, the Victorian Bushfires of 2009 and the Bushfire Royal Commission report, the DNSPs have identified a range of new or increased activities. The ESV has reviewed these activities and provided the AER with a recommendation as to the volume of works that are required by each business.

The ESV has also provided volume recommendations related to changes to regulatory obligations including the safety management scheme and line clearance. The unit costs of these items are also discussed in this section.

The AER has requested that Nuttall Consulting review and advise on the unit costs associated with these volumes.

10.1 CitiPower

CitiPower has proposed additional work volumes and unit rates associated with the introduction of the Electricity Safety (Electric Line Clearance) Regulations 2010. These regulations contain a number of changes to the way the DNSPs undertake their business activities.

10.1.1 Electricity Safety (Electric Line Clearance) Regulations

CitiPower is claiming additional expenditure due to changes to the Electricity Safety (Electric Line Clearance) Regulations:

- removal of LBRA clearance exemptions
- reduced clearances for insulated conductors
- environmentally or culturally significant (native) trees.

ESV has supported the need for additional work activity in each of these three areas.

The Nuttall Consulting assessment of the unit costs associated with the above additional works are provided in the following sections.

The total value of the additional vegetation management expenditures proposed by CitiPower is $6.53 million over the next regulatory period. This represents a 130% increase compared with current vegetation management costs[397].

397 [redacted].

10.1.1.1 Maintenance of the Clearance Space – LBRA

Clause 11 of the Electricity Safety (Electric Line Clearance) Regulations 2010 (the Code) establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 regulations[398]. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 regulations. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

[redacted] states that maintenance of the increased clearances will involve additional work in the nature of more spans to be cut relative to the cutting undertaken under the 2005 Code and more aggressive cutting of trees in spans.

[redacted] estimates that there are 3,000 spans in the CitiPower network which will need to be cut due to the removal of the allowance under the 2005 Code for reduced clearance spaces for powerlines other than ABC or insulated cables[399].

CitiPower is proposing that compliance with the revised clearance spaces will be established in 1 year.

For the remaining years of the next regulatory period, [redacted] estimate that there will be 1,800 spans each year which will require cutting to maintain the required clearance spaces.

[redacted] has used a unit rate of [redacted] a span in calculating the cost to comply with clause 11. This rate has also been used by [redacted] in determining the equivalent unit rate for Powercor.

The equivalent unit rate proposed by [redacted] is [redacted] per span for both LBRA and HBRA areas. [redacted] is proposing an annual program for vegetation management of HBRAs and this will result in a reduced cost per span due to the lesser regrowth time.

[redacted] is proposing a unit rate of [redacted] per span for LBRA areas.

[redacted] is also proposing a unit rate of [redacted] per span for LBRA areas.

Nuttall Consulting notes that [redacted] has assumed the same unit cost for the exemption removal for CitiPower as for Powercor. [redacted] notes elsewhere that urban areas are more likely to incur consultation and complaints than rural areas. It is not clear why [redacted] has assumed that the unit costs associated with the exemption removal are the same for both companies. One possible explanation is the longer travel times required to get to worksites in rural and remote areas.

The CitiPower/Powercor unit costs are considerably higher than those of the other Victorian DNSPs.

[398] Electricity Safety (Electric Line Clearance) Regulations 2005
[399] CitiPower does not have any designated High Bushfire Risk Areas (HBRA).

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.

On this basis, it is not possible to determine why the CitiPower and Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with the removal of the 2005 Code exemptions is $210 per span[400].

10.1.1.2 Reduced clearances for insulated conductor - ABC

The unit costs associated with reduced clearances for insulated conductors relate to the omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3 in the revised Electricity Safety (Electric Line Clearance) Regulations. CitiPower has identified two asset types that are impacted by the changed regulations: Aerial Bundled Conductor (ABC) and service lines. CitiPower have also identified annual and bi-annual clearing requirements associated with the Electricity Safety (Electric Line Clearance) Regulations.

In support of the additional costs, CitiPower has provided a [redacted][401]. [redacted] are the current providers of vegetation management services to Powercor and CitiPower. Nuttall Consulting notes that [redacted] may continue to provide vegetation management services to CitiPower and Powercor. This means that [redacted] are likely to be contracted to deliver the additional workloads described in the [redacted]. As such, Nuttall Consulting have sought where possible to identify third party estimates of the unit cost of meeting these obligations.

[redacted] have identified a unit rate of [redacted][402].

In 2009 CitiPower incurred costs of [redacted] for the clearing of [redacted] spans[403]. This equates to a unit cost of [redacted] per span. However the CitiPower information is not clear as to whether this included the cost of clearing for services or not. If so, this would reduce the cost per span considerably.

[400] Noting the [redacted] rate may be lower due to annual cutting.

[401] [redacted].

[402] Bid p22.

[403] Powercor and CitiPower response Step change Electricity Safety.pdf. Dated1 September 2010.

Nuttall Consulting notes the higher customer density of the CitiPower franchise area and the associated traffic management costs that are inherent with this territory. Nuttall Consulting also notes that the [redacted] unit rates provided are considered by [redacted] to be conservative.

Unit rate information provided by [redacted] identified costs associated with an elevated work platform and 2 crew to be [redacted] per hour. The cost associated with a wood chipper[404] vehicle and two crew was estimated at [redacted] per hour. These values suggest that CitiPower is estimating that the clearing of an ABC span will require in excess of 1 hour per span for both crews. Nuttall Consulting does not consider that the clearance of a single span of conductor would require both crews for more than an hour; particularly the chipper vehicle.

The [redacted] assessment of the number of LV spans does not appear to differentiate between stand-alone spans of ABC and those spans that are run on the same poles as other conductors. The CitiPower network is one of the most densely populated network areas in Australia and has a very significant proportion of poles with multiple circuits. The reduced costs associated with the clearing of ABC that is on the same span as another circuit does not appear to be recognised or considered by the [redacted].

The [redacted] also assumes an average span length of 50m for insulated conductor. This assumed span length is actually 25% greater than the actual average span length. The [redacted] identifies that CitiPower has 191km of ABC and 4,703 spans. This works out as an average of 40.6m per span. The reason why the longer span assumption was used when actual span length information was available is not clear. The assumption of a 25% increase in average span length would presumably impact the [redacted] assessment of cost per span.

CitiPower was requested to describe the level of scale efficiencies adopted in forecasting these costs. The CitiPower response to this question was: "Refer to sections 82 to 143 of the Witness Statement."[405] This reference is to the whole of the witness statement concerning insulated cables and does not contain any specific reference to scale efficiencies.

CitiPower was also requested to "describe and justify the savings that the DNSP anticipates associated with the 2010 Electric Line Clearance regulations". CitiPower responded that "There are no savings anticipated due to the omission of reduced clearances for aerial bundled and insulated cables"[406].

Nuttall Consulting notes that CitiPower is proposing to more than double (130% increase) the amount of expenditure on vegetation management. Given the compact territory of the CitiPower franchise, it is difficult to see how scale efficiencies would not be reasonable and significant when more than doubling the current level of activity.

[404] Vehicle for turning the cut vegetation into woodchips and transport of woodchips.
[405] Powercor and CitiPower response Step change Electricity Safety.pdf. Dated1 September 2010.
[406] Ibid

CitiPower was requested to quantify the impact that the step changes proposed would have on fault and emergency opex. In response, CitiPower stated that "The 2005 Regulations and HBRA/LBRA Exemption have been successful in establishing an achievable and practicable regulatory regime which does not compromise on safety. Consequently, there would appear to be significant costs and little community benefit, safety or performance justification for the change in the Regulations and the removal of the Exemption."[407]

Nuttall Consulting does not agree with the CitiPower position that there will be no impact on reliability outcomes from more than doubling the amount of expenditure associated with vegetation management. The trimming of vegetation has been proved to reduce vegetation related outages and also reduce damage to the network assets from contact and abrasion. The removal of more vegetation adjacent to powerlines will therefore have a resultant impact on vegetation related outages and network asset integrity. Nuttall Consulting recognises that the incremental removal of vegetation will have a lesser impact than the original trimming requirements.

Noting that CitiPower has applied the same unit rate for the clearance of insulated conductor (per span) as it has for the removal of the LBRA exemptions, it is reasonable to compare the CitiPower removed exemption unit rates with those of Jemena, United Energy and SP AusNet. The equivalent unit rate proposed by [redacted] is [redacted] per span. [redacted] and [redacted] are proposing a unit rate of [redacted] per span for LBRA areas.

Based on the above considerations, the CitiPower proposed unit rate of [redacted] per span is not considered efficient. Nuttall Consulting recommends a unit rate of $210 per span as an efficient average unit rate.

10.1.1.3 Reduced clearances for insulated conductor - Services

The unit costs associated with reduced clearances for insulated conductor relate to the omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3 in the revised Electricity Safety (Electric Line Clearance) Regulations. CitiPower has identified two asset types that are impacted by the changed regulations: Aerial Bundled Conductor (ABC) and service lines.

[redacted] has calculated that the average unit rate per service line would be [redacted], in either the annual initial cut or for ongoing recuts. This cost includes the cost of the cutting and clean-up of vegetation required as a result of the omission of clauses 9.2.1, 9.2.2 and 9.3 of the 2005 Code from the 2010 Code. The information provided by CitiPower did not provide any further breakdown of these costs or time required for the proposed works.

[redacted] also assessed the unit cost per service for compliance with the Electricity Safety (Electric Line Clearance) Regulations to be [redacted] for Powercor. [redacted] considered that there were likely to be [redacted]

[407] Ibid

[redacted].

In comparison, [redacted] has estimated a per service unit cost of [redacted] for the initial cut and [redacted] to "maintain clearance space" for insulated services. The initial cut cost comprises [redacted] and the ongoing recuts are costed at [redacted].

[redacted] has estimated the unit rate for the initial establishment of clearance space as [redacted] with an ongoing rate of [redacted] per service.

[redacted] has also estimated the unit rate for the initial establishment of clearance space as [redacted] with an ongoing rate of [redacted] per service.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.

On this basis, it is not possible to determine why the CitiPower and Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for a four-fold increase in ongoing service recuts in the CitiPower and Powercor areas.

The man-hour assessments provided by SP AusNet appear reasonable, as do the assumptions in relation to approximate times and crew numbers.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate for clearance of CitiPower insulated services to comply with the Electricity Safety (Electric Line Clearance) Regulations are as follows:

- initial clearance of services: $94.66
- ongoing clearance of services: $47.40.

Nuttall Consulting is recommending the higher initial clearance rate for CitiPower based on the [redacted] observation of increased consultation and complaints in more highly urban areas.

10.1.1.4 Environmentally or culturally significant (native) trees

Clause 2(3) of the 2010 Code requires that a responsible person must, as far as practicable, restrict the cutting or removal of native trees or trees of cultural or environmental significance to the minimum extent necessary to ensure compliance with the 2010 Code.

The cost impact of clause 2(3) on CitiPower arises from the requirement in respect of native trees. There was no provision in the 2005 Code that restricted the cutting or removal of native trees.

[redacted] has proposed a unit rate of [redacted] per span in calculating the cost of complying with clause2(3) of the 2010 Code. This represents the average cost per span of the additional work activity required as a result of the restriction on the ability to remove native trees introduced by the 2010 Code.

The unit rate for CitiPower of [redacted] is higher than that for Powercor of [redacted] based on the higher number of customer complaints and objections that are likely in CitiPower's predominantly urban network.

Jemena, United Energy and SP AusNet have not requested additional expenditure in relation to this obligation. As such, there are no costs to benchmark the CitiPower or Powercor unit rates against.

CitiPower and Powercor have not provided a breakdown of the proposed unit costs, so it is not possible to assess how the final unit rates were arrived at.

Neither the ESV assessment[408] or the CitiPower and Powercor information provide any indication of the sort of work that is anticipated to be undertaken in this cost category.

CitiPower and Powercor were requested to provide a detailed description of the physical change in work practices and other physical requirements relating to each area of change relating to the Electricity Safety (Electric Line Clearance) Regulations. The CitiPower and Powercor response referred to sections 170 to 181 of the [redacted]. These sections do not provide any quantification of the costs that are used as inputs to the unit rate. Nuttall Consulting does not consider that the CitiPower response is adequate. The CitiPower response does not provide a detailed description of the unit cost.

In the absence of a clear explanation of what constitutes the [redacted] unit rate, it is not possible for Nuttall Consulting to comment on whether this rate is efficient or not.

Nuttall Consulting notes that the [redacted] information relating to native trees or trees of cultural or environmental significance does not identify a cost reduction associated with the halt on the removal of this vegetation.

10.2 Jemena

Jemena is claiming addition expenditures for the next regulatory control period associated with the Electricity Safety (Electric Line Clearance) Regulations 2010. The main areas of additional expenditure are as follows:

- Strategic program expenditures
  - ESMS Process Compliance Costs
  - Replacement of Non-Preferred Services

[408] Assessment By Energy Safe Victoria Of EDPR Safety-Related Programs, ESV, 14 September 2010

  - Installation of Neutral Condition Monitors
  - Removal of Public Lighting Switch Wires
  - Ground Fault Neutralisers and Removal of SWER
  - Pole Top Fire Mitigation
  - Pole Top Replacement (Age & Condition)
  - Pole Replacement
  - Overhead Conductor Replacement
  - HV Installation Replacement
  - Distribution Substation & Overhead Switch Maintenance
  - Zone Substation Asset Conditioning Monitoring
  - Zone Substation Transformer Replacement
  - Zone Substation Circuit Breaker Replacement
- Electricity Safety (Electric Line Clearance) Regulation expenditure
  - Maintenance of the Clearance Space
  - Notification & Consultation
  - Service Line Clearance
  - Habitat Trees
  - Hazard Trees

Each of these expenditure items are covered in the following sections.

10.2.1 Strategic planning expenditures

Jemena has prepared a number of strategic planning papers targeted at specific asset classes. The papers identify additional expenditures associated with changes to the historical approach to managing these assets. The individual review of the ESV approved volumes for these strategies are considered below.

The ESMS compliance assessment has been grouped in this category for the sake of simplicity.

10.2.1.1 ESMS Process Compliance Costs

Jemena has identified the need for additional resources to meet its obligations under the new Electricity Safety (Management) Regulations. These regulations require Jemena to submit a risk-based Electricity Safety Management Scheme (ESMS).

ESV notes that the additional resources claimed by Jemena equate to less than 1 additional FTE over the five year period. ESV does not consider the level of resources to be material.

The following table provides the summary costs associated with the revised obligation.

Table 82 – Jemena process compliance costs

	2011	2012	2013	2014	2015
Jemena process compliance	$257,204	$166,068	$166,068	$166,068	$186,321

The Jemena unit rates are based on an internal labour rate of [redacted] per day. Nuttall Consulting notes that this is a relatively high rate and equates to an annual salary of approximately [redacted]. This level of remuneration is more consistent with a senior management or executive role, rather than a technical or administrative role.

On this basis, Nuttall Consulting recommends an annual FTE rate of $150k.

10.2.1.2 Replacement of Non-Preferred Services

Under its ESMS, Jemena is proposing a planned replacement program for non-preferred services. ESV noted that the need for the program was identified in the risk assessments conducted by Jemena in preparing its ESMS. The replacement of neutral screen services has been identified as a priority by the industry for more than a decade. The previous owner of the Jemena franchise area (AGL) identified that "particular attention" would be paid to neutral screen service replacement in 2004[409].

ESV note that the need for the program is supported by Jemena's statistics arising from defects detected during its Neutral Service Testing program and through the increasing trend in electric shocks reported by the public.

The majority of issues relate to neutral screened and twisted service cables. Both of these types of service cable are reaching the end of their service life and present levels of risk that require attention. ESV strongly supports the need for the proposed replacement program, which is expected to take 15 years.

The ESV supports the planned non-preferred service replacement and height replacement of services, but not the fault replacement. The ESV considered that fault replacement represented business as usual practice.

Nuttall Consulting notes that both the non-preferred service replacement and the height replacement programs are ongoing. It will be necessary to assess the historical volumes of service replacements and deduct these from the proposed replacement programs to determine the incremental volumes for the next regulatory period.

Jemena has proposed a unit rate for service replacement of [redacted].

Nuttall Consulting has reviewed the proposed replacement cost of [redacted] per service. The proposed per unit rate of [redacted] is not consistent with current Jemena prices to provide a new service. The new service and meter price charged by Jemena is currently [redacted].

[409] 2006 Electricity Distribution Price Review Submission By AGL Electricity Limited, 2004, page 49.

This service includes the installation of a service (single phase) and meter and will typically involve greater travel distances between jobs than a programmed replacement schedule.

An efficiently run replacement program would be undertaken to minimise travel time through undertaking all replacements within close proximity to each other where possible. As these services were often installed as suburbs were developed, many will be in adjacent houses.

The current [redacted] charges to install a temporary single phase service is [redacted] and this includes the disconnection and removal of the service at a later date. The cost for a temporary service installation with a coincident disconnection is [redacted]. This is essentially the same physical requirements as for a service replacement, with the additional costs of connecting a meter.

Nuttall Consulting notes that a percentage of neutral screen services may be three phase and that the connection time for these services may be a little longer than for a single phase service. The cost of the service materials may also be slightly higher.

To allow for the slightly higher three phase costs, Nuttall Consulting recommends a per unit amount of $160 for each service replacement.

10.2.2 Installation of Neutral Condition Monitors

Jemena has proposed a program to trial the effectiveness of a neutral condition monitor that will continuously monitor the integrity of the supply neutral, and provide an alarm when the integrity of the neutral is compromised. The aims of the program are:

- to trial the effectiveness of the monitors in the Jemena territory
- to target areas with high Neutral Screen Testing (NST) failure rates/public reported shocks
- to provide a targeted education campaign.

Jemena proposes to install 5,000 neutral condition monitors for each year of the forthcoming regulatory period, giving a total of 25,000 for the period.

The ESV supports the trial program.

Nuttall Consulting understands that the Neutral Condition Monitors are also commonly referred to as “WireAlert” monitors and, in Tasmania, as “Cable PI”.

Jemena has provided a unit costs of [redacted] per neutral condition monitor[410].

The distributors of WireAlert made a submission to the AER indicating a unit cost of $50[411].

In the absence of any additional information, Nuttall Consulting concludes that the proposed per unit cost of [redacted] is reasonable.

[410] Jemena Electricity Networks (Vic) Ltd Revised Regulatory Proposal 2011-2015, Appendix 8.36, Strategic Planning Paper - Trial of Neutral Condition Monitor - 20 July 2010

[411] Submission To The Victorian Electricity Distribution 2011-2015 Price Review. Responding to the draft Jemena Electricity Networks (Victoria) Ltd Distribution, Determination 2011–2015. Submitted by: Greg Mannion, Chief Executive Officer EziKey Group Pty Ltd (trading as WireAlert) - August 2010

10.2.3 Removal of Public Lighting Switch Wires

As identified by the ESV, public lighting switch wires have been largely redundant since the mid 1980’s as lighting control was transferred to photo electric switching. On the Jemena network, the switch wires were not removed when luminaires were replaced and in many places have still remained in place for over 30 years as an unmaintained asset.

Jemena has opportunistically removed switch wires during other programmed work, but it is estimated that around 5,100 spans remain on the Jemena network (based on experience). The presence of unmaintained switch wires represents a hazard (there have been several fatalities and near misses) and ESV strongly supports Jemena’s program to remove the remaining spans of switch wire on a planned basis.

The ESV supports this program.

The Jemena proposed approach to switch wire removal is to:

- continue and reinforce the opportunistic removal of switch wire during major maintenance
- identify the extent and presence of switch wire during the 4 yearly pole and line inspections
- remove the remaining sections of obsolete public lighting switch wire over a three year period to 2015. This is expected to require one line crew with traffic control for approximately 50% of the time over a three year period and would be co-ordinated with major maintenance and renewal activities as far as practicable.

Nuttall Consulting has assessed the per unit requirement for switchwire and concludes that the costs of a crew and traffic management for half a year for three years is reasonable. This provides a unit rate of approximately [redacted] per span.

Switchwires are typically uncovered copper, steel or aluminium conductors. These materials have a positive value when sold as scrap, particularly copper. Jemena has not identified a recovery price for these materials.

The size and the type of the switchwire conductors is not known. It would be necessary to know the lengths, gauge and type of conductors to determine the recovery value of the materials.

Jemena also identifies that there are costs of leaving the unmaintained asset on the network. These include the costs of failure of the asset as well as the time required to identify and make safe the switchwire every time a crew is working on or near these assets.

Nuttall Consulting considers that the unit rate identified (implicitly) by Jemena of [redacted] per span is a reasonable unit rate for this work. However, the unit rate does not recognise the benefits of removal of this asset as identified by Jemena.

10.2.4 Ground Fault Neutralisers and Removal of SWER

Jemena is proposing the removal of the remaining SWER lines in its service territory and the installation of Ground Fault Neutralisers (GFNs) in zone substations.

The ESV supports the volumes proposed for both of these works. These are the replacement of 13km of SWER and the installation of GFNs in three zone substations.

Jemena has provided the following unit rates to support the cost build up for this project.

Table 83 – GFN and SWER unit rates

Area	Item	Unit	Source	Unit rate
Zone Substation	GFN Unit	Per installation	FSH Actual Project	[redacted]
Zone Substation	Directional Relays	Per relay	Benchmark Price	[redacted]
Zone Substation	Unearth Cap Bank	Per cap bank	FSH Actual Project	[redacted]
Zone Substation	Other Costs	Per installation	FSH Actual Project	[redacted]
Distribution Network	SWER -Line	Per km	Benchmark Price	[redacted]
Distribution Network	SWER -Tx	Per km	Benchmark Price	[redacted]
Distribution Network	SA – Replace	Per 3 phase set	Benchmark Price	[redacted]
Distribution Network	SA -Retire	Per 3 phase set	FSH Actual Project	[redacted]
Distribution Network	Other Costs	Per installation	FSH Actual Project	[redacted]

Jemena states that they have also verified the pricing used to establish these unit rates and that actual costs have been back-calculated from an already complete GFN installation.

Nuttall Consulting has assessed the unit rates against the unit rates contained in the DNSP RIN submissions. Although not directly comparable in many cases, Nuttall Consulting considers that the proposed unit rates fall within the reasonable range of expected costs.

Nuttall Consulting recommends the following unit costs:

- $175,000 per km of SWER replacement
- $1.7m per zone substation for GFN installation.

Nuttall Consulting notes that the following unit rate does not make allowances for any of the following benefits:

- Bush fire start risk reduction - Significant reduction in the size of the phase to ground fault level reduces the risk of arcing for a conductor on ground and therefore reduces fire start risk. This will result in less fault and emergency work for Jemena and reduced claims.

- Improved safety - Significant reduction in the size of the phase to ground fault current reduces step and touch potentials during fault conditions.
- Improved reliability - The self-extinguishing capability of the GFN for transient faults will see a reduction in MAIFI. Jemena has valued this at $10k per annum per zone substation. The reduction in fault current will also have an impact through reduced wear of circuit breaker contact points and less strain on line fittings and fixtures. This value was not quantified by Jemena.
- Surge arrester end of life - Surge arrestors need to be replaced at their end of life. Upgrading surge arresters to cater for GFN operation will defer the need for the next replacement. Jemena has valued this at $75k per annum per zone substation.
- SWER constraints - Many SWER systems have significant constraints in terms of voltage and capacity. Retiring the SWER will alleviate these constraints. This value was not quantified by Jemena.
- Standardisation - Removal of SWER will mean that spare parts for this type of network will no longer be required. This value was not quantified by Jemena.

10.2.5 Pole Top Fire Mitigation

Jemena is proposing a targeted program for reducing the incidence of pole top fires. The Jemena program of targeted inspection and replacement involves the refurbishment of HV and subtransmission pole top structures, including inspection, cleaning, tightening and replacement of crossarms and insulators where there is evidence of deterioration, charring or burning.

Jemena's 2011-2015 Capital and Operating Works Plan identifies a total of [redacted] for pole fire mitigation over the period 2011 to 2015. This allows for the targeted replacement of approximately 3,000 pole top structures.

The unit rate for this activity is calculated at [redacted] per pole top structure. Nuttall Consulting considers that this is a very high rate for the described works. Mitigating this cost is the non-sequential nature of the replacement. Jemena's description of the proposed program is that it will be based on inspections and driven by observed condition triggers. On this basis, pole tops will be replaced in a relatively sporadic fashion with limited ability to aggregate and gain efficiencies through adjacent works.

In these cases, the majority of unit costs may relate to labour and vehicle requirements, rather than the material costs.

Based on the above, Nuttall Consulting considers that the proposed unit rate of [redacted] is reasonable.

Nuttall Consulting notes that this unit rate does not account for the following items:

- The reduction in emergency maintenance (identified by Jemena as $5,227 in the next regulatory period).
- The reduction in "pole fire events (that) have caused widespread impact on network performance and exposed JEN to significant potential reliability penalties (in the order of $1.9m in 2008)"[412].

10.2.6 Pole Top Replacement (Age & Condition)

Jemena proposes to replace crossarms in targeted areas based on their age and condition, to achieve a reduction in the number of pole fires. This program has been considered in conjunction with the pole top fire mitigation program discussed in the preceding section.

This Jemena program is aimed at reducing the risk of fire initiation, reducing the number of pole fire related interruptions, reducing the risk of electrocution/injury to the public and reducing the risk of high voltage injection.

Jemena is proposing to replace an additional 14,117 cross-arms (and associated assets) in the next regulatory period. The ESV supports these work volumes.

To assess the unit costs that Jemena has used to produce its capex forecast for this item, we have undertaken a comparative analysis exercise using:

- the replacement units costs provided by the DNSPs for the repex modelling exercise
- derived historical actual and forecast unit costs from the relevant pole top activity codes, which were provided by the DNSPs and used in our RQM review.

Based upon this analysis, the Jemena unit costs appear high based upon a number of comparisons:

- Jemena's unit costs are much higher than other DNSP's unit costs provided for our repex modelling exercise
- Jemena's unit costs are 2nd highest, based upon the forecast activity code data
- Jemena's average forecast unit costs are approximately 30% greater than its historical average, based upon the activity code data.

However, counter to this:

- it is noted that the Jemena historical average is much lower than other DNSPs equivalent historical average, possibly indicating this is not a reasonable metric to compare its costs
- Jemena's average forecast unit costs are near the lower end of the historical average of other DNSPs – only Powercor appears lower.

Based upon the above, we consider there is still a good case to reject the Jemena unit costs, and consider that the unit costs should be reduced by 15%. This brings Jemena's

[412] Jemena Electricity Networks (Vic) Ltd Revised Regulatory Proposal 2011-2015 Appendix 8.26. Strategic Planning Paper - Pole Top Fire Mitigation - 20 July 2010

unit costs more in line with its historical unit costs, and places these at the median of other DNSPs average forecast unit costs.

10.2.7 Pole Replacement

This Jemena program is aimed at reducing the risk of fire initiation, reducing the number of pole fire related interruptions, reducing the risk of electrocution/injury to the public, reducing the risk of high voltage injection and reducing OH&S issues for electrical workers.

Sound wood measurements have been the traditional criteria for assessing whether a pole is fit for service or should be condemned. It is noted that condemnation rates have been increasing in Jemena's territory over the last 10 years, and Jemena's incremental forecast reflects this trend.

There are two factors driving Jemena's forecast volumes of wood pole replacements, both of which are driven by the results of asset inspections (but the criteria for condemnation are different):

- poles condemned based on age and condition (sound wood measurements)
- undersized poles that are condemned based on girth measurements or the use of raiser brackets.

The undersized pole replacement program relates to poles with a natural girth less than the minimum for a serviceable pole and LV poles fitted with HV raiser brackets. The ESV argues that these poles should have been attended to in previous price reset periods. However, given that the problem exists, ESV considers that the work needs to be done.

Jemena estimates that there are around 5,000 such poles and plans to replace all of these over a ten year period.

To assess the unit costs that Jemena has used to produce its capex forecast for this item, we have undertaken a comparative analysis exercise using:

- the replacement units costs provided by the DNSPs for the repex modelling exercise
- derived historical actual and forecast unit costs from the relevant pole top activity codes, which were provided by the DNSPs and used in our RQM review.

Based upon this analysis, the HV and LV pole unit costs are high compared to the equivalent unit costs provided by the DNSPs for repex modelling.

However, the forecast average unit cost and historical average (derived from the activity code data) appear reasonable when compared to other DNSPs - only United Energy is lower.

Based upon this, we have accepted Jemena's pole unit costs.

However, we do note that the Jemena's forecast average unit cost is high compared to its historical average. This appears to be due to the assumed ratio of staked poles to replaced poles being much lower in the forecast (63% historical to 49% forecast).

It is not clear whether the ESV has assessed this issue. Therefore, the AER may need to consider whether this assumption should be moved in line with the historical ratio i.e. around 60%. This will result in a reduction in the overall capex allowance for this program.

10.2.8 Overhead Conductor Replacement

Jemena is proposing a proactive replacement program that is designed to secure the performance of the system used and improve network performance overall.

This Jemena program is aimed at reducing the risk of fire initiation, reducing the number of conductor failure related interruptions, reducing the risk of electrocution/injury to the public, reducing the risk of high voltage injection and reducing OH&S issues for electrical workers.

Jemena's unit costs are similar to United Energy, but appear very high compared to Powercor and SP AusNet's unit costs[413]. The unit cost is approximately 85% above Powercor's proposed unit cost and over 100% of our recommended unit cost for Powercor (see section 6.3.3). Jemena has not provided any detailed analysis of past project costs to support its unit cost estimates.

We accept Jemena's unit costs are likely to be higher than Powercor and SP AusNet due to the more urbanised nature of the existing lines. However, we do not consider that this is sufficient to explain the scale of the increase, particularly noting that we would expect the replacement to be largely on rural fringes where the fire hazards are greater.

We also note that the unit cost is more in the range of a complete rebuild or small upgrade. We do not consider this is reasonable, as we would expect in many circumstances restringing or partial rebuild will be possible.

Furthermore, we would also expect an overlap with other replacement needs allowed for in the pole and pole-top allowances. Given the large increases accepted by the ESV in these areas, it seems reasonable to assume that this overlap may be significant.

Based upon the above, and in the absence of more detailed analysis to support the Jemena unit cost, we consider a value of $55k/km to be reasonable.

This allows for a 66% increase, to cover the higher urban cost, on the efficient unit cost we recommended for Powercor.

10.2.9 HV Installation Replacement

The High Voltage Installation Replacement Program is targeted primarily at distribution system switchgear. This program includes the replacement of HV overhead switchgear, surge diverters, Auto Circuit Reclosers, HV overhead fuses and mounts and HV indoor type switchgear.

[413] It is worth noting that the SP AusNet unit cost should be much lower as it does not capture all the costs allowed for in other DNSP's unit costs.

ESV does not dispute the need for this program, but considers that most of the elements are driven primarily by factors other than safety (e.g. reliability of supply) and should be justified by those other factors.

The exception is the replacement of EDO fuses which would be strongly supported by ESV (forecast volumes for this activity have not been provided). ESV also recognises that the need for the program does contain a safety component, in reducing fire starts, risk of electrocution and OH&S issues for electrical workers.

ESV does not recommend work volumes under this program, but would support the replacement of EDO fuses. Nuttall Consulting has not assessed the unit costs for the program as the ESV does not support the program, with the exception of the EDO fuse replacements.

Based upon a comparison of the Jemena EDO fuse unit cost against the equivalent unit cost of the other DNSPs, Jemena's unit cost is significantly higher than the majority of the other Victorian DNSPs – other than United Energy. We consider that the median unit cost ($2185) is a suitable benchmark, and such, recommend that the Jemena unit cost is reduced to by approximately [redacted] to $2185 per unit. This reflects the [redacted] cost, which represents the median DNSP.

10.2.10 Distribution Substation & Overhead Switch Maintenance

This Jemena program covers increases to the routine inspection and condition monitoring of overhead HV switchgear and indoor and kiosk type distribution substations, and seeks to move Jemena from a corrective maintenance program to a preventative maintenance program.

ESV does not dispute the need for this program, but considers that most of the elements are driven primarily by factors other than safety (e.g. reliability of supply) and should be justified by those other factors. ESV also recognises that the need for the program does contain a safety component, in reducing fire starts, risk of electrocution and OH&S issues for electrical workers.

ESV did not recommend any work volumes under this program.

Nuttall Consulting has not assessed the unit costs for this program as it has not been recommended by the ESV. Replacement volumes and unit costs for this asset group have been assessed and provided for in the Nuttall Consulting recommendations on reliability and quality maintained capex.

10.2.11 Zone Substation Asset Conditioning Monitoring

This Jemena program provides for increases to the condition monitoring of ageing zone substation primary plant, including transient earth voltage testing, post-type CT and VT testing, transformer dry-outs, and transformer condition testing.

ESV does not dispute the need for this program, but considers that most of the elements are driven primarily by factors other than safety (e.g. reliability of supply) and should be justified by those other factors. ESV also recognises that the need for the program does contain a safety component, in reducing fire starts and OH&S issues for electrical workers.

ESV did not recommend any work volumes under this program.

Nuttall Consulting has not assessed the unit costs for this program as it has not been recommended by the ESV. Replacement volumes and unit costs for this asset group have been assessed and provided for in the Nuttall Consulting recommendations on reliability and quality maintained capex.

10.2.12 Zone Substation Transformer Replacement

The Jemena Zone Substation Transformer Replacement Program is a major asset replacement program intended to secure the ongoing performance and reliability of the Jemena network.

Jemena has a number of transformers entering the latter years of their life, and are forecast to require replacement. The ageing of this plant is affected by loading, and the increased utilisation.

A life model has been developed to estimate the condition of power transformers across the United Energy network. This model gives an indicator of the estimated life lost per annum, and when the transformer is expected to be at end of life.

ESV considers that the program is driven primarily by factors other than safety (e.g. reliability of supply) and should be justified by those other factors. ESV also recognises that the need for the program does contain a safety component, in reducing fire starts and OH&S issues for electrical workers.

ESV did not recommend any work volumes under this program.

Nuttall Consulting has not assessed the unit costs for this program as it has not been recommended by the ESV. Replacement volumes and unit costs for this asset group have been assessed and provided for in the Nuttall Consulting recommendations on reliability and quality maintained capex.

10.2.13 Zone Substation Circuit Breaker Replacement

Jemena has established an ongoing zone substation circuit breaker replacement program which is aimed at achieving a high level of supply reliability and availability.

The replacement program is based upon a set of established criteria that are used to prioritise the program. Switchgear replacement is based on condition and performance and is aligned with major augmentation work wherever possible.

This Jemena program covers the replacement of ageing and defective zone substation circuit breakers. ESV does not dispute the need for this program, but considers that the program is driven primarily by factors other than safety (e.g. reliability of supply) and should be justified by those other factors. ESV also recognises that the need for the program does contain a safety component.

ESV did not recommend any work volumes under this program.

Nuttall Consulting has not assessed the unit costs for this program as it has not been recommended by the ESV. Replacement volumes and unit costs for this asset group have been assessed and provided for in the Nuttall Consulting recommendations on reliability and quality maintained capex.

10.2.14 Electricity Safety (Electric Line Clearance) Regulations

Jemena is claiming additional expenditure due to changes to the Electricity Safety (Electric Line Clearance) Regulations:

- maintenance of the clearance space
- notification & consultation
- service line clearance
- habitat trees
- hazard trees.

ESV has supported the need for additional work activity in most of these areas.

The Nuttall Consulting assessment of the unit costs associated with the above additional works are provided in the following sections.

10.2.14.1 Maintenance of the Clearance Space – HBRA pre-summer

The management of vegetation in High Bushfire Risk Areas (HBRA) is required to change due to changes in the Electricity Safety (Electric Line Clearance) Regulations 2010. DNSPs currently inspect and cut vegetation in HBRAs cyclically with a special inspection and trim undertaken prior to the summer bushfire period. This section deals with the inspection and trimming associated with vegetation management undertaken prior to the bushfire season.

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

Jemena is proposing a unit rate of [redacted] per span for pre-summer vegetation management in HBRA areas.

[redacted] has used a unit rate between [redacted] and [redacted] a span[414] in calculating the cost to comply with clause 11. The equivalent unit rate proposed by [redacted] is [redacted] per span

[414] The [redacted] unit costs decrease over time because of increased productivity and, in the case of the HBRA rates, also the reduced workload per span after larger clearances are achieved (i.e., compliance is established) during 2011-13.

for both LBRA and HBRA areas[415]. [redacted] is proposing a unit rate of [redacted] per span for HBRA areas.

The CitiPower/Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. Powercor did not provide a working spreadsheet or detailed information to the level of the other companies. Powercor did identify that the unit rates for HBRA, in particular those for the cyclic and pre-summer programs, reflect the increased work activity per span, particularly in the early years of the period 2011-15, required as a result of the removal of the HBRA Exemption.

The Powercor explanation for the increased unit rates does not provide any differentiation from the other DNSPs. On this basis, it remains unclear as to why the Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with removal of the 2005 Code exemptions is [redacted] per span.

10.2.14.2 Maintenance of the Clearance Space – HBRA cyclic

The management of vegetation in High Bushfire Risk Areas (HBRA) is required to change due to changes in the Electricity Safety (Electric Line Clearance) Regulations 2010. DNSPs currently inspect and cut vegetation in HBRAs cyclically with a special inspection and trim undertaken prior to the summer bushfire period. This section deals with the inspection and trimming associated with vegetation management undertaken cyclically.

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

Jemena is proposing a unit rate of [redacted] per span for cyclic vegetation management in HBRA areas.

[415] Noting the proposed annual program for HBRA

[redacted] has used a unit rate between [redacted] and [redacted] a span[416] in calculating the cost to comply with clause 11. The equivalent unit rate proposed by [redacted] is [redacted] per span for both LBRA and HBRA areas[417]. [redacted] is proposing a unit rate of [redacted] per span for HBRA areas.

The CitiPower/Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. Powercor did not provide a working spreadsheet or detailed information to the level of the other companies. Powercor did identify that the unit rates for HBRA, in particular those for the cyclic and pre-summer programs, reflect the increased work activity per span, particularly in the early years of the period 2011-15, required as a result of the removal of the HBRA Exemption.

The Powercor explanation for the increased unit rates does not provide any differentiation from the other DNSPs. On this basis, it remains unclear as to why the Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Nuttall Consulting notes that the [redacted] unit rate is the lowest of the group at [redacted] per span. This unit rate was consistent for [redacted] across LBRA and HBRA areas. Nuttall Consulting notes that [redacted] is proposing an annual HBRA vegetation management cycle and considers that this approach would result in the slightly lower average cost per span.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with removal of the 2005 Code exemptions is [redacted] per span.

10.2.14.3 Maintenance of the Clearance Space – LBRA

The management of vegetation in Low Bushfire Risk Areas (LBRA) is required to change due to changes in the Electricity Safety (Electric Line Clearance) Regulations 2010.

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and

[416] The [redacted] unit costs decrease over time because of increased productivity and, in the case of the HBRA rates, also the reduced workload per span after larger clearances are achieved (i.e., compliance is established) during 2011-13.

[417] Noting the proposal annual program for HBRA.

powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

Jemena is proposing a unit rate of [redacted] per span for LBRA areas.

[redacted] and [redacted] have used a unit rate of [redacted] a span in calculating the cost to comply with clause 11. The equivalent unit rate proposed by [redacted] is [redacted] per span for both LBRA and HBRA areas[418]. [redacted] is proposing a unit rate of [redacted] per span for LBRA areas.

The CitiPower/Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.

On this basis, it is not possible to determine why the CitiPower and Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with removal of the 2005 Code exemptions is [redacted] per span[419].

10.2.14.4 Notification & Consultation

The 2010 regulations require consultation only in situations where a tree that is to be cut or removed is within the boundary of a private property. Under the 2010 regulations, responsible persons can notify affected persons of cutting/removal of trees by placing notices in newspapers. ESV found that the changes to the regulations represent a small reduction in burden on the electricity distributors.

Jemena has requested additional work associated with notification and consultation. ESV considers that the requirements in the current regulations are a slight reduction in burden from those contained in the previous regulations, and therefore does not support additional expenditure for notification and consultation.

ESV did not recommend any work volumes under this program.

Nuttall Consulting has not assessed the unit costs for this program as it has not been recommended by the ESV.

[418] A side note in the [redacted] spreadsheet suggests that these figures are not inflated to 2010 dollars.
[419] Noting the [redacted] spreadsheet notes of conversion of [redacted] to 2010 dollars.

10.2.14.5 Reduced clearances for insulated conductor - Services

The unit costs associated with reduced clearances for insulated conductor relate to the omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3 in the revised Electricity Safety (Electric Line Clearance) Regulations. Jemena has identified service lines as being impacted by this change.

Jemena has estimated the unit rate for the initial establishment of clearance space as [redacted] with an ongoing rate of [redacted] per service.

[redacted] has also estimated the unit rate for the initial establishment of clearance space as [redacted] with an ongoing rate of [redacted] per service.

[redacted] has calculated that the average unit rate per service line would be [redacted], in either the annual initial cut or for ongoing recuts[420]. The information provided by [redacted] did not provide any further breakdown of these costs or time required for the proposed works.

[redacted] also assessed the unit cost per service for compliance with the Electricity Safety (Electric Line Clearance) Regulations to be [redacted] for [redacted]. [redacted] considered that there were likely to be [redacted].

In comparison, [redacted] has estimated a per service unit cost of [redacted] for the initial cut and [redacted] to "maintain clearance space" for insulated services. The initial cut cost comprises [redacted] and the ongoing recuts are costed at [redacted].

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.

On this basis, it is not possible to determine why the CitiPower and Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for a four-fold increase in ongoing service recuts in the CitiPower and Powercor areas.

The man-hour assessments provided by [redacted] appear reasonable, as do the assumptions in relation to approximate times and crew numbers.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

[420] This cost includes the cost of the cutting and clean-up of vegetation required as a result of the omission of clauses 9.2.1, 9.2.2 and 9.3 of the 2005 Code from the 2010 Code.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate for clearance of Jemena's insulated services to comply with the Electricity Safety (Electric Line Clearance) Regulations are as follows:

- initial clearance of services: $83.46
- ongoing clearance of services: $47.40.

Jemena has also identified that some services may require undergrounding or relocation due to the revised Electricity Safety (Electric Line Clearance) Regulations 2010. The proposed unit costs for these activities are [redacted] and [redacted] respectively. The ESV has recommended volumes of 630 and 2,250 for these activities.

Nuttall Consulting has reviewed the proposed replacement cost of [redacted] per service. The proposed per unit rate of [redacted] is not consistent with current Jemena prices to provide a new service. The new service and meter price charged by Jemena is currently [redacted]. This service includes the installation of a service (single phase) and meter and will typically involve greater travel distances between jobs than a programmed replacement schedule.

The service replacement program will not be undertaken in a manner that would support minimising travel time as the services to be relocated may not be located in close proximity to each other. The relocation services may also require consultation with the landowner and adjacent landowners. To make allowances for these additional costs, Nuttall Consulting recommends a unit rate of $250 per service relocation.

The unit rate of [redacted] is greater than would be required to provide a simple underground service in a new residential estate. However, the installation of an underground service to replace an existing overhead service is a complex task. The costs associated with this task can vary dramatically based on factors such as soil type (e.g. rock, clay or sand), other services in the ground (gas, water, electric, sewer, telecoms, etc.), and reinstatement requirements (e.g. pavements, roads, nature strips).

Customer negotiations may also play a significant part in determining the unit cost of this activity. Nuttall Consulting assumes that the [redacted] unit rate excludes any works on the customer's premises with the exception of the disconnection and reconnection of the supply to the meter position.

The more densely populated an area, the greater the likelihood of increased costs. The proposed locations for the Jemena undergrounding of services are not known. As such, it is not possible to determine if the proposed unit rate of [redacted] is efficient as an overall average.

Nuttall Consulting therefore recommends that the proposed unit rate of [redacted] be accepted.

10.2.14.6 Habitat Trees

Clause 4 of the 2010 regulations requires a DNSP, before undertaking any pruning or removal of vegetation, to identify whether the tree is the habitat for fauna that is:

- listed as threatened in accordance with section 10 of the Flora and Fauna Guarantee Act 1988
- listed in the Threatened Invertebrate Fauna List with a conservation status in Victoria of ‘vulnerable’, ‘endangered’ or ‘critically endangered’ or;
- listed in the Threatened Vertebrate Fauna List with a conservation status in Victoria of ‘vulnerable’, ‘endangered’ or ‘critically endangered’.

In the event that the tree is the habitat for the fauna listed above, clause 4 of the 2010 regulations requires the cutting or removal of the tree to be undertaken outside of the breeding season wherever practicable.

In the event that it is not practicable to undertake cutting or removal of the tree outside of the breeding season for that species, the 2010 regulations require translocation of the fauna wherever practicable. These requirements did not exist in the 2005 regulations, although the management plan to be developed by the responsible person did require the identification of locations that had ‘rare or endangered’ species and details of the methods that will be used to avoid and minimise the impact on such vegetation.

Jemena proposes that an additional FTE specialising in the identification and maintenance of species and the maintenance of a register for endangered species and their habitat will be required to work in parallel with the Jemena vegetation management program.

Jemena state that this person would also arrange the training of assessors and other employees to be able to identify threatened species as well as obtain specialist services if required to ensure compliance with the regulations.

The ESV has confirmed that the new clause 4(1) does not require DNSPs to identify the location of ‘habitat’ trees. The current practice of obtaining information from local councils, government departments and community groups who hold such information will continue. ESV has advised that a DNSP will have met its obligation in regard to identifying the location of ‘habitat’ trees if it accesses the information held by others. Jemena considers that the need to obtain information from local councils, government departments and community groups, cross reference that information and analyse for threatened species and their breeding patterns will increase the workload above current practice.

As a result of discussions with the ESV Jemena has revised down its resource requirement to one FTE to establish the ‘habitat’ tree register in the first year (2011), followed by 0.4FTE in subsequent years to monitor and update the register, process questions and information requests, and provide on-going training to employees and vegetation contractors.

The ESV has approved the volume of work proposed by Jemena.

Jemena has used [redacted] per annum for the salary cost of the Scientific / Environmental Specialist based on existing salary band of Tier 6. Nuttall Consulting considers that the proposed FTE unit rate of [redacted] per annum is within the reasonable range of expected costs for this role. This rate is a gross rate and includes overheads and on-going costs associated with employment.

10.2.14.7 Hazard Trees

The Electricity Safety (Electric Line Clearance) Regulations 2005 clause 9(4)(o)(iii) required DNSPs to specify the methods used to monitor the condition of vegetation in the hazard space (defined as vegetation that is beyond the regrowth space and could become a hazard to the safety of the electric line under a range of weather conditions prevalent in the area).

The 2010 regulations (clause 3 of the Code) give DNSPs the authority to minimise hazards by pruning or removing trees that are likely to fall onto or otherwise come into contact with an electric line.

Jemena has included the cutting or removal of hazard trees in its line clearance management plan submitted to the ESV.

Jemena has estimated that the volume of work required for this activity includes 250 tree removals and 500 trees cut. These volumes have been recommended by the ESV.

The Jemena unit costs proposed for these volumes are [redacted] for each tree removal and [redacted] for each hazard tree trimmed.

Nuttall Consulting has assessed the tree removal costs against those advised by the Australian Institute of Architects (AIA)[421]. This cost guide suggested tree removal costs in Melbourne of between $300 and $1,600 per tree. The AIA noted that prices are extremely variable and depend on the following: tree height, trunk circumference, density of branches/foliage, access to site for travel towers, woodchippers & grinders, obstructions, buildings underneath, tree alive or dead. The range could be wider if all the factors counted against easy removal.

Nuttall Consulting considers that the sort of trees likely to be considered a hazard will tend towards larger and older trees that are higher than the overhead lines. On this basis, Nuttall Consulting accepts the proposed tree removal unit rate of [redacted] per tree.

The Jemena proposed unit rate of [redacted] per hazard tree trim exceeds the cyclic span clearing rates of between [redacted] and [redacted]. A span typically consists of more than one tree that requires trimming on average. This suggests a per tree trimming cost of less than [redacted] to [redacted]. Mitigating against this is the likelihood that the tree trimming required for hazard trees will not have ready street access and will require trimming at a higher level than is typical for cyclic trimming.

On balance, Nuttall Consulting considers that a more cost reflective average cost for hazard tree trimming is therefore [redacted] per tree.

[421] http://www.archicentre.com.au/2008JAN_Fullcostguide.pdf

10.3 Powercor

Powercor is claiming additional expenditure due to changes to the Electricity Safety (Electric Line Clearance) Regulations:

- removal of HBRA exemptions
- reduced clearances for insulated conductors (ABC and services)
- removal of LBRA clearance exemptions
- 100m span clearances
- environmentally or culturally significant (native) trees.

ESV has supported the need for additional work activity in each of these five areas.

The Nuttall Consulting assessment of the unit costs associated with the above additional works are provided in the following sections.

10.3.1 Removal of HBRA exemptions

The ESV has approved additional volumes of vegetation clearance required to comply with the Electricity Safety (Electric Line Clearance) Regulations 2010. Powercor has proposed clearance volumes for trimming undertaken prior to the bushfire season and for cyclic trimming. These two areas are discussed in the following section.

The management of vegetation in High Bushfire Risk Areas (HBRA) is required to change due to changes in the Electricity Safety (Electric Line Clearance) Regulations 2010. DNSPs currently inspect and cut vegetation in HBRAs cyclically with a special inspection and trim undertaken prior to the summer bushfire period. This section deals with the inspection and trimming associated with vegetation management undertaken prior to the bushfire season.

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

10.3.1.1 Maintenance of the Clearance Space – HBRA pre-summer

Powercor has used a unit rate between [redacted] and [redacted] a span[422] in calculating the cost to comply with clause 11. The equivalent unit rate proposed by [redacted] is [redacted] per span

[422] The Powercor unit costs decrease over time because of increased productivity and, in the case of the HBRA rates, also the reduced workload per span after larger clearances are achieved (i.e., compliance is established) during 2011-13.

for both LBRA and HBRA areas[423]. [redacted] is proposing a unit rate of [redacted] per span for HBRA areas.

[redacted] is proposing a unit rate of [redacted] per span for pre-summer vegetation management in HBRA areas.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. Powercor did not provide a working spreadsheet or detailed information to the level of the other companies. Powercor did identify that the unit rates for HBRA, in particular those for the cyclic and pre-summer programs, reflect the increased work activity per span, particularly in the early years of the period 2011-15, required as a result of the removal of the HBRA Exemption.

The Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The ESV determination of workload volumes for Powercor identified a change in obligations "resulting in the requirement for additional or more frequent cutting"[424]. Information contained in the Powercor submission indicated that the Powercor unit rates may include an allowance for line inspections. The ESV has advised Nuttall Consulting that the overall inspection rate is the same before and subsequent to the regulation change[425]. Nuttall Consulting considers that the apparent inclusion of inspection costs is therefore not consistent with the ESV recommendations.

The Powercor explanation for the increased unit rates does not provide any differentiation from the other DNSPs. On this basis, it remains unclear as to why the Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with removal of the 2005 Code exemptions is $150 per span.

10.3.1.2 Maintenance of the Clearance Space – HBRA cyclic

Powercor has used a unit rate between [redacted] and [redacted] a span[426] in calculating the cost to comply with clause 11. The equivalent unit rate proposed by [redacted] is [redacted] per span

[423] Noting that the [redacted] unit rate is based on an annual program in HBRA.
[424] Assessment By Energy Safe Victoria Of EDPR Safety-Related Programs, 21 September 2010, (Ver 2.0), section 2.4.
[425] Advised in email from ESV, dated 12 October 2010
[426] The Powercor unit costs decrease over time because of increased productivity and, in the case of the HBRA rates, also the reduced workload per span after larger clearances are achieved (i.e., compliance is established) during 2011-13.

for both LBRA and HBRA areas . [redacted] is proposing a unit rate of [redacted] per span for HBRA areas.

[redacted] is proposing a unit rate of [redacted] per span for cyclic vegetation management in HBRA areas.

The Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The ESV determination of workload volumes for Powercor identified a change in obligations "resulting in the requirement for additional or more frequent cutting"[427]. Information contained in the Powercor submission indicated that the Powercor unit rates may include an allowance for line inspections. The ESV has advised Nuttall Consulting that the overall inspection rate is the same before and subsequent to the regulation change[428]. Nuttall Consulting considers that the apparent inclusion of inspection costs is therefore not consistent with the ESV recommendations.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. Powercor did not provide a working spreadsheet or detailed information to the level of the other companies. Powercor did identify that the unit rates for HBRA, in particular those for the cyclic and pre-summer programs, reflect the increased work activity per span, particularly in the early years of the period 2011-15, required as a result of the removal of the HBRA Exemption.

The Powercor explanation for the increased unit rates does not provide any differentiation from the other DNSPs. On this basis, it remains unclear as to why the Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Nuttall Consulting notes that the [redacted] unit rate is the lowest of the group at [redacted] per span. This unit rate was consistent for [redacted] across LBRA and HBRA areas. Nuttall Consulting notes that [redacted] is proposing an annual HBRA vegetation management cycle and considers that this approach would result in the slightly lower average cost per span.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with the removal of the 2005 Code exemptions is $230 per span.

[427] Assessment By Energy Safe Victoria Of EDPR Safety-Related Programs, 21 September 2010, (Ver 2.0), section 2.4.
[428] Advised in email from ESV, dated 12 October 2010

10.3.2 Reduced clearances for insulated conductor - ABC

The unit costs associated with reduced clearances for insulated conductors relate to the omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3 in the revised Electricity Safety (Electric Line Clearance) Regulations. Powercor has identified two asset types that are impacted by the changed regulations: Aerial Bundled Conductor (ABC) and service lines. Powercor have also identified annual and bi-annual clearing requirements associated with the Electricity Safety (Electric Line Clearance) Regulations.

In support of the additional costs, Powercor has provided a statement by [redacted][429]. [redacted] are the current providers of vegetation management services to Powercor and CitiPower. Nuttall Consulting notes that [redacted] may continue to provide vegetation management services to CitiPower and Powercor. This means that [redacted] are likely to be contracted to deliver the additional workloads described in the [redacted]. As such, Nuttall Consulting have sought where possible to identify third party estimates of the unit cost of meeting these obligations.

[redacted] have identified a unit rate of [redacted][430].

In 2009 Powercor incurred costs of [redacted] for the clearing of [redacted] spans[431]. This equates to a unit cost of [redacted] per span. However the Powercor information is not clear as to whether this included the cost of clearing for services or not. If so, this would reduce the cost per span considerably.

Nuttall Consulting notes the lower customer density of the Powercor franchise area and the reduced traffic management costs that are inherent with this territory. Nuttall Consulting also notes that the [redacted] unit rates provided are considered conservative.

Unit rate information provided by [redacted] identified costs associated with an elevated work platform and 2 crew to be [redacted] per hour. The cost associated with a wood chipper[432] vehicle and two crew was estimated at [redacted] per hour. These values suggest that Powercor is estimating that the clearing of an ABC span will require in excess of 1 hour per span for both crews. Nuttall Consulting does not consider that the clearance of a single span of conductor would require both crews for more than an hour; particularly the chipper vehicle.

The [redacted] assessment of the number of LV spans does not appear to differentiate between stand-alone spans of ABC and those spans that are run on the same poles as other conductors. The Powercor network is one of the least densely populated network areas in Australia and consequently has a low proportion of poles with multiple circuits.

429 [redacted]

430 Bid p22.

431 Powercor and CitiPower response Step change Electricity Safety.pdf. Dated1 September 2010.

432 Vehicle for turning the cut vegetation into woodchips and transport of woodchips.

The reduced costs associated with clearing of ABC that is on the same span as another circuit does not appear to be recognised by the [redacted].

Powercor was requested to describe the level of scale efficiencies adopted in forecasting these costs. The Powercor response to this question was: "Refer to sections 82 to 143 of the Witness Statement."[433] This reference is to the whole of the witness statement concerning insulated cables and does not contain any specific reference to scale efficiencies.

Powercor was also requested to "describe and justify the savings that the DNSP anticipates associated with the 2010 Electric Line Clearance regulations". Powercor responded that "There are no savings anticipated due to the omission of reduced clearances for aerial bundled and insulated cables"[434].

Nuttall Consulting notes that Powercor is proposing to significantly increase the overall amount of expenditure on vegetation management. It is difficult to see how scale efficiencies would not be reasonable and significant based on these increased activity levels.

Powercor was requested to quantify the impact that the step changes proposed would have on fault and emergency opex. In response, Powercor stated that "The 2005 Regulations and HBRA/LBRA Exemption have been successful in establishing an achievable and practicable regulatory regime which does not compromise on safety. Consequently, there would appear to be significant costs and little community benefit, safety or performance justification for the change in the Regulations and the removal of the Exemption."[435]

Nuttall Consulting does not agree with the Powercor position that there will be no impact on reliability outcomes from the substantial increase in expenditure associated with vegetation management. The trimming of vegetation has been proven to reduce vegetation related outages and also reduce damage to the network assets from contact and abrasion. The removal of more vegetation adjacent to powerlines will therefore have a resultant impact on vegetation related outages and network asset integrity. Nuttall Consulting recognises that the incremental removal of vegetation will have a lesser impact than the original trimming requirements.

Noting that Powercor has applied the same unit rate for the clearance of insulated conductors as it has for the removal of the LBRA exemptions, it is reasonable to compare the Powercor unit rates with those of Jemena, United Energy and SP AusNet. The equivalent unit rate proposed by [redacted] is [redacted] per span. [redacted] and [redacted] are proposing a unit rate of [redacted] per span for LBRA areas.

Based on the above considerations, the Powercor proposed unit rate of [redacted] per span is not considered efficient. Nuttall Consulting recommends a unit rate of $210 per span as an efficient average unit rate.

433 Powercor and CitiPower response Step change Electricity Safety.pdf. Dated1 September 2010.
434 Ibid
435 Ibid

10.3.3 Reduced clearances for insulated conductor - Services

The unit costs associated with reduced clearances for insulated conductors relate to the omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3 in the revised Electricity Safety (Electric Line Clearance) Regulations. Powercor has identified two asset types that are impacted by the changed regulations: Aerial Bundled Conductor (ABC) and service lines.

[redacted] has calculated that the average unit rate per service line would be [redacted], in either the initial cut or for ongoing recuts. This cost includes the cost of the cutting and cleanup of vegetation required as a result of the omission of clauses 9.2.1, 9.2.2 and 9.3 of the 2005 Code from the 2010 Code. The information provided by Powercor did not provide any further breakdown of these costs or time required for the proposed works.

Refer to the comparison benchmarking of unit rates in section 10.1.1.3 for details of the unit rates proposed by CitiPower, United Energy, Jemena and SP AusNet.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate for clearance of Powercor insulated services to comply with the Electricity Safety (Electric Line Clearance) Regulations are as follows:

- initial clearance of services: $84.46
- ongoing clearance of services: $47.40.

Nuttall Consulting is recommending the lower benchmark initial clearance rate for Powercor based on the [redacted] observation of increased consultation and complaints in more highly urban areas.

10.3.4 Removal of LBRA clearance exemptions

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

[redacted] states that maintenance of the increased clearances will involve additional work in the nature of more spans to be cut relative to the cutting undertaken under the 2005 Code and more aggressive cutting of trees in spans.

[redacted] estimates that there are 15,000 spans in the Powercor network which will need to be cut due to the removal of the allowance under the 2005 Code for reduced clearance spaces for powerlines other than ABC or insulated cables.

Powercor is proposing that compliance with the revised clearance spaces is established in 2 years with 7,500 new clearances established in each year.

For the remaining years of the next regulatory period, [redacted] estimate that there will be 4,500 spans each year which will require cutting to maintain the required clearance spaces.

[redacted] has used a unit rate of [redacted] a span in calculating the cost to comply with clause 11. This rate has also been used by [redacted] in determining the equivalent unit rate for CitiPower.

The equivalent unit rate proposed by [redacted] is [redacted] per span for both LBRA and HBRA areas[436].

[redacted] is proposing a unit rate of [redacted] per span for LBRA areas.

[redacted] is also proposing a unit rate of [redacted] per span for LBRA areas.

Nuttall Consulting notes that [redacted] has assumed the same unit cost for the exemption removal for CitiPower as for Powercor. [redacted] notes elsewhere that urban areas are more likely to incur consultation and complaints than rural areas. It is not clear why [redacted] has assumed that the unit costs associated with the exemption removal are the same for both companies. One possible explanation is the longer travel times required to get to worksites in rural and remote areas.

The CitiPower/Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.

On this basis, it is not possible to determine why the CitiPower and Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with removal of the 2005 Code exemptions is $210 per span[437].

[436] A side note in the [redacted] spreadsheet suggests that these figures are not inflated to 2010 dollars.

10.3.5 100m span clearances

ESV has approved additional incremental volumes of 2,500 spans per year for Powercor to comply with the Electricity Safety (Electric Line Clearance) Regulations 2010 in relation to span in excess of 100m.

Table 2 of the 2010 Code sets out the minimum clearance spaces for powerlines in LBRA (other than ABC or insulated cable powerlines). These minimum clearance spaces are contained in Table 10.1 of the 2005 Code.

Table 2 of the 2010 Code requires a larger clearance space for spans exceeding 100 metres in LBRA than Table 10.1 of the 2005 Code. The minimum clearance space for spans exceeding 100 metres has been increased in Table 2 of the 2010 Code by 1 metre for powerlines under 1kV and 0.5 metres for powerlines over 1kV.

[redacted] state that this is a major change for Powercor, but not CitiPower because CitiPower does not have any spans exceeding 100 metres in its network.

[redacted] states that there are currently 29,793 LBRA spans across Powercor's network which are greater than 100 metres in length and 14,792 of those spans are vegetated. [redacted] considers that the majority of these vegetated spans are likely to require action as a result of the increase in the minimum and required clearance spaces for spans exceeding 100 metres in LBRA and estimate that 12,500 spans would require additional cutting work over the 5 years from 2011 to 2015.

[redacted] has used a unit rate of [redacted] per span representing an estimate of the average cost per span of the incremental work activities required due to the increase in the minimum and required clearance spaces for spans exceeding 100 metres.

[redacted] notes that this unit rate is higher than other LBRA average unit rates. The higher rate is claimed due to the proximity to irrigated areas and that there will be more vegetation per span. [redacted] state that unit rates for cutting in HBRA provide a better guide to the cost per span of the incremental work activities required on Powercor's spans exceeding 100 metres in LBRA.

Nuttall Consulting does not agree with the implied link between irrigated land and increased vegetation that requires trimming. Clearly irrigated land will tend to be more productive and vegetated, but these crops do not require trimming to maintain powerline clearances.

Land external to the irrigated crops may be subject to greater water availability and therefore vegetation growth. However, trees from either intentional planting or natural seeding can cause significant problems for irrigation channels and are typically removed by channel authorities or local farmers. For example[438]:

---

[437] Noting the [redacted] spreadsheet notes of conversion of [redacted] to 2010 dollars.

[438] Guidelines To Good Practice For The Construction And Refurbishment Of Earthen Irrigation Channel Banks, National Program for Irrigation Research and Development, 2001- Land and Water Resources Research and Development Corporation.

- tree roots may cause damage to the channel banks and batters
- trees can fall over or drop limbs, damaging fences and structures or impeding the flow in the channel
- the roots of some species (e.g. willows) can severely restrict the channel waterway
- access for operation and maintenance can be impeded
- the margin of land for disposal of silt can be reduced
- controlled grazing for weed control may not be possible in the years it takes the trees to become established
- the trees may be in danger from channel weed control operations.

On this basis, Nuttall Consulting considers that irrigated land and land adjacent to irrigation channels are likely to have less vegetation requiring trimming than is the average.

Nuttall Consulting concurs with the [redacted] position that the average span length for spans in excess of 100m is longer than the average overall span length for LBRA spans. Nuttall Consulting also concurs with the [redacted] statement that [redacted][439].

Based on the above considerations, Nuttall Consulting recommends that the average cost per span of $230 for cyclic clearing of HBRA vegetation remains appropriate for the clearing of spans in excess of 100m in LBRAs.

10.3.6 Environmentally or culturally significant (native) trees

Clause 2(3) of the 2010 Code requires that a responsible person must, as far as practicable, restrict the cutting or removal of native trees or trees of cultural or environmental significance to the minimum extent necessary to ensure compliance with the 2010 Code.

The cost impact of clause 2(3) on Powercor arises from the requirement in respect of native trees. There was no provision in the 2005 Code that restricted the cutting or removal of native trees.

[redacted] has proposed a unit rate of [redacted] per span in calculating the cost of complying with clause2(3) of the 2010 Code. This represents an average cost per span of the additional work activity required as a result of the restriction on the ability to remove native trees introduced by the 2010 Code.

The unit rate for Powercor of [redacted] is lower than that for CitiPower of [redacted] based on the lower number of customer complaints and objections that are likely in Powercor's predominantly urban network.

439 [redacted].

Jemena, United Energy and SP AusNet have not requested additional expenditure in relation to this obligation. As such, there are no costs to benchmark the CitiPower or Powercor unit rates against.

CitiPower and Powercor have not provided a breakdown of the proposed unit costs, so it is not possible to assess how the final unit rates were arrived at.

Neither the ESV assessment[440] or the CitiPower and Powercor information provide any indication of the sort of work that is anticipated to be undertaken in this cost category.

CitiPower and Powercor were requested to provide a detailed description of the physical change in work practices and other physical requirements relating to each area of change relating to the Electricity Safety (Electric Line Clearance) Regulations. The CitiPower and Powercor response referred to sections 170 to 181 of the [redacted]. These sections do not provide any quantification of the costs that are used as inputs to the unit rate. Nuttall Consulting does not consider that the CitiPower response is adequate. The CitiPower response does not provide a detailed description of the unit cost.

In the absence of an understanding of the what constitutes the [redacted] unit rate, it is not possible for Nuttall Consulting to comment on whether this rate is efficient or not.

Nuttall Consulting notes that the [redacted] information relating to native trees or trees of cultural or environmental significance does not identify a cost reduction associated with the halt on the removal of this vegetation.

10.4 SP AusNet

SP AusNet is proposing a number of enhanced replacement programs in addition to addressing the specific changes in the Electricity Safety (Electric Line Clearance) Regulations 2010.

Nuttall Consulting has assessed the unit rates for the enhanced replacement of crossarms, conductors, insulators, HV fuses, bird and animal proofing, protection and control, and asset inspections in the following sections. Volumes in each of these areas were approved by the ESV.

SP AusNet has also identified additional work volumes associated with the Electricity Safety (Electric Line Clearance) Regulations 2010. The unit rates associated with these ESV approved volumes are assessed in the final SP AusNet section of this report.

10.4.1 Enhanced replacement programs

SP AusNet's revised proposal includes a number of enhanced replacement programs. These are largely in response to the findings of the Bushfire Royal Commission and SP AusNet's analysis of bushfire risks.

The programs cover:

- enhanced cross arm replacement

[440] Assessment By Energy Safe Victoria Of EDPR Safety-Related Programs, ESV, 14 September 2010

- conductor replacements
- HV pin type insulator replacements
- EDO fuse replacements
- enhanced protection and control – involving OCR/ACR replacement/upgrades.

The ESV has accepted the volumes proposed by SP AusNet for these programs.

It is also noted that the AER has essentially accepted SP AusNet's unit costs for the insulators and conductors in its draft decision.

For the remaining programs, we have compared SP AusNet's unit costs against other similar unit costs used by the other DNSPs. In all cases, SP AusNet is among the lowest or, at worst, the median DNSPs. Due to the limitation in the available information, it has not been possible to determine actual historical unit rates for comparison purposes. Nonetheless, based upon the findings of our analysis, we have accepted SP AusNet's unit cost.

It is worth noting that in response to an AER request, SP AusNet has provided information on the other benefits that may result from these programs[441]. This includes opex benefits and reliability benefits. The value of these benefits is not great. Nonetheless, the AER may need to assess whether these have been allowed for in SP AusNet's operating forecast, and whether a small reduction should be made in the unit cost to account for the improvement in reliability that may result from these programs – and therefore, would be funded through the reliability incentive scheme.

On the issue of reliability benefits, these do not appear to be that significant (possibly not more than 3-5% of the capex). It is also not clear from SP AusNet's response whether it is anticipating an improvement or worsening in reliability due to SWER protection issues raised through the Royal Bushfire Commission (i.e. the enhanced protection and control program) if its enhanced program occurs.

10.4.1.1 Asset inspections by helicopter

In 2009, SP AusNet trialled the use of helicopter mounted, high resolution digital photography with GPS tracking to overhead line assets. With a 7% detection rate, SP AusNet concluded that this inspection process provided an effective means of asset condition inspection and monitoring.

SP AusNet is proposing a 5 year helicopter inspection interval, with a 2.5 year offset to that of the ground based inspection cycle. Intrusive inspection and treatment of timber poles, together with a range of inspection and maintenance activities undertaken through the ground based inspection cycle, will require that the ground based inspection program be maintained.

The incremental work load claimed by SP AusNet is an additional 209,500 spans inspected by helicopter. The ESV has approved this volume.

[441] SP AusNet email, dated 3 September 2010

In supplemental information to the AER, SP AusNet provided the following information about the proposed helicopter inspection program[442].

Table 84 – SP AusNet helicopter inspection costs

Enhanced Network Safety & Compliance Programs 2011-2015 Per Revised Regulatory Proposal July 2010	2006-2010 actual & forecast volumes	Increase to 2006-10 actual & forecast	Total Volume 2011- 2015	2011- 2015 ($2010M direct, excl escalation)
Asset Inspection – helicopter refer Opex Step Change Paper	15,500	209,500	225,000	$6.2

The SP AusNet reference to an "Opex Step Change Paper" is not clear as there is no document with this reference that was provided to Nuttall Consulting.

In its revised proposal, SP AusNet identified that it had introduced the use of a mid-cycle helicopter inspection. In 2009, SP AusNet developed and commenced the trial of helicopter mounted, high resolution digital photography with GPS tracking to overhead line assets. SP AusNet reports that this resulted in the inspection of 15,500 poles and the subsequent detection of 1,092 asset maintenance and replacement items in addition to the ground based inspection program. The cost of this program was $580k in the 2009 calendar year.

SP AusNet propose to inspect 45,000 poles per year at a cost of $6.2 million over the next regulatory period. This equates to an average unit rate of $27 per span.

SP AusNet state that the program has a 7% detection rate, and "substantial net benefits".

These net benefits are not explicitly identified. Nuttall Consulting considers that the benefits are likely to relate to reduced operating and maintenance expenditure relating to few asset failures and more timely replacements of assets. SP AusNet has not quantified these benefits.

In addition, some of the detected assets would have been identified by the ground based inspections, so the overall net benefit of the program should be considered in this context.

The new helicopter inspection program is proposed to involve a five year inspection interval, with a 2.5 year offset to that of the ground based five year inspection cycle.

As discussed above, SP AusNet has not provided any information about the unit costs of the helicopter or equipment installed. It is not possible to compare the helicopter costs with other helicopter provider costs due to the specific GPS and photography requirements of this approach.

On this basis, Nuttall Consulting is unable to state that the proposed unit rates for the helicopter inspection program are not efficient. Nuttall Consulting also notes that there are a large number of benefits from the program that are not recognised in the unit rate.

[442] EDPR 2011-2015, Additional Safety Expenditure Q&A, 3 Sep 2010, SP AusNet, page 11

10.4.2 Electricity Safety (Electric Line Clearance) Regulations

SP AusNet are proposing additional works to meet the requirements of the Electricity Safety (Electric Line Clearance) Regulations 2010. These additional works are classified into 6 areas and the unit costs associated with these works are considered by Nuttall Consulting in the following sections.

10.4.2.1 Hazardous trees

The Electricity Safety (Electric Line Clearance) Regulations 2005 clause 9(4)(o)(iii) required DNSPs to specify the methods used to monitor the condition of vegetation in the hazard space (defined as vegetation that is beyond the regrowth space and could become a hazard to the safety of the electric line under a range of weather conditions prevalent in the area).

The 2010 regulations (clause 3 of the Code) give DNSPs the authority to minimise hazards by pruning or removing trees that are likely to fall onto or otherwise come into contact with an electric line.

SP AusNet has included the cutting or removal of hazard trees in its line clearance management plan submitted to the ESV.

SP AusNet has estimated that the volume of work required for this activity includes 25,000 tree removals. These volumes have been recommended by the ESV.

The estimated cost for addressing 5,000 hazard trees per annum is $3.94 million per annum[443]. This equates to a value of $788 per tree. Nuttall Consulting notes that the ESV reference to this activity is "No. of hazardous trees removed". Nuttall Consulting has confirmed with ESV that the proposed activity and associated work volumes relate to the trimming of hazardous trees as well as tree removal. Nuttall Consulting has not been provided with a breakdown of the ratio of tree removal and tree trimming.

The [redacted] unit costs proposed for these volumes are [redacted] for each hazard tree trimmed and [redacted] for each tree removed.

The [redacted] proposed unit rate of [redacted] per hazard tree trim exceeds the cyclic span clearing rates of between [redacted] and [redacted]. A span typically consists of more than one tree that requires trimming on average. This suggests a per tree trimming cost of less than [redacted] to [redacted]. Mitigating against this is the likelihood that the tree trimming required for hazard trees will not have ready street access and will require trimming at a higher level than is typical for cyclic trimming.

On balance, Nuttall Consulting considers that a more cost reflective average cost for hazard tree trimming is therefore $250 per tree.

Nuttall Consulting has assessed the tree removal costs against those advised by the Australian Institute of Architects (AIA)[444]. This cost guide suggested tree removal costs in

443 Electricity Distribution Network Incremental Opex impact to 2009 Base Year, Appendix I, SP AusNet, page 22.

444 http://www.archicentre.com.au/2008JAN_Fullcostguide.pdf

Melbourne of between $300 and $1,600 per tree. The AIA noted that prices are extremely variable and depend on the following: tree height, trunk circumference, density of branches/foliage, access to site for travel towers, woodchippers & grinders, obstructions, buildings underneath, tree alive or dead. The range could be wider if all the factors counted against easy removal.

Nuttall Consulting considers that the sort of trees likely to be considered a hazard will tend towards larger and older trees that are higher than the overhead lines. On this basis, Nuttall Consulting accepts the proposed tree removal unit rate of $1,500 per tree.

Based on the recommended tree trimming costs of $230 per tree and removal costs of $1,500 per tree, the SP AusNet proposed unit rate of $788 may well represent a reasonable assessment of average unit cost of these combined activities. Without a more detailed breakdown of the activity types, Nuttall Consulting is unable to determine a more accurate assessment of the relative efficiencies of these activities.

10.4.2.2 HBRA clearance exemptions

The management of vegetation in High Bushfire Risk Areas (HBRA) is required to change due to changes in the Electricity Safety (Electric Line Clearance) Regulations 2010. DNSPs currently inspect and cut vegetation in HBRAs cyclically with a special inspection and trim undertaken prior to the summer bushfire period. SP AusNet is proposing increasing its cyclic trimming to an annual program. This approach therefore negates the requirement for a pre-summer assessment and trim.

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

SP AusNet is proposing a per unit rate of $195 per span for both LBRA and HBRA areas.

[redacted] is proposing a unit rate of [redacted] per span for cyclic vegetation management in HBRA areas. [redacted] has used a unit rate between [redacted] and [redacted] a span[445] in calculating the cost to comply with clause 11. [redacted] is proposing a unit rate of [redacted] per span for HBRA areas.

The CitiPower/Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. Powercor did not provide a working spreadsheet or

[445] The [redacted] unit costs decrease over time because of increased productivity and, in the case of the HBRA rates, also the reduced workload per span after larger clearances are achieved (i.e., compliance is established) during 2011-13.

detailed information to the level of the other companies. Powercor did identify that the unit rates for HBRA, in particular those for the cyclic and pre-summer programs, reflect the increased work activity per span, particularly in the early years of the period 2011-15, required as a result of the removal of the HBRA Exemption.

The Powercor explanation for the increased unit rates does not provide any differentiation from the other DNSPs. On this basis, it remains unclear as to why the Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Nuttall Consulting notes that the SP AusNet unit rate is the lowest of the group at $195 per span. This unit rate was consistent for SP AusNet across LBRA and HBRA areas. Nuttall Consulting notes that SP AusNet is proposing an annual HBRA vegetation management cycle and considers that this approach would result in the slightly lower average cost per span.

SP AusNet has noted that the 2010 weighted average unit rate per span has increased to $205.71/span. This average unit rate per span increase has not been calculated to include the increased volumes associated with the Electricity Safety (Electric Line Clearance) Regulations 2010. On this basis, Nuttall Consulting considers that the previous rates will remain more reflective of the average unit cost for the increased volume of activities.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with removal of the 2005 Code exemptions for SP AusNet is $195 per span.

10.4.2.3 LBRA clearance exemptions

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

SP AusNet is proposing a unit rate of $195 per span for both LBRA and HBRA areas[446].

[redacted] has used a unit rate of [redacted] per span in calculating the cost to comply with clause 11.

[redacted] is proposing a unit rate of [redacted] per span for LBRA areas. [redacted] is also proposing a unit rate of [redacted] per span for LBRA areas.

[446] A side note in the SP AusNet spreadsheet suggests that these figures are not inflated to 2010 dollars.

The CitiPower/Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.

On this basis, it is not possible to determine why the CitiPower and Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

SP AusNet has noted that the 2010 weighted average unit rate per span has increased to $205.71/span. This average unit rate per span increase has not been calculated to include the increased volumes associated with the Electricity Safety (Electric Line Clearance) Regulations 2010. On this basis, Nuttall Consulting considers that the previous rates will remain more reflective of the average unit cost for the increased volume of activities.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with the removal of the 2005 Code exemptions is $195 per span.

10.4.2.4 Habitat trees

SP AusNet claimed an additional 22 full time equivalent (FTE) employees to meet this obligation. The ESV noted[447] that SP AusNet claimed the 22 FTEs on the assumption that it has the responsibility to make the assessment in regard to endangered fauna. ESV considers that the distributors do not have to make the assessment themselves, but can rely on registers held by others. On this basis, ESV considered that the additional resource required would be 3 FTEs (one for each of SP AusNet's regions).

Nuttall Consulting understands that the role of the 3 FTEs described by ESV will be an administrative one. On that basis, Nuttall Consulting recommends the administrative unit rate adopted by SP AusNet of $60,000 per annum per FTE[448].

10.4.2.5 Reduced clearances for insulated conductor – services

The unit costs associated with reduced clearances for insulated conductors relate to the omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3 in the revised Electricity Safety (Electric Line Clearance) Regulations.

[447] Assessment By Energy Safe Victoria Of EDPR Safety-Related Programs, ESV, 14 September 2010, page 24.
[448] Note $2009.

SP AusNet has estimated a per service unit cost of $83.46 for the initial cut and $47.40 to "maintain clearance space" for insulated services. The initial cut cost comprises "2 men @ $60/hr for 30 minutes" and the ongoing recuts are costed at "2 men @ $60/hr for 15 minutes".

In comparison, [redacted] has calculated that the average unit rate per service line would be [redacted], in either the annual initial cut or for ongoing recuts. [redacted] also assessed the unit cost per service for compliance with the Electricity Safety (Electric Line Clearance) Regulations to be [redacted] for [redacted].

[redacted] has estimated the unit rate for the initial establishment of clearance space as [redacted] with an ongoing rate of [redacted] per service.

[redacted] has also estimated the unit rate for the initial establishment of clearance space as [redacted] with an ongoing rate of [redacted] per service.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.

On this basis, it is not possible to determine why the CitiPower and Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for a four-fold increase in ongoing service recuts in the CitiPower and Powercor areas.

The man-hour assessments provided by SP AusNet appear reasonable, as do the assumptions in relation to approximate times and crew numbers.

The information provided by SP AusNet, United Energy and Jemena is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate for clearance of SP AusNet insulated services to comply with the Electricity Safety (Electric Line Clearance) Regulations are as follows:

- initial clearance of services: $83.46
- ongoing clearance of services: $47.40

10.4.2.6 Overhangs

ESV is recommending a volume of 2,000 spans that require the removal of overhanging vegetation.

In HBRA areas, the standard Clearance Space requirement allows for no vegetation to overhang open wire electric lines. In recognition of constraints in environmentally significant areas, the regulations do allow for exceptions, with conditions that include:

- vegetation is at least 3 metres above the line
- limbs are structurally sound
- an annual inspection is performed by a qualified arborist and any necessary cutting action taken.

These rules also apply to 66kV lines in LBRA areas.

SP AusNet identifies such spans as 56M's, a code which originated in the SECV Line Inspection System (LIS). SP AusNet states that it has actively reduced the number of 56Ms over the past decade, through a combination of targeted tree removal and line augmentation. The remaining 5,000 trees are now contained in 2,000 spans and are classified by SP AusNet as generally very large and/or significant in areas where tree removal would be very costly with significant stakeholder/environmental impact.

SP AusNet is proposing a range of actions to relocate or underground the affected spans. The proposed cost for these works is approximately $36 million or $17,966 per span.

The proposed costs are considerably greater than those proposed by [redacted]. [redacted] has identified engineering solutions to address overhanging vegetation with unit rates of [redacted] and a [redacted] per span.

SP AusNet has provided a spreadsheet[449] detailing the cost estimate build up for the estimated $36 million. This spreadsheet provides a number of assumptions and identifies the primary input values for determining the forecast costs.

Nuttall Consulting has reviewed the information contained in this spreadsheet. In general, Nuttall Consulting considers that the approach was generally robust, given the relatively unknown nature of the actual rectification projects. The following items are areas where Nuttall Consulting does not agree with the assumptions or input costs.

- The HV option analysis reviewed only 81 overhang spans. This represents less than 6% of the total overhang HV spans.
- The SP AusNet analysis assumed a large percentage of rectification works would require the undergrounding of the HV line. This percentage was heavily influenced by one project where the recommended action was the underground replacement of 36 spans of overhang. HV undergrounding is the most expensive option of the actions considered by SP AusNet.
- SP AusNet has applied a contingency of 20% to every project. Nuttall Consulting does not consider that a contingency of 20% is valid to be applied equally to every project. Nuttall Consulting considers it likely that some projects will run over the average cost and others will be completed under the average cost. Nuttall Consulting recommends removal of the contingency amount.

[449] 56M options Feb 2010 rev 4.xls

- SP AusNet has assumed an average LV span of 70m. In Nuttall Consulting's experience this is longer than the average Victorian LV span.
- The assumption that replacement of 6 spans will be required to address a single span of overhang in 1489 cases (78%) appears conservative and may understate the requirements in some areas.
- The costs for undergrounding and ABC were hard-coded into the model and could not be separated in many instances. This meant that it was not possible to assess the underlying unit rates that had been assumed for these activities.
- The model does not include any recognition of reduced operating and maintenance costs or deferred capex. SP AusNet states that "there is no meaningful difference in outage risk of 56M spans compared to other spans on the network"[450]. Nuttall Consulting does consider that there is a considerable reduction in outage risk for ABC and underground conductors compared to bare overhead conductors.
- Nuttall Consulting considers that the assumption that a HV Switching cabinet will be required for a 6 span HV UG option to allow for supply to a pole substation will not always be necessary (e.g. relocation of the pole top transformer to an adjacent pole).
- The unit rates assumed by SP AusNet did not appear to assume the reuse of existing pole top transformers and assumed that new transformers would be used. Nuttall Consulting considers that this may not always be the case and that this would overstate the required expenditures.

On the basis of the above review, Nuttall Consulting recommends that the proposed unit rates for SP AusNet projects to address overhang (56m) should be reduced by 20%.

10.5 United Energy

United Energy is claiming additional expenditures for the next regulatory control period associated with the Electricity Safety (Electric Line Clearance) Regulations 2010. The main areas of additional expenditure are as follows:

- Strategic program expenditures
  - ESMS Process Compliance Costs
  - Replacement of Non-Preferred Services
  - Installation of Neutral Condition Monitors
  - Removal of Public Lighting Switch Wires
  - Ground Fault Neutralisers and Removal of SWER
  - Install ABC in HBRA
  - Pole Top Fire Mitigation

450 AMS – Electricity Distribution Network Vegetation Management (AMS 20-23), SP AusNet, page 11

  - Pole Top Replacement (Age & Condition)
  - Pole Replacement
  - Overhead Conductor Replacement
  - Zone Substation Transformer Replacement
  - Zone Substation Circuit Breaker Replacement
  - Backup earth fault protection systems
- Electricity Safety (Electric Line Clearance) Regulation expenditure
  - Maintenance of the Clearance Space
  - Notification & Consultation
  - Service Line Clearance
  - Habitat Trees
  - Hazard Trees
  - Overhanging trees

Each of these expenditure items are covered in the following sections.

10.5.1 Strategic planning expenditures

United Energy has prepared a number of strategic planning papers targeted at specific asset classes. The papers identify additional expenditures associated with changes to the historical approach to managing these assets. The individual review of the ESV approved volumes for these strategies are considered below.

The ESMS compliance assessment has been grouped in this category for the sake of simplicity.

10.5.1.1 ESMS Process Compliance Costs

United Energy has identified the need for additional resources to meet its obligations under the new Electricity Safety (Management) Regulations. These regulations require United Energy to submit a risk-based Electricity Safety Management Scheme (ESMS).

United Energy has claimed the need for additional resources to meet its obligations under the new Electricity Safety (Management) Regulations which require United Energy to submit a risk-based Electricity Safety Management Scheme (ESMS). The additional resources claimed are shown in the following table.

Table 85 – United Energy compliance costs

ESMS Processing FTE Total for 5 Year Period	2011-15
Scheme description	20
Formal Safety Assessments	200
Establish Technical Policy Committee	50
Incorporation of risk in AMP	20
Monitoring, reviewing, auditing of processes	10
Safety related KPIs	120
Specification of Access Authority System	10
Establishment of formal incident processes & systems	360
Reporting	40
Auditing	Not provided
Emergency Response Plans	50
Total	880

ESV notes that the additional resources claimed by United Energy equate to less than 1 additional FTE over the five year period. ESV does not consider the level of resources to be material.

The United Energy unit rates are based on an internal labour rate of [redacted] per day. Nuttall Consulting notes that this is a relatively high rate and equates to an annual salary of approximately [redacted]. This level of remuneration is more consistent with a senior management or executive role, rather than a technical or administrative role.

On this basis, Nuttall Consulting recommends an annual FTE rate of $150k.

10.5.1.2 Replacement of Non-Preferred Services

Under its ESMS, United Energy is proposing a planned replacement program for non-preferred services. ESV noted that the need for the program was identified in the risk assessments conducted by United Energy in preparing its ESMS. The replacement of neutral screen services has been identified as a priority by the industry for more than a decade.

ESV note that the need for the program is supported by Jemena's analysis[451] arising from defects detected during its Neutral Service Testing program and through the increasing trend in electric shocks reported by the public.

The majority of issues relate to neutral screened and twisted service cables. Both of these types of service cable are reaching the end of their service life and present levels of risk

[451] Asset Strategy, Strategic Planning Paper, UED Neutral Screened Services, United Energy – page 2

that require attention. ESV strongly supports the need for the proposed replacement program, which is expected to take 15 years.

The ESV supports the planned non-preferred service replacement and height replacement of services, but not the fault replacement. The ESV considered that fault replacement represented business as usual practice.

In the original report, Nuttall Consulting determined that United Energy had not demonstrated any change in regulation or business driver that suggests that the neutral screened replacement program should be materially different from currently adopted practices.

United Energy states that the drivers for the change of approach for the neutral screen services replacement program are twofold; ESMS regulations and an improved understanding of associated risk.

Revised Electricity Safety (Management) Regulations were introduced in 2009 and amendments were made to the Electricity Safety Act 2007 which came into effect on 1 January 2010. The new regulations allow a robust risk management process to manage its network safety based on risk. United Energy also states that the ESV has identified a number of principal risks including “unsafe connection to customer premises”[452] although no reference to this was provided.

United Energy states that they commenced a 10 year neutral screen service replacement program in 2008[453] due to an observed increasing trend of failure of this class of service and the resulting public safety hazard.[454] However, they state that “the potential of severe risks such as customer fatality were identified. The only realistic option to address the risk is to eliminate it by replacing this type of overhead service. Risks have been assessed as so severe that the program is to be accelerated so that it is completed by 2015”. Nuttall Consulting is concerned that these “severe risks” are not being addressed at present with the 5 year program not commencing until 2011. These statements appear contradictory.

To satisfy the Electricity Safety (Network Assets) Regulations 1999 United Energy determined that all overhead services needed to be measured for neutral to earth resistance by the end of 2009[455]. United Energy has reportedly halted this program for the duration of the AMI roll out.[456] This deferral suggests that United Energy does not consider the risks associated with this asset type to be of the highest priority.

Nuttall Consulting also noted that the electricity industry, and United Energy specifically, have been aware of issues relating to neutral screen services for a long time and have had dedicated testing and replacement programs in place for nearly a decade.

[452] UED’s Revised Regulatory Proposal 2011-2015, page 143

[453] This date has been stated as 2009 in a later paper (Asset Strategy Strategic Planning Paper, UED Neutral Screened Services – undated). Which date is correct is not discussed.

[454] Ibid

[455] LV Overhead Services Lifecycle Management Plan, Document No.: UE 4356 – 117, 10/09/2009.

[456] Ibid.

Nuttall Consulting also notes that between 2001 and 2003, United Energy had already identified that 68% of electrical shock reports occurred only in service cables which have a neutral screen[457]. This is a very high proportion of electrical shocks from this population of assets and again highlights that the problems with neutral screen services are not new.

United Energy also states that "(t)he reported level of customer tingles and shocks has not materially changed over the historical period covered by the neutral service testing program."[458] This suggests that the risk of the failure mode that results in shocks or tingles for the neutral screen service population has not changed in recent years.

The United Energy asset strategy for neutral screened services[459] also identifies a "direct benefit" of $100 savings for each unplanned (faulty) service replacement that is avoided through the replacement program. Although this was a specific issue identified by Nuttall Consulting in the original report, United Energy has not identified this benefit in terms of a reduced operating expenditure requirement.

The United Energy forecast expenditure for the neutral screen service replacement program does not appear to recognise the interaction with the proposed vegetation clearance requirements. The new clearance regulations applying to vegetation in proximity to overhead services will reduce the level of neutral screen service faults due to abrasion by vegetation. The impact of these new regulations do not appear to be considered in the risk assessments undertaken by United Energy.

Nuttall Consulting notes that both the non-preferred service replacement and the height replacement programs are ongoing. It will be necessary to assess the historical volumes of service replacements and deduct these from the proposed replacement programs to determine the incremental volumes for the next regulatory period.

United Energy has proposed a unit rate for service replacement of [redacted].

Nuttall Consulting has reviewed the proposed replacement cost of [redacted] per service. The proposed per unit rate of [redacted] is not consistent with current United Energy prices to provide a new service. The new service and meter price charged by United Energy is currently [redacted][460]. This service includes the installation of a service (single phase) and meter and will typically involve greater travel distances between jobs than a programmed replacement schedule.

An efficiently run replacement program would be undertaken to minimise travel time through undertaking all replacements within close proximity to each other where possible. As these services were often installed as suburbs were developed, many will be in adjacent houses.

---

[457] United Energy Electricity Safety Maintenance Plans For Overhead Service Heights Pole Mounted Substation Clearances Neutral Testing Program And The Management of Shallow Underground Cables. Document No. UE 4200-30.

[458] Asset Strategy, Strategic Planning Paper, UED Neutral Screened Services (undated).

[459] Ibid, page 11

[460] United Energy Distribution Prescribed and Excluded Service Charges - United Energy Distribution, 1 January 2010

The current United Energy charges to install a temporary single phase service is [redacted] and this includes the disconnection and removal of the service at a later date. The cost for a temporary service installation with a coincident disconnection is [redacted]. This is essentially the same physical requirements as for a service replacement, with the additional costs of connecting a meter.

Nuttall Consulting notes that a percentage of neutral screen services may be three phase and that the connection time for these services may be a little longer than for a single phase service. The cost of the service materials may also be slightly higher.

To allow for the slightly higher three phase costs, Nuttall Consulting recommends a per unit amount of $160 for each service replacement.

10.5.2 Removal of Public Lighting Switch Wires

As identified by the ESV, public lighting switch wires have been largely redundant since the mid 1980’s as lighting control was transferred to photo electric switching. On the United Energy network, the switch wires were not removed when luminaires were replaced and in many places have still remained in place for over 25 years as an unused asset.

United Energy has opportunistically removed switch wires during other programmed work, but it is estimated that around 7,236 spans remain on the United Energy network (based on experience). The presence of unmaintained switch wires represents a hazard (there have been several fatalities and near misses) and ESV strongly supports United Energy’s program to remove the remaining spans of switch wire on a planned basis.

The ESV supports this program.

The United Energy proposed approach to switch wire removal is to:

- continue and reinforce the opportunistic removal of switch wire during major maintenance
- identify the extent and presence of switch wire during the 4 yearly pole and line inspections
- remove the remaining sections of obsolete public lighting switch wire over a three year period to 2015. This is expected to require one line crew with traffic control for approximately 50% of the time over a three year period and would be co-ordinated with major maintenance and renewal activities as far as practicable.

The unit rate for this work implied by the United Energy submission information is [redacted] per span. This is based on the United Energy proposed expenditure of [redacted] per annum[461] and the ESV recommended volumes of 2,412 per annum.

Nuttall Consulting has assessed the per unit requirement for switchwire removal on the United Energy and [redacted] networks and concludes [redacted] rate of [redacted] per span is reasonable.

[461] Asset Strategy Strategic Planning Paper UED Public Lighting Switch Wire Removal, United Energy, page 11

Switchwires are typically uncovered copper, steel or aluminium conductors. These materials have a positive value when sold as scrap, particularly copper. United Energy has not identified a recovery price for these materials.

The size and the type of the switchwire conductors is not known. It would be necessary to know the lengths, gauge and type of conductors to determine the recovery value of the materials.

United Energy also identifies that there are costs of leaving the unmaintained asset on the network. These include the costs of failure of the asset as well as the time and confusion required to identify and make safe the switchwire every time a crew is working on or near these assets.

Nuttall Consulting considers that the unit rate of [redacted] per span is a reasonable unit rate for this work. However, the unit rate does not recognise the benefits of removal of this asset as identified by United Energy.

10.5.3 Ground Fault Neutralisers and Removal of SWER

United Energy is proposing the removal of the remaining SWER lines in its service territory and the installation of Ground Fault Neutralisers (GFNs) in zone substations.

The ESV supports the volumes proposed for both of these works. These are the replacement of 44km of SWER and the installation of GFNs in three zone substations.

United Energy has provided the following unit rates to support the cost build up for this project.

Table 86 – GFN and SWER unit rates

Area	Item	Unit	Source	Unit rate
Zone Substation	GFN Unit	Per installation	FSH Actual Project	[redacted]
Zone Substation	Directional Relays	Per relay	Benchmark Price	[redacted]
Zone Substation	Unearth Cap Bank	Per cap bank	FSH Actual Project	[redacted]
Zone Substation	Other Costs	Per installation	FSH Actual Project	[redacted]
Distribution Network	SWER -Line	Per km	Benchmark Price	[redacted]
Distribution Network	SWER -Tx	Per km	Benchmark Price	[redacted]
Distribution Network	SA – Replace	Per 3 phase set	Benchmark Price	[redacted]
Distribution Network	SA -Retire	Per 3 phase set	FSH Actual Project	[redacted]
Distribution Network	Other Costs	Per installation	FSH Actual Project	[redacted]

United Energy states that they have also verified the pricing used to establish these unit rates and that actual costs have been back-calculated from an already complete GFN installation.

Nuttall Consulting has assessed the unit rates against the unit rates contained in the DNSP RIN submissions. Although not directly comparable in many cases, Nuttall Consulting considers that the proposed unit rates fall within the reasonable range of expected costs.

Nuttall Consulting recommends the following unit costs:

- $175,000 per km of SWER replacement
- $1.7m per zone substation for GFN installation.

Nuttall Consulting notes that the following unit rate does not make allowances for any of the following benefits:

- Bush fire start risk reduction - Significant reduction in the size of the phase to ground fault level reduces the risk of arcing for a conductor on the ground and therefore reduces fire start risk. This will result in less fault and emergency work for United Energy and reduced claims.
- Improved safety - Significant reduction in the size of the phase to ground fault current reduces step and touch potentials during fault conditions.
- Improved reliability - The self-extinguishing capability of the GFN for transient faults will see a reduction in MAIFI. United Energy has valued this at $10k per annum per zone substation. The reduction in fault current will also have an impact through reduced wear of circuit breaker contact points and less strain on line fittings and fixtures. This value was not quantified by United Energy.
- Surge arrester end of life - Surge arrestors need to be replaced at their end of life. Upgrading surge arresters to cater for GFN operation will defer the need for the next replacement. United Energy has valued this at $75k per annum per zone substation.
- SWER constraints - Many SWER systems have significant constraints in terms of voltage and capacity. Retiring the SWER will alleviate these constraints. This value was not quantified by United Energy.
- Standardisation - Removal of SWER will mean that spare parts for this type of network will no longer be required. This value was not quantified by United Energy.

10.5.4 Pole Top Fire Mitigation

United Energy is proposing a targeted program for reducing the incidence of pole top fires. The United Energy program of targeted inspection and replacement involves the refurbishment of HV and subtransmission pole top structures, including inspection, cleaning, tightening and replacement of crossarms and insulators where there is evidence of deterioration, charring or burning.

United Energy's 2011-2015 Capital and Operating Works Plan identifies a total of $7.97m for pole fire mitigation over the period 2011 to 2015. This allows for the targeted replacement of approximately 3,000 pole top structures.

The unit rate for this activity is calculated at [redacted] per pole top structure. Nuttall Consulting considers that this is a very high rate for the described works. Mitigating this cost is the non-sequential nature of the replacement. United Energy's description of the proposed program is that it will be based on inspections and driven by observed condition triggers. On this basis, pole tops will be replaced in a relatively sporadic fashion with limited ability to aggregate and gain efficiencies through adjacent works.

In these cases, the majority of unit costs may relate to labour and vehicle requirements, rather than the cost of materials.

Based on the above, Nuttall Consulting considers that the proposed unit rates are reasonable as follows:

- [redacted] per insulator set
- [redacted] per crossarm.

However, Nuttall Consulting considers that the proposed inspection unit rate of [redacted] per inspection is not reasonable. United Energy has not provided any information to substantiate an inspection that would justify this equivalent labour amount. Nuttall Consulting considers that a unit cost of $100 per inspection represents a conservative estimate of the time required to inspect the pole top assets.

Nuttall Consulting notes that these unit rates do not account for the following items:

- the reduction in emergency maintenance
- the historical expenditure of $200-$300k p.a in this area[462]
- the reduction in "pole fire events (that) have caused widespread impact on network performance"[463].

10.5.5 Pole Top Replacement (Age & Condition)

United Energy proposes to replace crossarms in targeted areas based on their age and condition, to achieve a reduction in the number of pole fires. This program has been considered in conjunction with the pole top fire mitigation program discussed in the preceding section.

This United Energy program is aimed at reducing the risk of fire initiation, reducing the number of pole fire related interruptions, reducing the risk of electrocution/injury to the public and reducing the risk of high voltage injection.

[462] Asset Strategy Strategic Planning Paper, UED Pole Top Fire Mitigation , United Energy, page 8
[463] Asset Strategy Strategic Planning Paper, UED Pole Top Fire Mitigation , United Energy, page 2

United Energy is proposing to replace an additional 50,088 cross-arms (and associated assets) in the next regulatory period. These are proposed as additional works to the existing programs of pole top replacement. The ESV supports these work volumes.

To assess the unit costs that United Energy has used to produce its capex forecast for this item, we have undertaken a comparative analysis exercise using:

- the replacement units costs provided by the DNSPs for the repex modelling exercise
- derived historical actual and forecast units costs from the relevant pole top activity codes, which were provided by the DNSPs and used in our RQM review.

Based upon this analysis, the unit costs look low compared to the other DNSPs, both the individual unit costs and the average unit cost. Furthermore, the average forecast unit cost also looks lower than the historical average derived from activity code data.

Based upon this analysis, we have accepted the United Energy unit costs.

10.5.6 Install ABC in HBRA

Approximately 40% of the United Energy network area is within the HBRA including around 19,500 poles and 2,300 km of overhead conductor. United Energy proposes to replace specific routes of bare overhead conductor with ABC, selected on the basis of relative fire risk of the line assets and their surrounding environment. Replacing bare conductor with ABC will reduce the risk of fire starts, reduce vegetation management costs and improve reliability of supply.

The incremental work load claimed by United Energy is shown in the following table.

Table 87 – United Energy proposed ABC in HBRA

	2011	2012	2013	2014	2015	2011-15
HV ABC Projects in HBRA (m)	4,800	4,800	4,800	4,800	4,800	24,000
LV ABC Projects in HBRA (m)	2,950	2,950	2,950	2,950	2,950	14,750

ESV supports the need for the program and has concluded that the work volumes appear reasonable.

United Energy is proposing unit rates of [redacted] per metre for HV and [redacted] per metre for LV.

Nuttall Consulting has reviewed the proposed rates against the per kilometre costs provided by the DNSPs for other capital projects and considers that the proposed amounts are reasonable.

Nuttall Consulting notes that these unit rates do not account for any associated reduction in emergency maintenance.

10.5.7 Pole Replacement

This United Energy program is aimed at reducing supply interruptions, improving public perception and safety associated with pole failures, and to ensure the economic optimization of pole life.

To assess the unit costs that United Energy has used to produce its capex forecast for this item, we have undertaken a comparative analysis exercise using:

- the replacement units costs provided by the DNSPs for the repex modelling exercise
- derived historical actual and forecast unit costs from the relevant pole top activity codes, which were provided by the DNSPs and used in our RQM review.

Based upon this analysis, the individual replacement unit costs are low compared to the majority of other DNSPs, using the unit costs provided for repex modelling. Furthermore, the forecast average unit cost appears reasonable compared to the other DNSPs historical and forecast averages derived from the activity code data - United Energy is lowest of the five DNSPs.

Based upon this analysis, we have accepted the individual unit costs.

However, we do note that the United Energy forecast average unit cost is high compared to its historical average. This appears to be due to the assumed ratio of staked poles to replaced poles being much lower in the forecast (58% historical to 43% forecast).

It is not clear whether the ESV has assessed this issue. Therefore, the AER may need to consider whether this assumption should be moved in line with the historical ratio i.e. around 55%. This will result in a reduction in the overall capex allowance for this program.

10.5.8 Overhead Conductor Replacement

United Energy is proposing a proactive replacement program that is designed to secure the performance of the system used and improve network performance overall.

This United Energy program is aimed at reducing the risk of fire initiation, reducing the number of conductor failure related interruptions, reducing the risk of electrocution/injury to the public, reducing the risk of high voltage injection and reducing OH&S issues for electrical workers.

United Energy's unit costs are similar to Jemena, but appear very high compared to Powercor and SP AusNet's unit costs[464]. The unit cost is approximately 85% above Powercor's proposed unit cost and over 100% of our recommended unit cost for Powercor (see section 6.3.3). United Energy has not provided any detailed analysis of past project costs to support its unit cost estimates.

We accept United Energy unit costs are likely to be higher than Powercor and SP AusNet due to the more urbanised nature of the existing lines. However, we do not consider that

[464] It is worth noting that the SP AusNet unit cost should be much lower as it does not capture all the costs allowed for in other DNSP's unit costs.

this is sufficient to explain the scale of the increase, particularly noting that we would expect the replacement to be largely on rural fringes where the fire hazards are greater.

We also note that the unit cost is more in the range of a complete rebuild or small upgrade. We do not consider this is reasonable, as we would expect in many circumstances restringing or partial rebuild will be possible.

Furthermore, we would also expect an overlap with other replacement needs allowed for in the pole and pole-top allowances. Given the large increases accepted by the ESV in these areas, it seems reasonable to assume that this overlap may be significant.

Based upon the above, and in the absence of more detailed analysis to support the United Energy unit cost, we consider a value of $55k/km to be reasonable.

This allows for a 66% increase, to cover the higher urban cost, on the efficient unit cost we recommended for Powercor.

10.5.9 Zone Substation Transformer Replacement

The United Energy Zone Substation Transformer Replacement Program is a major asset replacement program intended to secure the ongoing performance and reliability of the United Energy network.

United Energy has a number of transformers entering the latter years of their life, and are forecast to require replacement. The ageing of this plant is affected by loading, and the increased utilisation.

ESV did not recommend any work volumes under this program.

Nuttall Consulting has not assessed the unit costs for this program as it has not been recommended by the ESV. Replacement volumes and unit costs for this asset group have been assessed and provided for in the Nuttall Consulting recommendations on reliability and quality maintained capex.

10.5.10 Zone Substation Circuit Breaker Replacement

United Energy has established an ongoing zone substation circuit breaker replacement program which is aimed at achieving a high level of supply reliability and availability.

The replacement program is based upon a set of established criteria that are used to prioritise the program. Switchgear replacement is based on condition and performance and is aligned with major augmentation work wherever possible.

This United Energy program covers the replacement of ageing and defective zone substation circuit breakers. ESV does not dispute the need for this program, but considers that the program is driven primarily by factors other than safety (e.g. reliability of supply) and should be justified by those other factors. ESV also recognises that the need for the program does contain a safety component.

ESV did not recommend any work volumes under this program.

Nuttall Consulting has not assessed the unit costs for this program as it has not been recommended by the ESV. Replacement volumes and unit costs for this asset group have been assessed and provided for in the Nuttall Consulting recommendations on reliability and quality maintained capex.

10.5.11 Backup earth fault protection

A number of United Energy's zone substations are reliant on a single protection scheme to detect and isolate earth faults on the HV network. ESV considers this situation to be unacceptable due to the increased risk of electrocutions, fire starts and damage to network assets.

United Energy has 15 of its zone substations without backup earth fault protection. The incremental work load claimed by United Energy is shown in the following table.

Table 88 - United Energy backup earth protection volumes

	2011	2012	2013	2014	2015	2011-15
Install backup protection schemes	3	3	3	3	3	15

ESV supports the need for the program and has concluded that the work volumes appear reasonable.

The installation of a backup earth fault protection scheme will ensure network faults are disconnected in the event that the primary (feeder) protection scheme fails to operate. However, the operation of the backup earth fault scheme will result in the loss of at least one zone substation bus, resulting in more customers off supply.

United Energy has estimated the unit rate to install backup earth fault protection at [redacted] per scheme.

Nuttall Consulting is not able to benchmark this cost against other protection schemes as the retro-fitting of a protection scheme is driven by integration with the existing protection schemes and communication infrastructure.

Nuttall Consulting considers that the proposed unit rate of [redacted] per scheme does not appear unreasonable, but is not able to confirm these proposed costs against existing benchmarks or similar work types.

10.5.12 Electricity Safety (Electric Line Clearance) Regulations

United Energy is claiming additional expenditure due to changes to the Electricity Safety (Electric Line Clearance) Regulations:

- Maintenance of the Clearance Space
- Notification & Consultation
- Service Line Clearance

- Habitat Trees
- Hazard Trees

ESV has supported the need for additional work activity in most of these areas.

The Nuttall Consulting assessment of the unit costs associated with the above additional works are provided in the following sections.

10.5.12.1 Maintenance of the Clearance Space – HBRA pre-summer

The management of vegetation in High Bushfire Risk Areas (HBRA) is required to change due to changes in the Electricity Safety (Electric Line Clearance) Regulations 2010. DNSPs currently inspect and cut vegetation in HBRAs cyclically with a special inspection and trim undertaken prior to the summer bushfire period. This section deals with the inspection and trimming associated with vegetation management undertaken prior to the bushfire season.

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

United Energy is proposing a unit rate of [redacted] per span for pre-summer vegetation management in HBRA areas.

[redacted] has used a unit rate between [redacted] and [redacted] a span[465] in calculating the cost to comply with clause 11. The equivalent unit rate proposed by [redacted] is [redacted] per span for both LBRA and HBRA areas[466]. [redacted] is proposing a unit rate of [redacted] per span for HBRA areas.

The CitiPower/Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The information provided by SP AusNet, United Energy and Jemena is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. Powercor did not provide a working spreadsheet or detailed information to the level of the other companies. Powercor did identify that the unit rates for HBRA, in particular those for the cyclic and pre-summer programs, reflect the increased work activity per span, particularly in the early years of the period 2011-15, required as a result of the removal of the HBRA Exemption.

[465] The [redacted] unit costs decrease over time because of increased productivity and, in the case of the HBRA rates, also the reduced workload per span after larger clearances are achieved (i.e., compliance is established) during 2011-13.

[466] Noting the proposed annual program for HBRA

The Powercor explanation for the increased unit rates does not provide any differentiation from the other DNSPs. On this basis, it remains unclear as to why the Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, Jemena and United Energy is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with removal of the 2005 Code exemptions is [redacted] per span.

10.5.12.2 Maintenance of the Clearance Space – HBRA cyclic

The management of vegetation in High Bushfire Risk Areas (HBRA) is required to change due to changes in the Electricity Safety (Electric Line Clearance) Regulations 2010. DNSPs currently inspect and cut vegetation in HBRAs cyclically with a special inspection and trim undertaken prior to the summer bushfire period. This section deals with the inspection and trimming associated with vegetation management undertaken cyclically.

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

United Energy is proposing a unit rate of [redacted] per span for cyclic vegetation management in HBRA areas.

[redacted] has used a unit rate between [redacted] and [redacted] a span[467] in calculating the cost to comply with clause 11. The equivalent unit rate proposed by [redacted] is [redacted] per span for both LBRA and HBRA areas[468]. [redacted] is proposing a unit rate of [redacted] per span for HBRA areas.

The CitiPower/Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The information provided by SP AusNet, Jemena and United Energy is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. Powercor did not provide a working spreadsheet or detailed information to the level of the other companies. Powercor did identify that the

[467] The [redacted] unit costs decrease over time because of increased productivity and, in the case of the HBRA rates, also the reduced workload per span after larger clearances are achieved (i.e., compliance is established) during 2011-13.

[468] Noting the proposal annual program for HBRA.

unit rates for HBRA, in particular those for the cyclic and pre-summer programs, reflect the increased work activity per span, particularly in the early years of the period 2011-15, required as a result of the removal of the HBRA Exemption.

The Powercor explanation for the increased unit rates does not provide any differentiation from the other DNSPs. On this basis, it remains unclear as to why the Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, Jemena and United Energy is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Nuttall Consulting notes that the [redacted] unit rate is the lowest of the group at [redacted] per span. This unit rate was consistent for [redacted] across LBRA and HBRA areas. Nuttall Consulting notes that [redacted] is proposing an annual HBRA vegetation management cycle and considers that this approach would result in the slightly lower average cost per span.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with removal of the 2005 Code exemptions is [redacted] per span.

10.5.12.3 Maintenance of the Clearance Space – LBRA

The management of vegetation in Low Bushfire Risk Areas (LBRA) is required to change due to changes in the Electricity Safety (Electric Line Clearance) Regulations 2010.

Clause 11 of the 2010 Code establishes the required clearance spaces for non-insulated powerlines. These requirements were previously contained in clause 10 of the 2005 code. Clauses 10(b) and (c) and Tables 10.2 and 10.3 of the 2005 Code provided for smaller clearance spaces than would otherwise apply to powerlines of 22,000 volts or less and powerlines of 66,000 volts where the responsible person complied with clause 12 of the 2005 Code. These exceptions have not been included in the 2010 Code, resulting in a requirement for additional cutting.

United Energy is proposing a unit rate of [redacted] per span for LBRA areas.

[redacted] have used a unit rate of [redacted] a span in calculating the cost to comply with clause 11. The equivalent unit rate proposed by [redacted] is [redacted] per span for both LBRA and HBRA areas[469]. [redacted] is proposing a unit rate of [redacted] per span for LBRA areas.

The CitiPower/Powercor unit costs are considerably higher than those of all the other Victorian DNSPs.

The information provided by SP AusNet, Jemena and United Energy is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to

[469] A side note in the [redacted] spreadsheet suggests that these figures are not inflated to 2010 dollars.

show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.

On this basis, it is not possible to determine why the CitiPower and Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for the differences in proposed unit costs.

The information provided by SP AusNet, Jemena and United Energy is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate associated with removal of the 2005 Code exemptions is [redacted] per span[470].

10.5.12.4 Additional resources

United Energy has claimed additional labour resources associated with maintenance of the clearance space.

ESV "questions the level of additional resources claimed"[471]. Nuttall Consulting assumes that this statement means that ESV does not approve the volumes proposed and has therefore not assessed the unit rates proposed for this item.

10.5.12.5 Mid-cycle pruning program

United Energy is proposing the addition of a mid-cycle pruning program to augment the vegetation management program. The ESV has approved additional work volumes associated with this activity.

The unit rates proposed by United Energy for this work are provided in the following table.

Table 89 – Proposed mid-cycle pruning rates

Mid-cycle Pruning Program	Rate/Span ($)
Span Cut Rate HBRA Inspection	[redacted]
Span Cut Rate LBRA Inspection	[redacted]
Span Cut Rate Service lines Inspection	[redacted]

Nuttall Consulting notes that the unit rates vary considerably between LBRA and HBRA areas. It is not clear why the LBRA inspection costs are greater than the cyclic trimming costs proposed by United Energy of [redacted].

In the absence of justification from moving from the existing LBRA unit rate of [redacted], Nuttall Consulting is unable to recommend the proposed unit rate of [redacted]. Nuttall

[470] Noting the [redacted] spreadsheet notes of conversion of [redacted] to 2010 dollars.

[471] Assessment By Energy Safe Victoria Of EDPR Safety-Related Programs, ESV, 14 September 2010, page 19

Consulting notes that the cyclic LBRA cost of [redacted] compares closely to the [redacted] unit rate for this work of [redacted].

The mid-cycle cut rate of [redacted] for services is also higher than other comparable unit rates. [redacted] and United Energy have estimated the initial establishment of service clearance space at a unit rate of [redacted] with an ongoing rate of [redacted] per service. In comparison, [redacted] has estimated a per service unit cost of [redacted] for the initial cut and [redacted] to maintain clearance space for insulated services.

United Energy has not provided evidence to justify the mid-cycle unit rate being greater than the ongoing service clearance rate.

Based on the above, Nuttall Consulting recommends the following unit rates:

Table 90 – Recommended mid-cycle pruning rates

Mid-cycle Pruning Program	Rate/Span ($)
Span Cut Rate HBRA Inspection	$188
Span Cut Rate LBRA Inspection	$210
Span Cut Rate Service lines Inspection	$47.33

10.5.12.6 Notification & Consultation

The 2010 regulations require consultation only in situations where a tree that is to be cut or removed is within the boundary of a private property. Under the 2010 regulations, responsible persons can notify affected persons of cutting/removal of trees by placing notices in newspapers. ESV found that the changes to the regulations represent a small reduction in burden on the electricity distributors.

United Energy has requested additional work associated with notification and consultation. ESV considers that the requirements in the current regulations are a slight reduction in burden from those contained in the previous regulations, and therefore does not support additional expenditure for notification and consultation.

ESV did not recommend any work volumes under this program.

Nuttall Consulting has not assessed the unit costs for this program as it has not been recommended by the ESV.

10.5.12.7 Reduced clearances for insulated conductor - Services

The unit costs associated with reduced clearances for insulated conductor relate to the omission of exceptions in clauses 9.2.1, 9.2.2 and clause 9.3 in the revised Electricity Safety (Electric Line Clearance) Regulations. United Energy has identified service lines as being impacted by this change.

United Energy has estimated the initial establishment of clearance space unit rate as [redacted] with an ongoing rate of [redacted] per service.

[redacted] has also estimated the initial establishment of clearance space unit rate as [redacted] with an ongoing rate of [redacted] per service.

[redacted] has calculated that the average unit rate per service line would be [redacted], in either the annual initial cut or for ongoing recuts[472]. The information provided by [redacted] did not provide any further breakdown of these costs or time required for the proposed works.

[redacted] also assessed the unit cost per service for compliance with the Electricity Safety (Electric Line Clearance) Regulations to be [redacted]. [redacted] considered that there were likely to be [redacted].

In comparison, [redacted] has estimated a per service unit cost of [redacted] for the initial cut and [redacted] to "maintain clearance space" for insulated services. The initial cut cost comprises [redacted] and the ongoing recuts are costed at [redacted].

The information provided by SP AusNet, Jemena and United Energy is highly consistent and is also the most detailed. Each of these companies provided detailed spreadsheets to show how the costs were built up. CitiPower and Powercor did not provide a working spreadsheet or detailed information to the level of the other companies.

On this basis, it is not possible to determine why the CitiPower and Powercor costs are considerably higher than those of the other Victorian DNSPs. Nuttall Consulting is not aware of any geographic or demographic reasons that would account for a four-fold increase in ongoing service recuts in the CitiPower and Powercor areas.

The man-hour assessments provided by SP AusNet appear reasonable, as do the assumptions in relation to approximate times and crew numbers.

The information provided by SP AusNet, Jemena and United Energy is sufficient for Nuttall Consulting to form the view that these represent efficient unit costs for the proposed works. Nuttall Consulting is unable to conclude that the costs proposed by CitiPower and Powercor are efficient and has therefore rejected these.

Based on the information provided, Nuttall Consulting considers that the efficient unit rate for clearance of United Energy insulated services to comply with the Electricity Safety (Electric Line Clearance) Regulations are as follows:

- initial clearance of services: $83.46
- ongoing clearance of services: $47.40.

[472] This cost includes the cost of the cutting and clean-up of vegetation required as a result of the omission of clauses 9.2.1, 9.2.2 and 9.3 of the 2005 Code from the 2010 Code.

United Energy has also identified that some services may require undergrounding or relocation due to the revised Electricity Safety (Electric Line Clearance) Regulations 2010. The proposed unit costs for these activities are [redacted] and [redacted] respectively. The ESV has recommended volumes of 16,590 and 4,150 for these activities.

Nuttall Consulting has reviewed the proposed replacement cost of [redacted] per service. The proposed per unit rate of [redacted] is not consistent with current United Energy prices to provide a new service. The new service and meter price charged by United Energy is currently [redacted][473]. This service includes the installation of a service (single phase) and meter and will typically involve greater travel distances between jobs than a programmed replacement schedule.

The service replacement program will not be undertaken in a manner that would support minimising travel time as the services to be relocated may not be located in close proximity to each other. The relocation services may also require consultation with the landowner and adjacent landowners. To make allowances for these additional costs, Nuttall Consulting recommends a unit rate of $250 per service relocation.

The unit rate of [redacted] is greater than would be required to provide a simple underground service in a new residential estate. However, the installation of an underground service to replace an existing overhead service is a complex task. The costs associated with this task can vary dramatically based on factors such as soil type (e.g. rock, clay or sand), other services in the ground (gas, water, electric, sewer, telecoms, etc.), and reinstatement requirements (e.g. pavements, roads, nature strips).

Customer negotiations may also play a significant part in determining the unit cost of this activity. Nuttall Consulting assumes that the [redacted] unit rate excludes any works on the customer's premises with the exception of the disconnection and reconnection of the supply to the meter position.

The more densely populated an area, the greater the likelihood of increased costs. The proposed locations for the United Energy undergrounding of services are not known. As such, it is not possible to determine if the proposed unit rate of [redacted] is efficient as an overall average.

Nuttall Consulting therefore recommends that the proposed unit rate of [redacted] be accepted.

10.5.12.8 Habitat Trees

Clause 4 of the 2010 regulations requires a DNSP, before undertaking any pruning or removal of vegetation, to identify whether the tree is the habitat for fauna that is:

- listed as threatened in accordance with section 10 of the Flora and Fauna Guarantee Act 1988

[473] United Energy Distribution Prescribed and Excluded Service Charges, United Energy Distribution, 1 January 2010, page 10.

- listed in the Threatened Invertebrate Fauna List with a conservation status in Victoria of 'vulnerable', 'endangered' or 'critically endangered'
- listed in the Threatened Vertebrate Fauna List with a conservation status in Victoria of 'vulnerable', 'endangered' or 'critically endangered'.

In the event that the tree is the habitat for the fauna listed above, clause 4 of the 2010 regulations requires the cutting or removal of the tree to be undertaken outside of the breeding season wherever practicable.

In the event that it is not practicable to undertake cutting or removal of the tree outside of the breeding season for that species, the 2010 regulations require translocation of the fauna wherever practicable. These requirements did not exist in the 2005 regulations, although the management plan to be developed by the responsible person did require the identification of location of areas of vegetation that is the habitat of 'rare or endangered' species and details of the methods that will be used to avoid and minimise the impact on such vegetation.

United Energy proposes that an additional FTE specialising in the identification and maintenance of species and the maintenance of a register for endangered species and their habitat will be required to work in parallel with the United Energy vegetation management program.

United Energy state that this person would also arrange the training of assessors and other employees to be able to identify threatened species as well as obtain specialist services if required to ensure compliance with the regulations.

The ESV has confirmed that the new clause 4(1) does not require DNSPs to identify the location of 'habitat' trees. The current practice of obtaining information from local councils, government departments and community groups who hold such information will continue. ESV has advised that a DNSP will have met its obligation in regard to identifying the location of 'habitat' trees if it accesses the information held by others. United Energy considers that the need to obtain information from local councils, government departments and community groups, cross reference that information and analyse for threatened species and their breeding patterns will increase the workload above current practice.

As a result of discussions with the ESV United Energy has revised down its resource requirement to one FTE to establish the 'habitat' tree register in the first year (2011), followed by 0.4FTE in subsequent years to monitor and update the register, process questions and information requests, and provide on-going training to employees and vegetation contractors.

The ESV has approved the volume of work proposed by United Energy.

United Energy has used [redacted] per annum for the salary cost of the Scientific / Environmental Specialist based on existing salary band of Tier 6. Nuttall Consulting considers that the proposed FTE unit rate of [redacted] per annum is within the reasonable range of expected costs for this role. This rate includes is a gross rate and includes overheads and on-costs associated with employment.

10.5.12.9 Hazard Trees

The Electricity Safety (Electric Line Clearance) Regulations 2005 clause 9(4)(o)(iii) required DNSPs to specify the methods used to monitor the condition of vegetation in the hazard space (defined as vegetation that is beyond the regrowth space and could become a hazard to the safety of the electric line under a range of weather conditions prevalent in the area).

The 2010 regulations (clause 3 of the Code) give DNSPs the authority to minimise hazards by pruning or removing trees that are likely to fall onto or otherwise come into contact with an electric line.

United Energy has included the cutting or removal of hazard trees in its line clearance management plan submitted to the ESV.

United Energy has estimated that the volume of work required for this activity includes 500 tree removals and 1,500 trees cut. These volumes have been recommended by the ESV.

The United Energy unit costs proposed for these volumes are [redacted] for each tree removal and [redacted] for each hazard tree trimmed.

Nuttall Consulting has assessed the tree removal costs against those advised by the Australian Institute of Architects (AIA)[474]. This cost guide suggested tree removal costs in Melbourne of between $300 and $1,600 per tree. The AIA noted that prices are extremely variable and depend on the following: tree height, trunk circumference, density of branches/foliage, access to site for travel towers, woodchippers & grinders, obstructions, buildings underneath, tree alive or dead. The range could be wider if all the factors counted against easy removal.

Nuttall Consulting considers that the sort of trees likely to be considered a hazard will tend towards larger and older trees that are higher than the overhead lines. On this basis, Nuttall Consulting accepts the proposed tree removal unit rate of [redacted] per tree.

The United Energy proposed unit rate of [redacted] per hazard tree trim exceeds the cyclic span clearing rates of between [redacted] and [redacted]. A span typically consists of more than one tree that requires trimming on average. This suggests a per tree trimming cost of less than [redacted] to [redacted]. Mitigating against this is the likelihood that the tree trimming required for hazard trees will not have ready street access and will require trimming at a higher level than is typical for cyclic trimming.

On balance, Nuttall Consulting considers that a more cost reflective average cost for hazard tree trimming is therefore [redacted] per tree.

10.5.13 Overhanging trees

The ESV has approved a proposal by United Energy to cut or remove overhanging trees. The ESV report is not clear as to the driver for this work. Nuttall Consulting has assumed that the driver for these works is the Electricity Safety (Electric Line Clearance) Regulations

[474] http://www.archicentre.com.au/2008JAN_Fullcostguide.pdf

2010. In HBRA areas, the standard Clearance Space requirement allows for no vegetation to overhang open wire electric lines.

The incremental resources claimed by United Energy are shown in the following table:

Table 91 – ESV approved overhanging tree volumes

	2011 - 2015
Opex – Cutting trees	2,400
Capex – Engineering (u/g, line relocation, ABC, etc)	728
Project Management (FTE)	2.5

ESV has concluded that the work volumes appear reasonable, but questions the level of additional FTEs claimed.

United Energy state that 328 spans overhanging the 66kV in LBRA as covered by clause 10(c) and that 2,800 spans are registered as overhanging the clearance space in HBRA. United Energy considers that the removal of vegetation directly above the clearance space as not feasible in approximately 25% of these locations due to a number of reasons which include:

- health and safety risk to personnel attempting to undertake this work
- adverse public reaction.

United Energy have estimated that there are 2,400 spans that are overhung and are capable of tree cutting to meet the Electricity Safety (Electric Line Clearance) Regulations 2010 requirements. The breakdown of these spans and the unit rates associated with the tree cutting are provided in the following table.

Table 92 – United Energy overhang spans (cutting)

Item	Spans	Unit rate
HBRA bare	2,100	[redacted]
LBRA 66kV	300	[redacted]
SUB - TOTAL	2,400	

The [redacted] unit cost proposed for compete tree removal is [redacted].

Nuttall Consulting has assessed the tree removal costs against those advised by the Australian Institute of Architects (AIA) . This cost guide suggested tree removal costs in Melbourne of between $300 and $1,600 per tree. The AIA noted that prices are extremely variable and depend on the following: tree height, trunk circumference, density of branches/foliage, access to site for travel towers, woodchippers & grinders, obstructions, buildings underneath, tree alive or dead. The range could be wider if all the factors counted against easy removal.

As discussed previously, Nuttall Consulting considers that the sort of trees likely to be considered a hazard will tend towards larger and older trees that are higher than the overhead lines.

United Energy has not identified the volume of trees that would be removed or whether some trees may only require the partial removal of vegetation. These factors may influence the average cost significantly. A greater number of trees to be removed per span would increase the average costs, while a greater number of partial removals would reduce the average costs.

In the absence of this information it is not possible to determine if the United Energy proposed unit rate of [redacted] is reasonable and reflects an efficient costs.

Noting the above, Nuttall Consulting recommends the unit rate of [redacted] per span.

In cases where vegetation removal is not feasible, United Energy has determined that a range of engineering solutions will be required. The engineering options proposed by United Energy include re-constructing the lines with insulated cables, offset crossarms, pole relocation, undergrounding or a combination of various option.

The following table provides a summary of the unit rates proposed by United Energy. The volumes have been approved by ESV.

Table 93 – United Energy overhang spans (engineering)

Item	Spans	Unit rate
HBRA bare	700	[redacted]
LBRA 66kV	28	[redacted]
SUB - TOTAL	728	

[redacted] is proposing a range of actions to relocate or underground the affected spans. The proposed cost for these works is approximately [redacted] per span.

The United Energy proposed unit rates compare favourably to those proposed by [redacted]. However, the [redacted] analysis provided to Nuttall Consulting was considerably more detailed than the analysis provided for United Energy.

Nuttall Consulting notes that United Energy have been relatively conservative in estimating that all 66kV works will be achieved through the fitting of offset crossarms and pole relocations where possible.

Nuttall Consulting has reviewed the costs of undergrounding and considers that the unit rates proposed by United Energy are low when compared to full undergrounding options. This suggests that United Energy is considering that pole relocations and offset crossarms may be used in a number of cases. The lack of any further breakdown of costs means that Nuttall Consulting is unable to assess the individual costs of the proposed engineering solutions.

Nuttall Consulting considers that the unit rates proposed by United Energy are reasonable.

Attachment A – Curriculum Vitae of main review team

Curriculum Vitae – Brian Nuttall

Summary

Brian Nuttall is the Director of Nuttall Consulting.

He has worked as a consultant specialising in electricity regulation, strategy and asset management for the past ten years after beginning his career as an engineer within a large consulting engineering firm.

Before relocating to Australia in 2000, Brian was based in Newcastle, UK, where he was primarily focused on the analysis related to electrical distribution and transmission network planning, design and operation. Since 2000, Brian has had a much greater focus on strategic projects, bringing his technical knowledge to bear on many regulatory related issues. He has provided consulting services to many regulatory authorities in Australia and New Zealand on a large number of projects, including: numerous distribution and transmission regulatory resets, incentive scheme design, reliability reporting, valuations, and compliance auditing. He has also provided strategic advice to the network business, undertaking reviews of expenditure proposals, and independent expenditure and performance modelling.

Focus

- Strategic electrical network regulatory and technical advice for governments, regulators and companies.
- Expenditure and performance forecasting and reviews for regulators and network businesses.
- Power system study analysis and review for network service providers and market participants.

Relevant project experience

Advice to regulatory agencies

- For the ACCC, ESCOSA, OTTER, and ESC, involved in a number of regulatory revenue application processes, primarily focused on reviewing transmission and distribution businesses' expenditure proposals. Revenue applications include: Powerlink, Vencorp / SPI Powernet, Murraylink, TransGrid, ETSA, Aurora, and the five Victorian distribution businesses.
- For the AER, advised on a number of strategic regulatory issues, including:
  - the scoping of a cost reporting and analysis framework for assessing distribution businesses' expenditure requirements;
  - the analysis of a number of differing capital expenditure incentive schemes; and
  - the assessment of a market constraint based service incentives scheme.
- For a number of regulators, including the ESC, IPART and the Commerce Commission (NZ), member of audit team performing a range of regulatory technical compliance audits.

Advice to network businesses – revenue applications

- For a number of network businesses, advice and assistance in preparing revenue or price reset applications. The primary focus for this assistance is normally expenditure and service standard forecasts.
- For a number of distribution businesses, developed expenditure and reliability forecasting models. The models were used to produce independent forecasts or benchmark the businesses' own forecasts.

Other general strategic projects

- For Australian TNSP, performed numerous projects, including a review of the planning process, re-drafted its planning criteria document, assisted in preparing internal board papers and public submission papers.
- For ESIPC, lead development of Adelaide CBD transmission development plan, looking at the long term development options of the transmission system requirements for supplying Adelaide CBD.
- For DITR, examined the proposed SNI scope of works and associated costs as part of a project assessing the technical and economic worth of SNI.
- For a Pacific island electricity authority, lead the preparation of a transmission development plan, looking at the long term development options of the transmission system.
- For ESIPC, produced a discussion paper to provide and elicit information on a transmission development plan.
- For a major international network business, part of team developing a Strategic Asset Management Plan.

Power system planning and studies

- For numerous network businesses, generators and developers, performed a wide range of power system studies, analysis and evaluations, to assess: power system performance; network and non-network developments, and network interconnections.

Qualifications

- Doctor of Philosophy, Modelling and Multivariable Control of Turbogenerators, University of Newcastle, UK, 1999;
- Master of Science, Control and Information Technology, UMIST, 1993;
- Bachelor of Engineering (Honours), Electronic and Mechanical Systems Engineering, University of Salford, 1992.

Anthony Seipolt (MBA MAICD)

Director Cadency Consulting

Contact details

Email: anthony@cadency.com

Phone: (03) 9421 0939

Mobile: 0418 889 890

Address: PO Box 5043, Burnley VIC 3121, Australia

Summary

Anthony Seipolt is a senior consultant with extensive experience in the electricity, water and gas utility management and regulation including significant international expertise. Anthony has over 20 years' experience in the utility industry and is the director of Cadency Consulting.

Anthony has extensive experience in advising business, government and regulators in the interaction between technical needs and commercial or regulatory objectives. Anthony consistently provides technical input that enables a more robust and workable outcome; be it regulation, policy or legislation.

He has a Master of Business Administration, is a Member of the Australian Institute of Company Directors (MAICD) and is a former National Manager and Director of Parsons Brinckerhoff Associates. Anthony has managed performance reviews for over 200 electricity and water companies across the world as part of the UMS Group's benchmarking program. Anthony has also held a number of Board positions for community not-for-profit organisations.

Focus

- Utility Regulation
  - Regulation of natural monopoly industries and the interaction with good engineering practice

  - Expenditure assessments including the review of forecast capital and operating expenditures
  - Asset management planning reviews of electricity and water businesses
  - Expert witness for the development of regulation frameworks and policy
  - Asset valuation and methodologies
  - Cost allocation policies and reviews including customer class, corporate and direct, rural and urban, etc
  - Development of forward pricing proposals in partnership with water and electricity companies
  - Detailed practical understanding of electricity, water and businesses, regulation, expenditure planning and service standards
  - Gas, water and electricity distribution pricing and reliability
  - Planning/forecasting studies and regulatory tests.
- Utility Management and processes
  - Development and review of Asset Management Plans
  - Capital governance and management processes
  - Operations efficiency analysis
  - Reliability assessments and trade-offs
  - Development and review of network business cases
  - Asset and condition assessments
  - Capital and operating forecasts
  - Benchmarking and performance
- Project and Business Management
  - Management of critical timelines and complex environments
  - Leadership and integration of diverse teams
  - Co-ordination of complex projects with multiple stakeholders and objectives
  - Process reviews and operational audits of water, gas and electric utilities.

Career Summary

Anthony commenced his career in 1985 as a District Technical Officer for the State Electricity Commission (SEC) of Victoria. During the period between 1985 and 1996, Anthony undertook project design and management of various electricity extension and development works in rural and urban Victoria. This included positions based in Geelong, Camberwell and the Melbourne head office of the SEC.

In the early 1990's he was involved in the privatisation of the SEC and undertook the role of project manager for the Data Room for the sale of CitiPower.

With the newly formed private company (CitiPower), Anthony was appointed to manage the relationship between the network and retail arms of the business – in particular the emerging regulatory requirements of the new industry structure.

In 1996 Anthony joined the international benchmarking firm UMS Group. He undertook a large number of performance assessments of Australian energy companies. This work later extended to provide benchmarking and performance assessment services to utility companies in New Zealand, Indonesia, Singapore, Hong Kong, the United Kingdom and the United States. Anthony also helped to develop the initial WSAA water benchmarking program.

Anthony moved to New Jersey (USA) in 1999 to manage the development and delivery of the international benchmarking products of the UMS Group.

In 2000, Anthony was appointed national manager for the technical consulting firm of PB Associates. Over the next 5 years Anthony directed a large number of consulting projects for the majority of energy sector businesses and regulators.

Key projects included price and expenditure reviews for Queensland, Victoria, New South Wales, South Australia and Tasmania. In 2005, Anthony was also project director for the expenditure reviews of the Melbourne Metropolitan Water Businesses.

Anthony joined FSC in 2005 as an Associate. Anthony's technical experience provided a highly complementary skillset with that of the FSC group and has increased the overall offering of FSC.

With FSC, Anthony undertook projects including water expenditure guidance, asset management planning reviews, supported regulatory submissions and provided project governance and establishment advice. Recent clients include Australian and New Zealand regulatory bodies, water and energy companies.

In 2009, Anthony established Cadency Consulting and has continued delivering energy regulation services. These have included the development of capital forecasts for the National Grid Company of the Philippines, peer review for regulatory frameworks for the Commerce Commission of New Zealand and expenditure reviews of the Victorian electricity distribution sector for the Australian Energy Regulator.

Relevant experience

Utility Management & Regulation

- Undertaken expenditure reviews of the Victorian electricity distribution sector for the Australian Energy Regulator. Specific areas of review included opex step changes and targeted capex expenditure categories. Developed and implemented a comparative analysis and trending assessment of DNSP capex.
- Reported to the Commerce Commission in relation to distribution network asset management in New Zealand including the current condition of those assets, an indication of likely future investment requirements, the impacts that the threshold regime has had on historical investment and how required investment might be addressed by future regulatory arrangements. This work included a high-level determination of asset replacement valuations for each of the 28 Electricity Line Businesses.
- Advised National Grid Company of the Philippines in relation to the setting of capital expenditure requirements for the regulatory reset process.
- Advised the Commerce Commission on the Information Disclosure Requirements. Works involved reviewing and advising on the technical, quality and reliability reporting aspects of the information disclosure requirements.
- Anthony worked with Melbourne Water to develop a pricing proposal for submission to the Victorian water regulator.
- Anthony led the review of the metropolitan Victorian water businesses (Melbourne Water, South East Water, Yarra Valley Water and City West Water) for the Essential Services Commission of Victoria.
- Anthony has led teams to review the FRC forecast expenditures of the major NSW gas distribution businesses including AGL, Origin Energy and Country Energy.
- Since the introduction of incentive based regulation in Australia, Anthony has advised the majority of Australian electricity utilities in

preparing for and/or responding to regulatory price reviews. Utility clients included; AGL, ACTEW/AGL, Alinta, Aurora, CitiPower, Energy, Ergon Energy, Energex, EnergyAustralia, ETSA Utilities, Integral Energy, Powercor, SP AusNet, and Western Power.

- A principal focus of this work was the current capital and operation expenditures of the Australia utility businesses as well as future expenditures. Over the last 5 years, Anthony has been involved in business and project planning exercises totalling over $1billion in proposed expenditures.
- Acted under expert witness provisions for the Commerce Commission in New Zealand in relation to the development of customised price path regulation.
- Undertaken technical and engineering reviews of Australian TNSPs and DNSPs for the Australian Energy Regulator with a primary focus on capital expenditure and operating expenditure forecasts.
- Undertook review of the Asset Management Plans for each of the ELBs on behalf of the Commerce Commission in 2005.
- Anthony has also directed audit teams for the electricity and water sectors – principally process and service level audits in line with regulatory requirements.
- Detailed reviews of cost allocation methodologies and processes for regulators and businesses including:
  - regulatory and non-regulated activities
  - corporate, indirect and direct cost allocations
  - customer type and location (including assessment of rural and urban allocations and customer class).
- Anthony has extensive experience in the assessment of proposed business expenditures and has developed and implemented expenditure review frameworks to meet business and regulatory requirements; including the application of the regulatory test.
- Responsible for the delivery of regulatory pricing reviews, access arrangement reviews and FRC reviews for the majority of Australian Energy Regulators.
- Led teams to deliver regulatory projects in the water, gas and electricity industry across Australia.
- As Project Director/Project Manager for numerous reviews and related projects, established strong relationships with the following regulatory bodies;

– Commerce Commission of New Zealand,
– Australian Energy Regulator (AER)/Australian Competition and Consumer Commission (ACCC),
– Independent Pricing and Regulatory Tribunal (IPART),
– Essential Services Commission (ESC),
– Independent Competition and Regulatory Commission (ICRC),
– Queensland Competition Authority (QCA),
– Essential Services Commission of South Australia (ESCOSA),
– Office of the Tasmanian Energy Regulator (OTTER), and
– Economic Regulatory Authority of Western Australia (ERA).

Price Review/Access Arrangements:

- Review of Transend's (Tasmanian Transmission Company) forecast and historical renewal expenditure for the Australian Energy Regulator in 2008.
- Supported Integral Energy in developing the 5-year pricing proposal for the period 2009 to 2014.
- Supported Melbourne Water in developing the 3-year pricing proposal.
- Technical review of the Water Plans of Melbourne Water, City West Water, South East Water and Yarra Valley Water for the Essential Services Commission of Victoria in 2005.
- Established and maintained a sound working relationship with the ACCC in terms of electrical transmission pricing in Australia. Through this relationship Anthony has undertaken price reviews for the ACCC (now AER) covering TransGrid (NSW), EnergyAustralia (NSW), PowerLink (Qld), Transend (Tasmania), VENCorp (Victoria), and SPI PowerNet (Victoria).
- Led the review of the Western Australian Technical Code for the Economic Regulatory Authority of Western Australia.
- Project manager for the Western Power capital and operating expenditure modelling and forecasting project in preparation for the introduction of the new regulatory regime in Western Australian.
- Project director for the South Australia Electricity Distribution Price Review for ESCOSA.

- Project Director for the technical component of the Distribution Price Review of Tasmania in 2001 involving a review of 5-year historical and forecast capital expenditure and operating expenditure. The review also assessed base-case reliability and made recommendations on a number of enhanced reliability outcomes.
- Regulatory price review of the Queensland distribution industry for the Queensland Competition Authority. As part of this review, reported on the capital efficiency and performance of the Queensland distributors as well reviewing asset valuations and forecasting.
- Led reviews of the costs of implementing Full Retail Contestability in NSW, Victoria and the ACT. These projects have assessed more than ½ Billion Australian dollars in claimed costs for the gas and electricity industries.
- Managed reviews for the Essential Services Commission into the costs of electrical connection services in rural Victoria as well as a review of the Melbourne CBD electrical outage.

Project and Business Management

- Anthony was National Manager for the Australian operations of PB Associates – a technical consulting firm servicing the energy and water industries. In this role, Anthony was responsible for annual budgets in excess of $2million as well as business development, business strategy and people management.
- Over the last 5 years, Anthony has managed a large number of projects across and broad sphere of activities. Activities included resource scheduling across multiple-competing objectives, managing conflicting stakeholder requirements, and solving complex issues with limited information.
- Anthony has provided project establishment and governance advise for a major energy retailer.
- Anthony has managed large infrastructure projects, complex regulatory projects, national and international studies across;
  - private and public businesses,
  - local, state and federal government,
  - regulatory bodies, and
  - non-profit operations.

Qualifications

- Master of Business Administration (MBA), Deakin University, Melbourne Australia, 2000
- Advanced Certificate in Business Management, Deakin University, Australia 1992
- Certificate of Technology, Electrical, Northern Metropolitan College, Australia, 1985
- Additional Studies: Project Management Courses – 1992,1998 Contract Law – 1990

Conference Papers

- "Strategic and regulatory issues facing the Australian Utilities market", Intergraph Users Conference 2008.
- "Water Pricing & Regulation", Water Pricing Conference, Melbourne, October 2005.
- Chairperson, "The National Network Service Provider's Asset Management Conference", Brisbane, December 2004.
- "Post Reform Performance - An Interim Check-Point", Energy Focus National Conference, Sydney 2003.
- "The Challenge of Universal Service for Efficient Economic Regulation", Urban Water Reform Conference, Westin Hotel, Melbourne. October 2003
- "Water Benchmarking", Global Developments in Water International Performance Benchmarking, Perth, Western Australia, 2003
- "A Brief History of Price Reviews", Australian Water Association Conference, Melbourne, Australia 2003
- "The Cost of Competition" 2nd Annual Energy Regulation Conference, Melbourne, Australia 2002.
- "Utility Structures", Hong Kong Institute of Engineers, Hong Kong Sheraton, Hong Kong, 2001.
- "Risk Management", PACE Annual Practices Conference, San Francisco, California, 2000
- "Asset Management – Performance Assessment", UK Asset Management Forum, Sheffield, UK, 2000
- "Performance Assessment", PACE Annual Practices Conference, Denver, Colorado, 2000
- "Benchmarking Water", WSAA Benchmarking Conference, Melbourne, Victoria, 1999

- "Regulation and De-regulation", ANZ CEO Conference – UMS Group, Queensland, 1999
- "Asset Management", UMS Group Conference, Marina del Ray, Los Angeles, 1999

ANDREW WEBSTER – INFORMATION TECHNOLOGY ANALYST

Innovator, Evangelist, Project Manager & Architect for deploying, managing and understanding Large Scale IT environments, with special emphasis on investigation of underlying costs to improve efficiencies and deliver automaton..

Age:	Nationality:	Languages:	Years of Experience:
41 Years	Australian	English	>20

International Experience:

Australia, Japan, Singapore

Specialities

- Lowering the Total Cost of Ownership (TCO) of Information & Communication Technology (ICT),
- Technology Architect – Storage, Database, **CRM** and **ERP** systems.
- Process Engineering - maximising efficiency, reducing operating costs and delivery a better (faster) level of service,
- Team Manager – highly motivating and inspiring leader, who maximises people's potential.

Employers/Contracts:

Investment Banking (Barclays Capital, Deutsche Bank, Barclays Global Investors, ANZ**),**
Financial Services (Knight Ridder Financial (then Bridge now Reuters), Suncorp Metway
Utilities & Telcos (Melbourne Water, Telstra, Sensis, Gas & Electricity utilities throughout NSW and Victoria)

KEY ATTRIBUTES

- **Practical** and **pragmatic** whilst being **innovative** in the delivery and operation of **strategic** IT infrastructure that delivers **within budget** but flexible to adapt to ever changing **business needs**.
- Proven **team management** in the operation and implementation of complex IT technology including day to day management of staff, appraisingly individual & teams, platform & process **re-engineering** and performance improvement, specifically on **improving efficiencies** whilst **driving costs down**.
- In-depth technical knowledge and real-world experience with large (>200TB) NAS, SAN and DAS **enterprise storage** and **clustered databases** (**Microsoft** & **Oracle**) in real-time, near-time and disaster recovery scenarios utilising **EMC, CISCO** & **Network Appliance** infrastructures.
- Committed to creating in-depth **documentation** and understands the importance of **Change Control** and **Change Management**.
- Extensive experience in identification and investigation of **technology costs** and advice for government regulators in Victoria (**Essential Services Commission**) and New South Wales (**IPART**).

EDUCATION

Bachelor of Science (Chemistry), Monash University

Certificate of Computing, Monash University

Microsoft Certified System Engineer (**MSCE**) (#13042)
Microsoft Certified Product Specialist
Since 1995 – one of the first

Novell Certified NetWare Engineer (**CNE**) (#6220282)
Since 1993, until 2003

ADDITIONAL STUDIES

Speed Reading & Superior Learning Skills (1992)
Performance Tuning and Optimisation of SQL Server Windows NT (1994)
Measuring and Managing IT (1995
Prince 2 Foundation (2005)

PROFESSIONAL ASSOCIATIONS

Australian Computer Society – Full Member (**MACS**) (#1207975)
Network Professionals Association (**NPA**) – Member (#205747)
Information Technology Professionals Association (**ITPA**) – Member

EMPLOYMENT HISTORY

Practice Lead – Infrastructure Optimisation

THE MASTERMIND GROUP
MELBOURNE, AUSTRALIA
July'2007 to current (Permanent)
The Mastermind Group (TMG) is boutique consultancy dedicated to ICT infrastructure optimisation and data migration for large enterprises including Telstra, Sensis, Suncorp, Transurban and the Health sector.

During his time at TMG Andrew has been involved the following projects:-

Suncorp, Brisbane (July'2007 until April'2008)

Suncorp embarked on rapid technology and organisation transformation following the acquisition of similar sized former competitor Promina. Andrew provided specialist advice and guidance to the Suncorp as part of this transformation, including developing strategies to meet business requirements for a NetApp Storage deployment for Unix and Windows systems, a solution to resolve Mainframe storage issues and deployment of a virtualisation platform (VMware ESX) within the new environment. Andrew developed a Storage Service Catalogue and Cost Model that continues to be used to this day.

Sensis, Melbourne (April'2008 until December'2008)

Andrew ran the Sensis Design & Build Storage Team, consisting of 7 members responsible for providing storage and backup solutions on both IP and FC Storage from NetApp and EMC. Andrew drove down deployment costs and introduced further automation into the environment. Andrew then recruited an permanent employee to become the new Team Leader.

Andrew is currently involved in a number of reviews and rationalisation projects for TMG including desktop strategies, data centre design & utilisation, database system design and systems architecture.

Head of Storage & Backup (APAC)

BARCLAYS CAPITAL

SINGAPORE, SINGAPORE

April 2004 to July'2007 (Permanent)

Barclays Capital is the investment banking division of Barclays Bank PLC, headquartered in the United Kingdom. Andrew was responsible for EMC SAN, NetApp NAS and IBM TSM Backup infrastructure for the firm's 14 sites throughout Asia Pacific. During this time:-

- Designed and published a Storage Capacity Planning model and budget for Asia Pacific and then drove the financial justification for deployment of new infrastructure that quadrupled the size of storage connectivity (SAN ports) and storage capacity (Disk Space) to keep up with demands.
- Engineered and deployed a new global real-time Backup infrastructure alerting, system, integrating with the firms Remedy problem management system.
- Designed and deployed new SAN and NAS environments for new data centres in Tokyo and Hong Kong.
- Performed numerous data migrations on NAS and SAN array to better utilise capacity.
- Designed a new 1st Line Support model, including negotiation a multi-million dollar contact. Then recruited and trained the team to perform 18 support tasks. On 24 by 7 basis. This lead to 25% reduction in support costs.
- Engineering and deployed a new storage solution for small sites, that used asynchronous replication to Singapore, where it could be centrally backed up, to meet the firm's revised Disaster Recovery requirements.
- Designed eleven process and procedures to meet US Sarbanes Oxley audit requirements. These processes were all implemented globally.

Senior IT Infrastructure Consultant

ECS AUSTRALIA

MELBOURNE, AUSTRALIA

July 2001 to April 2004 (Permanent)

ECS Australia is a specialist consulting organisation in the review, audit and design of IT infrastructure. During his tenure, at ECS, Andrew has provided senior consulting and management services in the following areas:-

- On behalf of various economic regulators, expert analysis of IT **budgets**, **strategic architecture** and **infrastructure** of energy retailers (AGL, Energy Australia, TXU etc.) And distributors (Integral, TXU, Envestra etc) operating throughout NSW, Victorian and South Australian. Provided detailed assessments of prudency, suitability, efficiency and readiness of metering, **ERP**, **CIS** and **B2B** systems,
- **Firewall** & **Network Architect** for an integrated Internet Service Provider (**ISP**), including the development a firewall solution for a custom application with unique technical requirements,
- Specialist advice and detailed assessment to the Essential Service Commission (Victoria) on **B2B/XML** requirements for the electricity industry,
- **Project Management** in relocations of IT infrastructure for three medium sized organisations (>250 users),
- Review and complete redesign of the IT infrastructure for an AFL football club, including **Microsoft Exchange 2000** and **PXE** infrastructure.
- **Storage Architecture** for **Network Appliance** in the design and implementation of **Disaster Recovery,** Filer **migration** projects and storage technologies,
- Development of a flexible and extensible Windows XP, Windows 2000 and **Windows 2003** automated build product that can be rapidly customised to each customer's unique needs.

Storage Architect/Project Management
DEUTSCHE BANK AG
SYDNEY, AUSTRALIA
October 2000 to July 2001 (Contract)

In this position, Andrew designed and implemented a slightly smaller version of the Solaris based backup/archive system that he previously implemented for Deutsche Bank in Tokyo. In addition, the role grew into project management of the relocation of sixty Windows servers, two **Network Appliance** Filers (1.5TB ea) and **EMC** (500GB) connected Notes servers to new central infrastructure and BCP/Disaster Recovery sites.

Storage & Backup Architect
DEUTSCHE REAL-ESTATE SERVICES
TOKYO, JAPAN
January 2000 to October 2000 (Contract)

In this position, Andrew designed and implemented the first **Network Attached Storage** (NAS) for Global and Equities markets at Deutsche Bank. This included complete project management of the relocation of over 1500 Windows servers and workstation, from five buildings around Tokyo, to one large building; Andrew designed and implemented a Gigabit based network of **Network Appliance** F760 Filers with 6 Terabytes of disk storage, including near-real-time replication to a series of backup Filers, plus the design and implementation of four **SAN** based **Tivoli Storage Manager** backup servers (3 **Solaris**, 1 **Windows 2000**), connected to a 95TB AIT-2 tape library with 18 tape drives. Andrew custom developed a brand new data retention policy, to solve logistical and operational problems with the previous policy. Andrew also developed a complete backup reporting infrastructure to provide daily reports to system administrators and summary reports to managers.

Senior Support Engineer (Projects)
DEUTSCHE BANK SECURITES
TOKYO, JAPAN
March 1999 to December 1999 (Permanent)

This position involved Andrew acting as the sole SL3 (Service Level 3) for the entire Deutsche Bank Windows environment in Japan. Andrew liaised with other senior technical staff throughout the region and around the world, including **change and control management** of several world-wide lines of business systems.

Andrew redesigned and re-implemented the Windows infrastructure, including **DNS**, **WINS**, **DHCP** and re-deploying of backup software for 80 Windows NT servers in both English & Japanese, migrate all user data (700GB) from several standalone NT servers to a series of NT 4 Enterprise clusters connected to **EMC** or **Compaq** based **SAN** storage systems, built test environment for evaluation of Windows 2000 for local deployment to solve localisation issues, rolled out of **Microsoft SMS** to 1200 desktops, and implementation of an **Oracle 8i** Windows **SAN** connected cluster for a worldwide line of business system.

Finally, Andrew designed and piloted a Windows NT4 and 2000 **Server SOE** in both Japanese and English. Andrew then implemented the new SOE to over 60 Windows English & Japanese application servers.

Technical Consulting Manager
ECLIPSE COMPUTING
TOKYO, JAPAN
August 1998 to February 1999 (Contract)
Eclipse is a financial services organisation delivering multi-language solutions. Andrew was engaged to reinvigorate the Technical Consulting Team. Andrew implemented a new Windows and **Exchange** 5.5 based infrastructure (migrating from **Novell** and **Groupwise**) plus undertaking an extensive technical and personal **appraisal** of all existing consultants. The customer consulting typically involved **Microsoft SQL** 7 design, administration, tuning, redundancy options and troubleshooting. Andrew then developed a training program to raise the level of technical skills and recruited one new consultant for a senior role.

Windows Architect
BARCLAYS GLOBAL INVESTORS
TOKYO, JAPAN
March 1998 to August 1998 (Contract)
This was a short-term contract role in implementing a new Windows infrastructure at BGI's new Tokyo office. During this brief time, Andrew designed and implemented a Japanese automated NT 4 **Standard Operating Environment** and rebuilt over 170 workstations with it. In addition, Andrew designed and implemented a new **dual-language print server** environment plus a new desktop management environment via Microsoft's SMS product.

SOE Architect
THE OPTIMISE GROUP (HP/TELSTRA)
MELBOURNE, AUSTRALIA
June 1997 to January 1998 (Contract)
This role involved the design, development and manufacture of an automated build process for installing of Windows NT workstation **SOE** (known as CLS4) for 50,000 computers for Australia largest telecommunications provider Telstra. Andrew liaised with the various technology groups throughout Telstra, design & developed six applications in **C++** and **Transact SQL** for automating a variety of tasks. The project had been successfully piloted, before Andrew joined his family in Tokyo, Japan, after his wife accepted an employment opportunity there.

Senior Systems Engineer
CANDLE AUSTRALIA
MELBOURNE, AUSTRALIA
October 1995 to September 1997 (Contract)
This role was to provide on going support and project management for the operation of Melbourne Water's extensive **Windows NT 3.51/4.0** network that operates throughout the state of Victoria. Projects included the relocation of **Microsoft SQL** & **Sybase** databases; implemented a new **WINS** infrastructure to support the environment, commissioning of Internet mail facilities, a Gauntlet based **firewall**, implementation of **SMS** and data-migration projects from **Unix** to Windows NT systems.

Team Leader Central Systems

KNIGHT RIDDER FINANCIAL (formerly EQUINET PTY LTD)
MELBOURNE, AUSTRALIA
November 1991 to September 1995 (Permanent)
This position involved Andrew managing the backend operation of KRF Knight Ridder Financial (KRF)/Equinet IT infrastructure for the real-time time delivery of equities market data to professional investors and fund managers around the world. The environment included the management of a group of five staff – plus over 30 OS/2 servers, 20 Windows NT 3.51, 2 Microsoft SQL 4.2 Servers, 3 System V Unix systems, 1 Data General mini-computer as wells as CISCO, Wellfleet routers plus several internal Novell Netware file and print servers for both Sydney and Melbourne.
Andrew also acted as the Asian-Pacific Change Control manager.

Senior Computer Operator

BUDGET RENT A CAR
MELBOURNE, AUSTRALIA ***January 1990 to October 1991 (Permanent)***

SUMMARY OF SKILLS AND EXPERIENCE

Skill	Experience
Windows NT 3.1/3.51/4/2000/XP/2003/2008 – Design, Implementation, In-depth Troubleshooting	11 Years
IBM Tivoli Storage Management (ADSM / TSM) – Design and Implementation	8 Years
Staff Management & Leadership, including technical & professional appraisals and recruitment	8 Years
TCP/IP Networking – Design, Implementation, In-depth Troubleshooting, Security, Analysis	8 Years
MS SQL v6.0/6.5/7.0/2000 / 2005 /2008, Sybase System 10 and 11 – Design, Implementation & Troubleshooting	7 Years
Oracle 8i / 10 / 11 RAC – Implementation & Troubleshooting	6 Years
Use of Enterprise Storage (DAS, NAS, SAN) systems from EMC, Network Appliance, Hitachi, Hewlett Packard and Compaq	9 Years
Visual C++, Visual Basic, Borland C++ Builder – Analysis and Programming	6 Years
Automated Windows Desktop and Servers in English, Japanese, Chinese (Simplified)	5 Years
Citrix and Microsoft Terminal Servers & Services	5 Years
COM/DCOM/MTS/Component Based/Distributed Computing Architectures and Implementation experience	5 Years
In-depth knowledge of high-availability, fault resilient network designs and implementations	5 Years
Managing Change, Change Control and Reporting	5 Years
Tivoli (IBM) 3.1/3.7/4.1/4.2) ADSM/TSM – Design, Implementation, In-depth Troubleshooting	5 Years
Microsoft AD/NDS Tree/ Enterprise Directories – Design and Implementation	4 Years
Multi Terabyte Backup/Archival and Business Contingency Systems & Planning	4 Years
Novell NetWare 3.X/4.X – Design, Implementation, In-depth Troubleshooting	4 Years
People and Project Management Skills	4 Years
Windows Enterprise Computing including Clustering & Fault Tolerance for >50,000 environments	4 Years
Linux (RedHat & Debian) – Design, Implementation, In-depth Troubleshooting	3 Years
Solaris – Design, Implementation, In-depth Troubleshooting	2 Years

CONTACT DETAILS

Email
webstean@gmail.com

Postal Address
12 Main Road,
Walhalla 3825

Telephone
Mobile: +61 4 3001 6095

References
Available Upon Request

Internet Links
http://www.linkedin.com/in/maketechnologywork

CRAIG OWENS

Senior Consulting Engineer

m/ 0418 536 610 438
e/ cowens@hmac.com.au f/ +61 (0)7 3236 4266

Craig joined Hill Michael in March 2007 and has over 25 years experience in the electricity industry.

Craig holds qualifications in Electrical Engineering, Computing and Management. He started his career as cadet engineer with the Sydney County Council, gaining valuable practical experience while completing his degree. Moving to Tasmania in 1989, he joined the Hydro Electric Corporation (HEC) as a Project Engineer.
Five years in the Retail Division was valuable in better understanding customers' needs, and the impact of end-use equipment on the distribution network.

Craig moved back to Network division in 1995. After the HEC was disaggregated in 1998 Craig joined the newly formed Aurora Energy and worked in System Planning, Strategic Improvement, Protection and Control, and Svstem Performance.

Specialist Areas

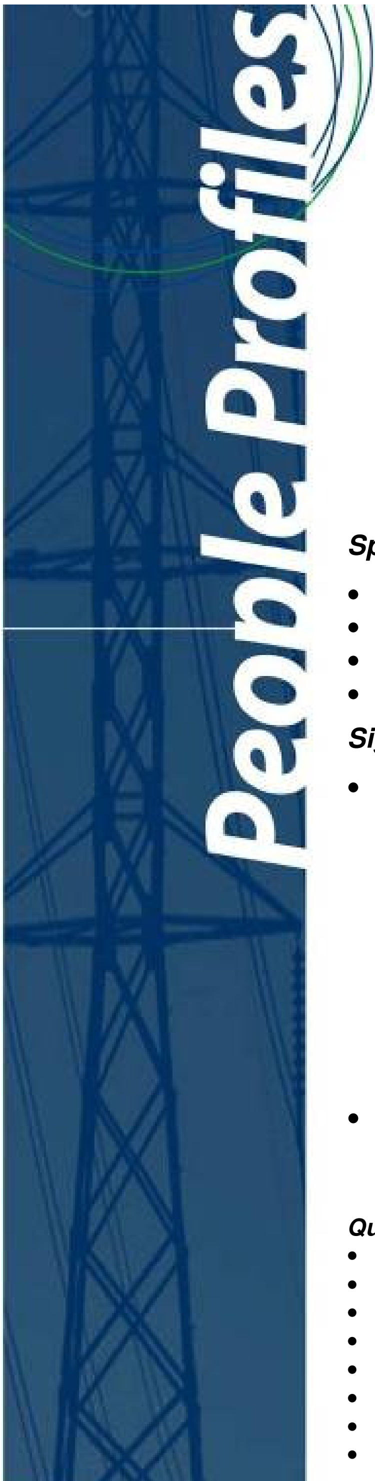
- Network Planning
- Reliability
- Power Quality
- Software development
- Artificial Intelligence applications in electrical engineering
- Protection

Significant Projects

- Development of Protection Analysis DINIS Software
- Leadership of a team that delivered average reliability improvements of 50% on targeted feeders in Aurora's 'Feeder Trunk Strategy'
- Development of Aurora Energy's policy on permissible loading of transformers
- Participation in production of the 'Greater Launceston Area Development Plan'

Qualifications, Professional Membership & Industry Involvement

- BE (Electrical)
- Postgraduate Diploma in Computing
- Postgraduate Diploma in Management
- MIEAust
- CPEng



DR JOHN H NIELSEN

Director Distribution and Subtransmission

m/ 0409 316 890 p/ +61 (0)7 3236 4244

e/ jnielsen@hmac.com.au f/ +61 (0)7 3236 4266

John has 15 years experience in the Queensland electricity supply industry and more than 10 years experience lecturing on a large range of electrical engineering subjects.

He has extensive experience with Ergon Energy as Principal Engineer Subtransmission Planning & Investigation and provides the highest level of professional support to Network Service Providers, energy users and generators in the technical aspects of connecting to the national electricity grid.

John is a Chartered Professional Engineer with a doctorate in electrical engineering and provides invaluable technical capability for network providers and users.

Specialist Areas

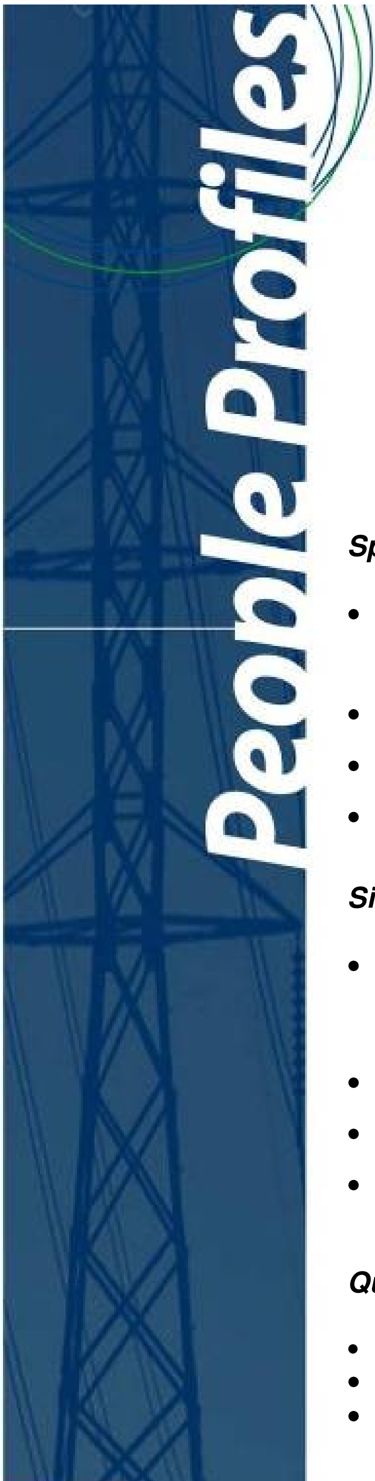
- Major customer load and generator connections to the shared electricity grid
- Harmonic analysis
- Network modelling and analysis
- Complex technical investigations

Significant Projects

- Network connection investigations for:
  - Townsville Power Station steam turbine generator, 80 MW
  - Pioneer Sugar Mill new steam turbine generators, 68 MW
  - Isis Sugar Mill new steam turbine generator, 25 MW
  - Condamine Power Station, 140 MW
  - Daandine Power Station, gas engine generators, 27 MW
  - Load increases associated with Abbot Point coal port expansion
  - Orica plant expansion at Gladstone
  - Proposed Wiggins Island coal port at Gladstone
  - Multiple major mining loads in the Mt Isa district
- Development of DINIS API (Application Programming Interface) code to automate Distribution Loss Factor calculations, fault level studies and contingency analyses

Qualifications, Professional Membership & Industry Involvement

- IEAust Representative, Standards Australia committees EL-048 and EL008 (2009)
- Registered Professional Engineer Queensland (2008)
- Chartered Professional Engineer, Institution of Engineers, Australia (1996)
- Member of IEEE (1981)
- PhD in Electrical Engineering, James Cook University (2003)
- Master of Engineering Science, James Cook University (1982)
- Bachelor of Engineering (Electrical) Class 1 Honours, James Cook University (1980)
- Graduate Certificate of Education in Tertiary Teaching (1996)



DR. CRAIG AUMULLER

Senior Distribution / Sub-Transmission Engineer

m/ 0403 991 828 p/ +61 (0)7 32364244
e/caumuller@hmac.com.au f/ +61 (0)7 3236 4266

Craig has worked in a wide variety of electrical engineering roles in the 13 years since graduating with a Bachelor of Engineering from James Cook University in Townsville, Queensland.

He has had extensive experience with power generation, power transmission and power distribution companies; spent time as a consultant industrial engineer. Craig has completed an industry funded PhD at the University of Queensland and lectured in power engineering at James Cook University.

Specialist Areas

- Power systems planning, load flow analysis, dynamic analysis, fault analysis and protection studies
- Power systems education
- Industrial protection and control system design
- Lighting and power reticulation design

Significant Projects

- Planning of major infrastructure projects for the Energex electricity sub-transmission and distribution networks through analysis, computer simulation and consultation with stakeholders.
- Protection coordination study for the Cairns Port Authority
- Design and installation of 132kV, 62.64Mvar capacitor bank at Boyne Smelters
- Design of replacement Kangaroo Valley Switching Station earth grid

Qualifications, Professional Membership & Industry Involvement

- BEng (Elec), James Cook University (1997)
- PhD in Electrical Engineering, University of Qld (2003)
- Graduate Certificate in Tertiary Education (2005)

Head Office:
Level 3, Bowman House
276 Edward St, Brisbane Qld 4000
GPO Box 3195, Brisbane Qld 4001
Australia

p/ +61 (0) 7 3236 4244
f/ +61 (0) 7 3236 4266

www.hmac.com.au

HILL MICHAEL

- Cairns
- Townsville
- Brisbane
- Canberra
- Melbourne
- Launceston

Hill Michael is a specialist electrical networks and strategic engineering firm. Focused on the application of engineering expertise in the context of organisational and project strategy, Hill Michael is a leading advisor to owners of electricity supply networks and those wishing to connect to them. Established 1987.

SORUBY K BHARATHY

Commercial Engineer

e/ sbharathy@hmac.com.au

p/ +61 (0)7 3236 4244

f/ +61 (0)7 3236 4266

Soruby is a qualified electrical / electronics engineer with a Masters in Engineering Management. She has more than 5 years experience in the electricity transmission sector.

Having previously worked in Transend and NEMMCO, Soruby provides valuable expertise in: strategic long term transmission planning, National Electricity Rules compliance, Australia's deregulated electricity industry regulatory framework, feasibility studies for high voltage connection options, power system studies and high voltage connection agreements.

Specialist Areas

- Stability and load flow using PSSE and other transmission planning software.
- Preparation of long term load flow scenarios for the Grid Vision Project
- Technical compliance of generators to the National Electricity Rules.
- Connection Strategy, Agreements and Regulatory advice / Management

Significant Projects

- Preparation of the Statement of Opportunities 2007 for NEMMCO.
- Development of concepts, methodology and implementation of constraint equations for the NEM Entry and Basslink projects.
- Pulp Mill Connection Options for 200MW Cogeneration plant at Bell Bay.
- Power system stabiliser tuning and commissioning for Gordon power station.
- Network Studies on 110kV, 132kV and selected 275kV Feeders, Energex.

Qualifications, Professional Membership & Industry Involvement

- Chartered Professional Engineer, Australian Institute of Engineers
- Master of Engineering Management (University of Canterbury)
- Bachelor of Electrical and Electronics Engineering (University of Canterbury)

Bill Heaps IEng MIET, HNC Electrical Eng (UK)

Bill has 32 years' experience that spans the electricity supply chain. He has worked on the implementation of electricity markets in both the UK and New Zealand and has practical experience of the Australian markets. He has also been involved with energy market developments across the Asia Pacific and India.

Bill has extensive experience in the commercial management of electricity distribution companies. He has been a commercial manager for distribution companies in the UK and New Zealand. During the first wave of retail competition in the New Zealand electricity market Bill established Energy Brokers Ltd, one of the first independent retailers to trade electricity across traditional boundaries. To achieve successful energy trading, it was essential to form an appropriate framework and Bill was directly involved in the establishment of market mechanisms for hedge contract trading, metering and reconciliation.

Whilst much of Bill's experience is in the commercial sector of the industry, he has also held executive roles in generation, distribution and transmission. He managed the largest New Zealand geothermal power stations through the transition from public to private ownership and was responsible for significant reductions in operating costs and increases in performance.

Alongside his commercial responsibilities in transmission, he also chaired industry taskforce groups managing electricity supply security events such as; the 2004 Upper South Island supply security, 1999 Upper North Island summer security and the dry winter management in 2002.

Bill Heaps has held directorships with Orion Group Limited d-cypha, the National Reconciler for the electricity industry and was Chairman of Critchlow Associates a geographic information system solutions company. In 2002/3 Mr. Heaps was involved in the successful establishment of an electricity futures contract platform in Australia with d-cyphaTrade and the Sydney Futures Exchange.

Bill currently chairs the Wholesale Market and Transmission Advisory Groups for the New Zealand Electricity Commission and chairs and facilitates other industry groups and projects for the Commission.

Bill's recent roles in the energy sector are:

- Director Orion Group Limited (2006 – 2008)
- Chairman Wholesale Market Advisory Group, NZ Electricity Commission (2004 – 2009)
- Chairman Transmission Advisory Group, NZ Electricity Commission (2004 – 2009)
- Chairman Technical Support Group, (WGIP), NZ Electricity Commission
- Chairman Retail Market Advisory Group, NZ Electricity Commission 2004 - 2006
- Chairman Switching and Registry Working Group, Gas Industry Company 2005 - 2006
- Chairman Model Retail Contracts Working Group, Gas Industry Company 2005 - 2006
- General Manager Commercial Services, Transpower NZ Ltd 1997 – 2003
- Director d-cypha Ltd. 1999 – 2003

- General Manager Geothermal, the Electricity Corporation of New Zealand (ECNZ)/Contact Energy 1995 – 97
- General Manager Energy Brokers NZ Ltd 1993-95
- Commercial Manager of CentralPower Ltd 1990-93
- Member of New Zealand's Metering and Reconciliation Information Agreement MARIA establishment committee 1993
- Chairman, New Zealand Upper North Island Summer Security Working Group 1999 and 2000
- Chairman, New Zealand Winter 2002 Industry Work Group

Clive Bull BE (Elec) (Hons)

Clive has 30 years experience across a range of roles in the corporate sector of New Zealand's electricity and gas industries. Following graduation as an electrical engineer from the University of Canterbury in 1980, Clive undertook a range of technical post graduate roles in the then New Zealand Electricity Department, leading to an early specialisation in electricity system operations. With corporatisation and the formation of Transpower, Clive's role became the management of transmission system operations in the pre-electricity market phase.

Clive transferred into a grid planning role in 1989 and took up responsibility for the planning and implementation of capital works projects for the North Island grid. This role provided exposure to all aspects of grid planning and the management of significant capital projects. In 1994 Clive took up an opportunity to participate in a management swap programme with Transpower in cooperation with the Georgia Power Company and relocated to the USA to undertake a one year work experience assignment in the area of bulk power markets. At the completion of this assignment, Clive completed the 13 week residential Program for Management Development at the Harvard Business School in Boston, Massachusetts.

On returning to New Zealand, Clive undertook a number of commercial roles at Transpower, at various stages managing transmission contract and pricing development and the customer relationship management team. Clive left Transpower to move into the distribution sector in 1999 taking on customer and commercial management roles with UnitedNetworks, immediately following the separation of line and retail functions in New Zealand. UnitedNetworks expanded its business into gas distribution and Clive was responsible for developing and negotiating a new suite of use of system agreements with electricity and gas retailers. Following the sale of UnitedNetworks to Vector, Clive continued in the newly merged business in the area of customer and commercial management, including a significant period with responsibility for developing a new business model to streamline aspects of Vector's portfolio of network businesses across electricity and gas and later incorporating the purchase of NGC's gas business.

Throughout this period, Clive has been a member of a number of industry advisory and working groups for various regulatory and industry bodies in a range of areas spanning the electricity and gas sectors, including transmission investment, distribution and retail commercial arrangements and industry-developed consumer and landowner complaints resolution schemes.

Most recently, Clive has had responsibility for developing aspects of Vector's business responses to climate change, in particular establishing a visionary programme of research and development activities in the areas of distributed generation based on emerging clean technologies, electric vehicles, smart metering and smart grids.

Clive left Vector in July 2009 to widen his experiences beyond the corporate sector and is currently active as an independent consultant, including as an Associate Consultant with Strata Energy Consulting on a growing range of energy industry assignments.

Clive Bull's relevant experience includes:

- Customer and commercial management roles at both transmission and distribution levels in the electricity and gas sectors, providing a broad customer-focused experience set and a detailed understanding of network company strategy and business operations.

- Asset management roles with specialisation in transmission system planning and project management for projects requiring significant capital expenditure and implementation complexity.

- Roles providing an in-depth understanding of the role and strategic impact of new technologies on network distribution businesses, in particular the types of technologies that are starting to appear on the near horizon with a particular interest and application for mainstream end-consumers.