**Report**
**to**

THE QUEENSLAND COMPETITION AUTHORITY

# CAPITAL AND OPERATING EXPENDITURE STUDY FOR DISTRIBUTION NETWORK SERVICE PROVIDERS IN QUEENSLAND – ERGON ENERGY

**Final Report 21st December 2004**

**Burns and Roe Worley Pty Ltd ("BRW")**

Level 15, 300 Flinders Street

Melbourne

Victoria 3000

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# 1 EXECUTIVE SUMMARY

## 1.1 Scope

This report reviews the operating expenditure, capital expenditure and asset management practices of Ergon Energy. An overall strategic view is provided with regard to whether the proposed levels of capital and operating expenditures, for the period 2004/05 to 2009/10, are reasonable and efficient.

A key input to the review of the requirements for Capital Expenditure ("CAPEX") and Operational Expenditure ("OPEX") was the assessment of Ergon Energy's growth forecasts.

Unless stated otherwise, all forecast and historical figures are in June 2004 dollars.

## 1.2 Business Environment

The Consultant took note of the business environment in which Ergon Energy conducts its business. This included the following requirements:

- Regulatory;
- Operational;
- Safety;
- Customer service standards;
- Environmental; and
- Geographic considerations.

The Consultant concluded that Ergon Energy generally operates in a similar business environment to electricity distributors in other jurisdictions, with the exception of geographic considerations. In assessing their CAPEX and OPEX requirements, the Consultant has taken into account the impact of lower customer densities, the larger distances involved and the requirement to overcome a large number of overloaded Single Wire Earth Return ("SWER") systems.

## 1.3 Asset Management

Asset management covers the processes for planning, development, operation and maintenance of all components of the electricity network. Clearly, sound asset management processes are a prerequisite for prudent and efficient capital and operating expenditure.

The general planning approach adopted by Ergon Energy is similar to that of other Australian electricity distributors. Ergon Energy has developed a 20 Year Vision for Network Asset Management, and is in the process of developing supporting Asset Policies, Asset Strategies and Asset Plans. Ergon Energy does not have reliable asset data for all of its network assets – currently only about 70% of the data has been reliably captured. Ergon Energy has accelerated its asset inspection program in order to more quickly capture the outstanding data.

There are still some outstanding integration issues, in areas such as substation design standards, drawing symbols and a range of maintenance practices.

At the formation of Ergon Energy, a significant backlog of maintenance existed, indicating an apparent under investment in maintenance in previous years. A life cycle approach to maintenance is now being adopted, with asset life expectancy being considered. Maintenance plans for each asset type have been prepared covering time based inspections, non-intrusive condition monitoring, condition based maintenance, refurbishment as required and replacement at life expiry.

## 1.4 Asset Utilisation

Ergon Energy has similar levels of asset utilisation to comparable Australian electricity distributors.

Ergon Energy applies a probabilistic approach, based on a modified "n-1" criterion, and in addition carries out a Reliability Assessment Planning ("RAP") analysis in particular situations to verify that the modified criterion represents an acceptable level of risk. The Consultant considers that Ergon Energy has a sound approach to planning for capital works, but it is noted that some of the current processes have been recently introduced and some policies and strategies are still under development.

## 1.5 Service Standards

Ergon Energy has a high level of complaints and indications are that Ergon Energy has room for improvement in the level of customer service provided, as viewed from a customer complaints perspective. Ergon Energy's supply reliability is worse than that of other comparable distributors for System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") but is in the mid range for Customer Average Interruption Duration Index ("CAIDI"). This is heavily influenced by the characteristics of Ergon Energy's supply system, and leaves a large scope for Service Quality Improvement works.

In establishing the CAPEX and OPEX building blocks for the next regulatory period, the distributors are required to submit forecasts associated with:

- Maintaining the current service quality level;
- Improving service quality aimed at delivering an agreed average level of service (which may be somewhat higher than current service levels); and
- Specific additional commitments aimed at improving service quality in specific parts of the network or addressing identified customer requirements and including clearly identified service quality outcomes.

Ergon Energy has developed three alternative spending scenarios with identified performance targets.

## 1.6 Cost Differentials

Factors which contribute to cost differentials between Ergon Energy and industry best practice include:

- Low customer densities;
- Large distances;
- Requirement to replace large numbers of overloaded SWER lines;

## 1.7 Pass Through Costs

Ergon Energy is faced with high levels of risk relating to uncontrolled expenditure, particularly in the area of major customer connections. The risk is related to the inability to predict when major customer initiated projects will proceed and the amount of infrastructure required to make the connection. In such cases, consideration should be given to excluding such projects/programs from the forecasts and applying a pass-through mechanism once the level of uncertainty has been removed or reduced to an acceptable level.

Projects which are highly likely to proceed within the next Regulatory period should not be considered for pass-through, regardless of cost, but should be clearly specified and included in the CAPEX forecasts. The Consultant recommends that the Queensland Competition Authority ("QCA") develop a detailed mechanism in conjunction with the two Queensland Distribution Network Service Providers ("DNSPs").

### 1.8 Efficient OPEX Program

The OPEX is made up of the following key components:

- Maintenance activities - Planned and unplanned maintenance work on all network assets; and
- Operating activities:
    - System Control Centres;
    - Network Systems Operations;
    - Fault Call Centre;
    - Executive and Financial Management;
    - Training;
    - IT Support;
    - National Electricity Market;
    - Network Planning;
    - Distribution Standards;
    - Customer Complaints; and
    - Work Practices and Safety.

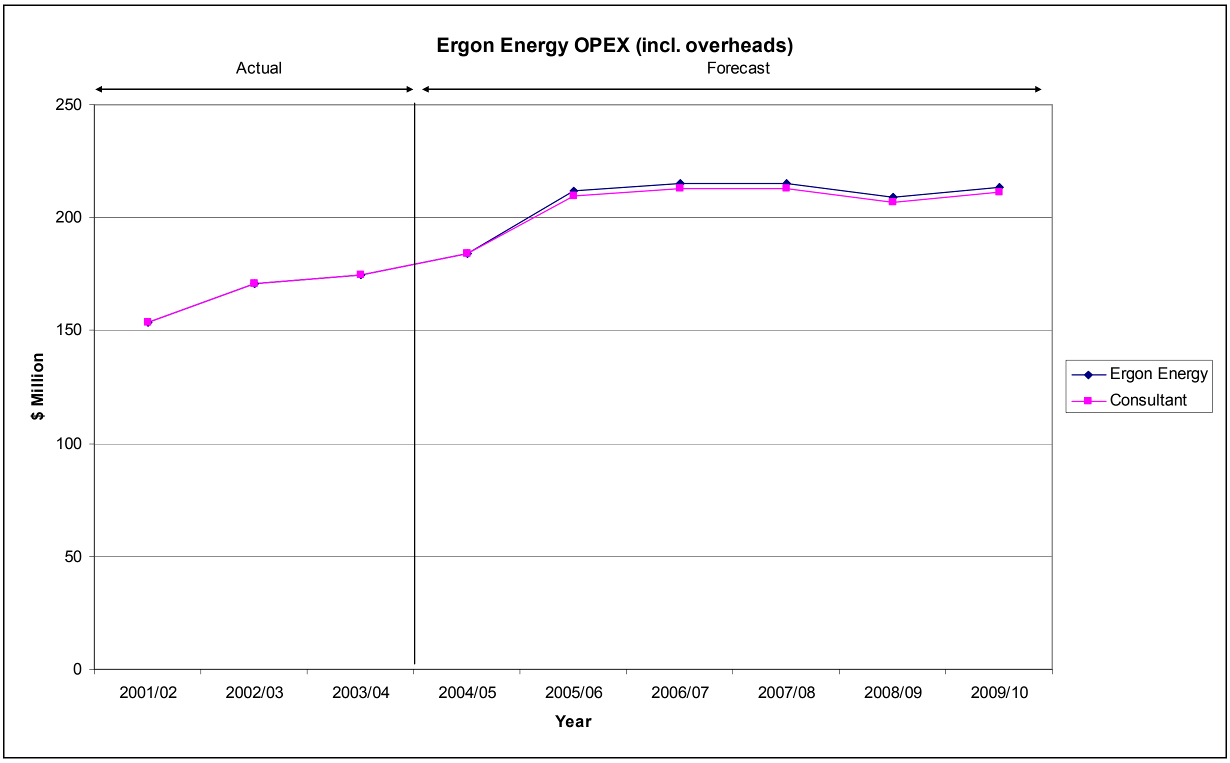
Over the five year period 2005/06 to 2009/10, Ergon Energy has estimated that the average annual OPEX expenditure will be approximately $217.2M. The Consultant has identified potential efficiency savings in the order of 1% per year, or $10.6M over the review period, in the Ergon Energy's OPEX forecast. The historical spending and forecast estimates are shown in Table 1-1 and Figure 1-1.

**Table 1-1: Overall Operational Budget (incl. overheads)**

| | | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Ergon Energy | **$M** | 153.80 | 175.50 | 174.34 | 184.22 | 211.70 | 214.95 | 214.86 | 208.89 | 213.20 | 1,063.59 |
| Consultant | **$M** | 153.80 | 175.50 | 172.59 | 182.38 | 209.58 | 212.80 | 212.71 | 206.80 | 211.06 | 1,052.95 |

*All forecast and historical figures are in June 2004 dollars.*

**Figure 1-1 OPEX expenditure**




*All forecast and historical figures are in June 2004 dollars.*

## 1.9 Review of Capital Projects

A wide range of capital projects was reviewed. The review identified the following issues of concern:

- The process of compiling project files to support capital expenditure is not well defined and should be improved;
- The process for project approval would be enhanced by the provision of pre-project information, use of quantified risk assessments, documented system planning/network capacity impacts and improved financial assessments;
- A major concern is the lack of comprehensive post implementation reviews. The Consultant considers that every project should be reviewed prior to closure, with the larger projects subject to a more formalised and detailed review; and
- A 23% difference between actual and estimated costs for projects, raising issues in regard to the estimating process.

Notwithstanding these concerns, the Consultant is of the view that the capital expenditure for the projects reviewed was generally prudent, with few exceptions, and that the expenditure appeared to be efficient.

## 1.10 Independent Review of Growth Forecasts

The growth forecasts have been separately reviewed by McLennan Magasanik & Associates ("MMA") who have predicted lower average growth in customer numbers but higher growth in maximum demand over the forecast period than Ergon Energy.

The Consultant has estimated that the difference in the forecasts of customer numbers and maximum demand equates to changes to the estimates over the period 2005/06 to 2009/10 of:

- $9.5M decrease for customer initiated works; and
- $31M increase for corporate initiated augmentation works.

## 1.11 Efficient CAPEX Program

Over the five year period 2005/06 to 2009/10, Ergon Energy has forecast total CAPEX of $2,314 million. The Consultant considers a CAPEX of $2,130 million would be more appropriate.

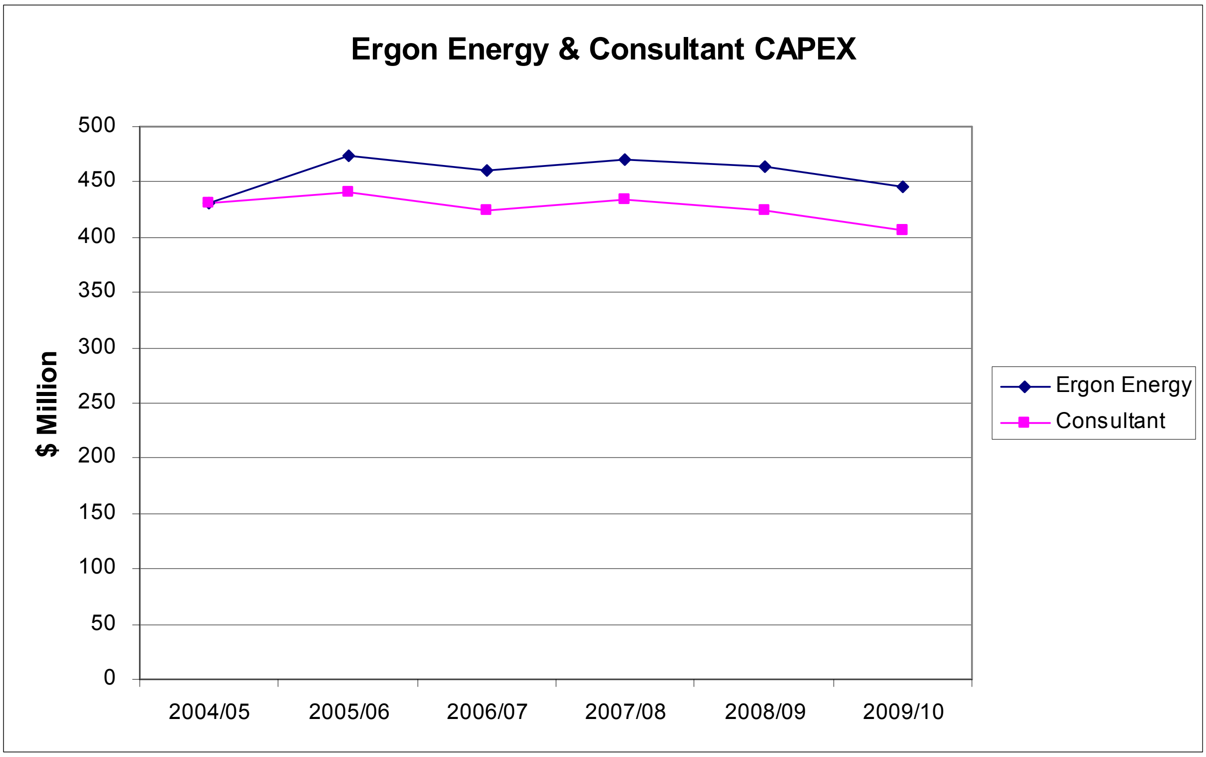
The historical spending (Actual) and Ergon Energy and the Consultant's estimates of Capital expenditure (Forecast) are shown in Table 1-2 and Figure 1-2 below.

**Table 1-2: Overall CAPEX Budget (incl. overheads)**

| | | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $M | 262.1 | 329.9 | 337.4 | 433.0 | 474.0 | 460.9 | 470.9 | 463.3 | 445.4 | 2,314.4 |
| Consultant | $M | | | | 431.6 | 440.0 | 425.1 | 434.1 | 425.0 | 406.0 | 2,130.2 |

*All forecast and historical figures are in June 2004 dollars.*

**Figure 1-2 CAPEX expenditure**




*All forecast and historical figures are in June 2004 dollars.*

The difference between Ergon Energy's CAPEX forecast and that of the Consultant is due to a reduced estimate for major customer works and a slightly reduced estimate for subdivisions.

## 1.12 Step Change in CAPEX from Historical Levels

Ergon Energy has forecast a significant increase in CAPEX from $337M in 2003/04 to $433M in 2004/05, rising to $474M in 2005/06.

The main contributors to the increase in 2004/05 are:

- A significant increase in customer initiated works - $81M (due to specific major customer projects); and
- An increase in System Other expenditure – $13M (due to the replacement of the SCADA Master Station).

The main contributors to the increase in 2005/06 are:

- A significant increase in Asset Replacement expenditure - $38M (mainly due to replacing poor copper and steel conductor, replacing the Substation Control and Data Acquisition ("SCADA") Master Station and associated Remote Terminal Units ("RTUs") and replacement of distribution line switchgear);
- A significant increase in Corporate Initiated Augmentation expenditure - $49M (mainly due to increasing transmission capacity and associated sub-transmission and zone substation works in the Wide Bay Region, Toowoomba, Townsville and Cairns, and works to reduce the level of distribution system constraints); and
- A reduction in the allowance for major customer works - $41M.

The Consultant considers that the forecast increases are reasonable, with the exception of Subdivisions expenditure which has been marginally reduced by the Consultant.

## 1.13 Resource Capability

Ergon Energy has prepared a resource plan which details the organisation's capacity to find the resources (internal and external) required for the delivery of the 2004/05 works program and outlines the proposals for delivery of the five year works program.

The Consultant is reasonably confident of Ergon Energy's capability to resource the forecast workload for 2004/05, but considers there is an increased risk with regard to 2005/06. This is not seen as a great concern, as it is the first year of the Regulatory period and is followed by a forecast decrease in resource requirements. Delays in obtaining the additional resources would thus result in a shift of some expenditure to later years but are unlikely to impact on the total spending over the full regulatory period.

# 2 SCOPE AND METHODOLOGY

This section covers the review of operating expenditure and capital expenditure and associated asset management practices of Ergon Energy for its electricity network. An overall strategic view is provided with regard to whether the proposed levels of capital and operating expenditure, for the period 2004/05 to 2009/10 are reasonable and efficient.

As requested by the QCA, the Consultant has based its forecasts of OPEX and CAPEX on growth forecasts provided by Ergon Energy. As discussed further in Section 9.4.3, variations in Maximum Demand ("MD") or customer numbers will necessitate changes to expenditure requirements.

## 2.1 Terms of Reference

For OPEX, the Terms of Reference issued by the QCA required the Consultant to:

- Assess the current efficiency of the DNSP's OPEX and determine anticipated future efficiency gains, taking into account comparisons with suitable peers and the efficiency study undertaken in setting the current regulatory arrangements; and
- Determine the rate of growth in OPEX expected to result from growth in demand for the DNSPs' services.

For CAPEX, the Terms of Reference issued by the QCA required the Consultant to:

- Review the procedures in place for assessing CAPEX;
- Assess the reasonableness of the major drivers of each DNSP's CAPEX program;
- Provide an opinion on the efficiency of each DNSP's estimates of CAPEX in the roll-forward period from 1 July 2004 to 30 June 2005;
- Provide an opinion on the efficiency of each DNSP's estimates of CAPEX for each year from 1 July 2005 to 30 June 2010; and
- Provide estimates of the level of aggregate CAPEX for each year that the Consultant considers to be efficient.

## 2.2 Methodology

The review was conducted in six stages:

Stage one - Data Collection

Stage two - "Desk Study" Review

Stage three - Further Gathering of Information

Stage four - Review of Significant Issues

Stage five - Preparation of Draft Report

Stage six – Preparation of Final Report (still to be done).

Unless stated otherwise, all figures are in June 2004 dollars. The Consultant has used the Australian Bureau of Statistics all groups CPI for Brisbane as a deflation factor to convert historical expenditure to June 2004 dollars.

The deflation factors are:

**Table 2-1: Deflation factors**

| Period | Percentage change from previous financial year |
|---|---|
| 2000-01 | 5.9 |
| 2001-02 | 2.9 |
| 2002-03 | 3.2 |
| 2003-04 | 2.9 |

The Consultant was also required to consider the relationship between CAPEX and OPEX and trade offs between same.

### 2.2.1 Data Collection

This stage involved gaining a detailed understanding of the operation of the Ergon Energy regulated electricity distribution business and its key processes. A wide range of information was collected, collated, reviewed and cross-referenced as the foundation for detailed analysis. A number of site visits were made and interviews held with key personnel within Ergon Energy. Details of the site visits (for this and later stages) are contained in Appendix 14.1 and a list of key documents accessed (during this and later stages) is contained in Appendix 14.2.

### 2.2.2 "Desk Study" Review

This stage involved the detailed review of the information gained in Stage one. Factors considered included the following:

- Operating, maintenance, augmentation and replacement strategies;
- Asset details - numbers, types, ages, condition;
- Planning processes;
- Network capacity and utilisation;
- Regulatory, safety and environmental compliance issues;
- Organisation and staffing;
- Performance standards;
- Comparisons with other electricity utilities; and
- Assumptions underpinning Ergon Energy's forecasts of CAPEX and OPEX.

Outcomes from this stage were the identification of key issues, identification of areas requiring further information and identification of valid causes for significant differences between Ergon Energy and other utilities. In making comparisons with other utilities, the Consultant has utilised only information that is available in the public domain, particularly on the Websites of jurisdictional regulators and utilities. The Consultant recognises that some of the information available may not be directly comparable; however the Consultant is of the opinion that the comparisons provide a reasonable indication of relative performances. The Consultant has also drawn on its experience with other DNSPs, but has not directly used information provided to it on a commercial-in-confidence basis.

### 2.2.3 Further Gathering of Information

This stage involved meetings with Ergon Energy staff to assess processes and design, planning, operating and maintenance standards. It also involved audits of specific assets and systems to verify their condition and operational risks. A detailed review of a range of capital projects was also undertaken to assess the prudency and efficiency of associated capital expenditure.

### 2.2.4 Review of Significant Issues

Significant issues identified in the earlier stages of the review were discussed with relevant managers within Ergon Energy to ensure that the Consultant correctly understood the issues and to gain further insights into the business.

### 2.2.5 Preparation of Draft Report

The findings, analysis and conclusions arising from the four preceding stages were collated and integrated into this draft report.

### 2.2.6 Preparation of Final Report

Comments received and issues raised from the Draft Report will be considered and used as input into the preparation of the Final Report.

# 3 ORGANISATIONAL DESCRIPTION

## 3.1 Purpose and Scope of Section

The organisation structure and its personnel can have a significant effect on the efficiency of an electricity utility. This section describes the organisation structure of Ergon Energy Electricity Distribution and the relationship with Ergon Energy at the corporate level.

## 3.2 Organisation Structure

### 3.2.1 Corporate

The six former regional electricity distribution corporations in Queensland were merged to form Ergon Energy Corporation Limited and its retail subsidiary, Ergon Energy Pty. Ltd.

Ergon Energy is divided into seven areas:

- Stakeholder Relations; covering stakeholder management, corporate communications and customer advocacy.
- Corporate Counsel; covering secretariat, legal services, risk management and records.
- Distribution; covering distribution regulation, network management, field operations, distribution projects and logistic services.
- Retail; covering retail regulation, trading, marketing and retailing.
- Finance; covering finance, business development, strategic planning and logistics contracting.
- People and Change; covering human resources, health and safety, learning and development, business integration, employee relations ("IR") and culture.
- Service and Process; covering information technology, telecommunications, business systems and customer service.

The Finance, People and Change, and Service and Process areas provide services to the Distribution and Retail areas.

### 3.2.2 Electricity Distribution

The organisation structure for Ergon Energy Electricity Distribution is shown in Appendix 14.3. This group is divided into ten areas:

- Network; covering network strategy, network data management, maintenance and standards, network connection and pricing, network planning and development, network protection and control, and network asset management;
- Operations Northern; covers regional services, stakeholders management, asset management and operations management for the Northern service area;
- Operations Central; covers regional services, stakeholders management, asset management and operations management for the Central service area;
- Operations Southern; covers regional services, stakeholders management, asset management and operations management for the Southern service area;
- Transmission and Distribution Services ("TaDS"); covering major projects, power services, transmission services, generation and transmission projects, technical services and market development;
- Strategy and Change; covers staff relations, strategy and planning, change programs, process integration and communications;
- Planning and Resourcing; covering programming and resourcing, contracts, materials, logistics and compliance;

- Distribution Support; covering network operations support, field support services, fleet management, technical services and safety compliance;
- Network Regulation; covering strategic development, performance, reporting, regulation and policy; and
- Commercial; covering business performance, finance, costing, administration and special projects.

### 3.2.3 Personnel Numbers

The current number of personnel in each business stream within Ergon Energy is as follows:

**Table 3-1: Ergon Energy Personnel numbers**

| Business Unit | Personnel Numbers |
|---|---|
| Office of the CEO (incl. Stakeholder Relations, and Corporate Counsel) | 23 |
| Retail | 128 |
| Finance | 180 |
| People and Change | 78 |
| Service and Process | 315 |
| Electricity Distribution | |
| Network | 167 |
| Operations Northern | 493 |
| Operations Central | 286 |
| Operation Southern | 422 |
| TaDS | 662 |
| Strategy and Change | 30 |
| Planning and Resourcing | 74 |
| Distribution Support | 117 |
| Network Regulation | 7 |
| Commercial | 139 |
| TOTAL | 2,400 |
| **Grand Total** | **3,124** |

# 4 BUSINESS ENVIRONMENT

## 4.1 Purpose and Scope of Section

In assessing the prudency and efficiency of expenditure, it is necessary to consider the business environment in which the business operates. This section considers such issues that may impact on the prudency and efficiency of capital and operating expenditure.

## 4.2 Regulatory

The key regulations applicable to the electricity industry in Queensland are:

- The National Electricity Code (“NEC”);
- The Electricity Act 1994; and
- The Queensland Competition Authority Act 1997.

The QCA is the Jurisdictional Regulator for electricity distribution network service providers under the NEC in Queensland.

The NEC governs the following:

- The National Electricity Market;
- The terms, conditions and technical requirements of access to the transmission and distribution networks; and
- The methodology for the pricing of network services.

The Electricity Act 1994 regulates:

- The contestability timetable;
- Authorisations and special approvals;
- Pricing and service quality for customers in relation to transmission, distribution and retail functions;
- Customer protection, including standard customer contracts and the resolution of disputes under those contracts; and
- Electricity rationing.

The QCA Act, Electricity Act and the NEC provide the QCA with the following responsibilities:

- Acting as Jurisdictional Regulator under the NEC to regulate pricing for electricity distribution networks and ring fencing between distribution entities and contestable activities;
- Making and enforcing conduct rules;
- Monitoring service quality standards (set by the Minister) of electricity entities; and
- Assessing competitive neutrality.

The Queensland electricity distributors hold an authority, issued by the Office of Energy, to distribute electricity in Queensland. The distributors are required to comply with the conditions of their licences, the Electricity Act, the Electricity Regulation and other applicable laws.

The distributors are also required to adhere to a range of other Acts, Regulations and Codes, including:

- Electricity Safety Act 2002;
- Electrical Safety Regulation 2002;
- Electricity Regulation 1994;
- Code of Practice – Electrical Work;
- Code of Practice – Working Near Exposed Live Parts;
- Code of Practice - Works (Protective Earthing, Underground Cable Systems and Maintenance of Supporting Structures for Powerlines);
- Workplace Health & Safety Act 1995;
- Integrated Planning Act 1997; and
- Environment Protection Act 1994.

The Consultant considers that the Regulatory environment in which the electricity distributors operate is substantially the same as that which applies elsewhere around Australia, so no special considerations are required in this area.

### 4.3 Operational Requirements

The parameters for supply quality are governed by the National Electricity Code and the Electricity Act. The Electricity Act includes the requirement to operate, maintain and protect the supply network to ensure the adequate, economic, reliable and safe supply of electricity. Standards for frequency and voltage are contained in the Electricity Regulation 1994.

The Electricity Safety Act requires the distributors to ensure that works are operated in a way that is electrically safe, and includes the obligation to inspect, test and maintain.

The Consultant considers that the operational requirements are very similar to those that apply in other Australian jurisdictions, so no special considerations are required in this area.

### 4.4 Safety Requirements

The distributors are required to adhere to the Workplace Health & Safety Act 1995 and the Electricity Safety Act 2002. Under the Electricity Safety Act, electricity entities are obliged to:

- Ensure their works are electrically safe; and
- Ensure their works are operated in a way that is electrically safe.

This obligation includes ensuring their works are inspected, tested and maintained.

The Electricity Safety Regulations:

- Prescribe matters in support of the electrical licensing arrangements established under the Act;
- Prescribe requirements for working around exposed parts;
- Prescribe requirements for electrical installations;
- Prescribe matters about electrical equipment;
- Prescribe requirements and procedures for the design, building and maintenance of electric lines and the works of electricity entities;
- Prescribe requirements for the performance of electrical work;
- Provide for the preparation, lodging and auditing of safety management plans;
- Prescribe requirements for the operation of cathodic protection systems and requirements for particular systems to be registered; and
- Prescribe notification and reporting requirements for serious electrical incidents and dangerous electrical events.

More detailed electrical safety requirements are contained in the following Codes of Practice:

- Code of Practice - Electrical Work;
- Code of Practice - Working Near Exposed Live Parts; and
- Code of Practice - Works (Protective Earthing, Underground Cable Systems and Maintenance of Supporting Structures for Powerlines).

It is apparent that Ergon Energy has a high level of commitment to Health and Safety matters throughout the business and that sound processes are in place to achieve measurable outcomes in this area.

The Consultant considers that the safety requirements applicable to the Electricity Networks business are very similar to those that apply elsewhere around Australia, so no special considerations are required in this area.

### 4.5 Customer Service Standards

Customer service standards are not prescribed; however, the distributors are required to report to the QCA on a number of reliability and service quality measures, as detailed in the Electricity Distribution: Service Quality Reporting Guidelines issued by the QCA.

Further discussion in regard to customer service standards is contained in Section 5.6.3.

### 4.6 Environmental Requirements

For medium to large projects, Ergon Energy is required to conduct an environmental assessment, ranging from a Review of Environmental Factors to a full Environmental Impact Study with community consultation. These take into account a range of issues, including the management of vegetation, fauna, waste and social issues.

Ergon Energy has an Environmental Management System that is externally certified to ISO14001. Although some environmental objectives and targets have been set, these are in the process of being further developed across the entire business.

Although there are some differences in emphasis, the Consultant considers that the environmental requirements are similar to those that exist elsewhere around Australia, so no special considerations are required in this area.

### 4.7 Geographic Considerations

Ergon Energy’s distribution network covers the widest area of any electricity distributor in Australia, and includes many very long, radial distribution lines and a large amount of SWER distribution. This impacts on Ergon Energy’s operations in a range of ways, including:

- Higher investment costs per customer due to lower customer densities;
- Lower levels of supply reliability associated with the lengths of exposed, radial feeders without interconnection capability;
- The need for capital investment to replace overloaded SWER systems; and
- Costs associated with providing services over a very large area.

The Consultant has taken these considerations into account when benchmarking Ergon Energy against other Australian distributors.

# 5 ASSET MANAGEMENT

## 5.1 Scope of Section

Asset management covers the processes for planning, development, operation and maintenance of all components of the electricity network. Clearly, sound asset management processes are a prerequisite for prudent and efficient capital and operating expenditure.

This section considers the asset management policies and practices of Ergon Energy and compares them to best practice.

## 5.2 Approach to Asset Management

An effective approach to Asset Management should ensure that:

- Assets are developed, operated and maintained in a manner which will permit customer service delivery targets to be achieved and asset economic life to be maximised, whilst minimising environmental impact and costs.
- Appropriate financial records relating to the assets are maintained.
- Processes and procedures are in place for undertaking sound asset management activities with respect to:
    - Network planning, development and augmentation;
    - Network capacity and performance assessment;
    - Network operation;
    - Asset protection;
    - Network condition assessment, maintenance planning and maintenance execution; and
    - Asset data capture and management.

Ergon Energy has developed a 20 Year Vision for Network Asset Management, and is in the process of developing supporting Asset Policies, Asset Strategies and Asset Plans. Ergon Energy does not have reliable asset data for all of its network assets – currently only about 70% of the data has been reliably captured. Ergon Energy has accelerated its asset inspection program in order to more quickly capture the outstanding data.

Ergon Energy was formed in 1999 from six previous electricity businesses, and although a lot of work has clearly been done to create a homogeneous business, there are still some outstanding integration issues, in areas such as substation design standards, drawing symbols and a range of maintenance practices.

## 5.3 Policies

### 5.3.1 Planning and Development

Ergon Energy is currently developing a range of formal asset management policies. In regard to the planning and development of the electricity network, key policies can be summarised as follows:

- Have a clear vision for the management of the network (a 20 Year Vision for Network Asset Management is currently in draft form) supported by policies, strategies and plans;
- Develop ten year (sub-transmission) and five year (distribution) planning horizons with annual updates;
- Factor risk analysis into all network investment evaluations;
- Meet, as a fundamental focus of network asset management, all duty of care obligations; and
- Keep abreast of new technology and where appropriate, support research or development.

The Consultant considers that these policies are similar to those adopted by other electricity distributors and are acceptable for the planning and development of Ergon Energy's network.

### 5.3.2 Operation and Maintenance

#### 5.3.2.1 Operation Policies

Following its formation, Ergon Energy had a decentralised control system with major control centres in each of the six regions. While the procedures for sub-transmission access (including live line access) and switching are typically common across the control regions, distribution access and after hours work procedures tend to vary. In response to this problem a Control Centre Strategy was developed with the aim of developing a standard approach for control centres and day desks across the organisation, and to develop an organisational structure for managing switching and access. This strategy was developed by reviewing the current state of the Ergon Energy control system and comparing it against best practice in other distribution organisations.

The recommendation of the Control Centre Strategy was to centralise network control in two Main Control Centres (which are 24 hour operations) located in Townsville and Rockhampton. In addition two co-located Day Desks were proposed for the management of planned and unplanned distribution network access and switching during normal working hours. By centralising the network control in this way, the two groups of Network Controllers (North and South) can work as a single team to manage peak workloads etc. rather than on a purely regional basis.

It is expected that the distribution network will still be managed using manual techniques until at least 2007, whereas the sub-transmission network will be managed by a new SCADA system by the first quarter in 2005. To facilitate these changes, major upgrades to the Distribution Management System ("DMS") and SCADA systems are required as discussed in Section 9.9.1.8.

#### 5.3.2.2 Maintenance

Ergon Energy services a very wide geographical spread of Queensland with large areas of arid country and elsewhere heavily vegetated hinterland. Therefore, the development of maintenance planning systems requires a unique approach.

At the formation of Ergon Energy a significant backlog of maintenance existed, particularly in relation to line assets, indicating an apparent under investment in maintenance in previous years. A life cycle approach to maintenance is now being adopted, with asset life expectancy being considered. Maintenance plans for each asset type have been prepared covering time based inspections, non-intrusive condition monitoring, condition based maintenance, refurbishment as required, and replacement at life expiry. This approach closely resembles the successful policy used by Powercor in Victoria.

Given that asset data bases have been lacking and inconsistent, it has been necessary to commence an asset inspection and data collection program to enable appropriate asset condition assessments. This Asset Identification and Defects Management ("AIDM") program is based on two full three year inspection cycles of various network assets including poles, pole tops, and zone substation assets. This program will establish a baseline of asset data which will facilitate future maintenance planning.

The underground cable maintenance policy also incorporates these aspects, but places more emphasis on nurturing and developing knowledge and skills, recording performance and assessing causes of failure. This is because the technology is still developing, and the effects of ageing and environment on cable performance are not well understood.

Ergon Energy has not yet used Reliability Centred Maintenance ("RCM") on a formal basis. However, the Object-Damage-Cause-Task codes used to log defects in the SAP Project Management ("PM") system are based on a RCM philosophy. It is expected that when sufficient data is gathered from the AIDM program, RCM will be adopted in the development of efficient maintenance plans.

## 5.4 Support Systems

### 5.4.1 IT Systems

Appropriate information systems from the previous organisations have been adapted for use across the Ergon Energy business to cover all functions required.

A study of the future requirements of a Distribution Management System incorporating all functions required is well advanced and this will include some of the current systems listed below.

#### 5.4.1.1 FDRSTAT

The FDRSTAT system was developed by Ergon Energy to manage notifications of issues on the electrical network. The system uses a model of the network to automatically analyse the notifications and create managed events. Every activity which is associated with an event or notification is allocated an 'owner' so that these activities can be traced through their entire lifecycles from discovery to final analysis and reporting.

The FDRSTAT system manages a range of network functions including:

- Customer fault calls;
- Customer notifications (e.g. planned outages, outage updates etc.);
- Government and internal reporting on Network Performance; and
- Analysis of work processes (e.g. determining times taken for each activity in a network outage).

It is expected that the FDRSTAT system will be used by Ergon Energy until a DMS solutions is implemented after the completion of the SCADA master station implementation. The current timeline for the proposed DMS solution is approximately three to five years.

#### 5.4.1.2 Change Notification System ("CNS")

The CNS is a tool which automatically notifies staff (by email) of changes which are relevant to their business processes. This ensures that all staff operate from current schematics, keep financial registers updated and stay well informed about the current network status.

Ultimately, it is expected that the CNS will be integrated with the Smallworld Geographical Information System ("GIS") as a notification package although there are no immediate plans to do so.

#### 5.4.1.3 Switching Diary

The Switching Diary system manages requests for access to the electrical network to perform work. By utilising an underlying network model this system provides tools for the user to determine risk and potential customer impacts. It can also create a set of switching tasks and print an approved switching sheet.

The Switching Diary system functions fall under the DMS umbrella and the system is likely to be replaced post a DMS implementation.

#### 5.4.1.4 Load Information Management System ("LIMS")

The LIMS can generate a load profile for any point on the network based on an accumulation of the load profiles of customers who are downstream of that point. In this way the system allows for statistical logging of critical power flows through all distribution substations without requiring dedicated logging devices. The information obtained from LIMS enables Ergon Energy to manage the growth of customer energy consumption at all levels of the network.

It is expected that LIMS will be used for at least another five years, before it is replaced with a product which can be integrated with the DMS and SCADA systems.

#### 5.4.1.5 Geographical Information System

Ergon Energy is implementing the Smallworld GIS system throughout all regions. The graphical database is expected to be completed in 2004 although population of the detailed data such as equipment types and age will take much longer. Ergon Energy has begun trials on a Smallworld GIS in Cairns and it is expected that this system will be implemented throughout Ergon Energy by June 2004. The GIS contains a spatial representation of all of Ergon Energy's High Voltage ("HV") electrical network and the majority of the Low Voltage ("LV") network. The network is overlayed with information from external sources such as Environmental Protection Authority ("EPA") environmental views, Native title, Natural Resources, Mines and Energy ("NR&E") land use, cadastral information, property owners and topographical details.

The GIS is to be the sole tool for designing distribution infrastructure to Bill of Material level. It allows for generation of estimates, quotes and final 'construction issue' works plans. Purchase and delivery of equipment to site can be managed through an interface to ORACLE financials Automatic Bill of Materials ("ABOM"). By using a Grouped Assemblies ("GRASS") interface, the use of standard constructions can be managed.

The Smallworld GIS is part of Ergon Energy's long term strategic plan. Over time more elements will be integrated into this system (e.g. ABOM and GRASS).

#### 5.4.1.6 SCADA

Ergon Energy currently has six separate, regionally based SCADA systems with varying protocols and network process standards. Furthermore, less than half of Ergon Energy's zone substations have SCADA facilities. This aging SCADA network is incapable of meeting the current demands for improved reliability, supply quality, and customer service. Therefore Ergon Energy has developed a comprehensive SCADA strategy which outlines the future direction for SCADA within the organisation.

In essence, the SCADA strategy proposes rationalised SCADA Master Station facilities and expanded SCADA coverage across the sub-transmission network. Implementation and commissioning of this system is expected to be completed by December 2005. Ultimately the SCADA system is to be integrated with the Ergon Energy DMS and will be designed to interface with existing and future Information Technology ("IT") systems such as FDRSTAT.

The expected positive outcomes associated with this major SCADA project include:

- Improved network performance and reliability;
- Improved customer service;
- Improved reporting of asset maintenance data (reduced OPEX) and performance data leading to more effective network planning; and
- Enhanced control centre capability.

#### 5.4.1.7 NetBill

The NetBill system is a billing system that is used to manage Ergon Energy's Contestable Customer Bills. The system uses information including individual contestable customer energy consumption and Ergon Energy's total franchise customer base energy consumption to determine the bill for any given month. The system accounts for Distribution Use of System ("DUOS") charges and Transmission Use of System ("TUOS") charges, including algorithms to account for electrical losses.

It is expected that NetBill will be replaced within the next one to two years as greater capability is required to manage major customers.

#### 5.4.1.8 DINIS

DINIS is a third party product used for load flow and network capacity analysis. It receives source files from the GIS as the basis of its analysis algorithms and allows the planning department to perform complex network studies.

DINIS is part of Ergon Energy's long term strategic plan. It is expected that it will be more closely integrated with the GIS in the future.

#### 5.4.1.9 Capital Project Management ("CPM") System

The CPM system manages the delivery of Capital projects in the business plan.

It is expected that the CPM system will be decommissioned as Ergon Energy moves towards an Enterprise Resource Planning ("ERP") environment which contains this functionality.

#### 5.4.1.10 Ergon Energy Drawing Management Solution ("EDMS")

All of Ergon Energy's design drawings are managed through a third party package called Wedge/filenet.

It is expected that this system will be used long term as Ergon Energy's drawing management solution.

#### 5.4.1.11 Multi-Vendo90 ("MV90")

The MV90 system reads all of Ergon Energy's statistical meters remotely and automatically. The information is used to cross check customer billing and determine losses.

In the future it is expected that MV90 sourced data will be externally supplied through an arrangement with a National Electricity Marketing Management Company ("NEMMCO") Metering Data Agency ("MDA").

#### 5.4.1.12 SAP

The SAP Plant Management module is currently used to manage the inspection and maintenance of Ergon Energy's pole base. Interfaces between SAP, the GIS and Field Mobile Computing ("FMC") allow Ergon Energy to issue work to contractors for the remote inspection and repair of these assets.

Several legacy systems (including WASP, Management Informational Maintenance System ("MIMS"), PowerView Assets and Enguarde) are still in place for the management of assets other than poles. However, it is expected that all asset management will be co-ordinated through SAP within the next year.

#### 5.4.1.13 FACTS

The purpose of the FACTS application is to control the recording, issuing and following up of a variety of electronic forms including Corrective Action Request Forms (“CARS”), Customer Feedback Forms and Compensation Claim Forms. These forms are routed via e-mail to relevant people in the organisation. There are also a number of “generic” reports available in the FACTS system so that past and present feedback and claims can be analysed.

### 5.4.2 Quality System

Apart from one area of the business, Ergon Energy does not have in place a formal quality management system. The exception is Zone Substation Design carried out by the TaDS Group, which is certified to ISO 9001. Although this is not likely to have a material impact on the efficiency of CAPEX and OPEX programs, the Consultant notes the increased risk of some inefficiencies resulting from the lack of quality management processes (e.g. applying out of date processes due to the lack of document control processes).

### 5.4.3 Performance Management

The use of a diverse range of Key Performance Indicators (“KPIs”) and their application at all levels in the organisation, is considered to represent industry best practice. The Consultant considers that each employee should be able to see a clear link between what he or she does and the objectives of the business, which should be reflected in the KPIs.

The Consultant noted an emphasis on KPIs in managing the activities of the Distribution business. The Distribution Business monthly reports contain a range of KPIs covering the key areas of the business measures, with all KPIs having quantified targets. The Consultant considers the range and application of KPIs to be appropriate.

## 5.5 Planning Process

### 5.5.1 Capital Works

Ergon Energy has developed a draft 20 Year Vision for Network Asset Management, and is in the process of developing supporting Asset Policies, Asset Strategies and Asset Plans. When fully developed, the vision, policies, strategies and plans will provide the framework for determining the appropriate levels of capital works required to manage the network.

Ergon Energy considers the requirements for investment in three main areas:

- Customer Requested Work - supplies to commercial, industrial, residential and rural developments, and requests for customer connections/metering. This is mainly driven by developers and planning authorities i.e. Ergon Energy reacts to requests from other parties.
- Corporate Initiated Work - projects initiated by Ergon Energy to cater for increased load, the replacement/refurbishment of ageing assets and to achieve service level and efficiency improvements. This is largely driven by load growth (in relation to network capacity), regulatory requirements for supply reliability, quality, safety, network efficiency and environment protection and by aging of the assets.
- Fixed Assets Acquisitions - expenditure relating to property, vehicles and plant, and business and IT systems that support the electricity network business. This is driven by the need to achieve operating efficiency and productivity gains.

Details regarding the processes for approval and prioritisation of capital expenditure are contained in Section 9.2.

Each of Ergon Energy’s five Regions prepares a Five Year Sub-transmission Network Augmentation Plan that identifies the capital works that are needed to meet the augmentation requirements of the

Region's sub-transmission networks in order to accommodate the normal load forecasts for the next five years. These plans form the initial stage of the annual augmentation capital works program that is developed as part of the Ergon Energy capital budgeting process.

The Distribution Network Planning Cycle consists of the preparation of an annual Distribution Network Current State Assessment, Capability Review and Five Year Distribution Augmentation Plan for each Region. The Region reviews and plans are consolidated into a Summary Report.

The following capital expenditure drivers are identified in the document "Network Planning Criteria – Deliverable NP02":

- Plant overload;
- Safety;
- Environment;
- Loss reduction;
- Reduce operating expenditure;
- Reliability Improvement;
- Quality of supply (including voltage regulation); and
- Ageing equipment.

A key consideration in planning the development of the electricity network is the need to ensure that the network has sufficient capacity to meet the maximum demand. This involves the careful consideration of the level of spare capacity on the various elements of the network against the projected increases in demand. The Five Year Sub-transmission Network Augmentation Plans contain estimates of summer maximum demands for each zone substation and connection point, and compare these against the station ratings.

Ergon Energy carries out its planning based on the most probable growth scenario i.e. 50% Probability of Excedence ("POE"). In determining the most probable scenario, Ergon Energy obtains input from an independent authority, the National Institute of Economic and Industry Research ("NIEIR"), who consider low, base and high scenarios at both 10% POE and 50% POE. The Consultant suggests that Ergon Energy extend the level of sophistication of its planning processes to include high and low scenarios in its investment forecasting processes.

The Consultant considers that Ergon Energy has a sound approach to planning for capital works, but it is noted that some of the current processes have been recently introduced and policies and strategies are still under development.

### 5.5.2 Maintenance Planning

Ergon Energy's maintenance plans for the period between 2005 and 2020 are summarised in the "Network Assets Maintenance & Replacement Plan." This document details the maintenance requirements for all classes of network asset as summarised in Section 8.2. These maintenance plans are currently managed via two systems - SAP is used to manage pole maintenance and the Line Maintenance Planning ("LMP") Access database is used to manage all other network assets.

The SAP PM module, including templates, was recently purchased from Powercor in Victoria and was commissioned in April 2003. Currently, the SAP system is only used to manage pole maintenance, and this is done on a feeder basis. However, the template includes data structures for a range of data classes including feeders, switch-zones, substations, switches, pillars etc. The template also has a defect management facility.

A well developed Substation Contingency Asset Management System (“SCAMS”) already exists for the condition assessment of zone substation plant (including transformers, reactors, regulators, circuit breakers, and secondary plant). In addition, approximately 95% of zone substation assets have been transferred to SAP from the variety of information systems used in the pre Ergon Energy era. Ultimately, all maintenance scheduling and defect records will be managed out of the SAP system.

The SAP PM system is linked to the Smallworld GIS. This system is currently on trial in Cairns but is due to be employed throughout Ergon Energy within the next month. Eventually, GIS will become the main asset register for Ergon Energy and will be used as a design tool for all Ergon Energy work so that asset data can automatically be updated during commissioning.

Ergon Energy has also implemented FMC which interacts with SAP to download Work Orders for inspection contractors. FMC is used to record required line asset data and to report on asset condition so that trends can be analysed for future action.

As mentioned already, the LMP Access database is still being used to manage the maintenance of all network assets apart from poles. This database records assets on a line basis, and stores dates for programmed maintenance activities. This information is used to generate work requests. All data stored in the LMP database is gradually being transferred to the SAP PM system as part of the Network Asset Preventative Maintenance project. This project is expected to be completed within five years.

The SAP PM module does not include full works management and costing facilities. These tasks are currently managed using a Job Ticketing system, a carry over from one of the previous corporations, which is not linked to SAP. The planning for a fully integrated asset management information system and ERP is to commence in 2004.

## 5.6 Description of Best Practices

### 5.6.1 Asset Provision

Ergon Energy has installed equipment on the network that is consistent with industry standards. The plant and equipment installed on the network conforms to Australian and/or International Standards and is used by other electricity distributors in Australia. The Consultant has seen no evidence to indicate that Ergon Energy is using inappropriate plant and equipment.

### 5.6.2 Asset Utilisation

The Consultant has used a number of measures to benchmark Ergon Energy’s asset utilisation:

#### 5.6.2.1 Energy Utilisation Factor ("EUF")

The EUF is the percentage ratio of total energy distributed to the capacity of the zone substation transformers times the time period. On an annual basis, the time period is 8,760 hours.

EUF% = (Energy*100)/(Capacity*8,760) %

where: Energy = total annual energy distributed by the network (MWh)

Capacity = total zone substation transformer capacity (MVA)

The EUF provides an indication of how effectively the zone substation transformers are being utilised from an energy perspective. A higher EUF would mean a greater income in relation to zone substation transformer capacity.

#### 5.6.2.2 Network Load Factor ("NLF")

The Network Load Factor is the percentage ratio of the total network average load to the network peak load.

NLF% = ((Energy/8760)*100)/Maximum Demand %

where: Energy = total annual energy distributed by the network (MWh)

Maximum Demand = the network coincident maximum demand (MW).

The NLF gives an indication of how hard the network assets are working on average in relation to the heaviest load conditions. A higher NLF indicates a more effective use of the network assets. Effective demand management activities would result in an increase in the NLF.

#### 5.6.2.3 Plant Utilisation Factor ("PUF")

The PUF is the percentage ratio of the network peak load to the installed zone substation transformer capacity.

PUF% = (Maximum Demand)*100/Capacity %

where: Maximum Demand = the network coincident maximum demand (MVA)

Capacity = total zone substation transformer capacity (MVA).

The PUF gives an indication of how hard the network assets are working in relation to the heaviest loading conditions. A higher PUF indicates a more effective use of the network assets.

#### 5.6.2.4 Asset Energy Factor ("AEF")

The AEF is the ratio of the dollar value of the network assets to the energy distributed.

AEF = (Asset/Energy)($/MWh)

where: Asset = the value of the Regulated Asset Base ($AUD)

Energy = total annual energy distributed by the network (MWh)

The AEF gives an indication of the size of the asset base required to distribute energy around the network. A lower AEF indicates a more efficient use of the assets.

Table 5-1 shows Ergon Energy's performance for each of these measures as well as the performance of other Australian electricity utilities for the 2002/2003 year (the indicators for the Victorian distributors are for the 2002 calendar year).

**Table 5-1: Asset Utilisation**

| | ENERGY UTILISATION FACTOR (%) | NETWORK LOAD FACTOR (%) | PLANT UTILISATION FACTOR (%) | ASSET ENERGY FACTOR ($/MWhr) | CUSTOMERS PER km |
|---|---|---|---|---|---|
| ERGON ENERGY | 34 | 75 | 46 | 201 | 3.6 |
| COUNTRY ENERGY | 34 | 60 | 63 | 201 | 4.2 |
| POWERCOR | 34 | | | 147 | 4.2 |
| ETSA | 29 | 48 | 68 | 248 | 9.7 |
| TXU | 36 | | | 163 | 19.4 |
| INTEGRAL ENERGY | | 54 | | 156 | 26.9 |
| ENERGY AUSTRALIA | | 58 | | 151 | 33.8 |
| UNITED ENERGY | 30 | 51 | 65 | 144 | 47.7 |
| AGL | 32 | | | 121 | 37.7 |
| CITIPOWER | 28 | 46 | 67 | 148 | 67.5 |

Although a range of Australian distributors are included in Table 5-1, the Consultant considers that a reasonable comparison can be made between Ergon Energy and Country Energy and Powercor (whilst recognising that there are differences in the characteristics of the networks).

It can be seen that Ergon Energy has the same EUF as the comparable utilities. Information allowing the calculation of the NLF and PUF was not available for Powercor. In comparison to Country Energy, Ergon Energy has a higher NLF and a lower PUF

It can be seen that the AEF for Ergon Energy is the same as for Country Energy and higher than for Powercor. Given the widely dispersed network and low customer density, it would be expected that Ergon Energy's AEF would be high. The high NLF (higher than any other distributor shown in Table 5-1) indicates a relatively flat load curve. A low PUF generally indicates a network that has assets which are being used at a relatively low level, but this could be expected to be reflected in a high AEF, which is not the case for Ergon Energy in comparison to Country Energy.

A major contributor to Ergon Energy's low PUF is the largely radial nature of the network, with less opportunities for interconnection resulting in the need for higher levels of zone substation capacity. Another contributor is Ergon Energy's high power factor at time of MD (a high power factor will result in a lower PUF).

The Consultant considers that there is scope for Ergon Energy to improve its PUF over time to around 55-60%. The opportunity for improved PUF has been recognised by Ergon Energy who have predicted an increase in PUF of around 3% percentage points over the forthcoming regulatory period. This trend would need to continue into the subsequent regulatory period.

The level of asset utilisation is driven not only by the growth in load and demand, but also by the network planning and design philosophies which dictate the points at which network augmentation will be carried out.

A deterministic system planning philosophy is based on zero supply interruptions to customers in the event of any single outage of a network element. Any planned or unplanned outage of individual network elements (this is the "n-1" criterion) can be tolerated without affecting customer supply due to redundancy built into the distribution network. The strict application of a deterministic philosophy using the "n-1" criterion can result in inefficient network investment, as the risk of customer interruptions is reduced by providing reserve or backup capacity without consideration of the cost of likely interruptions or alternatives.

Under a probabilistic planning philosophy, the strict deterministic "n-1" criterion is relaxed, depending on the assessed risk, with investment proceeding only when the expected (probability weighted) total costs of outages exceeds the cost of augmentation. With this approach, there will be some conditions under which all the load cannot be supplied with a network element out of service, but the load at risk should be very small when considering the probability of an unplanned outage

As detailed in their Distribution Planning Reports, Victorian Electricity distributors have all adopted a probabilistic approach to network planning.

Based on information compiled by the NSW Ministry of Energy and Utilities, the NSW electricity distributors are also moving towards a probabilistic approach but have not progressed as far as those in Victoria.

Ergon Energy applies a probabilistic approach, primarily based on the "n-1" criterion, but modified to the extent that it is defined as:

> *The maximum load that should be supplied by either a zone substation or sub-transmission lines that will ensure that the remaining network load (after load transfers and the curtailment of switchable load) can be supplied for 99% of the time.*

This is referred to by the Consultant as the "n-1, 1%" criterion.

In addition to the "n-1, 1%" criterion, Ergon Energy carries out a RAP analysis in particular situations to verify that the 1% condition represents an acceptable level of risk. The Consultant considers that Ergon Energy's system planning philosophy is good industry practice.

Integrating the investment planning and risk management processes will maximise the benefits from network investments. For this approach to be adopted, sound outage data is required.

An alternative to network augmentation may be to install embedded generation or implement demand management programs. It is noted that Ergon Energy encourages the use of stand-alone generation where connection to the network would be un-economic. The Consultant considers that Ergon Energy should more actively explore non-network solutions, including the use of incentive payments to customers who implement such solutions, which defer or avoid network augmentation. The Essential Services Commission in Victoria has indicated that it favours a more or less equal sharing of savings between the customer and the distributor.

### 5.6.3 Service Standards

Technical service standards for electricity supply are largely governed by the NEC and the Electricity Act.

Service standards for customer service are not prescribed, although Ergon Energy provides quarterly service quality reports to the QCA that include information regarding system reliability, call centre performance, appointments, timeliness of connections, response to faults, streetlight maintenance, Guaranteed Service Levels ("GSLs") and complaints.

The level of customer service provided by Ergon Energy can be assessed by:

- The number of complaints received (normalised per 100,000 customers);
- The number of GSL payments made (normalised per 100,000 customers); and
- Performance against supply reliability targets.

Ergon Energy has introduced a number of GSLs and makes payments to customers on application by the customer when the guaranteed performance standard has not been achieved. GSLs apply to the following:

- New Connections – if a customer has lodged the necessary paperwork and supply is available, their electricity will be connected and working by the requested and agreed date. A credit of $25 applies for each day that Ergon Energy is late. This is a lower payment amount than comparable interstate utilities.
- Planned Interruptions – when carrying out upgrades and maintenance that requires Ergon Energy to interrupt supply, they will notify the customer at least 4 days prior to the outage. A credit of $25 applies to residential customers and $50 for business customers, if this is not achieved. This GSL is consistent with that offered by other utilities, but is considered by the Consultant to be a relatively easy one to meet.
- Street Lights – Ergon Energy will carry out streetlight repairs in a customer's street by the nominated and agreed date. A credit of $10 applies to the first customer who reported the fault, if Ergon Energy is late. This is a lower standard than most other utilities, who have a higher quantum and/or nominate a set time period.
- Hot Water – Ergon Energy will attend to hot water enquiries within 1 day where it is due to a fault on its electricity control system. A credit of $20 applies for each day Ergon Energy is late.
- Trees & Overhead Powerlines – If a customer contacts Ergon Energy regarding vegetation growth close to powerlines around their premises, Ergon Energy will:
  - Give the situation its immediate attention if it is posing a risk to public safety;
  - If it is not urgent and the tree is not on Ergon Energy's vegetation works schedule, they will visit to make a risk and safety assessment within 20 days of the call and implement appropriate action.

  A credit of $20 applies. Ergon Energy is the only utility of those surveyed to offer a GSL in this regard.

Overall, the Consultant considers that the standards of service relating to the GSLs offered by Ergon Energy are at the softer end of the range, with the exception of responses to hot water problems (the GSL relating to vegetation is considered to be relatively infrequent and easy to achieve). The Consultant also notes the requirement for customers to apply for the GSL credit, rather than it being provided as a matter of course when Ergon Energy fails to meet its customer service standards, resulting in a lower number of GSL payments. A detailed comparison between Ergon Energy's GSLs and those of other utilities is contained in Appendix 14.11. It is noted that Ergon Energy offers GSL payments on a voluntary basis, whereas in Victoria and South Australia, the GSL schemes form part of the regulatory arrangements.

Table 5-2 shows the number of complaints and GSL payments for Ergon Energy and other Australian distributors for 2003 calendar year for Ergon Energy, for 2002 calendar year for Victoria and for 2002/03 financial year for the others.

**Table 5-2: Complaints & GSL Payments**

| | NO. OF COMPLAINTS PER 100,000 CUSTOMERS | NO. OF GSL PAYMENTS MADE PER 100,000 CUSTOMERS |
|---|---|---|
| ERGON ENERGY | 1,113 | 44 |
| COUNTRY ENERGY | 322 | |
| POWERCOR | 27 | 11 |
| TXU | 131 | 16 |
| ETSA | 447 | 402 |
| INTEGRAL ENERGY | 234 | |
| ENERGY AUSTRALIA | 37 | |
| UNITED ENERGY | 113 | 142 |
| AGL | 97 | 141 |
| CITIPOWER | 45 | 170 |

*All figures are for the 2002/03 financial year except for Ergon Energy which are for the 2003 calendar year and the Victorian utilities which are for the 2002 calendar year.*

It can be seen from Table 5-2 that Ergon Energy has a high level of complaints but a relatively low level of GSL payments per 100,000 customers. The Consultant considers that the lower number of GSL payments has been influenced by the standards set for which GSL payments apply, as discussed earlier. Another factor could be the level of understanding by customers about GSLs. GSL payment statistics are also heavily influenced by customer expectations. For example, if customers expect a higher level of service, then the same level of complaints might be experienced even though a higher level of service is being provided. In spite of these limitations, indications are that Ergon Energy has room for improvement in the level of customer service provided, as viewed from a customer complaints perspective. It is noted that Ergon Energy offers GSL payments on a voluntary basis, whereas the GSL schemes form part of the Regulatory arrangements in Victoria and South Australia.

In its Final Determination covering the current Regulatory period, the QCA signalled its intention to consider including some form of service quality incentive mechanism in the next Regulatory period. The QCA issued a Final Decision - Service Quality Incentive Scheme for Electricity Distribution Services in Queensland in April 2004, proposing a scheme that would target specific service quality outcomes to be achieved by the end of the next regulatory period.

In establishing the CAPEX and OPEX building blocks for the next regulatory period, the distributors are required to submit forecasts associated with:

- Maintaining the current service quality level (Tier (a));
- Improving service quality aimed at delivering an agreed average level of service (which may be somewhat higher than current service levels) (Tier(b)); and
- Specific additional commitments aimed at improving service quality in specific parts of the network or addressing identified customer requirements and including clearly identified service quality outcomes (Tier (c)).

The CAPEX and OPEX expenditures associated with these three tiers of service levels are discussed later in this report.

Key measures of supply reliability are:

- SAIDI – this is a measure of how long each customer is without supply for the year when averaged over all customers;
- SAIFI – this is a measure of the number of sustained supply interruptions each customer experiences for the year averaged over all customers (a sustained interruption is one in excess of a specified duration, usually 1 minute);
- CAIDI – this is a measure of the average duration of each supply interruption per customer who experienced an interruption, and indicates how quickly a distributor restores supply; and
- Momentary Average Interruption Frequency Index ("MAIFI") – this is a measure of the number of momentary interruptions each customer experiences for the year averaged over all customers (a momentary interruption is one less than the specified duration).

It is noted that Ergon Energy does not monitor and record momentary interruptions, so a comparison of performance using MAIFI as an indicator could not be made. Based on the Consultant's experience, momentary interruptions are an increasing cause for concern to customers, with the proliferation of electronic and digital equipment. The Consultant recommends that the QCA consider introducing such a performance measure in the regulatory period following the forthcoming period.

Table 5-3 shows key supply reliability indicators for Ergon Energy and other Australian electricity distributors.

**Table 5-3: Supply Reliability**

| | | ERGON ENERGY | COUNTRY ENERGY | POWERCOR | TXU | ETSA | INTEGRAL ENERGY | ENERGY AUSTRALIA | UNITED ENERGY | AGL | CITIPOWER |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **SAIDI** MINUTES | PLANNED | 102 | 48 | 17 | 29 | | 35 | 5 | 16 | 6 | 9 |
| | UNPLANNED | 392 | 239 | 187 | 219 | | 182 | 113 | 73 | 74 | 33 |
| | TOTAL | 494 | 287 | 203 | 248 | 179 | 217 | 118 | 89 | 80 | 41 |
| **SAIFI** | PLANNED | 0.5 | 0.21 | 0.11 | 0.13 | | 0.12 | 0.03 | 0.05 | 0.03 | 0.03 |
| | UNPLANNED | 4.0 | 2.18 | 2.21 | 2.96 | | 2.62 | 1.25 | 1.49 | 1.49 | 0.69 |
| | TOTAL | 4.5 | 2.39 | 2.32 | 3.09 | 1.79 | 2.78 | 1.28 | 1.55 | 1.52 | 0.72 |
| **CAIDI** MINUTES | PLANNED | 220 | 234 | 155 | 234 | | 305 | 184 | 305 | 238 | 286 |
| | UNPLANNED | 97 | 109 | 85 | 74 | | 69 | 81 | 49 | 49 | 47 |
| | TOTAL | 110 | 121 | 88 | 81 | 100 | 78 | 92 | 58 | 53 | 57 |

*All values are for 2002/03 financial except the Victorian utilities which are for the 2002 calendar year.*

It can be seen that Ergon Energy's SAIDI is significantly higher than any other utility, both planned and unplanned. This indicates that when averaged across all customers, Ergon Energy's customers are off supply for a longer period each year than any other distributor. This is to be expected, given the nature of Ergon Energy's supply system, with a large number of very long, radial feeders. The ratio of planned to unplanned SAIDI is higher than for other utilities, which could be attributable to the level of activity associated with the accelerated defect management plan and restrictions on live line work due to a shortage of qualified personnel and bans on live work on poor conductors.

It can also be seen that Ergon Energy's SAIFI is significantly higher than any other utility, both planned and unplanned. This indicates that when averaged across all customers, Ergon Energy's customers are experiencing significantly more interruptions than any other distributor. Again, this can be attributed to the nature of Ergon Energy's supply system.

Ergon Energy's CAIDI is in the mid range of the comparable distributors, for both planned and unplanned interruptions. This indicates that for unplanned interruptions, Ergon Energy is able to restore supply in a similar time frame to the comparable distributors. Considering its large distribution area, this is a positive achievement by Ergon Energy.

Overall, Ergon Energy's supply reliability is worse than that of other comparable distributors for SAIDI and SAIFI but is in the mid range for CAIDI. This is heavily influenced by the characteristics of Ergon Energy's supply system, and leaves a large scope for Service Quality Improvement works.

# 6 REVIEW OF ASSETS

## 6.1 Scope of Section

Key drivers of operating expenditure and replacement capital expenditure include the number, age and condition of the various elements of the electricity network. This section describes the number, age, condition and type of key equipment items of the network.

## 6.2 Overview of Electricity Network

The Ergon Energy electricity network incorporates 140,000 km of sub-transmission and distribution lines spread over one million square km of regional Queensland. It is characterised by long radial rural feeders and low customer densities compared to other DNSPs.

The Ergon network is supplied by the Powerlink transmission network at 220 kV, 132 kV, and 110 kV. The bulk supply substations owned by Ergon Energy are located at 30 sites:

- 220 kV: Mica Creek;
- 132 kV:Barcaldine, Boat Creek, Clermont, Dysart, Egans Hill, Gladstone South, Kamerunga, Turkinje, Garbutt, Dan Gleeson / Condon, Clare, Ingham, Bundaberg, Isis, Kilkivan, Maryborough, Cardwell, Innisfail, Cairns Terminal / Harley St., Tully, Clayton and Nebo
- 110 kV: Dalby, Yarranlea, South Toowoomba, Warwick, Stanthorpe, Roma, Torrington.

The Ergon Energy sub-transmission network operates at 132 kV, 110 kV and 66 kV. This network supplies the Ergon Energy distribution system which incorporates three-phase, single-phase and SWER radial distribution networks. These networks mainly operate at 33 kV, 22 kV, 11 kV and 415 V, although a small number of networks still exist at legacy voltages including 6.6 kV and 3.3 kV.

Ergon Energy is also responsible for 33 isolated generators and stand alone distribution networks. However, these networks are not part of the regulated business and therefore will not be part of this review.

## 6.3 Description of Assets

This section contains a brief summary of the electricity network assets.

Inadequate asset data models and reporting tools is a common theme which has emerged in the review of Ergon Energy's assets. This is primarily due to the poor asset management and varying resource levels inherited from the six distribution corporations which were merged to form Ergon Energy. In response to this problem, a concerted effort is being made to collect and record asset information using a standardised approach across the business.

### 6.3.1 Meters

#### 6.3.1.1 Quantities

Ergon Energy has approximately 1.13 million revenue meters and 380,000 ripple control meters in service. There are a wide range of meters which have been used across the six regions. This has been recognised and there is now a philosophy to migrate towards common meter standards and rationalisation.

#### 6.3.1.2 Age profile

Only limited age profile information is available for the Ergon Energy revenue meters because of the previous poor data collection practices. However, it is known that approximately 14% of the meters are aged greater than 40 years.

#### 6.3.1.3 Condition

With the centralisation of Ergon Energy, a standardised management approach is being developed for revenue meters. This program which was commenced recently, has found that there are significant numbers of older meters that are outside the allowable tolerance. Other issues which have been identified include:

- The receivers which were installed in the Wide Bay region between 1981 and 1986 (approx. 30,000) have discrete electronic components which have begun to fail and will require replacement over the next five years;
- Reports indicate that Warburton Franki Meters have a high risk of plastic becoming brittle and plastic register gears failing due to temperature. This results in energy use not being recorded and consequently a loss in revenue; and
- Metal cased meters have been identified as a potential safety hazard because they are located at customer sites and have exposed metallic surfaces which are un-earthed. These meters are all greater than 50 years old and are typically under rated.

### 6.3.2 Poles

#### 6.3.2.1 Quantities

Ergon Energy has approximately 850,000 poles of which approximately 795,000 are wood. This includes street lighting, low voltage, distribution and sub-transmission poles. These numbers are estimates only based on data taken from the GIS system in February 2004. It is expected that more accurate figures will be available once the first cycle of the reduced time (three year) inspection cycle is complete in June 2004 and all the required pole data has been captured.

#### 6.3.2.2 Age Profiles

The age profile of Ergon Energy's pole population is not well defined. The best estimate of age profile has been based on SAP pole data collected in the three year inspection data to data. Pole age data to date indicates that there is a significant population from the early 1960's and some from before this period.

#### 6.3.2.3 Condition

With the introduction of the intensified program of pole inspection and the rectification of priority defects, the condition of poles and accessories will be fully established by June 2005. At this time the condition of all poles will be known and this will provide a sound basis for the establishment of firm plans for the management of these assets.

Over the next regulatory period, Ergon Energy anticipates the condemnation rate of poles inspected to be 1.63%. The industry standard is 0.4%. It is expected that 41% will be staked or nailed and 59% will be replaced. There has been a significant improvement as the condemnation rate prior to the formation of Ergon Energy was 8-12%. This is explained by the improved practices developed by Ergon Energy staff since its formation, and can be expected to further improve over the next five years.

The current unassisted pole failure rate as of March 2004 is 0.9 failures per 10,000 poles.

### 6.3.3 Pole Top Structures

#### 6.3.3.1 Quantities

The estimated population of pole top structures is 1.221 million.

#### 6.3.3.2 Age profile

No accurate age profile information is available, although it is known that there is a significant population from as far back as the early 1960's.

#### 6.3.3.3 Condition

Data related to pole top structures has not previously been recorded and so the condition of the existing population is relatively unknown.

### 6.3.4 Line Conductors and Connectors

#### 6.3.4.1 Quantities

The majority of Ergon Energy's sub-transmission and distribution networks, as summarised in Table 6-1, are overhead conductors which are typically hard drawn bare copper ("HDBC"), all aluminium conductor ("AAC"), aluminium conductor steel reinforced ("ACSR") or all aluminium alloy conductor ("AAAC") and galvanised or alumoweld steel construction. There is a wide range of connector types. No detailed information on conductor or connector types is available.

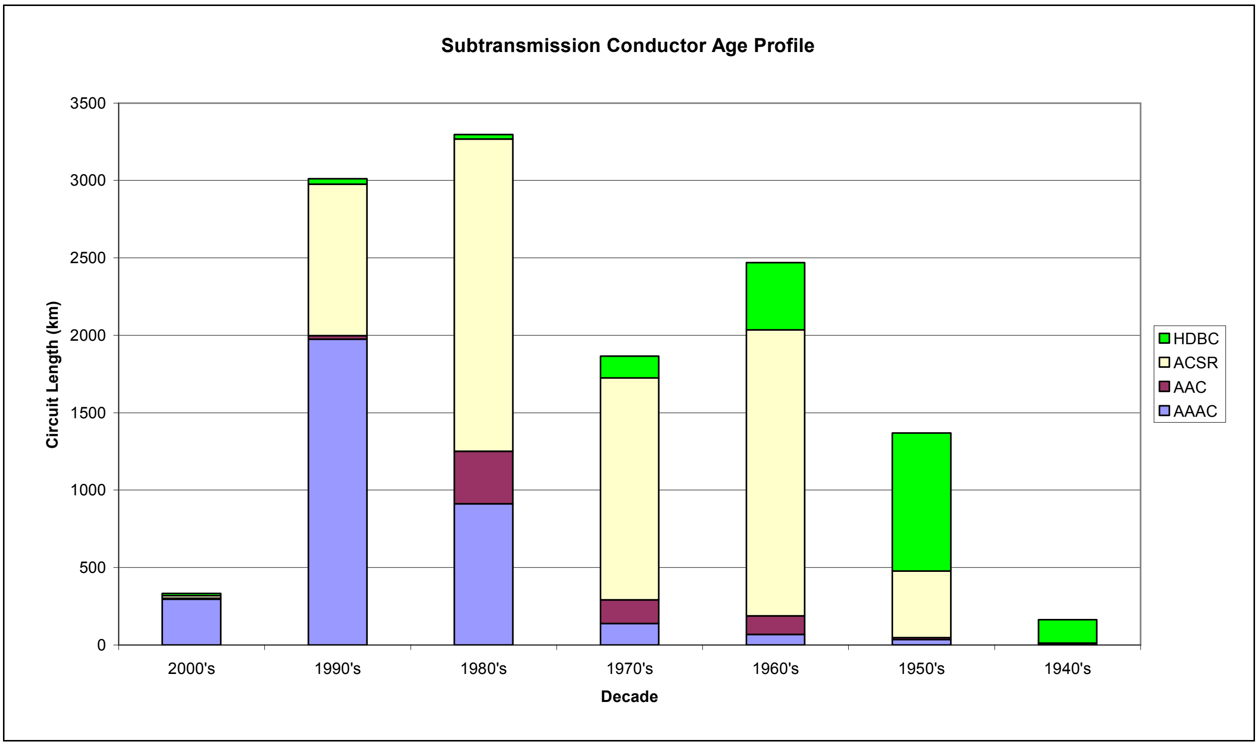
**Table 6-1: Conductor Type and Quantity**

| Conductor Type | Qty (km) |
|---|---|
| Overhead sub-transmission lines | 13,984 |
| Overhead distribution lines | 43,903 |
| Overhead SWER lines | 62,500 |
| Overhead LV distribution lines | 15,234 |

#### 6.3.4.2 Age profile

Figure 6-1 shows the age profile of Ergon Energy's sub-transmission conductors. No age profile information has been made available for overhead distribution conductors.

**Figure 6-1: Sub-transmission Conductor Age Profile**



#### 6.3.4.3 Condition

Similar to other Ergon Energy assets, historically, the recording of asset data has been very limited so detailed information on the condition of these assets is unavailable. However, it is recognised that a significant proportion of the line assets was constructed prior to 1960 and is therefore now over 40 years old. Some specific issues which have been identified include:

- A large number of overhead conductors with inadequate ground clearance were identified, particularly in the Wide Bay region. It has been necessary to review ground clearance of lines in this region to ensure they meet statutory requirements.
- A number of small copper conductors in the range of 7/064 and 7/080 have been reported as being brittle. Consequently live line work bans currently exist for these conductors. At present there has been no structured approach to understanding and rectifying this problem but the need for a maintenance and replacement plan has been recognised.
- The security and reliability of some of Ergon Energy's sub-transmission networks is poor due to aged conductor and network configuration limits. A condition profile of the sub-transmission lines has been developed in response to the problem. This has identified a significant quantity of degraded copper and ACSR conductor.
- 3/2.75 SC/GZ conductors have significant rust issues, particularly in corrosive coastal environments.
- Sugar cane burning has resulted in conductor damage. Cane burning has been found to damage the coating on steel conductors leading to corrosion, softening of aluminium conductors, and annealing of copper conductor.
- There have been a number of problems with a range of connectors, particularly in high load or high fault current areas.

### 6.3.5 Underground Cables and Joints

#### 6.3.5.1 Quantities

Table 6-2 below details the approximate populations of Ergon Energy's underground cable assets.  This data does not include underground communications (supervisory) cables.

**Table 6-2: Underground Cable Type and Quantity**

| Conductor Type | Qty |
|---|---|
| LV Cable | 2,000 km |
| HV Cross-linked Polyethylene ("XLPE") (11, 22 & 33 kV) Cable | 620 km |
| HV PLY (11, 22 & 33 kV) Cable | 161 km |
| HV Submarine Cable | 52 km |
| 66 & 132 kV Cable | 10 km |
| LV Pillars | 42,000 |

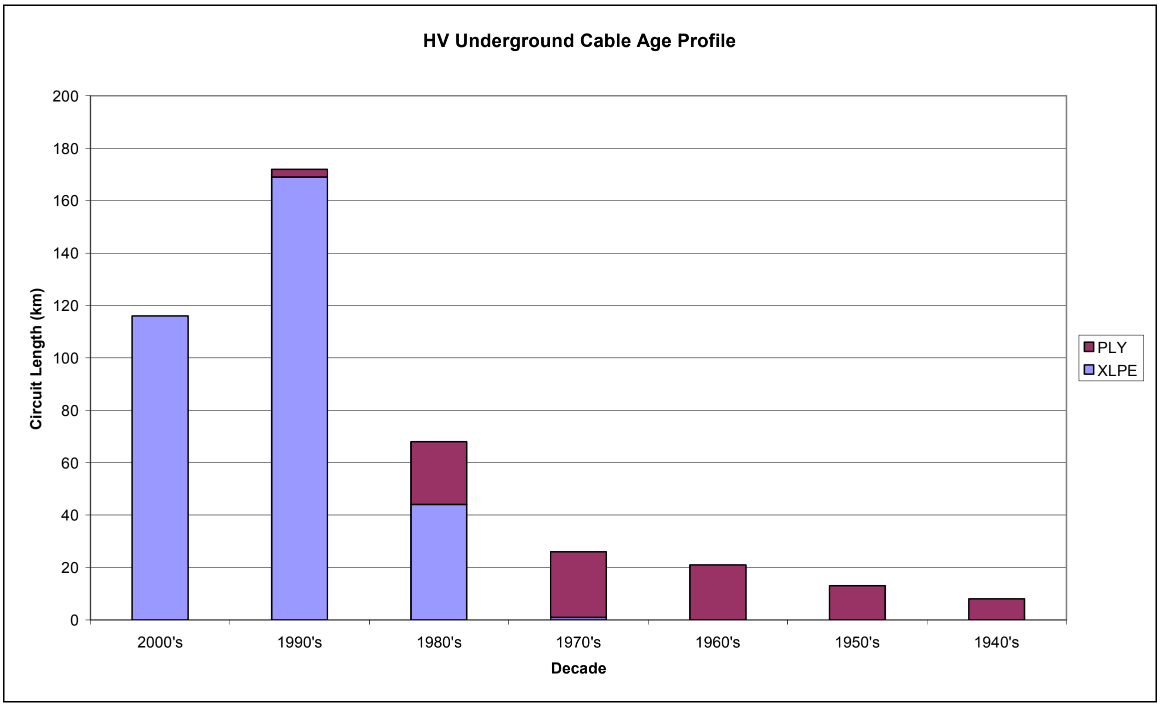
The quantity of underground cable will increase at a rate greater than demand growth because of the use of underground construction for new residential estates and the undergrounding of selected network sections to improve the security of supply to important public infrastructure in cyclone prone areas.

Ergon Energy has a variety of types of cable and associated accessory types as well as installation and jointing types. This is a result of its formation from six the independent regional corporations. Future standardisation of cable, accessories and installation practices will be essential.

#### 6.3.5.2 Age profile

Figure 6-2 below gives the age profile of Ergon Energy's HV underground cable assets.

**Figure 6-2: HV Underground Cable Age Profile**




Data has not been provided for the age profile of LV cables. Low voltage cable is the largest component of Ergon Energy's cable population in terms of length. Further work should be done to estimate the age where actual recorded data is not available.

#### 6.3.5.3 Condition

Parts of Ergon Energy's territory have environmental features that can reduce underground cable lives.

- The high rainfall and humidity in the north can shorten the life of some types of XLPE cable;
- Particularly high lightning activity in the western area causes an above average failure rate; and
- Termite attack in some areas.

Specific issues associated with Ergon Energy's underground cables have been identified as:

- XLPE HV cable dielectric failures commenced in the late 1990s in the Far North region with cables over 20 years old. Investigations have discovered that 'water trees' in the cable dielectric are a probable cause. These have been caused by the high humidity environment. Fault location and recommissioning tests as well as installation techniques may have also contributed to degradation of cable quality. Ergon Energy has formed collaborative agreements with academic institutions to better understand this issue. These collaborations link Ergon Energy to industry forums relevant to cable aging performance which will provide access to information regarding technology developments in this area. As an alternative to cable replacement, refurbishment techniques for water tree affected cables have been developed commercially and will be trialled during 2004;

- It is anticipated that water trees will reduce the life of XLPE cables in other areas of Ergon Energy, but not to the same extent as those in wet environments. Cables manufactured more recently are expected to be less affected by this problem and the issue of inappropriate testing is now recognised. Low voltage XLPE cables do not suffer from the debilitating affects of water trees because of the lower electrical stresses;
- There are four lengths of 66 kV Paper Insulated Gas Pressurised Cable installed in Ergon Energy, one of which has been particularly troublesome because of its gas leaks. After much investigation these have not been found, and although these cables have been assessed as serviceable a business case has been prepared for their replacement;
- There are six lengths of PLY and XLPE submarine cables to islands off the mainland. They are subject to risks not experienced by buried cables, such as tidal movement, extreme weather, vessel anchor damage, sea worms and corrosion. Historically, there has not been a high incidence of failure due to these factors. However Ergon Energy does not have the expertise or equipment to work on these assets within the business so in the event of failure, long fault finding and repair times can be expected; and
- Cast cable terminations (potheads) are an early technology and have reached the end of their expected asset lives. As the consequence of failure is catastrophic, there is a risk associated with their continued use. A program is in place to locate the remaining cast cable potheads and replace them with present standard technology.

The condition of both LV underground cables and the HV paper/lead (PLY) cables, including their sealing ends and cable boxes, is generally considered to be excellent and there is no evidence of emerging trends to change that assessment.

Ergon Energy has prepared a comprehensive management plan for its underground assets, the UG Cable Maintenance Plan. This plan is currently being implemented.

### 6.3.6 Distribution Transformers

#### 6.3.6.1 Quantities

Ergon Energy has a total distribution transformer population of approximately 78,700, including both pole and ground (pad) mounted transformers as summarised in Table 6-3.

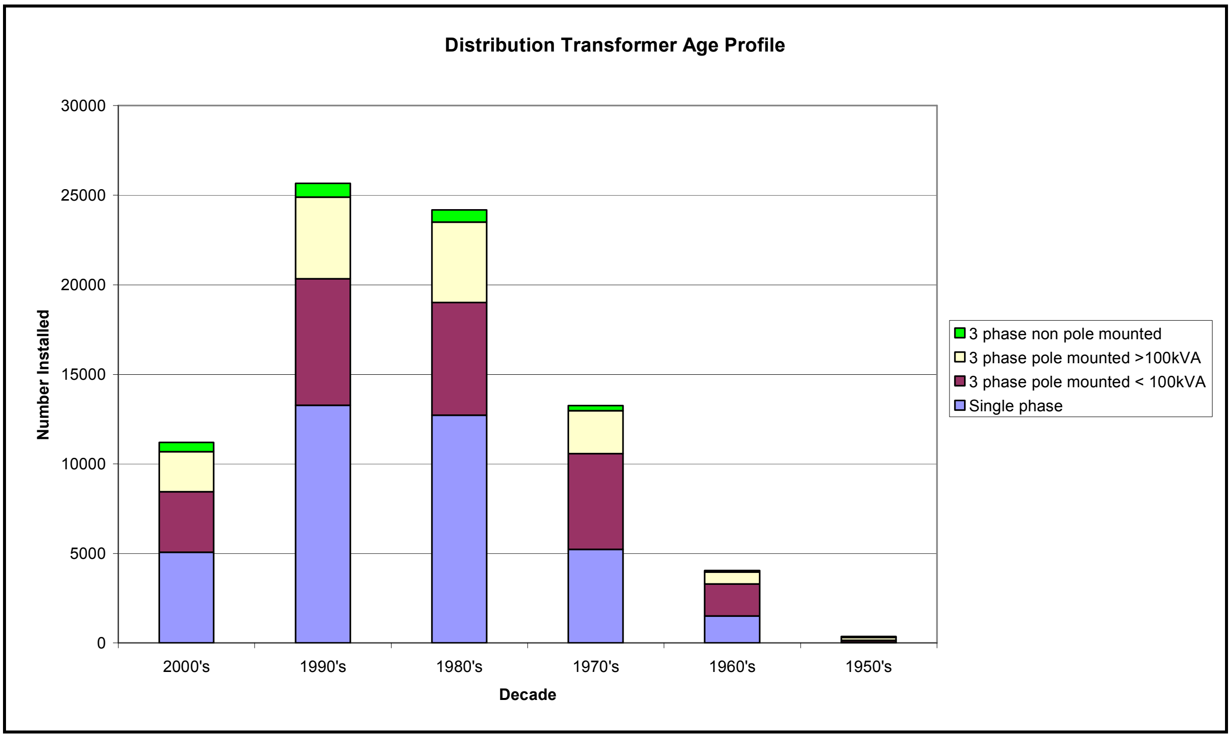
**Table 6-3: Distribution Transformer Type and Quantity**

| Transformer Type | Qty. |
|---|---|
| 1 ph. transformers (incl. SWER) | 37,833 |
| 3 ph. pole mounted transformers <100 kVA | 23,945 |
| 3 ph. pole mounted transformers >= 100 kVA | 14,549 |
| 3 ph. non-pole mounted transformers | 2,360 |
| **Total** | **78,687** |

#### 6.3.6.2 Age profile

The distribution transformer age profile is shown in Figure 6-3.

**Figure 6-3: Distribution Transformer Age Profile`**




#### 6.3.6.3 Condition

Similar to many of Ergon Energy's assets, very little historical condition data is available for the distribution transformers. This has been recognised as an issue, and systems are now in place to improve data collection in the future. Devices, such as smart switches, which are being implemented on the network, will help facilitate this data collection. Ergon Energy has also started taking Dissolved Gas Analysis ("DGAs") and Maximum Demand Indicators ("MDI") readings on the larger distribution transformers in an effort to extend the asset lives.

Accelerated transformer aging due to moisture is a significant issue for Ergon Energy, particularly in coastal areas because of the tropical operating environment. High moisture levels can cause leaks in seals, rust and mechanical damage. This problem has been recognised and the transformers are routinely monitored for moisture levels.

No other significant distribution transformer problems have been identified by Ergon Energy.

### 6.3.7 Other Distribution Equipment

This section covers switchgear (automatic circuit reclosers ("ACR"), air break switches ("ABS"), enclosed switches, ring main units ("RMU") etc.), fuses, surge arrestors, LV services, street lighting, earthing systems, line regulators, capacitors and reactors.

#### 6.3.7.1 Quantities

Available population numbers for the relevant distribution items are summarised in Table 6-4.

**Table 6-4: Distribution Line Equipment Type and Quantity**

| Asset | Approx. Qty. |
|---|---|
| SWER ACR | 858 |
| 3 phase ACR | 405 |
| SWER pole mounted isolators | 547 |
| Pole mounted ABS | 8,990 |
| Distribution substation switchgear (incl. RMU) | 221 |
| HV fuses | > 100,000 |
| LV fuses | > 500,000 |
| SWER regulators | 88 |
| 2 phase regulators | 152 |
| 3 phase regulators | 118 |
| Sectionalisers | 912 |
| SWER reactors | 455 |
| 3 phase ground mounted line reactors | 460 |
| Lightning arrestors | 194,000 |
| LV services | 536,179 |
| Street lighting | 110,000 |

#### 6.3.7.2 Age profile

No age profile data is available for these distribution items, primarily because of the lack of record keeping in the past.

#### 6.3.7.3 Condition

The condition data available for these distribution items is of varying standards due to the poor record keeping practices of Ergon Energy's predecessors. The specific issues are:

- The number of substandard customer service lines;
- SWER system earthing safety;
- Some types of air break switch have foreshortened lives due to corrosion;
- Earthing of air break switch handles; and
- Maintenance intensive types of high voltage fuses.

### 6.3.8 Zone Substation Transformers, Regulators and Reactors

#### 6.3.8.1 Quantities

Ergon Energy has 573 power transformers (including 12 Earthing Transformers and 10 Auto Transformers), 60 Regulators, and 25 Reactors. The voltage distributions of these devices is given in Table 6-5.

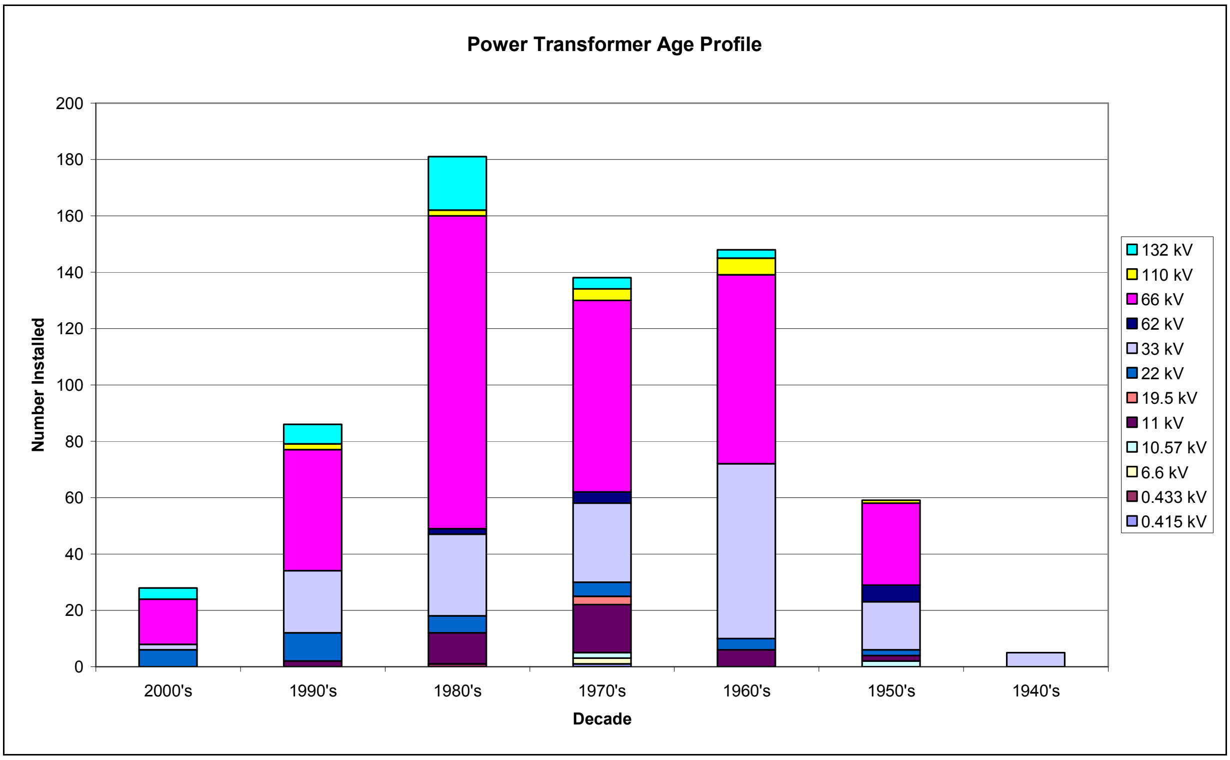
**Table 6-5: Power Transformer Type and Quantity**

| Sec. / Prim. | 110 kV | 66 kV | 33 kV | 22 kV | 11 kV | other | Total |
|---|---|---|---|---|---|---|---|
| 132 kV | 2 | 21 | 1 | 4 | 7 | 2 | **37** |
| 110 kV | - | - | 15 | - | - | - | **15** |
| 66 kV | - | - | 22 | 69 | 226 | 4 | **321** |
| 33 kV | - | - | - | 6 | 129 | 22 | **157** |
| 22 kV | - | - | - | - | 6 | 1 | **7** |
| 11 kV | - | - | - | 4 | - | 13 | **17** |
| other | - | - | - | | 17 | 2 | **19** |
| **Transformer Total** | **2** | **21** | **37** | **83** | **385** | **44** | **573** |
| Regulators | - | 7 | 10 | 18 | 21 | 5 | **60** |
| Reactors | - | 11 | - | 6 | 6 | 2 | **25** |

#### 6.3.8.2 Age Profiles

The age profile of Ergon Energy's power transformer, regulator and reactor assets (based on primary voltage) is given in Figure 6-4.

**Figure 6-4: Power Transformers Age Profile (incl. regulators and reactors).**



#### 6.3.8.3 Condition

There is a wide variation in Ergon Energy's transformer population in terms of manufacturer, age and expected life. As such, management of transformer maintenance and replacement presents a major technical challenge. Nevertheless, Ergon Energy has maintained relatively good historical condition data for these assets as part of the SCAMS systems.

A number of problem areas have been identified including:

- A number of transformers of late 70's to early 80's vintage are showing signs of advanced aging;
- Cromptom Parkinson transformers of 60's vintage have reached the end of their expected life and are due for replacement;
- High moisture content levels have been recorded in the oil DGA test figures for a number of transformers. Models for the assessment of moisture content in transformers are being developed. These will assess life cycle maintenance requirements for a range of transformers under investigation. Various modifications appropriate to each situation are being applied, including improved breathers, use of conservator bags, use of molecular sieves to control moisture, and a range of dryout techniques; and
- Five on-load tapchangers have been found to be gassing due to mechanism failures. At present, tapchanger maintenance is based on time rather than the number of operations.

### 6.3.9 Zone Substation Circuit Breakers

#### 6.3.9.1 Quantities

Ergon Energy has approximately 2500 Zone Substation ("ZSS") Circuit Breakers ("CBs") as detailed in Table 6-6. These include SF6, Vacuum and oil type breakers.

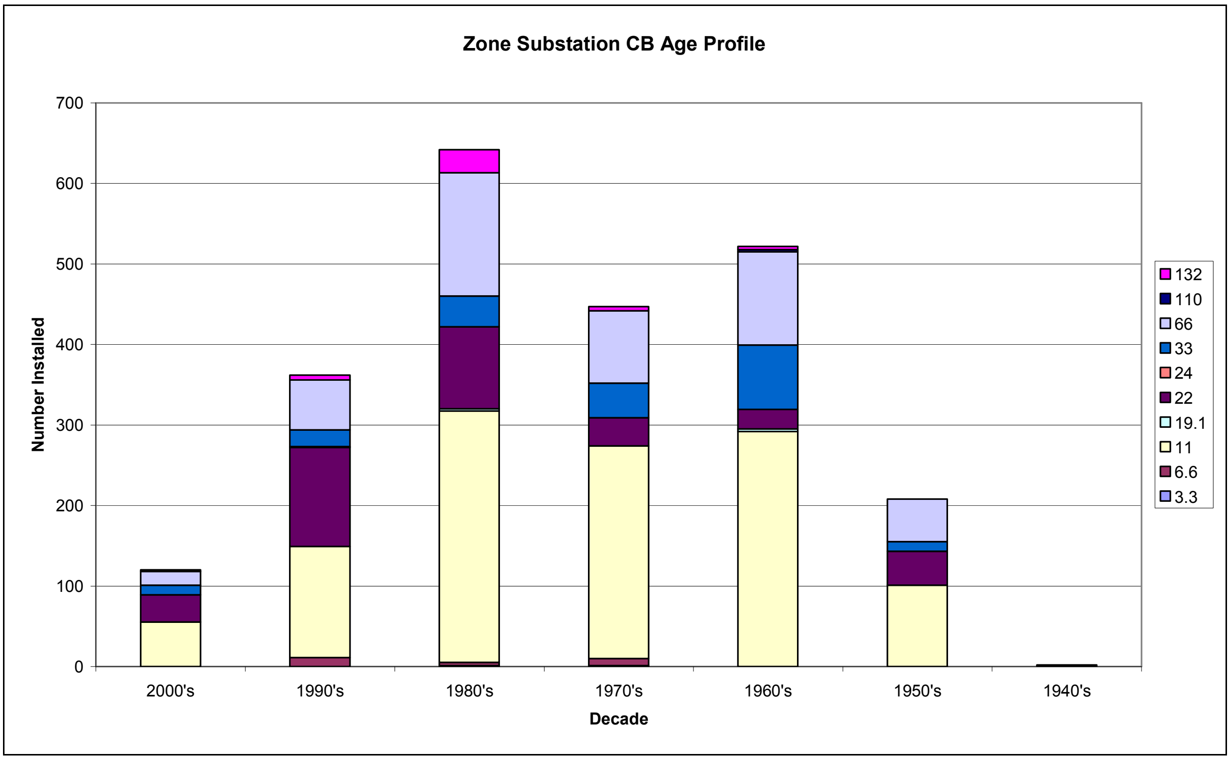
**Table 6-6: Zone Substation CB Voltage and Quantity**

| Voltage (kV) | 132 | 110 | 66 | 33 | 22 | 11 | other | Total |
|---|---|---|---|---|---|---|---|---|
| No. of ZS CB's | 47 | 3 | 506 | 258 | 365 | 1317 | 32 | 2528 |

#### 6.3.9.2 Age Profiles

Figure 6-5 gives an approximate age profile for the ZSS CB population. It is noted that year of manufacture ("YOM") data is only available for 63% of the total population. It is likely that this figure skews the profile towards younger CBs because there has been a significant improvement in data collection over recent years. Indeed, Ergon Energy has suggested that a large number of oil CBs from the 60's and 70's vintage are still in service, but this peak is not obvious in the given age profile.

**Figure 6-5: Zone Substation CB Age Profile**




### 6.3.9.3 Condition

Ergon Energy has a program in place to refurbish or replace circuit breakers on a life expectancy basis. Given that oil circuit breakers were installed in all of Ergon Energy's substations during the 60's and 70's, there are a large number of breakers which are due for replacement during the early years of this assessment. The current strategy is to replace oil breakers with vacuum or SF6 breakers.

Specific problem areas which have been identified include:

- Oil LMT CB Bushings; following a catastrophic failure of a Reyrolle type LMT 11 kV CB in New South Wales ("NSW"), the bushing insulation of 230 Ergon Energy CBs has been tested. A number of bushings have failed electrical tests (i.e. Dielectric Loss Angle ("DLA")). Furthermore, operating restrictions preventing racking up into live bus have been placed on all pre 1970 LMT CBs, unless tested and determined suitable for normal service. This program has resulted in a replacement rate of 6% of CBs in the 25+ year category, the replacement of switchboards at two sites, replacement of a number of CBs with spares and a program of workshop replacement of individual bushings of a number of CBs. It is noted that while attempts have been made within the industry to refurbish bushings, these have been largely unsuccessful to date;
- GEC OLX 11 kV CBs (1960's and 1970's vintage) have had similar issues to the LMT circuit breakers. A testing program is currently been developed;
- GEC 66 kV FL1 CBs (1980's vintage) have a history of mechanical mechanism failures. One of these has been replaced and others are continuing to be troublesome;
- DELLE – Alstom 66 kV CBs (late 1960's and 1970's vintage) are reaching the end of their expected asset life and have a history of failure;
- BTH 66 kV CBs (late 1960's and 1970's vintage) - there was an explosive failure of one of these units at Yarranlea. A number of units have failed DLA bushing tests and have had mechanism failures;

- Ferguson Pailin 33 kV Oil CBs (late 1950's vintage)- these units have reached their expected asset life. Also, the current rating on these devices is indeterminate as the units do not have name plates;
- Reyrolle 33 kV ORT and 11 kV OYT oil CBs (1960's vintage) - there have been problems with leaking pitch filled bushings, as well as mechanical mechanism failures; and
- ASEH HKEY 66 kV Oil CBs (mid 1950's vintage) - these units are aged and mechanically worn. Replacement of these breakers has already begun in North Queensland.

### 6.3.10 Other Zone Substation Primary Equipment

#### 6.3.10.1 Quantities

This section covers switches, capacitors, Current Transformers ("CTs"), Voltage Transformers ("VTs") and static VAR compensators ("SVC").

**Table 6-7: Zone Substation Primary Plant Equipment and Quantity**

| Switch Asset | Total |
|---|---|
| CTs | 3700 |
| VTs | 1500 |
| Capacitor Banks | 128 |
| SVC | 4 |
| Earth Switches | 681 |
| Isolators | 2855 |
| Links (set of 3) | 590 |
| Fuses and Fused Switches | 344 |
| Throw Switches | 54 |

#### 6.3.10.2 Age profile

The four SVC units were installed between 1986 and 1992. The age of capacitor banks and switches is generally unknown, although switch age is typically assumed to be the same as the substation age.

#### 6.3.10.3 Condition

Points made by Ergon Energy in relation to these assets include:

- High levels of substation construction during the 1960's and 1970's mean that significant quantities of plant will reach the end of their useful life during the next regulatory period;
- While the SVCs have proved to be reliable they are reaching the end of their useful life;
- Following routine sampling and testing of 66 kV Energoinvest CTs it has been necessary to replace 30 of these due to the presence of acetylene; and
- Diaphram type 33 kV CTs have experienced numerous failures.

### 6.3.11 Zone Substation Secondary and Auxiliary Equipment

This section covers auxiliary systems, communications, control and protection systems, (including Substation and Distribution System Automation ("DSA") systems), Remote Terminal Units ("RTUs") and Static Frequency Units ("SFU").

#### 6.3.11.1 Quantities

The approximate quantities of each of these items are summarised in Table 6-8.

**Table 6-8: Zone Substation Secondary and Auxiliary Equipment Type and Quantity**

| Asset Description | Approx. Qty. |
|---|---|
| Battery/DC auxiliary systems | 360 |
| Protection relays - electronic | 1,714 |
| Protection relays - electromechanical | 1,850 |
| Master station control systems | 8 |
| Substation RTU | 181 |
| DSA RTUs | 103 |
| Radio site RTUs | 13 |
| Substation Local Control Interfaces | 53 |
| Audio frequency load management controllers and SFU | 44 |
| Supervisory cable | Approx 293 km |

#### 6.3.11.2 Age profile

There is very limited information available for the age profile of these items.

#### 6.3.11.3 Condition

The specific issues regarding condition are:

- There are a large variety of Direct Current ("DC") systems which do not comply with current standards for DC chemical storage systems and DC supply systems. Therefore a program has been initiated to standardise these systems across substations;
- There are three types of battery in use: flooded lead acid, valve regulated lead acid ("VRLA") and nickel cadmium. In the past two years 40 battery banks have been replaced each year. It is a normal practice to replace battery chargers with battery replacement to ensure DC supply reliability;
- The flooded lead acid type have had problems with positive post growth. The nickel cadmium type, which have been used for many years, are approaching the end of there useful life and have reduced capacity. Because of the higher ambient temperatures in Queensland the VRLA type, which require less maintenance, are found to have a reduced life of an average of seven to eight years, instead of a normal life of ten years;
- The Programmable Logic Controller ("PLC") system population is aging and spares are an issue. In general it is cost prohibitive to replace these systems with alternative technologies so these systems are typically replaced with compatible PLCs;
- Ergon Energy currently has six separate, regionally based SCADA facilities with varying standards for systems, protocols and network processes. The technology used in these systems is obsolete and the systems cannot be integrated or expanded to meet future business requirements. A SCADA business strategy has been developed and the key recommendation is to install two centralised SCADA Master Stations which requires remote communication facilities at all of the zone substations; and

- Less than 40% of substations have remote control / alarm systems. 45% of the installed systems require replacement to communicate with the proposed SCADA Master Station. Significant modifications and expansion of the communications network and DMS facilities is are required to meet the needs of the SCADA Master Station.

### 6.4 Asset Data Accuracy

Ergon Energy was formed from six regional corporations relatively recently and hence inherited various sets of data and systems for recording asset information. The accuracy and level of detail was mixed and systems were mostly incompatible. Consequently Ergon Energy has basically had to build new asset data systems and repopulate these with reliable data.

Ergon Energy well recognises this situation and is undertaking full and accurate data capture which could be expected to be completed part way through the regulatory period.

Approximately 65% of the asset categories contain some data with inaccuracies relating to the following attributes:

- Total number count of the asset and the number of each type;
- Age profile; and
- Records of present condition.

The Consultant's assessment is that about 70% of the asset data has been accurately captured at this point in time.

A number of techniques have been used by Ergon Energy to fill in the gaps, including sampling and extrapolation from known data. The Consultant considers that the approach used by Ergon Energy is appropriate and that they have provided the best estimates practicable given the current situation.

Based on its experience, the Consultant has made a judgement that the data provided by Ergon Energy could be expected to be within an accuracy of 10%. The consequence of the data inaccuracies, and therefore the level of risk, for forecasting the requirements for both CAPEX and OPEX would lead to the possibility of both under-estimating and over-estimating in various areas. Therefore, the overall accuracy in forecasting both OPEX and CAPEX expenditure is expected to be greater than 90%. This is considered to be acceptable by the Consultant.

### 6.5 Summary

The defect rate found during the accelerated inspection cycle indicates that the general condition of assets can be regarded as fair.

The asset data, including condition and age, will become more certain in 2008 when the second cycle of asset inspections is completed. At this stage, the Consultant has made a judgement that the data provided could be expected to be within an accuracy of greater than 90%.

# 7 OVERHEAD AND CORPORATE SUPPORT COSTS

## 7.1 Areas of Expenses

Overhead support costs including Corporate costs and Distribution Business support costs.

The overhead support costs cover the follow range of areas:

- Finance and Administration;
- Business System and Processes;
- Human Resources;
- CEO, Board and Stakeholder relations;
- Network Regulatory Services;
- Insurance Premiums;
- Insurance Claims;
- Telecommunications;
- Brisbane Office;
- Property Services; and
- Business Unit Support Costs.

Further details are contained in Appendix 14.4.

## 7.2 Allocation

The expenses incurred in the various areas of overhead and corporate support are allocated to the various business units of Ergon Energy via a variety methodologies depending on the nature of the expense.

The methodologies for allocation include:

- User pays;
- Utilisation or occupancy;
- Historical precedents;
- Weighting of users;
- Personnel numbers;
- Volume of work;
- Asset value and ownership; and
- Equal share.

### 7.3 Application

The base overhead rate is established at the start of each year and is reviewed and adjusted quarterly to reflect actual expenditure. These adjustments are proportionately distributed across Ergon Energy's cost groups. Each year, Ergon Energy submits its Regulatory Cost & Revenue Allocation Principles to the QCA for approval. Ergon Energy's forecasts have been prepared using overheads based on the approved allocation principles.

The QCA commissioned Sinclair Knight Mertz ("SKM") to develop a set of unit rates, including an approach to the allocation of overheads. SKM has proposed the allocation of overheads against labour only, based on market rates. Ergon Energy has provided revised OPEX and CAPEX forecasts for the period 2004/05 to 2009/10 on the basis developed by SKM. The application of the SKM overhead methodology results in an increase in Ergon Energy's estimated OPEX of $110.1M and a decrease in the estimated CAPEX of $110.8M over the forthcoming regulatory period. The expenditure forecasts in this report are based on the revised overhead rates as developed by SKM.

For comparison purposes with other utilities, the SKM approach results in a current overhead rate which is approximately 42% of the total OPEX and CAPEX costs. This is at the high end compared with other electricity utilities, and is considered by the Consultant to be reasonable.

It is expected that the overhead rate will decrease over the next review period because the direct costs will grow over the period, whereas support costs will remain relatively constant.

# 8 OPERATIONAL REVIEW

## 8.1 Purpose and Scope of Section

This section considers the functions and costs of maintenance and operations. It also considers the efficiency and effectiveness of these functions against industry standards. Comments are based on the review of assets presented in the previous section. Based on this review of assets, the Consultant accepts the proposed OPEX budget as being reasonable.

## 8.2 Review of Inspection and Preventative Maintenance Practices

Ergon Energy has developed inspection, maintenance, refurbishment and replacement plans for all of its network assets. These plans include a risk assessment for each asset category. Suitable performance measures at the asset category level are identified in some cases but not yet implemented. The inspection and maintenance policies and techniques encompassed are sound and in accord with current industry good practice for a DNSP with an ageing, diverse and extensive network asset base.

### 8.2.1 Meters

Prior to the formation of Ergon Energy, meter maintenance plans were given a low priority. A metering policy covering the whole of Ergon Energy has been developed with the following key features:

- In-situ sample testing to determine accuracy in accordance with Australian Standard 1284.13. The results will be used to determine meter replacement strategies;
- Low voltage current transformer metering installations will be tested on either a five year or ten year cycle depending on customer size. Sites with electromechanical meters will be upgraded with electronic meters during this inspection process;
- High voltage metering installations are to be inspected on a two and a half year cycle and tested on a five year cycle. The accuracy of instrument transformers will be tested on a ten year cycle. These time periods are in accordance with NEMMCO requirements;
- Electromechanical meters and high usage electronic meters will be refurbished, if within technical guidelines. This will be done by external contractors; and
- A program of upgrading and standardizing is in place for current transformer metering and wholesale metering.

### 8.2.2 Poles

Poles are inspected above and below ground as a part of the line inspection program. This is a three year cycle program and asset data collection is a key output in addition to the assessment of the pole condition. Data is recorded and managed in a SAP based maintenance management system.

The line asset inspection cycle will be kept at three years until 2008 and then extended to five years.

A number of preventative maintenance activities are included in the line asset inspection activity. These are:

- External and internal rot treatment and termite treatment for wood poles;
- Treatment of corrosion for steel poles and towers;
- Replacement of covers and guards; and
- Inspection of customer service lines.

### 8.2.3 Pole Top Structures

Pole top components are visually inspected as a part of the three year cycle of line asset inspections, however this will not provide a complete assessment. Detailed inspection may be performed dead-line or live-line by linesmen either climbing the structure or inspecting from an Elevating Platform Vehicle (“EPV”). Aerial inspection using a helicopter could also be used.

Pole top structures will be inspected, starting at an age of 15 years, according to the following regime:

- Transmission – 66 kV or above using steel towers or concrete poles;
    - A 5% reference sample of intermediate and termination poles every five years between 15 years and 30 years.
    - After 30 years, the same reference pole will be climbed and sampled every two years.
- Transmission – 66 kV or above using wood poles;
    - In wet areas, with above 1500 mm rainfall, a pole top inspection of all poles after 15 years and thereafter every five years.
    - A pole top inspection of all other poles after 20 years and thereafter every five years.
- Distribution Wood Poles;
    - In wet areas, with above 1500 mm rainfall, a pole top inspection of all poles after 15 years and thereafter every five years.
    - In other wet areas, a pole top inspection of all poles after 20 years and thereafter every five years.
    - In dry areas, a pole top inspection of all poles after 30 years and thereafter every five years.

In general pole tops are not refurbished, instead individual components are replaced. Pole top defects identified during the cyclic asset inspections are packaged up on a feeder basis and completed as capital works.

### 8.2.4 Line Conductors and Connectors

Line conductor is visually inspected as a part of the Line Inspection process. In addition, Ergon Energy has a specific asset management plan for line conductor and associated hardware fittings. The key features are:

- Data capture for all conductor to quantify numbers, type, age and condition;
- Undertake a comprehensive thermal imaging survey, implement systems to effectively manage the resulting data and prepare a quantified action plan;
- Replacement of conductor through reconductoring or complete line section replacement; and
- Hardware replacement where conductors are otherwise sound.

### 8.2.5 Underground Cables and Joints

Ergon Energy has prepared a comprehensive management plan for its underground assets, the Under Ground (“UG”) Cable Maintenance Plan. This plan is currently being implemented. The key features are:

- A system to record and analyse cable performance;
- A database covering details of cable type and age linked to performance data. This will be used for forward budgeting of resource requirements to match the impact of cable asset ageing;
- Current knowledge of failure trends and refurbishment techniques for polymeric cables;
- Jointing, maintenance and test standards revision; and
- Strategies to address current gaps in the ability to maintain and repair submarine and sub-transmission cables.

The cable maintenance plan contains 12 programs including replacement and refurbishment actions.

Underground Residential Distribution (“URD”) areas are currently visually inspected through a dedicated program. This is a three year cycle driven by the need for visual inspection of pillars to manage public safety risks and to inspect street light poles in URD areas. Inspections cover:

- Inspection of the cable related above ground assets, pillars and padmount substations;
- Inspection along cable routes for evidence of subsidence;
- Inspection of street light standards; and
- Stand-alone RMU.

A sample number of pillars are internally inspected each year for integrity of connections particularly the neutral.

### 8.2.6 Distribution Transformers

Distribution transformers are one of the most reliable components of the distribution network and are mostly low maintenance items. They also have a long life if not overloaded above their cyclic rating. The consequences of a distribution transformer failure can be significant for industrial and commercial customers.

Pole mounted transformers are inspected as a part of the three yearly line asset inspection program. All pole mounted transformers with major defects are replaced in the field.

Ground mounted, kiosk and indoor substations are inspected every six months where they supply major customers and annually where they supply large commercial or industrial customers. Distribution substations for URD estates are inspected through the three yearly cycle underground asset program.

Ergon Energy has started taking samples for DGA and MDI readings on the larger distribution transformers in an effort to better quantify their condition and loading for the purposes of managing and extending the asset life, reducing risk and reducing major customer interruptions.

Accelerated transformer aging due to moisture is a significant issue for Ergon Energy in some areas because of the tropical operating environment. High moisture levels can cause leaks in seals, rust and mechanical damage. This problem has been recognised and the transformers are routinely monitored for moisture levels where appropriate.

#### 8.2.7 Other Distribution Equipment

Distribution line equipment, customer service lines and street lighting luminaires are visually inspected as a part of the three yearly line asset inspection program and the data is recorded and managed through a SAP based maintenance management system.

Automated equipment is inspected at six monthly intervals and tested at yearly intervals.

Air break switches are maintained on a six year cycle. All new and replacement switches are low maintenance types.

Major road public lighting patrols are conducted on a six monthly basis. Bulk lamp replacement is used for minor road lamps on a four year cycle.

Earth systems are physically inspected and tested every three years for SWER systems and every nine years for other distribution earths.

#### 8.2.8 Zone Substation Transformers

Zone substation equipment is routinely inspected visually and subjected to an infrared image scan every two years. General maintenance and condition monitoring are applied to zone substation transformers as follows:

- Tested and the oil sampled on a two yearly basis;
- Maintenance and servicing (for the transformer and tapchanger) on a four yearly basis; and
- DLA testing of transformer bushings above 66 kV.

Where judged necessary, more frequent condition monitoring of particular transformers is undertaken. Other specialised testing will be done determined by condition.

Ergon Energy has started a program of insulation moisture measurement and assessment as this technique has emerged as a significant tool in estimating the remaining life of oil/paper insulated transformers.

#### 8.2.9 Zone Substation Circuit Breakers

Zone substation equipment is routinely inspected visually and subjected to an infrared image scan every two years. General maintenance and condition monitoring is applied to zone circuit breakers as follows:

- Oil circuit breakers are serviced every four years; and
- Gas or vacuum circuit breakers are serviced every four years.

The current replacement strategy is to replace oil circuit breakers with vacuum or gas circuit breakers which require less maintenance.

Condition analysis has resulted in identifying the circuit breakers in the network that require replacement as a CAPEX program.

#### 8.2.10 Other Zone Substation Primary Equipment

Other zone substation equipment is routinely inspected visually and subjected to an infrared image scan every two years. General maintenance and condition monitoring is applied to general substation plant as appropriate. Instrument transformers have oil sampled and tested every three years.

### 8.2.11 Zone Substation Secondary Equipment

DC systems are inspected as part of the four monthly routine substation inspections. Annual impedance tests for sealed banks and capacity testing to prove end of life for ageing banks are also used. No routine maintenance is performed on battery chargers but new chargers are designed with self analysis and alarms.

Communications cables at control centres, base stations and along optical fibre cable routes are inspected on a routine basis. When remote measurement is unavailable, transmitter output powers are checked and antenna systems operation is measured.

During inspections, routine maintenance is carried out on equipment that requires regular adjustment, for example battery terminals are tightened and cleaned, battery electrolyte topped up, removal of dust, and cleaning of air filters.

Historically there has been no asset management system which has recorded the details and history of protection relays. However, information on protection relays and settings is now being collected, standardised and upgraded through the AIDM. The following inspections are carried out on a four monthly basis:

- Inspection of protection relays, auxiliary relays, meters, indicators, relay flags and alarms on the protection panel;
- Inspection of transducers, panel wiring and terminals; and
- Retrieval of data from protection equipment for investigation and analysis.

The following tests are carried out on a four yearly basis:

- Secondary injection tests on protection relays;
- Checks on Buchholz winding temperature and oil temperature relays;
- Checks on panel meters, winding temperature indicators, oil temperature indicators and transducers; and
- Secondary injection tests on electronic reclosers and sectionalisers if this test feature is available, including functional testing of the protection unit complete with the recloser primary components.

The following routine maintenance is carried out:

- Replacement of recloser trip/close supply batteries every two years;
- Replacement of protection relay internal batteries every four years; and
- Firmware is upgraded on protection equipment as required.

There is a need to develop protection control design and maintenance standards and replacement programs to improve the safety and reliability of the network. This program is currently restricted because of a shortage of staff with these skills. It is recommended that steps be taken to address this to ensure that these systems meet the required standard of reliability.

### 8.2.12 Vegetation Management

In the past, Ergon Energy (and its predecessors) has adopted a reactive, rather than preventative, approach to vegetation management. That is, the vegetation has been trimmed to achieve basic clearance requirements. A policy has now been developed where there is an emphasis on removal of problem vegetation and replacement with trees and planting which will avoid clearance problems in the future. This, together with an awareness program, both for the public and the local councils, has produced very positive results.

In addition to the vegetation clearance responsibilities, it is necessary to maintain access to the overhead lines. This is particularly relevant in the vast areas of country Queensland and the heavily timbered hinterland areas. Tracks, gates and relations with property owners have to be maintained to ensure access at all times for routine inspections and maintenance work. A database of vegetation and tracks is being established, and this will enable better planning in the future.

The current vegetation expenditure is relatively high, due to the removal and replacement program, but this is expected to reduce after two years. At present, the clearing cycle is set at three years. However, in the longer term, an 18 month trimming cycle is planned so that the clearing cycle period can be increased to five years.

Two main contractors are used for all vegetation and track maintenance and significant progress has been made with the establishment of performance standards, reduction of costs and management of the contracts.

## 8.3 Other Maintenance Practices

### 8.3.1 Enterprise Bargaining Agreement

Prior to the last Enterprise Bargaining Agreement (“EBA”) in February 2002, productivity improvements through the EBA process were limited because of the consolidation period since the amalgamation of the six regions. During this period, a levelling strategy was adopted and the seven existing salary structures (including retail) were standardised into a single salary structure. During the last EBA period, there has been a move toward guidelines which allow greater flexibility in working arrangements. Consequently the workforce has become more mobile, demarcation issues have been eliminated and there is now the flexibility to work outside normal hours.

### 8.3.2 Multi-skilling

Many people have multiple skills. Extra skills are rewarded by nominal adjustments in pay structure.

A mix of tradespeople / power workers is used in construction works and to a lesser extent in maintenance. Tradespeople are used in areas such as customer service, fault restoration etc. due to the level of multi-skilling required. For similar reasons, there is a predominance of tradespeople in smaller depots.

### 8.3.3 Live Line Work

Live Line work techniques are being investigated to reduce outages particularly on long rural feeders. This is expected to be costly because of the specialised equipment required and the training involved. This work is only suited to particular tasks, such as crossarm and insulator work. A large proportion of line maintenance would still require a shutdown.

### 8.3.4 Spare Equipment

Spare equipment for overhead and underground assets is generally provided from warehouse stock or from material stored within the depots, and items are ordered as required. The warehouses are located in Cairns, Townsville, Rockhampton, Maryborough and Toowoomba. The material is distributed from these warehouses to the depot or direct to the job site.

Material that is stored in the depots and which has not been allocated to a particular job is managed and co-ordinated within the overall material management process. This includes spares such as transformers, poles, etc which are held for fault restoration or other emergency works.

Zone substation spare equipment does not appear to be managed in a formal way. Although spares are held, each region manages them in different ways and they may not be inspected on a regular basis. The spares for some major substation items (including power transformers, transformer bushings circuit breakers, CTs and VTs) have been (or are in the process of being) catalogued and details are available in the SCAMS database. Compatible spare equipment which is available is then detailed in the substation contingency plans. Other items (including isolators, structures, insulators, trip coils, close coils, parts of CB's etc.) are not catalogued and it is generally up to the local work unit to source these items from local suppliers as required.

Some substation sites in North Queensland (i.e. Townsville, Glenmore and Rockhampton) have introduced a four monthly routine inspection program (managed via SAP) for spare equipment which involves inspection for oil leaks, inspection/replacement of silica gel etc. There are plans to expand this program to cover the Far North and Wide Bay regions.

Because Ergon Energy was formed from six independent distribution corporations, there exists a wide range of equipment types within many of the asset categories, thus making the management of spares a very challenging task. In response to this problem, Ergon Energy now uses a philosophy of standardisation for replacement equipment. Work is also progressing to assess the advantages of consolidating the management of substation spares.

## 8.4 Review of Operating Practices

### 8.4.1 Network Operations Staffing

The Network Operations group is responsible for network planning, control and switching and switching functions. As most network switching is charged to the job it is associated with. The Operations Group expenditure is primarily determined by personnel numbers.

The current staffing levels for the Network Operations Group are summarised in Table 8-1. Despite future plans for the rationalisation of network control functions (see Sections 5.3.2.1and 8.4.2) and increased automation via the SCADA upgrade project, the Network Operations staffing levels are expected to increase by as much as 30% with subsequent offsets in field depots. This is because distribution operational management functions which were previously done out of the local depots will be transferred to the centralised Day Desks. This is a reasonable strategy as it leads to better work efficiency for the local depot staff and uses the more appropriately skilled operations centre staff to do this specialized work. The use of operations centre staff for this activity will also lead to a higher work quality and improved safety. The Consultant is satisfied there are commensurate efficiencies at the local depot level.

**Table 8-1: Network Operations Staffing Levels**

| Group | Function | Employee Numbers |
|---|---|---|
| Control Centre (sub-transmission operation) | 24 hours | 20 |
| Network Operations Outage Coordination | Planning | 9 |
| Network Operations Standards | Rules and regulations for switching; training and authorisation of switching operator contractors | 8 |
| Analysis | Engineering; post event analysis; prevent contingency planning. | 5 |
| Fault analysis | Monitor fault calls, dispatch appropriate resources | 8 |
| Cairns Day Desk | 5 days/wk, manage 22 kV distribution system | 2 |
| Management | Administration | 3 |
| **TOTAL** | | **55** |

### 8.4.2 Control Centre

Following its formation, Ergon Energy had a decentralised control system with major control centres in each of the six regions. While the procedures for sub-transmission access (including live line access) and switching are typically common across the control regions, distribution access and after hours work procedures tend to vary. In response to this problem a Control Centre Strategy was developed with the aim of developing a standard approach for control centres and day desks across the organisation, and to develop an organisational structure for managing switching and access. This strategy was developed by reviewing the current state of the Ergon Energy control system and comparing it against best practice in other distribution organisations.

The recommendation of the Control Centre Strategy was to centralise network control in two Main Control Centres (which are 24 hour operations) located in Townsville and Rockhampton. In addition two co-located Day Desks were proposed for the management of planned and unplanned distribution network access and switching during normal working hours. By centralising the network control in this way, the two groups of Network Controllers (North and South) can work as a single team to manage peak workloads etc. rather than on a purely regional basis.

As part of this Control Strategy, major upgrades to the Ergon Energy DMS and SCADA systems are required as described below.

### 8.4.3 Emergency Procedures

Ergon Energy has procedures and work instructions in place for managing unplanned interruptions. It also has comprehensive plans for managing significant events when a disaster or emergency (e.g. cyclone, severe storm, floods etc.) has been declared.

### 8.4.4 Load Shedding

The National Electricity Code requires the ability to automatically interrupt 60% of expected load demand and manually interrupt at least 60% of load at any given time. Ergon Energy has comprehensive procedures in place for the review and management network load shedding to achieve this requirement.

### 8.4.5 Fault Call Centre

Fault calls to Ergon Energy are received via the National Contact Centre and are managed using the in-house FDRSTAT application as described in Section 5.4.1.1. Ergon Energy also has an Interactive Voice Recording ("IVR") to provide messages to customers during outages. These messages are placed and updated by National Contact Centre staff.

### 8.4.6 Complaint Management

Customer complaints are managed by the FACTS system. This application records complaints using forms including CARS, Customer Feedback Forms, and Compensation Claim Forms. The feedback is forwarded via email to the appropriate staff for acknowledgement and/or actioning.

## 8.5 Operational Budget

The Terms of Reference ("TOR") issued by the QCA require the Consultant to provide an opinion on the efficiency of each DNSP's OPEX forecasts. In assessing efficiency, the Consultant has analysed the data provided, recognising the timeframes available, and has made judgements based on its experience within the industry. The Consultant has used the term "reasonable'' in the assessment of OPEX to convey the view that the expenditure is considered to be efficient, within these limitations (i.e. available data and time).

The OPEX estimates for Ergon Energy are given below in Table 8-3 and Figure 8-1. It is noted that these estimates include forecasts for Prescribed Services including:

- Recoverable works (not subject to legislated provisions);
- Temporary builders supplies;
- Subdivision services; and
- Reconnection/disconnection services.

The expected growth in the Ergon Energy network over the next regulatory period is detailed in Table 8-2. It is interesting to note that while the Ergon Energy customer base is expected to increase by approximately 1.8% p.a. and the network demand is expected to increase by 3.3% p.a., the OPEX forecast remains relatively constant across the regulatory period. This may seem counter intuitive i.e. it is reasonable to expect that OPEX will increase with network size. However, Ergon Energy is focusing on data collection over the next regulatory period to acquire an increased knowledge of the network assets. Once-off efficiency improvements which result from this acquired knowledge can be expected to balance any OPEX increases due to network growth.

It is also noted that there is some discrepancy between the historical OPEX expenditures (2001/02 and 2002/03) reported here and those reported to QCA in the regulatory accounts. This is because adjustments have been made for shared assets and prescribed services in the figures reported to QCA.

Ergon Energy has an extensive network across regional Queensland serving some areas of particularly low density load. Historically there has been insufficient maintenance and inadequate expenditure on asset replacement. The total OPEX expenditure per year is tabled below. The OPEX will peak within the regulatory period as the large asset inspection and vegetation management programs peak.

It should be noted that the costs detailed in Table 8-3 include overheads. However, only direct costs have been included for the individual OPEX categories described in the following sections.

**Table 8-2: Basis of Operational Budget**

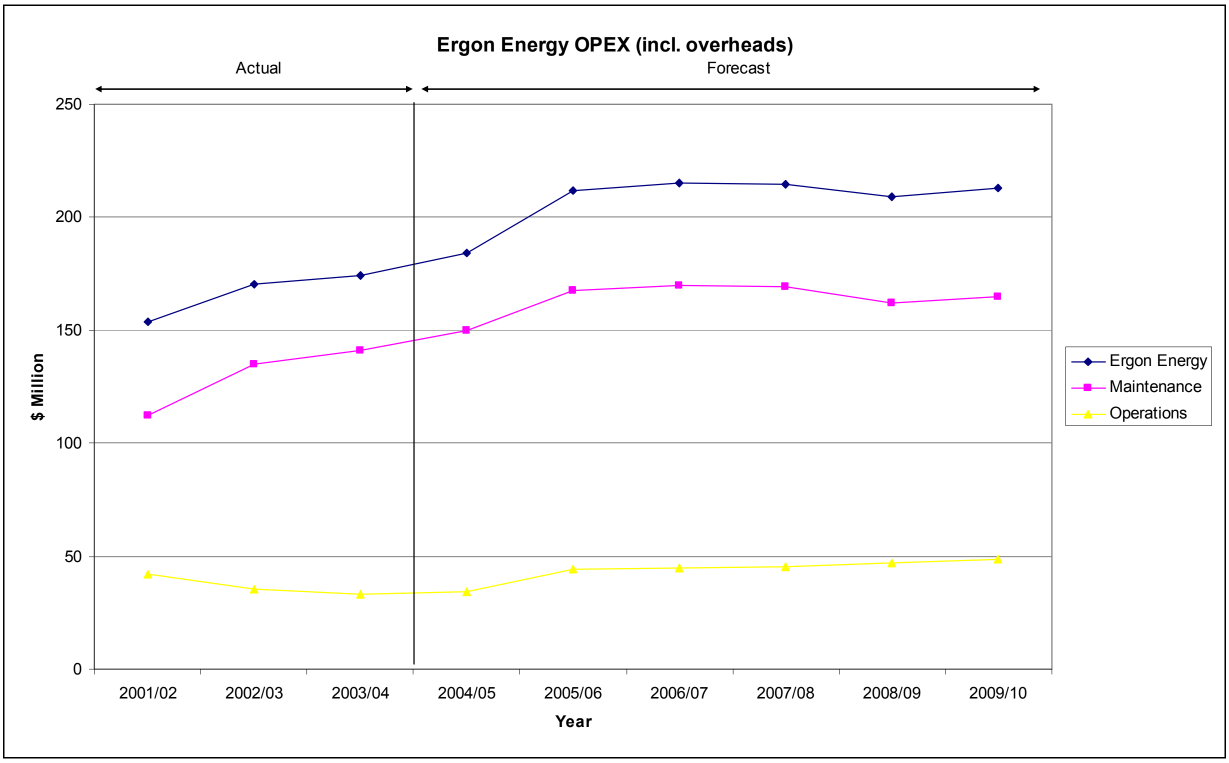
| | | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|---|
| Customers | **No.** | 561,817 | 572,016 | 577,186 | 587,642 | 598,309 | 609,180 | 620,261 | 631,559 |
| Circuit | **km** | 138,372 | 138,372 | 140,863 | 143,398 | 145,979 | 148,607 | 151,282 | 154,005 |
| Max. Demand | **MW** | 2,074 | 2,020 | 2,213 | 2,203 | 2,311 | 2,377 | 2,449 | 2,562 |

**Table 8-3: Ergon Energy's Proposed Operational Budget (incl. overheads)**

| | | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Maintenance** | | | | | | | | | | | |
| Lines | $M | 36.39 | 56.22 | 77.50 | 87.08 | 92.88 | 94.07 | 93.79 | 78.31 | 79.58 | 438.63 |
| Vegetation | $M | 36.14 | 41.60 | 41.26 | 41.40 | 49.05 | 49.36 | 49.11 | 55.77 | 56.28 | 259.57 |
| Substations | $M | 36.71 | 34.48 | 19.92 | 19.21 | 22.65 | 22.97 | 23.03 | 23.82 | 24.39 | 116.85 |
| Meters | $M | 2.79 | 2.71 | 2.34 | 1.98 | 2.92 | 3.52 | 3.56 | 3.90 | 4.49 | 18.39 |
| **Total Maintenance** | **$M** | **112.03** | **135.00** | **141.02** | **149.68** | **167.50** | **169.92** | **169.49** | **161.80** | **164.74** | **833.45** |
| **Operations** | | | | | | | | | | | |
| Network Operations | $M | 8.74 | 9.63 | 10.26 | 12.76 | 11.92 | 11.99 | 11.93 | 12.23 | 12.42 | 60.50 |
| Customer Service | $M | 33.03 | 25.88 | 23.06 | 21.79 | 32.27 | 33.04 | 33.44 | 34.86 | 36.03 | 169.64 |
| **Total Operations** | **$M** | **41.77** | **35.50** | **33.32** | **34.55** | **44.19** | **45.03** | **45.37** | **47.09** | **48.45** | **230.14** |
| **Total OPEX** | **$M** | **153.80** | **170.50** | **174.34** | **184.22** | **211.70** | **214.95** | **214.86** | **208.89** | **213.20** | **1063.59** |
| | $/cust | | 303 | 305 | 319 | 360 | 359 | 353 | 337 | 338 | |
| | $/km | | 1,232 | 1,260 | 1,308 | 1,476 | 1,472 | 1,446 | 1,381 | 1,384 | |
| | $/MW | | 82,209 | 86,304 | 86,979 | 96,095 | 93,011 | 90,392 | 85,295 | 83,215 | |

*All forecast and historical figures are in June 2004 dollars*

**Figure 8-1 Ergon Energy OPEX expenditure (incl. support costs)**



### 8.5.1 Meters

OPEX expenditure on metering was $1.79M in 2003/04 and planned to be $2.67M in 2009/10. As a complete definition of the quantity, type and location of condition problems is not yet available, expenditure on inspections has increased and will stay high for the review period. More rigorous inspection will lead to higher defect rates and increased component replacement.

**Table 8-4: Metering Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Meters | **$M** | 0.98 | 1.79 | 2.18 | 1.88 | 2.20 | 2.23 | 2.37 | 2.67 | 11.36 |

*All forecast and historical figures are in June 2004 dollars.*

A program of upgrading and standardising is in place for current transformer metering and wholesale metering. This is a CAPEX program, and the impact has been included in the OPEX forecasts.

The estimate for meter related OPEX is considered reasonable.

### 8.5.2 Poles

OPEX expenditure on pole inspection and maintenance is projected to be $22.92M in 2003/04 and forecast to be $24.02M in 2004/05. Pole OPEX will remain around $23M until the end of the second line asset inspection cycle in 2008.

**Table 8-5: Pole Inspection Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Poles | **$M** | *n/a* | 22.92 | 24.02 | 23.39 | 23.77 | 24.38 | 14.59 | 14.66 | 100.79 |

*All forecast and historical figures are in June 2004 dollars.*

The inspection cycle will remain at three years until 2008 and then change to a five year cycle. Defect rates have been left unchanged as there are expected to be three balancing effects:

- The defect rate would tend to decrease during the second round of inspections;
- The ageing pole population will result in a higher number of defects; and
- Increased inspection will result in higher number of defects being identified and therefore increased OPEX but will also lower Ergon Energy's risk profile.

The pole population figures are estimates only and no allowance has been made for pole number growth. The quantity values for the inspection period contracts are based on actual values from June 2003 to January 2004 and extrapolated to a 12 month period.

Pole inspection work is outsourced to specialist asset inspection companies. A number of preventative maintenance activities are included in the line asset inspection activity.

The estimate for pole related OPEX is considered to be reasonable considering the adequacy of the available data. Future savings could be assessed once the pole population and condition is fully quantified.

### 8.5.3 Pole Top Structures

OPEX expenditure on pole tops is projected to be $1.62M in 2003/04 and forecast to be $4.47M in 2004/05. The low expenditure prior to 2004/05 suggests that there has not previously been a formal program of pole top inspection. Ergon Energy has now recognised this area as a priority and have implemented a program to rectify this problem. As a complete definition of the quantity, type and location of condition problems is not yet available, expenditure on inspections has increased significantly and will stay high for the review period. More rigorous inspection will lead to higher defect rates and increased component replacement.

**Table 8-6: Pole Top Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Pole Top | **$M** | *n/a* | 1.62 | 4.47 | 7.36 | 7.27 | 7.19 | 7.12 | 7.04 | 35.99 |

*All forecast and historical figures are in June 2004 dollars.*

The estimate for pole top related OPEX is considered to be reasonable considering the adequacy of the available data. Future savings could be assessed once the asset population and condition is fully quantified.

### 8.5.4 Line Conductor and Hardware

OPEX expenditure on conductors and associated line hardware is projected to be $2.82M in 2003/04. This is mainly reactive as a complete definition of the quantity, type and location of condition problems is not yet available. The lack of detailed quantification also shows as a constant annual OPEX allocation of $3.56M per year for 2004/05 onwards.

Ergon Energy will experience a relatively high level of reactive maintenance in the short to medium term for conductor related problems because of the quantity of poor condition conductor. A significant quantity of conductor replacement (reconductoring and rebuilding of short line sections) will be OPEX expenditure because of the Ergon Energy practice for capitalisation. That is, Ergon Energy will not capitalise a project if only a small section of conductor is being replaced. The Consultant is of the view that it would be more appropriate to capitalise all conductor replacements which would result in a reduced OPEX. This issue is discussed further in Section 10.

**Table 8-7: Line Conductor and Hardware Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Line Conductor | **$M** | *n/a* | 2.82 | 3.56 | 3.56 | 3.56 | 3.56 | 3.56 | 3.56 | 17.79 |

*All forecast and historical figures are in June 2004 dollars.*

Generally maintenance of line conductor and associated hardware is viewed as a high priority because:

- Below clearance conductors are a potential public liability; and
- Conductor breakage causes public safety risk and reliability performance in the radial parts of the network is degraded.

The poor condition of some conductors is inhibiting live line work in some locations which in turn degrades the reliability performance and tends to decrease work efficiency and options for other maintenance activities. Considerable CAPEX has been planned to replace the substandard condition conductors in distribution and sub-transmission lines. The impact of this CAPEX spending has been included in the OPEX estimates.

The quantity of overhead line conductor and associated hardware will increase with the increase in new line construction. New conductor will not require any significant increase in OPEX costs over the period, with the level of spending being dominated by the condition of the existing assets.

The estimate for conductor related OPEX appears reasonable based on the lack of data and the risks associated with conductor failure. Future savings would be expected and could be assessed once the asset population and condition is fully quantified.

### 8.5.5 Underground Cables and Joints

The annual OPEX expenditure on underground cables and joints increases from $1.04M in 2003/04 to $2.38M in 2004/05. This step change is primarily due to the increased inspection of underground pillars to meet safety requirements. Between 2004/05 and 2009/10 the OPEX expenditure increases at approximately 1.8% per annum.

**Table 8-8: Underground Cables and Joints Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Underground Cable | **$M** | *n/a* | 1.04 | 2.38 | 2.43 | 2.47 | 2.51 | 2.56 | 2.60 | 12.57 |

*All forecast and historical figures are in June 2004 dollars.*

The quantity of underground cable will increase at a rate greater than demand and connection growth because of the use of underground construction for new residential estates and the undergrounding of selected network sections to improve the security of supply to important public infrastructure in cyclone prone areas.

The major component of the OPEX expenditure is above ground inspection and this will increase with increasing underground assets. The impact of CAPEX expenditure for cable refurbishment and replacement has been appropriately recognised in the estimates.

The estimate for underground cable OPEX is considered reasonable.

### 8.5.6 Distribution Substations

The current annual OPEX expenditure on distribution substations is approximately $0.47M. This expenditure increases by around 45% to $0.68M in 2005/06. This is due to the introduction of condition monitoring tests, such as, DGA and moisture content. Thereafter, the OPEX expenditure increases at a rate less than 1% per annum. This is consistent with the expected growth of distribution substations which is 0.5% per annum.

**Table 8-9: Distribution Substations Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Distribution Substation | **$M** | *n/a* | 0.47 | 0.47 | 0.68 | 0.68 | 0.68 | 0.69 | 0.69 | 3.42 |

*All forecast and historical figures are in June 2004 dollars.*

The population of distribution substations will grow on average at a rate of 0.5% per year between 2005/06 and 2009/10.

### 8.5.7 Other Distribution Equipment

This asset category includes line switchgear, automatic circuit reclosers, regulators, earthing systems, fuses, customer service lines, street lighting and site maintenance.

The OPEX for this category is affected by a number of influences. A complete definition of the quantity, type and location of condition problems is generally not yet available.

Expenditure provision has been on a best estimate basis and remains relatively constant for the review period. More rigorous inspection and data collection is expected to lead to higher defect rates and increased component replacement.

Details of the component programs are given in Appendix.14.7.7.

**Table 8-10: Other Distribution Equipment Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Line Earths | **$M** | *n/a* | 2.96 | 3.70 | 3.69 | 3.69 | 3.43 | 3.31 | 3.24 | 17.37 |
| Line Fuses | **$M** | *n/a* | 4.96 | 4.47 | 4.47 | 4.47 | 4.47 | 4.47 | 4.47 | 22.36 |
| Line ABS | **$M** | *n/a* | 1.56 | 1.59 | 1.59 | 1.59 | 1.34 | 1.35 | 1.37 | 7.24 |
| Line Enc. Switchgear | **$M** | *n/a* | 0.48 | 0.59 | 0.60 | 0.61 | 0.63 | 0.63 | 0.63 | 3.10 |
| Line Regulators, Capacitors and Reactors | **$M** | *n/a* | 0.24 | 0.28 | 0.34 | 0.35 | 0.35 | 0.35 | 0.35 | 1.74 |
| Line Lightning Arrestors | **$M** | 0.17 | 0.18 | 0.19 | 0.19 | 0.21 | 0.22 | 0.23 | 0.24 | 1.09 |
| LV Services | **$M** | *n/a* | 1.86 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 9.99 |
| Street Lights | **$M** | *n/a* | 2.00 | 1.72 | 1.53 | 1.52 | 1.52 | 1.51 | 1.51 | 7.59 |
| Line Sites | **$M** | *n/a* | 2.58 | 2.53 | 2.53 | 2.53 | 2.53 | 2.53 | 2.53 | 12.64 |

*All forecast and historical figures are in June 2004 dollars.*

The estimate for other distribution related OPEX is considered to be reasonable considering the adequacy of the available data. Future savings could be assessed once the asset population and condition is fully qualified.

### 8.5.8 Zone Substation Transformers

OPEX expenditure on zone substation transformer inspection and maintenance is projected to be $1.67M in 200304 and forecast to be $1.61M in 2004/05. OPEX will remain around this level for the review period.

Ergon Energy currently has 563 zone substation transformers and 90 other plant items included in this asset grouping.

**Table 8-11: Zone Substation Transformers Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Zone Substation Transformers | **$M** | 1.76 | 1.67 | 1.61 | 1.65 | 1.65 | 1.65 | 1.66 | 1.67 | 8.28 |

*All forecast and historical figures are in June 2004 dollars.*

For the purposes of determining the replacement date for transformer type assets, a range of diagnostic techniques is applied to quantify the condition of the asset and estimate its expected remaining engineering life. Similarly the optimum refurbishment point for transformer assets is determined from the condition information and financial analysis. Effective condition assessment and asset management for zone substation transformers is a critical OPEX component. Failures of these items generally have a big impact on customer reliability and can involve catastrophic failure.

Transformer tap changer maintenance is still programmed on a fixed time interval basis. This could be changed to a number of operations, plus condition basis, which would introduce some savings into that component of the OPEX.

The estimate for zone substation transformer OPEX is considered reasonable. The Consultant considers that some ongoing savings could be achieved through the introduction of operation plus condition based tapchanger maintenance but such savings would be minimal.

### 8.5.9 Zone Substation Circuit Breakers

OPEX expenditure on zone substation circuit breaker inspection and maintenance is projected to be $1.46M in 2003/04 and forecast to be $1.53M in 2004/05. OPEX will remain around this level for the review period as the impact of circuit breaker replacement on the population of oil circuit breakers will be minor. New and replacement circuit breakers are of the low maintenance type. Reliability Centred Maintenance techniques have been introduced and the benefit of this has been factored in to the OPEX.

**Table 8-12: Zone Substation Circuit Breakers Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Zone Substation Circuit Breakers | $M | 1.73 | 1.46 | 1.53 | 1.59 | 1.58 | 1.58 | 1.58 | 1.55 | 7.88 |

*All forecast and historical figures are in June 2004 dollars.*

The estimate for zone substation circuit breakers OPEX is considered reasonable.

### 8.5.10 Other Zone Substation Site and Equipment

OPEX expenditure on other substation plant and site inspection and maintenance is projected to be $4.50M in 2003/04 and forecast to be $4.76M in 2004/05. OPEX will increase slowly over the regulatory period with the increasing number of new zone substations and the minimal impact of plant replacement on the closer inspection and monitoring of older equipment in this time frame.

**Table 8-13: Other Zone Substation Equipment Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Other Zone Substation Equipment | $M | 1.40 | 1.20 | 1.31 | 1.44 | 1.44 | 1.44 | 1.44 | 1.46 | 7.23 |
| Zone Substation Site | $M | 3.38 | 3.30 | 3.45 | 3.46 | 3.49 | 3.52 | 3.55 | 3.59 | 17.61 |

*All forecast and historical figures are in June 2004 dollars.*

The estimate for zone substation equipment OPEX is considered reasonable.

### 8.5.11 Zone Substation Secondary Equipment

OPEX expenditure on the substation secondary equipment inspection and maintenance is projected to be $5.94M in 2003/04 and forecast to be $5.74M in 2004/05. OPEX will increase slowly over the regulatory period with the increasing quantity of equipment and the minimal impact of plant replacement on the closer inspection and monitoring of older equipment in this time frame.

**Table 8-14: Zone Substation Secondary Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Secondary Equipment | $M | *n/a* | 5.94 | 5.74 | 5.84 | 5.93 | 6.01 | 6.10 | 6.17 | 30.05 |

*All forecast and historical figures are in June 2004 dollars.*

The estimate for zone substation secondary equipment OPEX is considered reasonable.

### 8.5.12 Vegetation Management

OPEX expenditure on vegetation management including access track maintenance is projected to be $26.97M in 2003/04 and forecast to be $29.41M in 2004/05. The vegetation management expenditure will increase significantly from the current level. In the last few years the vegetation management activity has been ramped up in the Northern and Far North Regions enabling these regions to now manage clearing to an optimum cycle of one year for urban areas and three years for rural feeders. This is not the case for the Central and Southern Regions where increased activity and expenditure is required to catch up.

Ergon Energy has capped spending in the period 2004/05 to 2007/08 because of expected resource constraints. However, the Consultant does not necessarily agree with this view because Vegetation Management is primarily managed by outside contractors. The issues associated with resourcing proposed OPEX work are discussed further in Section 11.

**Table 8-15: Vegetation Management Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Vegetation Management | $M | 25.78 | 26.97 | 29.41 | 29.41 | 29.41 | 29.41 | 32.60 | 32.38 | 153.21 |

*All forecast and historical figures are in June 2004 dollars.*

The estimate for vegetation management OPEX is considered reasonable.

### 8.5.13 Operations

Network operations expenditure is largely driven by personnel numbers. The centralisation of some distribution network operations functions from depot level to region level will cause an increase in expenditure in this category. This is viewed as an improvement in the overall efficiency of the network operations. The commensurate savings would occur under the relevant OPEX asset category (poles, distribution substation, line switches etc), however the available data is not presently accurate enough to see these savings.

Implementation of the control centre structure will require some additional personnel during the various transitions involved.

**Table 8-16: Operations Operational Budget (excl. overheads)**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Network Operations | $M | 6.30 | 6.70 | 7.14 | 6.85 | 6.93 | 6.89 | 7.03 | 7.11 | 34.81 |
| Customer Service | $M | 16.92 | 15.07 | 15.35 | 18.55 | 19.08 | 19.32 | 20.05 | 20.62 | 97.62 |

*All forecast and historical figures are in June 2004 dollars.*

## 8.6 Efficiency Assessed Against Industry Standards

A comparison of Ergon Energy's actual operating expenditure for the 2002/03 period with the operating expenditure of other DNSPs is shown in Table 8-17. Considering the large geographical area of Ergon Energy and the low density, Country Energy is the only utility where a reasonable comparison can be made. It is noted that the OPEX / circuit km ratio of these two DNSPs are very similar. The OPEX / customer ratio for Ergon Energy is higher than that for Country Energy which is expected given Ergon Energy's lower customer density. Ergon Energy's OPEX / GWhr ratio compares favourably with that of Country Energy in spite of a lower customer density.

If consideration is given to travelling costs, a considerable amount of time and cost is contained in the operating expenditure. This has been estimated at $67.9 mill for 2003/04 for work parties and staff. Ergon Energy can therefore be considered to be reasonably efficient when compared to Country Energy which covers a smaller area and is likely to have significantly lower travel costs.

**Table 8-17: Comparison of the Actual OPEX in 2002/03 with Comparable Expenditure of other DNSPs.**

| | OPEX ($M) | No. of Customers (M) | GWHr | Circuit km | OPEX / Circuit km | OPEX / customers | OPEX / GWHr |
|---|---|---|---|---|---|---|---|
| **Ergon Energy** | **165.70** | **0.52** | **13,251** | **143,000** | **1,159** | **322** | **12,504** |
| **Country Energy** | 192.85 | 0.72 | 9,965 | 169,167 | 1,140 | 268 | 19,500 |
| **Energex** | 120.98 | 1.13 | 17,936 | 41,146 | 2,940 | 110 | 6,745 |
| **AGL** | 40.40 | 0.27 | 3,988 | 7,041 | 5,738 | 152 | 9,890 |
| **UE** | 75.62 | 0.58 | 7,108 | 12,198 | 6,199 | 130 | 10,650 |
| **Energy Australia** | 254.00 | 1.49 | 25,402 | 44,014 | 5,771 | 213 | 12,500 |
| **Powercor** | 74.80 | 0.60 | 9,376 | 84,000 | 890 | 125 | 6,189 |
| **CitiPower** | 46.83 | 0.26 | 5,336 | 3,919 | 11,949 | 177 | 11,478 |
| **TXU** | 84.04 | 0.54 | 6,469 | 28,000 | 3,001 | 155 | 12,883 |

## 8.7 Relationship Between Demand Growth and OPEX

Leaving aside the issue of efficiency gains, it can be expected that there will need to be a modest increase in OPEX over time due to growth in the size of the network. This can be related to both growth in customer numbers and growth in demand. Historically, there has not been a strong relationship between Ergon Energy's OPEX and growth in customer numbers or maximum demand. The Consultant considers that levels of OPEX are driven more by the age, condition and type of the various elements of the network. Improved knowledge of the quantity and condition of network assets is projected to be the major contributor to variations in OPEX.

### 8.7.1 Relationship Between Customer Numbers & OPEX

Changes in the growth rate of customer numbers will directly affect the expenditure required in the following Ergon Energy categories:

- LV Services;
- Public Lighting;
- Meters; and
- Customer Service.

Table 8-18 shows that the annual increase in customer driven OPEX over the five year review period varies between 1.0% and 3.4% with an average value of approximately 2.4%. This is relatively consistent with the expected customer growth of 1.8%. Figure 8-2 confirms a strong relationship between customer numbers and customer driven OPEX for Ergon Energy's forecast expenditure. However, this relationship is not reflected in historical and current data. This is in part because it is not possible to isolate all customer driven costs (e.g. streetlights and LV services) in the historical data which has been provided.

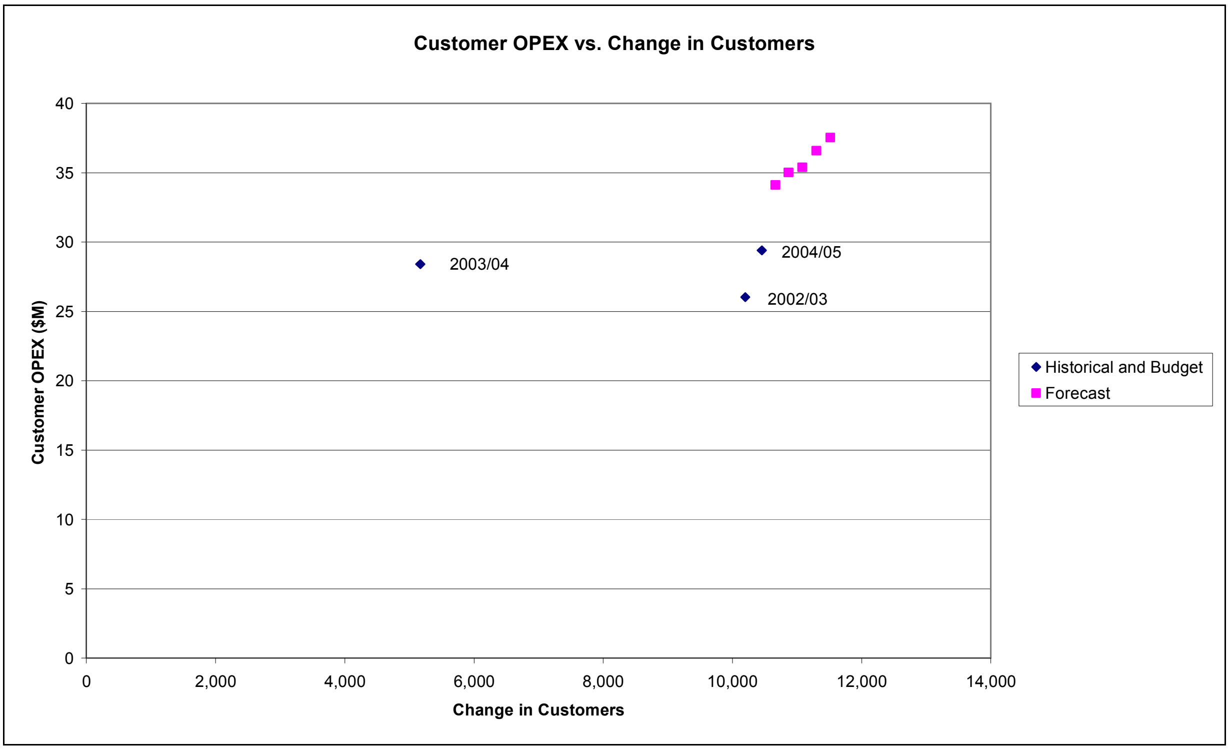
It should also be recognised that the total OPEX for these customer related categories is approximately $178.7M over the five year review period. This value corresponds to only 20% of the total forecast OPEX expenditure. Therefore, it is concluded that there is not a strong relationship between Ergon Energy's total OPEX expenditure and growth in customer numbers.

**Table 8-18: Customer Driven OPEX Budget**

| | | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|
| Customer Driven OPEX | **$M** | 34.13 | 35.03 | 35.40 | 36.60 | 37.55 | 178.71 |
| (Consultant Forecast) | **% Change** | | 2.64 | 1.05 | 3.40 | 2.61 | |

*All forecast figures are in June 2004 dollars.*

**Figure 8-2 Changes in Customer Numbers vs OPEX**




### 8.7.2 Relationship Between Maximum Demand & OPEX

It is expected that changes in the maximum demand growth will affect the expenditure required in a range of Ergon Energy's OPEX categories including:

- Distribution and Transmission Overhead Feeders;
- Underground Cables;
- Distribution Poles and Pole Tops;
- General Distribution Equipment;
- Zone Substation Primary Equipment; and
- Network Operations.

The total OPEX expenditure forecast by Ergon Energy for these categories is approximately $312.2M over the review period as shown in Table 8-19. It can be seen that there is a significant step decrease in OPEX between 2007/08 and 2008/09. This step change is related to the change from 3 year cycles to 5 year cycles for line asset inspections. Otherwise, the annual increase in OPEX varies between 1.0% and 1.8% which is approximately half the forecast MD growth of 3.3%.

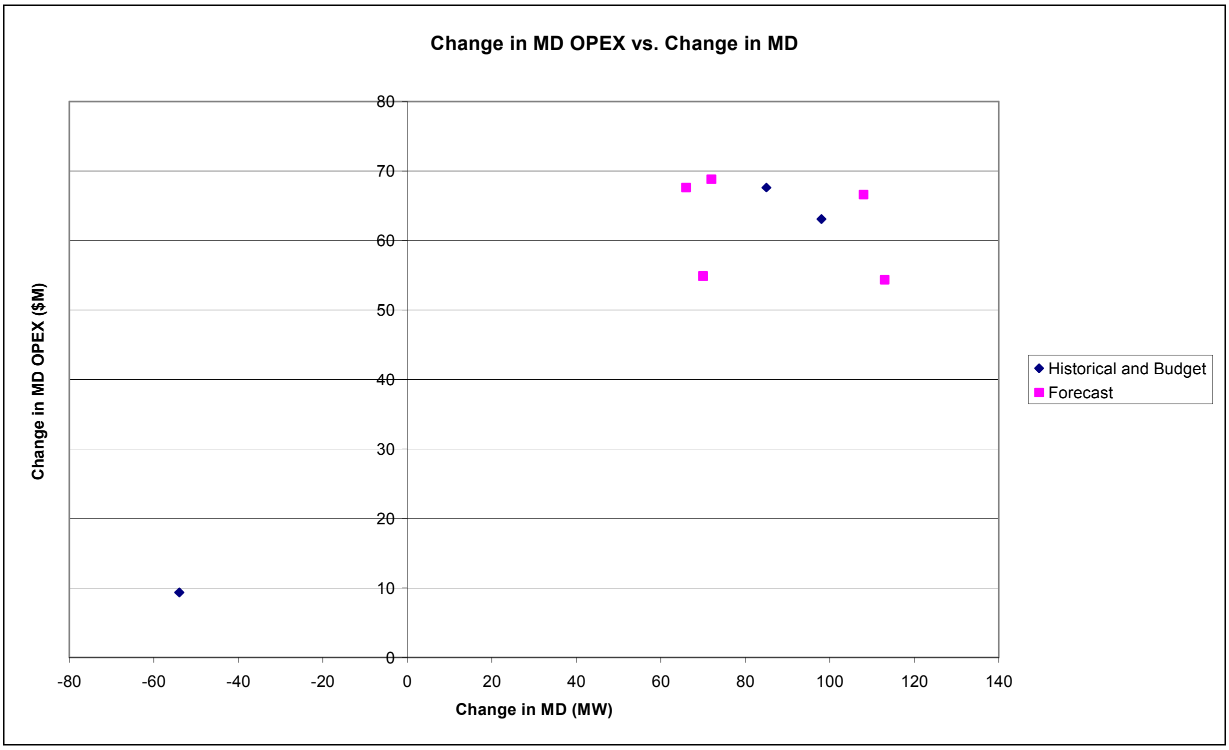
Figure 8-3 confirms that there isn't a strong relationship between MD driven OPEX and MD growth. This is because the relationship between demand growth and OPEX expenditure is not a direct one and is influenced by a range of factors. In particular, new plant items typically have lower maintenance costs than older plant items.

**Table 8-19: Maximum Demand Driven OPEX Budget.**

| | | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|
| MD Driven OPEX (Consultant Forecast) | **$M** | 66.60 | 67.61 | 68.80 | 54.33 | 54.86 | 312.19 |
| | **% Change** | | 1.52 | 1.76 | -21.03 | 0.97 | |

*All forecast figures are in June 2004 dollars.*

**Figure 8-3 Changes in Maximum Demand vs OPEX**




## 8.8 Impact of Differences Between Forecasts

The demand forecasts have been separately reviewed by MMA who have forecast peak demands, energy consumption and customer numbers. MMA have predicted a 3.6% average growth in MD over the forecast period compared to Ergon Energy's predictions of 3.3%. Similarly, MMA has predicted a 1.6% average growth in customer numbers compared to 1.8% predicted by Ergon Energy.

The Consultant has estimated that the difference in the forecast MD equates to an increase in Ergon Energy's estimates over the period 2005/06 to 2009/10 of approximately $0.9M for MD related categories and a decrease of approximately $2.5M for customer related categories. To determine the new estimates for the MD related categories, an escalation factor of 1.8% has been applied. This value is equal to half the MD growth predicted by MMA. However the step change associated with the revised inspection cycles has been maintained.

Clearly, the variations associated with the differences between forecasts are insignificant in relation to the total OPEX budget but this is expected given the relatively weak relationships that exist between OPEX and these quantities.

## 8.9 Efficient OPEX Program 2005/06 to 2009/10

Ergon Energy has a range of efficiency savings factored in to the OPEX forecast based on the impact of effective rationalisation of the six legacy systems into a single system. Nevertheless, the Consultant has identified a small number of additional savings which may result from improved efficiencies. These include:

- The Consultant has identified a number of asset categories where the inspection and planned maintenance intervals are shorter than industry standards (refer to Table 14-1). Small savings can be made by extending these inspection intervals in line with industry standards.
- The Consultant is of the opinion that significant efficiency gains will be made as Ergon Energy moves towards RCM, particularly in zone substation maintenance. However, given that the implementation of RCM requires the collection of a significant amount of data, it is likely that only a small fraction of these gains will be seen over the next regulatory period.
- Potential savings can be achieved by obtaining the full benefit of the EBAs that have been agreed but have not been fully implemented. These include flexibility of working hours and multi-skilling.
- A significant proportion of Ergon Energy's OPEX expenditure is associated with travelling costs. While Ergon has made a number of scheduling improvements which have reduced travel costs (e.g. carrying out line asset inspections on a feeder basis) it is likely that further gains could be made in the scheduling of zone substation maintenance work in particular.
- It can be expected that Ergon Energy's increased CAPEX spending will result in improved reliability. Consequently the required emergency repair expenditure should be reduced.

It is noted that Ergon Energy do not use an activity based costing method. If this type of system was implemented it is likely that further efficiencies in maintenance costs would be achieved. Activity based costing will allow a closer focus on the actual costs of doing tasks and enable efficiency improvements in OPEX.

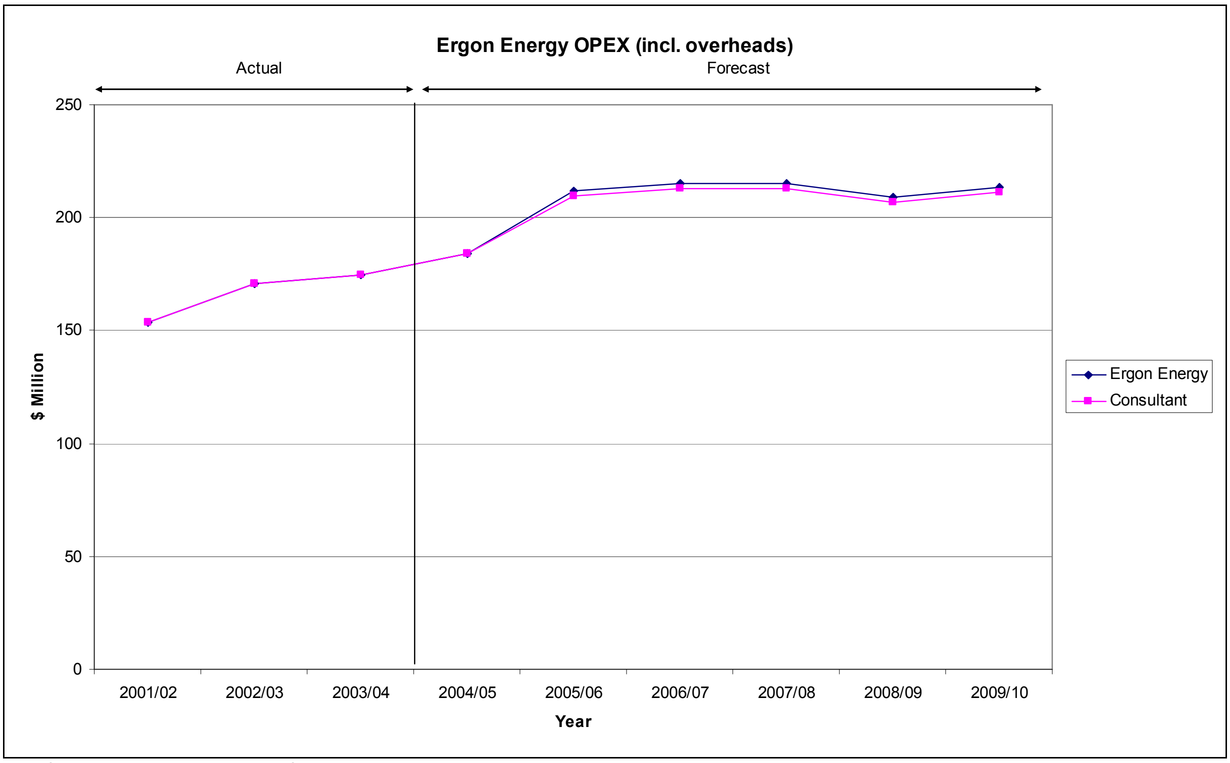
Given the uncertainty in available asset data which has previously been discussed (refer to Section 6.4), it is difficult to quantify the potential savings which result from efficiency improvements. Furthermore, the efficiency gains are likely to be partially offset by increasing labour and contract costs due to the scarcity of skilled electricity industry personnel. Taking these factors into account, the Consultant considers that a saving of 1% p.a. in the OPEX budget is reasonable. This corresponds to a saving of approximately $10.6M over the five year review period as shown in Table 8-20 and Figure 8-4. It should be noted that this level of saving will possibly be masked by variations caused by data uncertainties.

**Table 8-20: Ergon Energy and Consultant's Consolidated OPEX (incl. overheads)**

| | | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|
| | | | | **ERGON ENERGY** | | | |
| **Maintenance** | | | | | | | |
| Lines | $M | 92.88 | 94.07 | 93.79 | 78.31 | 79.58 | 438.63 |
| Vegetation | $M | 49.05 | 49.36 | 49.11 | 55.77 | 56.28 | 259.57 |
| Substations | $M | 22.65 | 22.97 | 23.03 | 23.82 | 24.39 | 116.85 |
| Meters | $M | 2.92 | 3.52 | 3.56 | 3.90 | 4.49 | 18.39 |
| **Total Maintenance** | **$M** | **167.50** | **169.92** | **169.49** | **161.80** | **164.74** | **833.45** |
| **Operations** | | | | | | | |
| Network Operations | $M | 11.92 | 11.99 | 11.93 | 12.23 | 12.42 | 60.50 |
| Customer Service | $M | 32.27 | 33.04 | 33.44 | 34.86 | 36.03 | 169.64 |
| **Total Operations** | **$M** | **44.19** | **45.03** | **45.37** | **47.09** | **48.45** | **230.14** |
| **Total OPEX** | **$M** | **211.70** | **214.95** | **214.86** | **208.89** | **213.20** | **1063.59** |
| | | | | **CONSULTANT** | | | |
| **Maintenance** | | | | | | | |
| Lines | $M | 91.95 | 93.13 | 92.86 | 77.53 | 78.78 | 434.24 |
| Vegetation | $M | 48.56 | 48.87 | 48.62 | 55.21 | 55.72 | 256.98 |
| Substations | $M | 22.42 | 22.74 | 22.80 | 23.58 | 24.15 | 115.68 |
| Meters | $M | 2.89 | 3.49 | 3.52 | 3.86 | 4.45 | 18.21 |
| **Total Maintenance** | **$M** | **165.83** | **168.22** | **167.79** | **160.18** | **163.09** | **825.11** |
| **Operations** | | | | | | | |
| Network Operations | $M | 11.80 | 11.87 | 11.81 | 12.11 | 12.30 | 59.89 |
| Customer Service | $M | 31.95 | 32.71 | 33.10 | 34.51 | 35.67 | 167.94 |
| **Total Operations** | **$M** | **43.75** | **44.58** | **44.92** | **46.62** | **47.97** | **227.84** |
| **Total OPEX** | **$M** | **209.58** | **212.80** | **212.71** | **206.80** | **211.06** | **1052.95** |

*All forecast and historical figures are in June 2004 dollars*

**Figure 8-4: Ergon Energy and Consultant's Total OPEX**




*All forecast and historical figures are in June 2004 dollars*

# 9 CAPITAL INVESTMENT REVIEW

## 9.1 Purpose and Scope of Section

This section considers the current capacity of the network, growth predictions, the requirements for asset replacements, a detailed review of capital projects and the procedures for assessing capital expenditure. Based on the foregoing and the comparisons to best practice contained in Section 5.6, a revised CAPEX program is recommended by the Consultant.

## 9.2 Ergon Energy's Procedures for Assessing Capital Expenditure

The procedures for approval and prioritisation of capital expenditure are as follows:

### 9.2.1 Financial Budgets & Long Term Forecasts

The planning processes that feed into the preparation of the long term forecasts and budgets are described in Section 5.5.1.The initial stage of the annual augmentation capital works program is the preparation of Regional Five Year Sub-transmission Network Augmentation Plans. These plans identify the items on the network that are projected to exceed their limits and propose projects to overcome the limitations. Included in the considerations are load control systems, reactive compensation, embedded generation, the impact on Powerlink's transmission system and the impact of potential major customers.

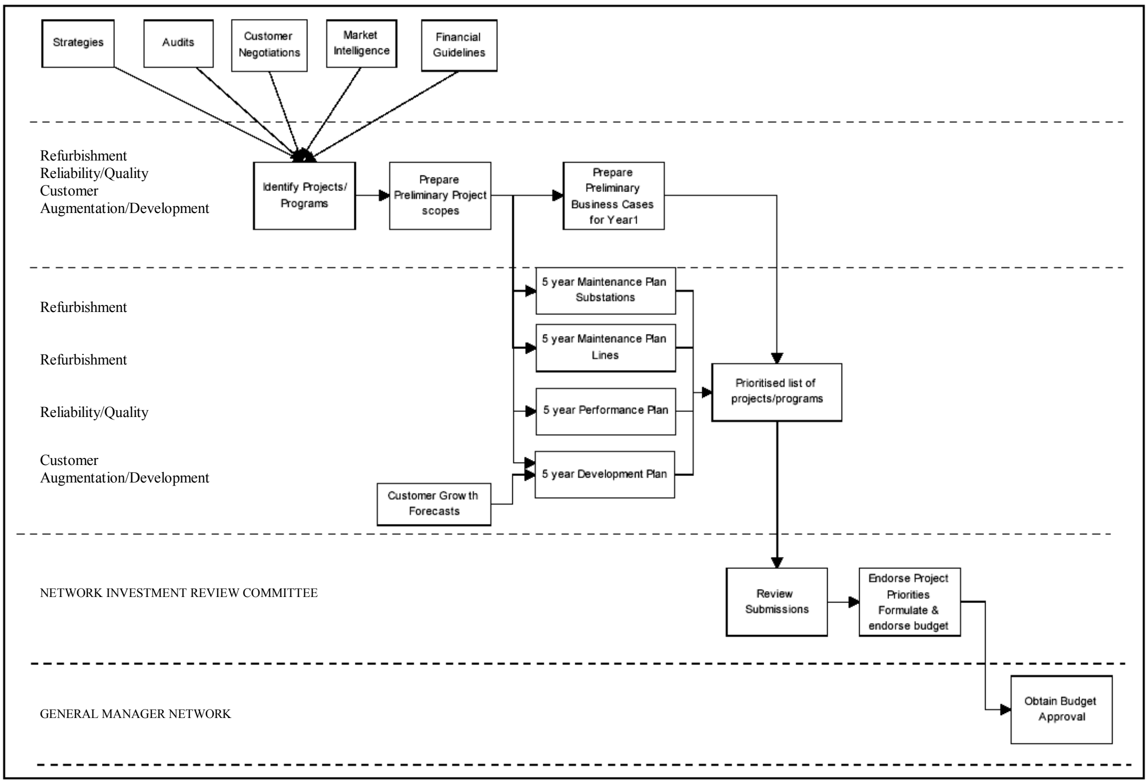
At the HV feeder level, the annual Capability Review and Five Year Distribution Augmentation Plans for each Region identify the distribution feeder constraints and propose projects to overcome the constraints. These are further supported by more detailed Distribution Planning Studies.

Ergon Energy has recently prepared a Network Assets Maintenance and Replacement Plan, covering the next 15 years. The plan includes detailed asset-by-asset plans which consider risk, safety, cost and reliability outcomes. This plan forms the basis for forecasting and budgeting for asset replacement (as well as maintenance) and is discussed further in Section 9.9.1.

Forecasts and budgets for customer initiated work are developed in three main segments – subdivisions, industrial/commercial and major customers, based on historical trends, economic factors and specific information available from local and State Government. The budgets for subdivisions and industrial/commercial projects can be more readily prepared, based on the projected physicals and average costs. Major projects present a high level of uncertainty due to project timing, project lives and project locations (often in remote areas). This issue is discussed further in Section 9.9.3.

The budget formulation process is shown in Figure 9-1.

**Figure 9-1: Budget Formation Process**




### 9.2.2 Project Prioritisation

Ergon Energy utilises a project risk analysis tool to rank projects. The Regional Asset Managers collectively assign a rating for each project, with the process going through several iterations. Strategic perspectives and resource availability are also considered. This process works well for ranking projects within a project group but is difficult to apply across project streams.

The Consultant considers that the approach to project prioritisation should be improved to enable a more rigorous assessment of the relative merits of various projects, with the capability of application across project streams.

### 9.2.3 Project Approval Process

Like other electricity distributors, Ergon Energy has large numbers of small projects and relatively small numbers of large projects. Smaller projects are authorised locally by Region Asset Managers, in accordance with Ergon Energy's Schedule of Delegated Financial Authorities.

Projects in excess of $100,000 for Corporate Initiated or $250,000 for Customer Initiated are referred to the Network Investment Review Committee ("NIRC") for endorsement, prior to authorisation at the appropriate level. The NIRC is a sub-committee of the Corporate Investment Review Committee ("IRC"). As such it forms an integral part of the Ergon Energy expenditure and infrastructure investment management process.

The NIRC acts across the following four steps of the investment management process:

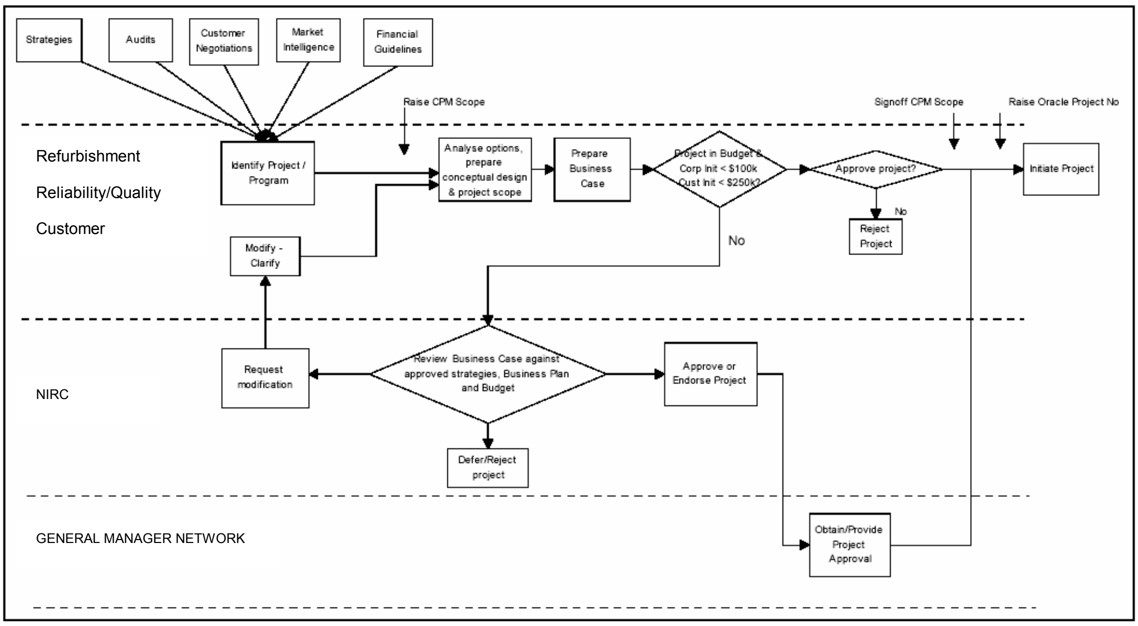
- The generation of investment proposals;
- The evaluation and selection of those proposals;
- The approval and control of expenditure, and
- The post completion audit of investment projects (the NIRC has not yet been active in this area).

The NIRC is charged with facilitating the efficient and effective management of the capital and operating expenditure of the Network Group in accordance with the Business Plan. Such expenditure includes all Network and Customer Initiated capital projects, asset replacement/refurbishment programs for network and generation assets, preventative and corrective maintenance programs, and operational projects.

NIRC authority is limited to review and endorsement of the capital works and operating programs under the responsibility of Network. Final approval of the capital works and operating program rests with the General Manager Network.

The process for project approval is shown in Figure 9-2.

**Figure 9-2: Project Approval Process**



### 9.2.4 Conclusions

From the review of capital projects (as discussed in Section 9.5), the Consultant observed that the project approval process is largely being followed, but noted a few exceptions. The Consultant considers that the process would be enhanced by a more rigorous approach to the preparation of project justifications, through the more comprehensive economic evaluation of alternatives (including life cycle costs) and quantified risk assessment, and by the completion of all supporting material and filing it in comprehensive and structured project files.

Ergon Energy needs to implement an improved process for project prioritisation to ensure that capital spending is optimised.

For every project, regardless of size, it is essential that a reconciliation be conducted after project completion to review costs and achievement of the project objectives. For each major project, a formal Post Implementation Review should be conducted to evaluate whether the costs and benefits projected in the business case were realised. Such reviews, whether for minor or major projects, provide the opportunity for learning and improvement (e.g. revisions to the estimating rates).

These modifications to the approval process would provide an enhanced level of rigour and improve the likelihood that capital expenditure is optimised.

## 9.3 Capital Expenditure Categories

Ergon Energy splits its capital expenditure into the categories shown in Table 9-1.

**Table 9-1: Capital Expenditure Categories**

| LEVEL 2 | BUSINESS UNIT | CATEGORY | QCA CATEGORY |
|---|---|---|---|
| CORPORATE INITIATED WORKS | AGEING ASSET REPLACEMENT | DISTRIBUTION | ASSET REPLACEMENT |
| | | SUBTRANSMISSION | |
| | | TRANSMISSION | |
| | AUGMENTATION | SUBTRANSMISSION | DEMAND RELATED |
| | | TRANSMISSION | |
| | | DISTRIBUTION LOAD GROWTH | |
| | LOAD ENERGY MANAGEMENT | LOAD ENERGY MANAGEMENT | |
| | NETWORK REFURBISHMENT | LINE REFURBISHMENT | ASSET REPLACEMENT |
| | OTHER | DISTRIBUTION OTHER | OTHER |
| | | SUBTRANSMISSION OTHER | |
| | | TRANSMISSION OTHER | |
| | | ENVIRONMENTAL CLEAN UP | |
| | | SECURITY | |
| | | EMERGING RISK | |
| | RELIABILITY | DISTRIBUTION RELIABILITY IMP | RELIABILITY/QUALITY IMPROVEMENT |
| | | SUBTRANSMISSION RELIABILITY IMP | |
| CUSTOMER REQUESTED WORKS | COMMERCIAL & INDUSTRIAL | COMMERCIAL & INDUSTRIAL | DEMAND RELATED |
| | DOMESTIC & RURAL | DOMESTIC & RURAL | |
| | OTHER | METERING | |
| | | PUBLIC LIGHTING | |
| | | SUBDIVISIONS | |
| | | SPECIAL CONDITIONS | |
| FIXED ASSETS ACQUISITIONS | CHANGE PROGRAMS | CM - CORPORATE | OTHER |
| | | CM – LINE MANAGED | |
| | COMPUTER FACILITIES | BUSINESS SYSTEMS | |
| | | BS&P LINE | |
| | | FIXED ASSETS | |
| | | HUMAN RESOURCES | |
| | | FIXED ASSETS | |
| | LAND& BUILDINGS | PROPERTY | |
| | OTHER | FIXED ASSETS | |
| | | WHOLESALE MARKET GROUP | |
| | | PROPERTY | |
| | | FIXED ASSETS CONTRACT SERVICES | |
| | VEHICLES & MOBILE PLANT | FIXED ASSETS FIELD OPS | |
| OTHER SYSTEM ASSETS | OTHER SYSTEM ASSETS | SYSTEM WORKS | |

There appears to be a good alignment between the categories used by Ergon Energy and those required by the QCA.

## 9.4 Current & Projected Growth and Capacity

The current regulatory determination was based on a Maximum Demand ("MD") growth rate forecast averaging 3% pa over the regulatory period. This compares with an actual average growth over the first three years of the period of 6.6% pa (4.6% pa temperature corrected), as shown in Figure 9-4. The volatility of maximum demand since 1993/94 is also apparent in Figure 9-5, with several reductions and large increases evident.

**Figure 9-3: Customer Numbers Growth Rate – Ergon Energy Forecasts**

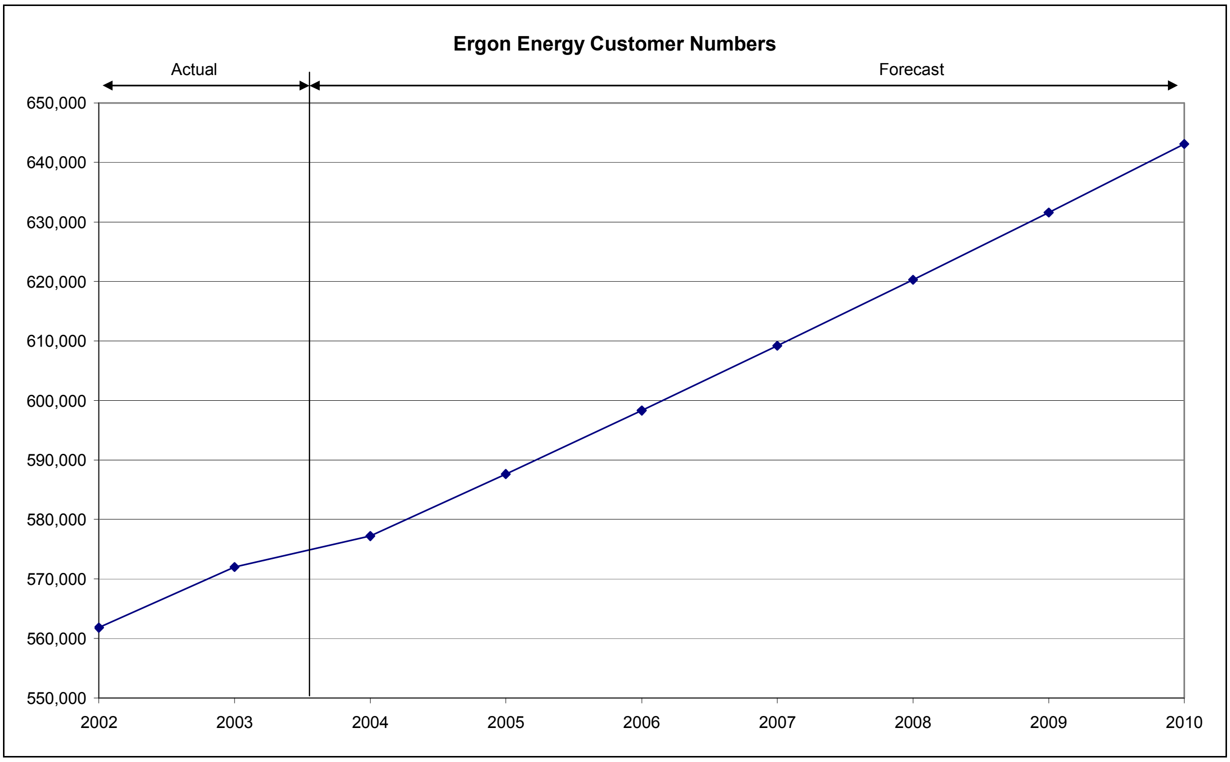


**Figure 9-4: Maximum Demand Growth Rate - Ergon Energy Forecasts**

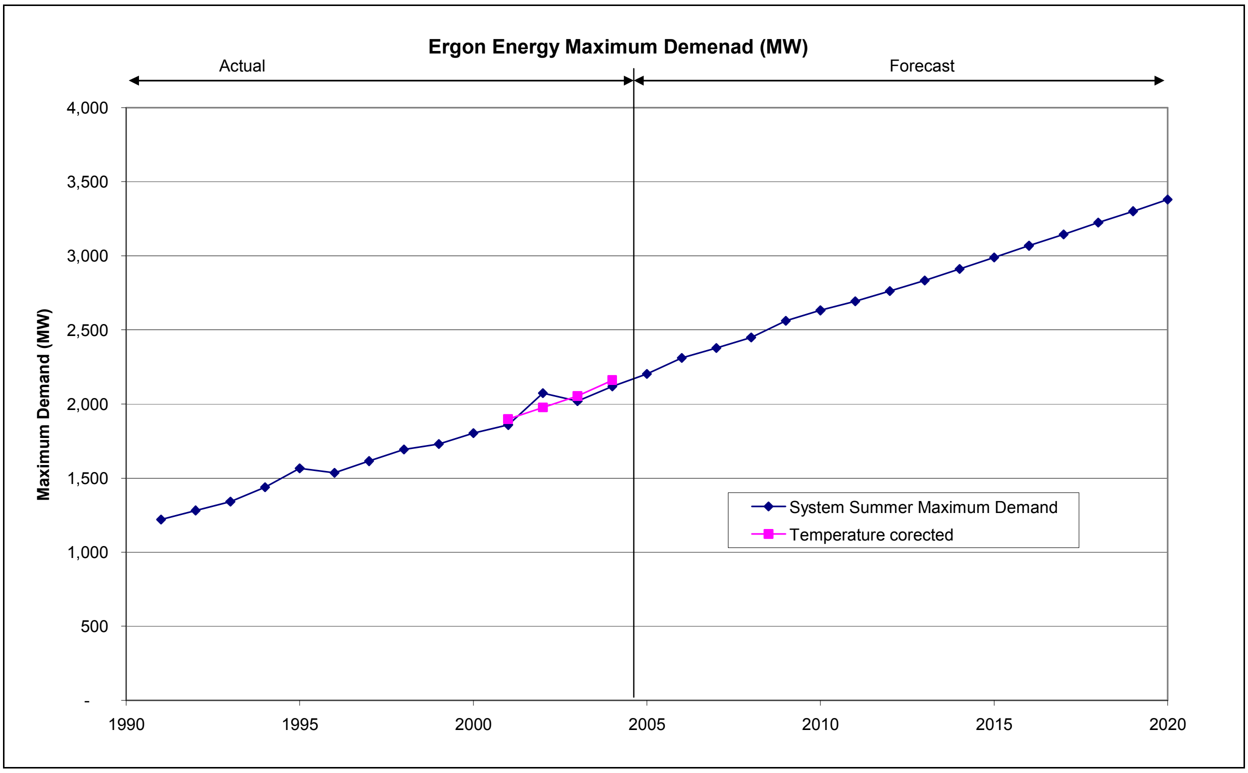
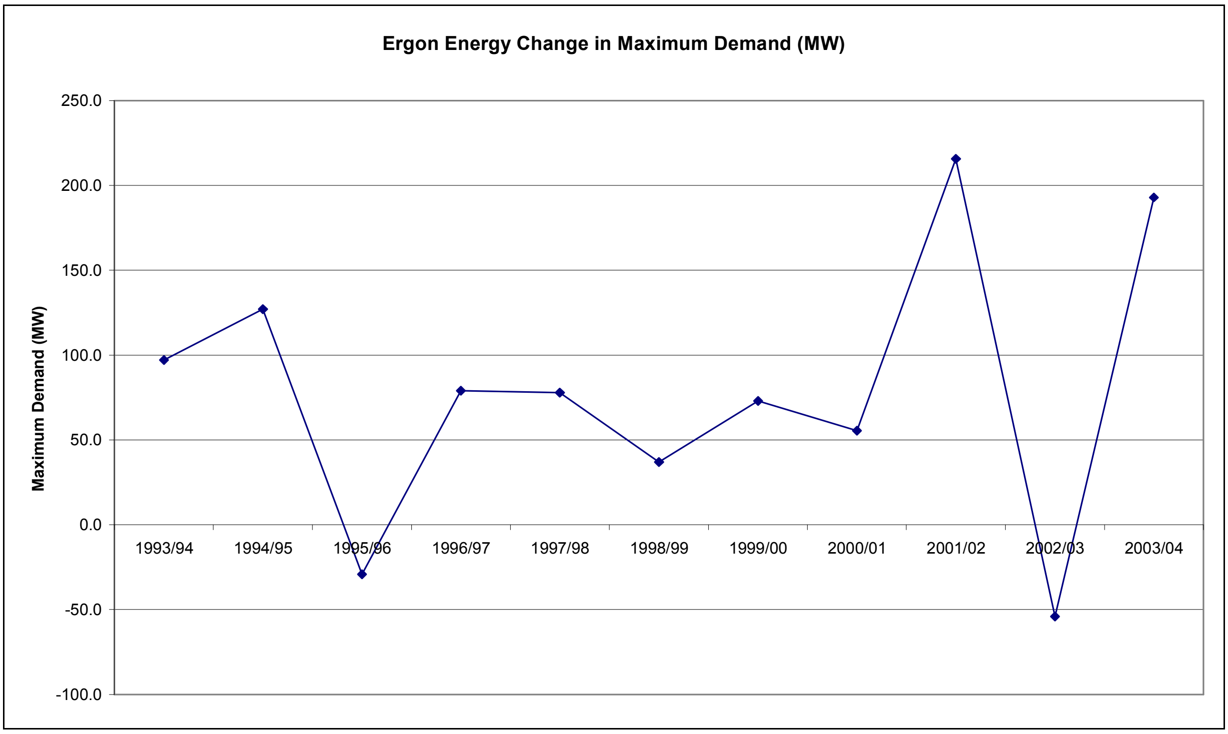



**Figure 9-5: Change in Maximum Demand Growth Rate - Ergon Energy Actuals**




Ergon Energy attributes the significant increases in growth rates to the penetration of air conditioning, and predicts that this will continue for the next few years. MD growth rates are predicted by Ergon Energy to be an average of 3.7% p.a. over the next regulatory period. The growth forecasts have been separately reviewed by MMA who have forecast peak demands, energy consumption and customer numbers. The results of this review are discussed in section 9.4.3.

Changes to the growth rate (as measured by customer numbers and MD) will result in changes to the requirement for capital spending.

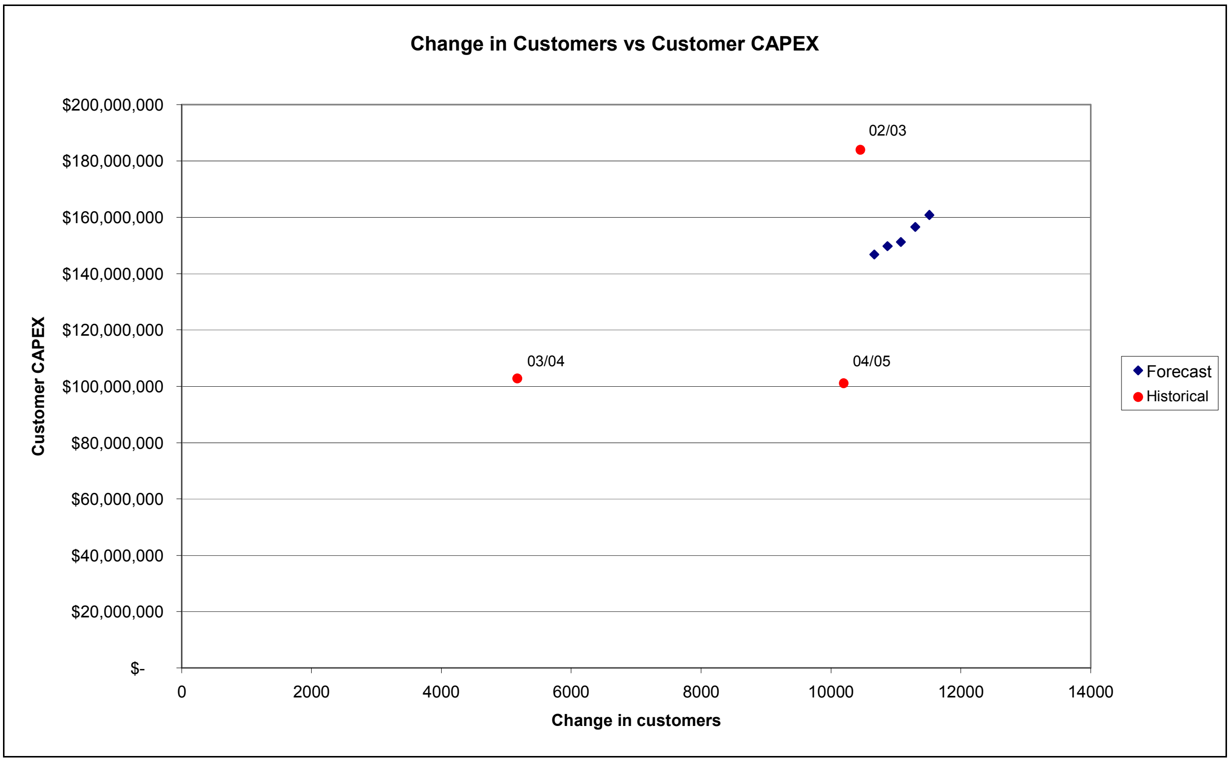
### 9.4.1 Relationship Between Customer Numbers & Customer Related CAPEX.

Changes to the growth rate of customer numbers will result in immediate changes to expenditure required in the following Ergon Energy categories:

- Domestic & Rural;
- Commercial & Industrial; and
- Other Customer Requested.

The values of Customer CAPEX and change in customer numbers are shown in the following graph:

**Figure 9-6: Changes in Customer Numbers vs Customer CAPEX**




Ergon Energy has not been able to provide consistent customer numbers for 2000/01, so the Consultant was unable to compute the increase in customer numbers for 2001/02. This has limited the amount of analysis that can be performed and the conclusions that can reasonably be reached. These three points are wide spread and the differences may be attributed to factors such as differing work performed, quantity of new customers and differing accounting/category allocations. Although the data is limited, an “order of” cost per new customer of approximately $14,000 can be deduced.

In spite of these limitations, several conclusions can be drawn:

- The forecast points are all tightly grouped - this would indicate a consistent expenditure per new customer is proposed.
- The future points all lie within the boundaries of the historical points, in particular the points for the years 2002/03 and 2004/05.

Thus, whilst not conclusive, the analysis would indicate that the customer CAPEX proposed is consistent with the forecast number of new customers being connected to the network.

The cost per new customer for the Victorian distributors over the current Determination period has been analysed. Ergon Energy is more expensive than Powercor ($5,500 per new customer) and TXU ($8,100 per new customer) which is to be expected given the nature of Ergon Energy’s network.

### 9.4.2 Relationship Between MD & Demand Related CAPEX

Changes to the growth rate of maximum demand will result in changes to the expenditure required in the following Ergon Energy categories:

- Augmentation; and
- Load & Energy Management.

The values for temperature corrected maximum demand have been made available for years 2000/01 to 2003/04. These have been used in place of the measured maximum demand in order to remove any temperature related irregularities and allow more meaningful comparisons in demand related expenditure.

The relationship between changes in the growth rate of maximum demand and Demand Driven CAPEX are not as straight forward as that between changes in growth of customer numbers and Customer Initiated CAPEX, due to uncertainties in the timing of the required CAPEX to meet the increased demand. In some cases, work will be required immediately, but in other cases there may be sufficient spare capacity to cope with the increased demand, deferring the need for increased CAPEX for many years.

Whilst Ergon Energy was able to supply maximum demand values back to the year 1991, consistent historical CAPEX expenditure values were only available back to the year 2001/02. This has limited the number of historical points to three.

These values are shown the in following table:

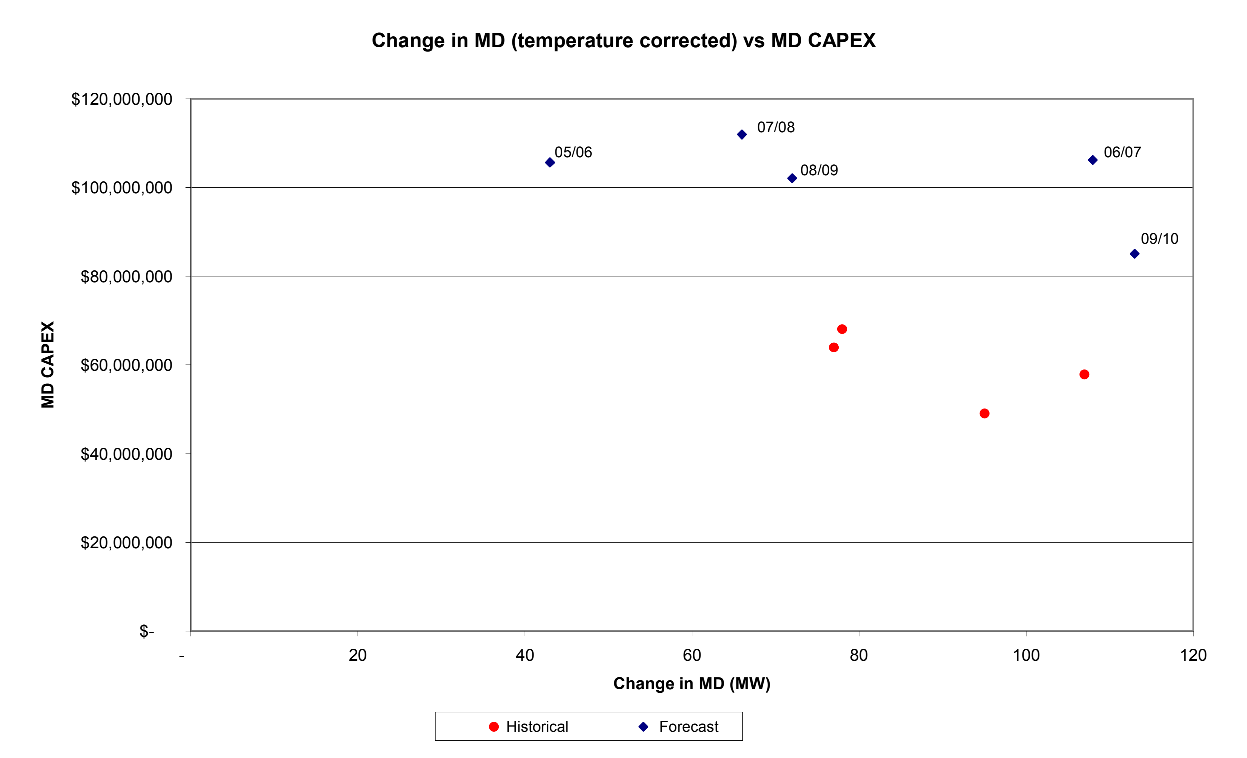
**Table 9-2: Maximum Demand and Maximum Demand CAPEX**

| | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 |
|---|---|---|---|---|---|---|---|---|---|
| MD (MW) | 1,858 | 2,074 | 2,020 | 2,213 | 2,203 | 2,311 | 2,377 | 2,449 | 2,562 |
| MD – temperature corrected (MW) | 1,898 | 1,976 | 2,053 | 2,160 | | | | | |
| Change MD (MW) | 95 | 78 | 77 | 107 | 43 | 108 | 66 | 72 | 113 |
| **MD CAPEX ($M)** | 49.1 | 68.1 | 63.9 | 57.8 | 105.7 | 106.2 | 111.9 | 102.1 | 85.1 |

*All forecast and historical figures are in June 2004 dollars.*

The values of demand CAPEX and change in maximum demand are shown on the following graph:

**Figure 9-7: Changes in Maximum Demand vs Maximum Demand CAPEX**




The graph shows that four of the five points of future expenditure are grouped together at a higher level of demand CAPEX but with a wide variation in change in maximum demand. These points are for the years 2005/06 through to 2008/09. These four points, taken in isolation, would indicate a consistent level of demand CAPEX expenditure independent of the given change in maximum demand.

However, the proposed demand CAPEX expenditure for the year 2009/10 is significantly lower than the other four future demand CAPEX expenditures and yet for a similar increase in maximum demand as the demand for 2006/07 and for the previous expenditure in years 2001/02 and 2004/05. This increase in expenditure may be attributable to the need for “catch-up” works through most of the Regulatory period, then a return to levels of expenditure more consistent with current levels by 2009/10.

The level of expenditure to meet maximum demand for a particular year and the maximum demand in that year are not directly related. The expenditure in one year may over compensate for the maximum demand expected that year. That is, expenditure in one year may result in network assets that are not fully utilised until later years and thus later year’s expenditure may be less as network assets become fully utilised. Given the geographical size and radial nature of the Ergon Energy network this may be an issue as assets are installed to meet local conditions where a slight increase in maximum demand requires extensive network augmentations and simpler options, such as revised network switching operations, are not possible.

The Consultant has averaged the expenditure and increase in demand over the first three years of the current regulatory period regulatory periods, with a resultant cost of about $0.7M per additional MW. It should be noted that significant increases in augmentation expenditure are forecast, so this ratio will increase.

The Consultant considers that the relationship between MD CAPEX and maximum demand is such that it cannot be used with confidence as an indication of the appropriateness or otherwise for demand related CAPEX. It can, however, be used as a broad cross-check, with expenditures around $0.7M per MW increase in maximum demand. This has been compared to the cost for the Victorian distributors over the current Determination period. Ergon Energy is more expensive when compared to Powercor and TXU at $0.5M per MW increase in MD. Again, it would be expected that Ergon Energy would be more expensive because of the above-mentioned geographical considerations. The comparative data is not sufficiently accurate to draw meaningful conclusions as to whether Ergon Energy's costs are too high.

Ergon Energy has noted a significant increase in temperature-sensitive (air-conditioning) loads, with the summer peaks shifting from evening to afternoon. This has combined with a flatter load profile to effectively de-rate electrical equipment, requiring augmentation works to be implemented earlier to maintain existing risk profiles.

Ergon Energy currently has a significant proportion of its network operating outside its planning thresholds, indicating the need for higher levels of augmentation CAPEX.

### 9.4.3 Impact on CAPEX of Differences Between Forecasts

The growth forecasts have been separately reviewed by MMA for the period 2005/06 to 2009/10. MMA have forecast peak demands, energy consumption and customer numbers. MMA have predicted lower average growth in customer numbers but higher growth in MD over the forecast period than Ergon Energy, as shown in the following table:

**Table 9-3: Growth Forecasts 2005/06 to 2009/10**

| | MAXIMUM DEMAND (MW) | CUSTOMER NUMBERS |
|---|---|---|
| ERGON ENERGY FORECAST | 3.3% | 1.8% |
| MMA FORECAST | 3.6% | 1.6% |

The Consultant has estimated that the difference in the forecasts of customer numbers and MD equates to changes to the Consultant's estimates over the period 2005/06 to 2009/10 of:

- $9.5M decrease for customer initiated works; and
- $31M increase for corporate initiated works.

## 9.5 Review of Projects - Prudency and Efficiency

The Terms of Reference issued by the QCA required the Consultant to ascertain the efficiency of the most significant capital projects having regard to:

- The existing infrastructure and renewals requirements;
- The demographic circumstances;
- Service quality and reliability (for a base level defined by current service quality and reliability standards and any alternative levels that the DNSP may propose);
- Asset utilisation; and
- The potential for demand management and /or embedded generation solutions to defer capital expenditure.

In order to assess the efficiency of capital projects, the Consultant carried out a detailed review of a range of capital projects from the perspective of whether the expenditure was prudent (did the money need to be spent) and efficient (was there appropriate value for the money spent).

### 9.5.1 Projects Selected

The Consultant had proposed to the QCA to establish materiality thresholds for the various types of projects and to review a number of projects of each type above the thresholds. After discussion, the QCA expressed a preference for the project review to cover a wider range of project costs and so materiality thresholds were not established.

The Consultant nominated a number of projects in each category, ensuring a spread between geographic location, completed and current projects, project value and project type. Due to the logistics of transporting project files, most of the projects reviewed were managed from two Regional centres – Rockhampton and Townsville. In spite of this restriction, the Consultant considers that the projects reviewed formed a representative sample. In all, 39 projects were reviewed, as listed in Appendix 14.8.

### 9.5.2 Methodology

The selected projects were reviewed against the five criteria listed by the QCA, as well as minimising life cycle costs/economic evaluation, risk analysis, environmental requirements and planning standards. Past projects were also evaluated in terms of their efficiency on the basis that the Consultant considers that past performance provides a key indication of likely future performance.

To ensure that a consistent approach was adopted by the review team, a pro-forma was developed and utilised to evaluate each project and record the information. A copy of the pro-forma is contained in Appendix 14.9.

Given the significant number of projects sighted, the Consultant is confident that they have achieved a detailed overview of the capital projects for the period 2000/01 to 2003/04. Detailed project information was not available for earlier or later periods.

### 9.5.3 Observations

The Consultant considers that the following observations were made in the course of the review:

- There was not a consistent approach to the project file recording process, for example:
  - For projects of similar value and complexity, records ranged from comprehensive to relatively sketchy.
  - Many files were disorganised, with material not in order (chronological or subject matter) and items loose in project pockets.
- There were many examples where there was little supporting detail, particularly in regard to:
  - Pre-project information, explaining the background and how the need for the project was identified;
  - Consideration of or details provided for alternative options; and
  - Quantified risk assessments, consideration of life-cycle costs, environmental assessments and the system planning/network capacity impacts (there is some evidence that the latter had been considered, but the information was not generally recorded in the project files).
- Projects were generally authorised in accordance with delegated authority. Exceptions were a number of projects for which authorisations were not found in the material provided;
- There were a number of issues with project reconciliation and sign-off:
  - No evidence of reconciliation being conducted or projects signed off – this was a common occurrence;
  - Reconciliations not endorsed (i.e. signed by Project Manager only);
  - Lack of explanations of variances, even for some significant overspending;
- There was no evidence that feedback from project reviews was occurring. A project review conducted prior to project closure provides an opportunity for improving the process (for example, to amend estimating rates or to change the project management approach).

- Several examples where the project was allocated to an incorrect category, based on the information presented.
- Construction files frequently did not contain a copy of the project authorisation.
- A major IT project, worth $10M and relating to the provision of core services, did not appear to have been apportioned across the various Ergon Energy business streams (i.e. Network & Retail).
- There was often no evidence of NIRC approval. Other instances gave implied approval, but no formal record was provided.
- A project to develop strategies for e-commerce was capitalised, where in the Consultant's view on the information provided, much of this should have been an operational expense.

#### 9.5.4 Conclusions

The process of compiling project files to support capital expenditure is not well defined at Ergon Energy and should be improved. Despite this, there was sufficient evidence to suggest that the existing infrastructure and renewals, service standards and asset utilisation are appropriately considered by Ergon Energy in the assessment and approval of capital projects.

The demographic circumstances were not relevant for individual projects in many cases, but were considered at a high level in network planning studies.

The process for project approval would be enhanced by the provision of pre-project information, use of quantified risk assessments, documented system planning/network capacity impacts and improved financial assessments.

The potential to contract for distributed (embedded) generation and demand management to defer or reduce network capital expenditure was not considered by Ergon Energy for any of the projects reviewed. This was not an option for many projects (for example; asset replacements, supply to new developments etc). Ergon Energy has been very active in implementing Remote Area Power Supplies and is currently conducting a trial of a new type of un-interruptible power supply ("UPS"). This device can be adapted to provide supply for an extended period if connected to batteries and the demand management component of the control system is activated and wired in to the customer's installation. Ergon Energy is currently developing a commercialisation approach and it is expected that these UPS systems may be commercially available in the next two years or so.

Of the additional criteria considered in ascertaining the prudency of the capital expenditure, the Consultant has some concerns about the level of consideration given to minimising life cycle costs/economic evaluation and risk analysis. In the absence of such information, the need for a few of the projects has not been clearly established, based on the information contained in the project files, although it is possible that other supporting information exists elsewhere in the organisation. The review did not raise any concerns in regard to the consideration of environmental requirements and planning standards, although these areas were often not well documented.

It is appreciated that the need for a customer initiated project is readily established by the request from the customer; however, the method by which that need is met must be justified for the expenditure to be considered prudent.

Notwithstanding the observations and concerns raised in the preceding paragraphs, the Consultant is of the view that the capital expenditure for the projects reviewed was generally prudent, with few exceptions.

In assessing the efficiency of capital expenditure for the projects reviewed, the Consultant considered the basis for preparing the cost estimate, the comparison of actual with estimated cost (for completed projects), and the design/planning approach adopted.

A major concern is the lack of comprehensive post implementation reviews. Every project should be reviewed prior to closure, with the larger projects subject to a more formalised and detailed review. It is suggested that reconciliations be signed off at the level at which the projects were authorised, in order to provide feedback at the appropriate level in the organisation.

A comparison between actual and estimated costs for projects for which actual costs were available (23 completed projects), revealed that the total actual costs were $11.6M, against an estimated $9.3M (i.e. over expenditure of $2.3M or 23.8%), which raises some concerns about the estimating process. Improvements to the estimating process are discussed earlier in this section. The Consultant considers that the expenditure was consistent with the design and planning guidelines established by Ergon Energy. The Consultant has concluded that expenditure for the projects reviewed generally appeared to be efficient.

### 9.6 Projects Associated with Customer Contributions

The Terms of Reference required the Consultant to review and comment on the DNSPs' forecast level of customer contributed capital projects.

The policy for how Ergon Energy currently imposes capital contribution charges is detailed in a document "Policy Relating to New Connections". Ergon Energy has recently reviewed its customer contributions methodology and has submitted the proposed amendments to the QCA for approval. Ergon Energy has advised that customer capital contributions are expected to remain much the same under the proposed new arrangements.

A comparison between Ergon Energy's actual (for 2001/02 and 2002/03) and budget (for 2003/04 and 2004/05) expenditure and the QCA Allowance for the current period for Customer Contributions (in $ millions) is shown in the following table:

**Table 9-4: QCA Determination and Ergon Energy Customer Contributions**

| | | 01/02 | 02/03 | 03/04 | 04/05 | TOTAL |
|---|---|---|---|---|---|---|
| QCA Determination | $ M | 16.8 | 17.1 | 17.5 | 17.9 | 69.3 |
| Ergon Energy Actual/Budget | $ M | 16.9 | 19.9 | 25 | 25 | 86.8 |

*All forecast and historical figures are in June 2004 dollars.*

It can be seen that the level of Customer Contributions has been higher than allowed for, which is consistent with an increase in the level of Customer Initiated CAPEX.

Ergon Energy's forecasts are shown in the following table:

**Table 9-5: Ergon Energy's Forecast of Customer Contributions**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Cash contributions | $ M | 25 | 25 | 24 | 23 | 22 | 21 | 115 |
| In kind contributions | $ M | 0 | 1 | 2 | 4 | 5 | 7 | 19 |
| Total | $ M | 25 | 26 | 26 | 27 | 27 | 28 | 134 |

*All forecast and historical figures are in June 2004 dollars.*

Ergon Energy has forecast a reducing level of customer cash contributions and an increase in in-kind contributions as a result of an expected introduction of contestability for customer works.

The Consultant considers that the total customer contributions should increase in line with the forecast customer growth rate, and has reduced the forecast contributions as shown in the following table.

**Table 9-6: Consultant's Forecast of Customer Contributions**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Cash contributions | $ M | 25 | 25 | 24 | 23 | 22 | 21 | 115 |
| In kind contributions | $ M | 0 | 0.5 | 1.9 | 3.4 | 4.9 | 6.3 | 16.9 |
| Total | $ M | 25 | 25.5 | 25.9 | 26.4 | 26.9 | 27.3 | 131.9 |

*All forecast and historical figures are in June 2004 dollars.*

## 9.7 Works in Progress & Commencement of Depreciation

Ergon Energy advises that Works in Progress ("WIP") is higher than it should be, but that it is now being regularly reviewed and acted on vigorously. It appears that Ergon Energy has only recently directed attention to this area but is taking appropriate steps to manage WIP.

Currently, depreciation commences when the project is reconciled and signed off. This approach is being reviewed and it is proposed that depreciation commence when an asset is put into service. The Consultant supports such a change, and notes that this will reduce the level of WIP. The reconciliation and sign-off would normally take place after the asset is put into service.

## 9.8 Cost Pass-Through

In its Final Determination, Regulation of Electricity Distribution, May 2001, the QCA commented:

> *"A cost pass-through allows a regulated organisation to increase (decrease) its revenue cap in response to an increase (decrease) in a cost that is typically beyond the regulated organisation's control and is readily observable. Cost pass-through arrangements shift the risk associated with a specific cost from the regulated organisation to the customer. However, because cost pass-through usually only applies to costs that are beyond the regulated organisation's control, this approach is also a way to avoid regulated organisations being subject to windfall gains and losses."*

Ergon Energy is faced with high levels of risk relating to uncontrolled expenditure, particularly in the area of major customer connections. The risk is related to the difficulties in predicting when major projects will proceed and the amount of infrastructure required to make the connection (i.e. timing and cost).

Major projects for Ergon Energy fall into four main categories:

- Generation;
- Coal Mines;
- Large industrial; and
- Other (gold mines, very large commercial etc).

Once the level of uncertainty has been removed or reduced to an acceptable level, the costs of such works should be able to be recovered by the DNSP through a pass-through mechanism. Such a mechanism should be simple in application to avoid the need for significant administration costs.

Ergon Energy contends that the ideal solution is to isolate major customer connections from the rest of the asset base and revenues, but recognizes that this will not be achievable in the short to medium term due to system constraints.

Projects which are highly likely to proceed within the next Regulatory period should not be considered for pass-through, regardless of cost, but should be clearly specified and included in the CAPEX forecasts. The issue is the mechanism for determining which projects should be eligible for pass-through consideration. Ergon Energy has suggested a number of possible criteria for defining such projects and has highlighted some of the issues associated with making a pass-through mechanism work in practice.

The development of a detailed pass-through mechanism is beyond the scope of this report. The Consultant recommends that the QCA develops a detailed mechanism in conjunction with the two DNSPs, which can then be applied in the event that the forecast CAPEX for major customers is likely to be significantly over spent. In developing the mechanism, DNSPs would need to identify potential projects and make an assessment regarding the probability of the projects proceeding within the current regulatory period. The Consultant suggests that the process would require a DNSP to make an application to the QCA for a pass-through when certain agreed requirements have been met. The QCA would then assess the application and would approve it or reject it, depending on the assessment. This is discussed further in Section 9.9.3.6.

## 9.9 Efficient CAPEX Program 2005/06 - 2009/10

In providing forecasts of expenditure, Ergon Energy has provided three alternative levels of spending, based on differing levels of Service Quality (refer to Section 5.6.3). These impact directly on the spending in the Reliability Improvement category, and indirectly on all of the other categories due to the allocation of overheads (refer to Section 7.3). For the purpose of the following analysis, the spending in categories other than Reliability Improvement has been based on maintaining the existing levels of service although it is noted that spending in some other categories will result in some improvements to reliability. The changes due to the re-allocation of overheads are relatively minor.

The Terms of Reference (“TOR”) issued by the QCA require the Consultant to provide an opinion on the efficiency of each DNSP’s CAPEX forecasts. In assessing efficiency, the Consultant has analysed the data provided, recognising the timeframes available, and has made judgements based on its experience within the industry. The Consultant has used the term “reasonable’’ in the assessment of CAPEX to convey the view that the expenditure is considered to be efficient, within these limitations (i.e. available data and time).

**Table 9-7: Ergon Energy CAPEX Expenditure**

| | | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **System Assets** | | | | | | | | | | |
| Ageing Asset Replacements | **$ M** | 70.1 | 93.6 | 97.9 | 98.4 | 136.0 | 130.4 | 131.6 | 128.3 | 129.1 |
| Corporate Initiated Augmentation | **$ M** | 48.4 | 67.1 | 62.9 | 55.9 | 105.3 | 104.7 | 110.6 | 100.7 | 83.7 |
| Customer Requested Works | **$ M** | 74.5 | 101.1 | 102.8 | 183.9 | 146.8 | 149.8 | 151.2 | 156.5 | 160.8 |
| Reliability Improvement | **$ M** | 9.9 | 10.8 | 8.6 | 7.5 | 1.5 | 1.6 | 1.5 | 1.6 | 1.6 |
| Other | **$ M** | 3.0 | 1.0 | 5.2 | 17.8 | 8.6 | 9.8 | 9.5 | 9.3 | 8.7 |
| **Total System CAPEX** | **$ M** | 206.0 | 273.5 | 277.4 | 363.6 | 398.2 | 396.2 | 404.6 | 396.4 | 383.9 |
| **Non-System Assets** | | | | | | | | | | |
| Change Program | **$ M** | 9.6 | 18.0 | 23.9 | 14.6 | 22.4 | 17.5 | 17.5 | 17.5 | 17.5 |
| Computer Facilities | **$ M** | 18.4 | 5.9 | 6.3 | 6.2 | 14.2 | 8.1 | 9.1 | 8.2 | 7.1 |
| Vehicles & Mobile Plant | **$ M** | 17.2 | 27.1 | 17.0 | 27.3 | 25.0 | 25.0 | 25.8 | 26.3 | 21.7 |
| Land & Buildings | **$ M** | 8.9 | 4.2 | 8.8 | 15.4 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 |
| Other fixed Assets | **$ M** | 1.3 | 1.3 | 4.0 | 5.9 | 1.2 | 1.1 | 0.9 | 0.9 | 1.1 |
| Other Unclassified Acquisitions | **$ M** | 0.7 | 0.0 | 0.0 | 0.0 | 1.0 | 1.0 | 1.0 | 2.0 | 2.0 |
| **Total Non-System Assets** | **$ M** | 56.2 | 56.5 | 60.0 | 69.5 | 75.8 | 64.7 | 66.3 | 66.9 | 61.4 |
| **Total CAPEX** | **$ M** | **262.1** | **329.9** | **337.4** | **433.0** | **474.0** | **460.9** | **470.9** | **463.3** | **445.3** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 9-8: Consultant's CAPEX Program**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 |
|---|---|---|---|---|---|---|---|
| **System Assets** | | | | | | | |
| Ageing Asset Replacements | **$ M** | 98.4 | 136.0 | 130.4 | 131.6 | 128.3 | 129.1 |
| Corporate Initiated Augmentation | **$ M** | 55.9 | 105.3 | 104.7 | 110.6 | 100.7 | 83.7 |
| Customer Requested Works | **$ M** | 182.4 | 108.9 | 106.9 | 107.6 | 111.4 | 114.7 |
| Reliability Improvement | **$ M** | 7.5 | 1.5 | 1.6 | 1.5 | 1.6 | 1.6 |
| Other | **$ M** | 17.8 | 8.6 | 9.8 | 9.5 | 9.3 | 8.7 |
| **Total System CAPEX** | **$ M** | 362.1 | 360.4 | 353.3 | 361.0 | 351.3 | 337.8 |
| **Non-System Assets** | | | | | | | |
| Change Program | **$ M** | 14.6 | 22.4 | 17.5 | 17.5 | 17.5 | 17.5 |
| Computer Facilities | **$ M** | 6.2 | 14.3 | 8.1 | 9.1 | 8.2 | 7.1 |
| Vehicles & Mobile Plant | **$ M** | 27.3 | 25.0 | 25.0 | 25.8 | 26.3 | 21.7 |
| Land & Buildings | **$ M** | 15.4 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 |
| Other Fixed Assets | **$ M** | 5.9 | 1.2 | 1.1 | 0.9 | 0.9 | 1.1 |
| Other Unclassified Acquisitions | **$ M** | 0.0 | 1.0 | 1.0 | 1.0 | 2.0 | 2.0 |
| **Total Non-System** | **$ M** | 69.5 | 75.8 | 64.7 | 66.3 | 66.9 | 61.4 |
| **Total CAPEX** | **$ M** | **431.6** | **436.2** | **418.0** | **427.3** | **418.2** | **399.2** |

*All forecast and historical figures are in June 2004 dollars.*

### 9.9.1 Asset Replacements

A comparison between Ergon Energy's actual (for 2001/02 and 2002/03) and budget (for 2003/04 and 2004/05) expenditure (in $ millions including overheads) for Asset Replacement CAPEX is shown in the following table:

**Table 9-9: QCA Determination and Ergon Energy Asset Replacement Expenditure**

| | | 01/02 | 02/03 | 03/04 | 04/05 | TOTAL |
|---|---|---|---|---|---|---|
| QCA Determination | **$ M** | 43.34 | 36.14 | 32.90 | 31.50 | 143.89 |
| Ergon Energy Actual/Budget | **$ M** | 70.13 | 93.55 | 97.92 | 98.43 | 360.03 |

*All forecast and historical figures are in June 2004 dollars.*

The QCA Determination figures are taken from the QCA Final Determination and Capital Expenditure Study - Ergon Energy by PB Associates. All figures are in June 2004 dollars.

It can be seen that Ergon Energy's expenditure on Asset Replacement far exceeds that allowed in the previous Determination. Ergon Energy state that this is due to the number of assets reaching the end of their lives (following significant expansion of the network in the late sixties and seventies) and the change from a five year to a three year inspection cycle (moving the primary criteria for asset replacement from the elapsed life to a more condition-based replacement program).

At the time of the last review, the QCA's consultant, PB Associates, highlighted the need for increased levels of Replacement CAPEX in future periods, and indicated that Ergon Energy's estimates were low, due largely to the poor availability of asset data. The Consultant agrees with PB Associates' view that Ergon Energy made insufficient allowance for Asset Replacement CAPEX in the current period, as demonstrated by the level of spending above that provided in the QCA Determination.

Ergon Energy has begun an intensive Asset Inspection and Defects Maintenance Program, and an important component of this relates to reducing the inspection cycle to three years to speed up the data capture process and assess the state of the assets. Ergon Energy plans to maintain this period for the next inspection cycle to confirm data captured in the first cycle, and then revert back to longer inspection periods, commencing in 2007-2008. Although the data capture is not complete, there is sufficient information to form a reasonable estimate of the CAPEX required.

As discussed in Section 8.6, the Consultant has made a judgement that the data provided could be expected to be within an accuracy of 10%.

Ergon Energy has prepared detailed estimates of the physicals and costs for the various asset items, projected up to 2019/20.These are contained in the Network Assets Maintenance and Replacement Plan, which sets out the goals, methods and plans for the maintenance and replacement of the network assets. In projecting physical quantities, Ergon Energy has considered a range of factors, including inspection and testing regimes, asset ages, maintenance practices, defect rates, historical levels and life extension strategies. The Consultant considers that the process followed has been rigorous, but in some cases, the results have been affected by the quality of the asset data available. Ergon Energy is well aware of the need for accurate data and has taken appropriate steps to address this issue.

Ergon Energy has engaged an external consultant, PB Associates, to benchmark the asset replacement expenditure. PB Associates projected a slightly higher replacement cost than that forecast by Ergon Energy. The replacement models used result in a stabilisation of the network remaining life at 50% by 2019/20.

The need for many of the asset replacement programs was supported by observations made by the Consultant on field inspections.

Ergon Energy has developed and applied a detailed and comprehensive model for asset replacements. The Consultant considers that Ergon Energy's model is rigorous and very detailed (it is by far the best model encountered by the Consultant in dealing with a wide range of distributors). The Consultant has carefully reviewed Ergon Energy's model, and in the analysis phase, discovered some inconsistencies and errors that were addressed in subsequent revisions. As a consequence, the Consultant has a high level of confidence in Ergon Energy's model.

As a cross-check, the Consultant applied a high level model for some asset categories, based on age profiles, asset lives and unit rates. It should be noted that models based on the application of the economic life of assets, as the Consultant's is, are likely to provide misleading results when applied in the medium term, as assets are replaced based on their condition and not their age. The Consultant considers that the model applied by Ergon Energy provides a more accurate representation than the high level model applied by the Consultant. It should be noted that the Consultant's model predicted significant fluctuations from year to year, which is dependent on the number of assets reaching the end of their economic life in a particular year.

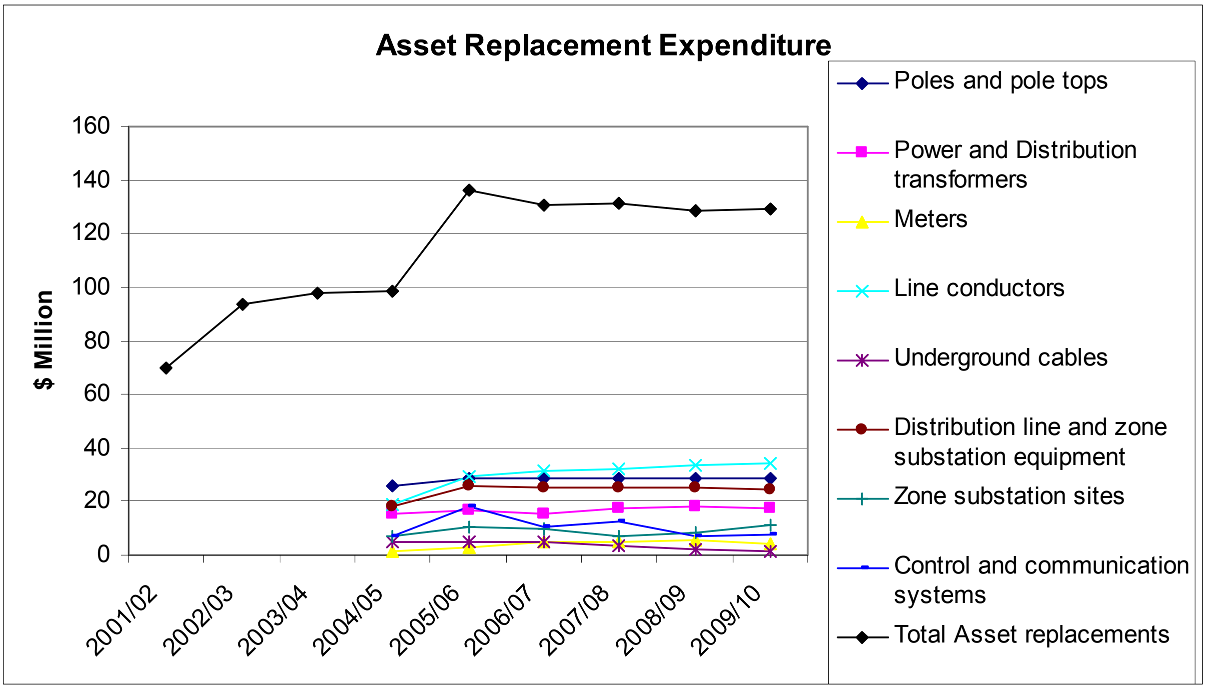
**Table 9-10: Ergon Energy's Asset Replacement Expenditure**

| | | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Poles and pole tops | $ M | *n/a* | *n/a* | *n/a* | 25.8 | 28.5 | 28.8 | 29.0 | 28.7 | 28.9 | 143.8 |
| Power and Distribution transformers | $ M | *n/a* | *n/a* | *n/a* | 15.4 | 16.5 | 15.6 | 17.4 | 17.9 | 17.4 | 84.8 |
| Meters | $ M | *n/a* | *n/a* | *n/a* | 1.2 | 2.7 | 5.2 | 5.0 | 5.9 | 3.9 | 22.7 |
| Line conductors | $ M | *n/a* | *n/a* | *n/a* | 18.6 | 29.5 | 31.1 | 32.4 | 33.6 | 34.0 | 160.7 |
| Underground cables | $ M | *n/a* | *n/a* | *n/a* | 5.2 | 4.6 | 4.7 | 3.2 | 1.8 | 1.5 | 15.8 |
| Distribution line and zone substation equipment | $ M | *n/a* | *n/a* | *n/a* | 18.0 | 25.5 | 25.1 | 25.0 | 25.1 | 24.7 | 125.5 |
| Zone substation sites | $ M | *n/a* | *n/a* | *n/a* | 7.0 | 10.2 | 9.5 | 7.2 | 8.2 | 11.0 | 46.3 |
| Control and communication systems | $ M | *n/a* | *n/a* | *n/a* | 7.2 | 18.3 | 10.4 | 12.4 | 7.0 | 7.6 | 55.7 |
| **Total Asset Replacements** | $ M | 70.1 | 93.5 | 97.9 | 98.4 | 136.0 | 130.4 | 131.6 | 128.3 | 129.1 | 655.4 |

*n/a – figures not available*

*All forecast and historical figures are in June 2004 dollars.*

**Figure 9-8: Asset Replacement Expenditure**




*All forecast and historical figures are in June 2004 dollars.*

#### 9.9.1.1 Poles and Pole tops

The Consultant has modelled the replacement CAPEX for poles and pole tops, based on the pole age profile, asset lives and unit rates. A comparison of Ergon Energy's forecasts and the Consultant's model is shown in the following table (values are total costs in $ millions):

**Table 9-11: Pole and Pole Top Replacement Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $ M | 25.8 | 28.5 | 28.8 | 29.0 | 28.7 | 28.9 | 143.8 |
| Consultant Model | $ M | 13.2 | 9.6 | 27.3 | 34.8 | 32.6 | 43.6 | 147.9 |

*All forecast and historical figures are in June 2004 dollars.*

The spending on pole replacement CAPEX is forecast by Ergon Energy to decrease slightly over the period, driven largely by the increase in pole nailing from 45% to 70% by 2009.

The replacement CAPEX for pole tops is driven by the defect rates identified from ground inspections and those conducted from an EPV. Pole top defects identified during the cyclic asset inspections are packaged and completed as capital works. This work involves replacement of defective components. Ergon Energy has trailed a regime of pole top inspections from an EPV of sub-transmission lines and lines in areas of rainfall greater than 1500mm per year. The defect rates identified in this trial have been applied in Ergon Energy's model.

Whilst the Consultant model shows a different fall of expenditure over the period and a slightly lower overall expenditure than Ergon Energy, the Consultant considers the level of forecast expenditure to be reasonable.

#### 9.9.1.2 Power and Distribution Transformers

The Consultant has modelled the replacement CAPEX for power and distribution transformers, based on the transformer age profile, asset lives and unit rates. A comparison of Ergon Energy's forecasts and the Consultant's model is shown in the following table (values are total costs in $ millions):

**Table 9-12: Power and Distribution Transformers Replacement**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $ M | 15.4 | 16.5 | 15.6 | 17.4 | 17.9 | 17.4 | 84.8 |
| Consultant Model | $ M | 18.8 | 6.4 | 20.4 | 20.6 | 20.1 | 22.6 | 90.1 |

*All forecast and historical figures are in June 2004 dollars.*

Power transformers are high cost assets and as such the replacement programs for these are driven by the level of risk and the consequences of failure, based on assessments of the condition of the transformers. The expenditure is based on predicted asset failure, and end of life estimations. The remaining life of a transformer is significantly altered by the loading applied to the transformer and the fault level of the substation.

Distribution transformers, on the other hand, are replaced on failure, and the forecast expenditure is based on historical failure rates. The slight decline is based on the installation of lightning arresters in place of spark gaps which are expected to reduce the failure rate of the transformers.

Whilst the Consultant model shows a different fall of expenditure over the period, the overall expenditure is the same as that forecast by Ergon Energy. The Consultant considers the level of forecast expenditure to be reasonable.

#### 9.9.1.3 Meters

**Table 9-13: Meter Replacement Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $ M | 1.2 | 2.7 | 5.2 | 5.0 | 5.9 | 3.9 | 22.7 |

*All forecast and historical figures are in June 2004 dollars.*

Ergon Energy has forecast an increase in meter replacement costs, driven by anticipated failure rates based on the age profile and known issues. Although accurate records are not available for the total meter population, Ergon Energy has extrapolated the known data and applied it across the rest of the meter population. The Consultant considers the level of forecast expenditure (shown in the table above in total $ millions) to be reasonable.

#### 9.9.1.4 Line Conductors and Connectors

**Table 9-14: Line Conductor and Connectors Replacement Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $ M | 18.6 | 29.5 | 31.1 | 32.4 | 33.6 | 34.0 | 160.7 |
| Consultant Model | $ M | 12.3 | 8.9 | 26.0 | 33.9 | 32.7 | 44.8 | 146.3 |

*All forecast and historical figures are in June 2004 dollars.*

Ergon Energy has forecast a significant increase in expenditure in this area, as shown in the above table (values are total costs in $ millions). The step increase and subsequent slight increase in expenditure is due to a planned program of replacement of aged sub-transmission lines, aged small copper conductors and rusty steel conductors. The condition of aged conductors has raised reliability and safety issues, and current work bans apply. The Consultant’s model shows a lower level of expenditure however, the Consultant considers that the level of forecast expenditure is reasonable, given that Ergon Energy is faced with significant lengths of conductor that have reached the end of their life at an earlier time than that predicted by a rigid application of an economic life replacement model. The impact of this level of replacement capital has been included in the OPEX estimates.

#### 9.9.1.5 Underground Cables and Joints

**Table 9-15: Underground Cables and Joints Replacement Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $ M | 5.2 | 4.6 | 4.7 | 3.2 | 1.8 | 1.5 | 15.8 |

*All forecast and historical figures are in June 2004 dollars.*

Ergon Energy has forecast an initial increase in expenditure followed by a reduced expenditure for the rest of the period, mainly to replace aged XLPE HV cables and sub-transmission cables. Given the reported history of early failures of cables, the Consultant considers the level of forecast expenditure to be reasonable. The impact of cable replacements has been included in the OPEX estimates.

### 9.9.1.6 Other Distribution Line Items and Zone Substation Equipment

**Table 9-16: Distribution Line Items and Zone Substation Equipment Replacement Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $ M | 18.0 | 25.5 | 25.1 | 25.0 | 25.1 | 24.7 | 125.5 |
| Consultant Model | $ M | 18.6 | 8.1 | 37.9 | 28.2 | 23.7 | 23.5 | 121.4 |

*All forecast and historical figures are in June 2004 dollars.*

Distribution line item includes line switchgear, fuses, surge arrestors, LV services, public lighting, earthing systems, regulators, capacitors and reactors. Ergon Energy has forecast a stable expenditure in this area over the next Regulatory period. The step change in expenditure from 2004/05 to 2005/06 is mainly for the replacement of line switchgear.

Zone Substation equipment includes circuit breakers, current and voltage transformers, switches, capacitors, SVC, DC systems and protection schemes. The forecast level of expenditure is significantly higher than the current level ($1.7M for 2003/04) and includes a further step increase in 2005/06, largely due to the need to replace electronic relays experiencing age related failures and significant numbers of electro-mechanical relays over 40 years old.

Due to the level of detailed data provided by Ergon Energy, the Consultant's model has overlaps between these two categories and thus they have been modelled together. The Consultant considers the level of forecast expenditure to be reasonable.

### 9.9.1.7 Zone Substation Sites

**Table 9-17: Zone Substation Sites Replacement Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $ M | 7.0 | 10.2 | 9.5 | 7.2 | 8.2 | 11.0 | 46.3 |

*All forecast and historical figures are in June 2004 dollars.*

This category includes fences, earth mats, bus work, lighting, structures, buildings, oil bunding and minor plant items. The forecast level of expenditure is significantly higher than the current level ($2.3M for 2003/04) and includes a further step increase in 2005/06, largely driven by regulatory requirements. Programs include achieving statutory clearances, oil containment, bringing earthing systems up to current standards and fencing. The Consultant considers the level of forecast expenditure to be reasonable.

#### 9.9.1.8 Zone Substation Control Systems & Communications

**Table 9-18: Control Systems and Communications Replacement Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $ M | 7.2 | 18.3 | 10.4 | 12.4 | 7.0 | 7.6 | 55.7 |

*All forecast and historical figures are in June 2004 dollars.*

The forecast levels of expenditure are consistent with the program to replace the SCADA Master Stations (already commenced), replace aged RTUs, and replace aged load control equipment, resulting in a step change in 2005/06 and reduced (but still relatively high) expenditure in 2006/07 and 2007/08. The Consultant considers the level of forecast expenditure to be reasonable.

#### 9.9.1.9 Total Asset Replacement Capital

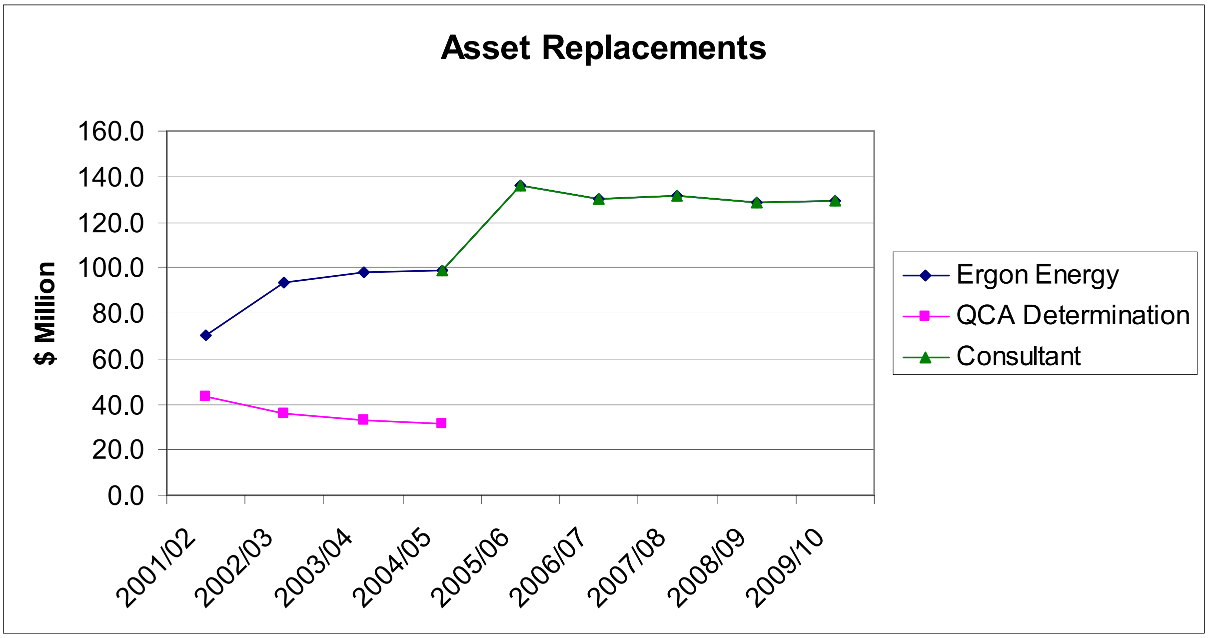
The Consultant considers that Ergon Energy's forecast for Asset Replacement capital expenditure, for the roll-forward period 1 July 2004 to 30 June 2005, to be reasonable. The total asset replacement CAPEX is shown in the following table and graph:

**Table 9-19: Ergon Energy and QCA Determination - Total Asset Replacement Expenditure**

| | | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Ergon Energy | $ M | 70.1 | 93.5 | 97.9 | 98.4 | 136.0 | 130.4 | 131.6 | 128.3 | 129.1 |
| QCA Determination | $ M | 43.3 | 36.1 | 32.9 | 31.5 | | | | | |
| Consultant | $ M | | | | 98.4 | 136.0 | 130.4 | 131.6 | 128.3 | 129.1 |

*All forecast and historical figures are in June 2004 dollars.*

**Figure 9-9: Total Asset Replacement CAPEX**




*All forecast and historical figures are in June 2004 dollars.*

It can be seen that Ergon Energy is forecasting a significant increase (some $38M) in replacement CAPEX in the 2005/06 year. The Consultant considers that the need for the projects and programs and the associated expenditures appear reasonable.

### 9.9.2 Corporate Initiated Augmentations

A comparison between Ergon Energy's actual (for 2001/02 and 2002/03) and budget (for 2003/04 and 2004/05) expenditure (in $ millions) and the QCA allowance for Corporate Initiated Augmentation CAPEX is shown in the following table:

**Table 9-20: QCA Determination and Ergon Energy Corporate Initiated Augmentation CAPEX**

| | | 01/02 | 02/03 | 03/04 | 04/05 | TOTAL |
|---|---|---|---|---|---|---|
| QCA Determination | $ M | 50.01 | 40.70 | 36.91 | 35.18 | 162.80 |
| Ergon Energy Actual/Budget | $ M | 48.44 | 67.10 | 62.94 | 55.92 | 234.40 |

*All forecast and historical figures are in June 2004 dollars.*

The QCA Determination figures are taken from the QCA Final Determination and Capital Expenditure Study – Ergon Energy by PB Associates. All figures are June 2004 dollars.

It can be seen that Ergon Energy expects to exceed the expenditure allowed by QCA in the last Determination by $72M, with the increased expenditure driven largely by higher growth in MD. The additional increase in demand projected for the current Regulatory period, over and above that inherent in the Determination, equates to about 100 MW. Using the "rule of thumb" discussed in Section 9.4.2, (namely $0.7M per 1 MW increase in MD) equates to an additional spending of about $70M over the period, which is consistent with the increased expenditure of $72M.

The forecast expenditure is shown in the following table:

**Table 9-21: Corporate Initiated Augmentations Expenditure**

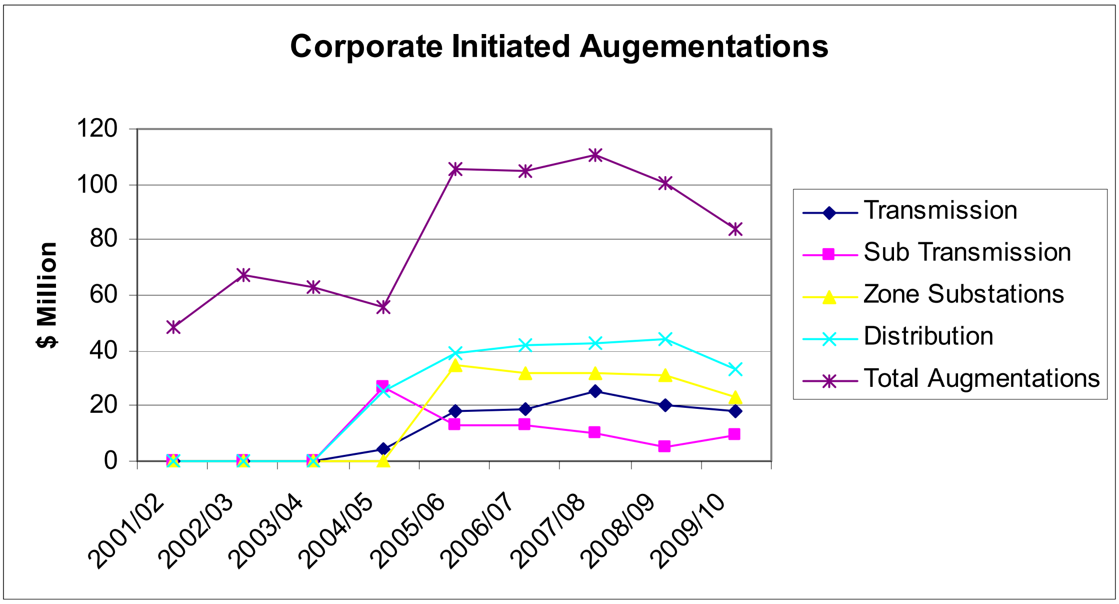
| | | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission | $ M | *n/a* | *n/a* | *n/a* | 4.2 | 18.0 | 18.5 | 25.6 | 20.1 | 17.8 | 100.0 |
| Sub Transmission | $ M | *n/a* | *n/a* | *n/a* | 26.5 | 13.0 | 12.8 | 10.4 | 5.3 | 9.5 | 50.9 |
| Zone Substations | $ M | *n/a* | *n/a* | *n/a* | 0.0 | 35.0 | 31.9 | 31.7 | 31.2 | 22.9 | 152.7 |
| Distribution | $ M | *n/a* | *n/a* | *n/a* | 25.2 | 39.3 | 41.6 | 43.0 | 44.1 | 33.5 | 201.5 |
| Ergon Energy - Total | $ M | 48.4 | 67.1 | 62.9 | 55.9 | 105.3 | 104.7 | 110.6 | 100.7 | 83.7 | 505.1 |

*n/a – figures not available*

*All forecast and historical figures are in June 2004 dollars.*

The historic, budget and forecast expenditure is shown in the following graph:

**Figure 9-10: Corporate Initiated Augmentations – CAPEX**




*All forecast and historical figures are in June 2004 dollars.*

The significant increase in forecast expenditure is mainly driven by:

- The need to increase capacity of the transmission network, mainly in the Wide Bay Region (where significant load growth and minimal augmentation has eroded the available capacity) and to reinforce the high growth areas of Toowoomba, Townsville and Cairns;
- Associated Zone Substation works in the above and other areas; and
- Increased Distribution Network expenditure aimed at reducing the high level of constraints across parts of the network.

Ergon Energy contends that these increased expenditures are required to address augmentation backlogs from the erosion of spare capacity during the current Regulatory period. The Consultant agrees that significant increases in expenditure are required for this purpose.

The need for specific transmission, sub-transmission and zone substation works has been identified through a rigorous planning process based on five year strategic plans. Ergon Energy has also developed a 20-year plan for the network. Network limitations are identified and options considered to overcome the limitations. This top-down approach is complemented by a bottom-up approach where local knowledge is used as an input into the process. Overall, the Consultant considers that Ergon Energy has a sound system planning approach, which appropriately identifies works required in accordance with established planning criteria.

Ergon Energy is in the first year of a rigorous analysis of distribution feeders to identify constraints (voltage and current), based on load flow studies. The analysis has been conducted on a feeder-by-feeder basis, although not to the same level of detail as for the sub-transmission level.

Within the limitations of this review, the Consultant considers that the need for the projects and programs and the associated expenditures are reasonable.

### 9.9.3 Customer Initiated Works

A comparison between Ergon Energy's actual (for 2001/02 and 2002/03) and budget (for 2003/04 and 2004/05) expenditure (in $ millions) and the QCA allowance for Customer Initiated CAPEX is shown in the following table:

**Table 9-22: QCA Determination and Ergon Energy Customer Initiated – CAPEX**

| | | 01/02 | 02/03 | 03/04 | 04/05 | TOTAL |
|---|---|---|---|---|---|---|
| QCA Determination | **$ M** | 54.5 | 63.2 | 63.1 | 61.0 | 241.8 |
| Ergon Energy Actual/Budget | **$ M** | 74.5 | 101.1 | 102.8 | 183.9 | 462.3 |

*All forecast and historical figures are in June 2004 dollars.*

The QCA Determination figures are taken from the QCA Final Determination and Capital Expenditure Study - Ergon Energy by PB Associates. All figures are in millions of 2003/04 dollars. It can be seen that Ergon Energy has significantly exceeded the allowance made by QCA.

The following tables shows a breakdown of historical and budget expenditure for the current Regulatory period, expressed in $ millions. Although this table has been prepared on a different basis and the figures are not intended to be reconcilable to those shown in the preceding table (the two sets of figures should not be the same), they nevertheless indicate the changes in expenditure.

**Table 9-23: Historical Customer Initiated Expenditure**

| | | 01/02 | 02/03 | 03/04 | 04/05 |
|---|---|---|---|---|---|
| Domestic & Rural | **$ M** | 15.5 | 20.9 | 22.3 | 17.4 |
| Subdivisions | **$ M** | 11.2 | 19.0 | 35.8 | 32.5 |
| Public Lighting | **$ M** | 3.2 | 2.6 | 3.3 | 4.1 |
| Meters & Services | **$ M** | 6.8 | 9.6 | 12.0 | 12.4 |
| Commercial & Industrial (See Note 1) | **$ M** | 29.8 | 40.2 | 41.7 | 34.4 |
| Major Customers | **$ M** | 0 | 0 | 20.2 | 83.0 |
| Total | **$ M** | **66.1** | **92.3** | **135.4** | **183.9** |

*All forecast and historical figures are in June 2004 dollars.*

Note 1: Major customers are included in Industrial and Commercials for 2001/02 and 2002/03.

It can be seen that there has been a significant increase in customer initiated works, particularly in the areas of subdivisions, commercial/industrial and major customers.

**Table 9-24: Forecast Customer Initiated Expenditure**

| | | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total |
|---|---|---|---|---|---|---|---|
| Domestic & Rural | **$ M** | 18.7 | 19.1 | 19.3 | 20.1 | 20.6 | 97.8 |
| Subdivisions | **$ M** | 33.3 | 34.2 | 34.7 | 36.1 | 37.2 | 175.5 |
| Public Lighting | **$ M** | 4.2 | 4.3 | 4.4 | 4.5 | 4.7 | 22.1 |
| Meters & Services | **$ M** | 12.4 | 12.8 | 13.0 | 13.5 | 13.9 | 65.5 |
| Commercial & Industrial | **$ M** | 36.3 | 37.4 | 38.1 | 39.7 | 41.2 | 192.7 |
| Major Customers | **$ M** | 41.8 | 42.0 | 41.8 | 42.6 | 43.1 | 211.4 |
| Total | **$ M** | **146.8** | **149.8** | **151.2** | **156.5** | **160.8** | **765.1** |

*All forecast and historical figures are in June 2004 dollars.*

#### 9.9.3.1 Domestic & Rural

The forecast expenditure for Domestic and Rural is shown in the following table:

**Table 9-25: Domestic and Rural Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | **$ M** | 17.4 | 18.7 | 19.1 | 19.3 | 20.1 | 20.6 | 97.8 |

*All forecast and historical figures are in June 2004 dollars.*

The forecast expenditure for the period is very similar to historical levels, with a slight escalation that is in line with the increase in additional customers connected, and is considered by the Consultant to be reasonable.

#### 9.9.3.2 Subdivisions

Ergon Energy's and the Consultant's forecast expenditure for Subdivisions is shown in the following table:

**Table 9-26: Subdivision Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | **$ M** | 32.5 | 33.3 | 34.2 | 34.7 | 36.1 | 37.2 | 175.5 |
| Consultant | **$ M** | 31.1 | 31.7 | 32.3 | 32.9 | 33.6 | 34.2 | 164.7 |

*All forecast and historical figures are in June 2004 dollars.*

The Consultant has slightly reduced the forecast for Subdivisions, based on a cost of $3,315 per lot multiplied by the number of expected lots. (This rate was derived from $3,500 per lot supplied by Ergon Energy and adjusted for the change in overhead rates.)

#### 9.9.3.3 Public Lighting

The forecast expenditure for Public Lighting is shown in the following table:

**Table 9-27: Public Lighting Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | **$ M** | 4.1 | 4.2 | 4.3 | 4.4 | 4.5 | 4.7 | 22.1 |

*All forecast and historical figures are in June 2004 dollars.*

The forecast expenditure is similar to historical levels, with a slight escalation that is broadly in line with an escalating increase in additional customers connected, and is considered by the Consultant to be reasonable.

#### 9.9.3.4 Meters & Services

The forecast expenditure for Meters & Services is shown in the following table:

**Table 9-28: Meters and Services Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | **$ M** | 12.4 | 12.4 | 12.8 | 13.0 | 13.5 | 13.9 | 65.5 |

*All forecast and historical figures are in June 2004 dollars.*

The forecast expenditure is broadly in line with the forecast increases in subdivisions, and is considered by the Consultant to be reasonable.

#### 9.9.3.5 Commercial & Industrial

The forecast expenditure for Commercial & Industrial is shown in the following table:

**Table 9-29: Commercial and Industrial Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | **$ M** | 34.4 | 36.3 | 37.4 | 38.1 | 39.7 | 41.2 | 192.7 |

*All forecast and historical figures are in June 2004 dollars.*

The forecast expenditure is very similar to that experienced in the last few years, with a slight escalation and is considered by the Consultant to be reasonable.

#### 9.9.3.6 Major Customers

The forecast expenditure for Major Customers is shown in the following table:

**Table 9-30: Ergon Energy Major Customer Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | **$ M** | 83.0 | 41.8 | 42.0 | 41.8 | 42.6 | 43.1 | 211.4 |

*All forecast and historical figures are in June 2004 dollars.*

The Consultant considers that Ergon Energy's estimate of $211.4M for the period 2005/06 to 2009/10 to be reasonable. There are, however, major risks associated with the timing and costs associated with major customer connections. Ergon Energy has based its estimates on recent historical spending and known projects for the first two years of the forthcoming regulatory period. Even for known projects, there is considerable uncertainty relating to timing and scope of work (and hence costs).

Major projects for the forthcoming regulatory period can be split into the following three categories:

- Category 1: Projects with a reasonable degree of certainty (80% and greater) in regard to the cost and implementation within the period or a value less than $5 million (these have been included in the estimates);
- Category 2: Known projects which are likely to proceed, but the timing and/or the cost is uncertain (less than 80%) and having a value greater than $5 million (these have not been included in the estimates and cost pass-through by the QCA would apply if judged appropriate by the QCA); and
- Category 3: Projects which are unknown at the present time (no allowance has been made for these in the Consultant's estimates and cost pass-through by the QCA would apply if judged appropriate by the QCA).

Ergon Energy has provided details of individual known projects, but these have not been included in this report for reasons of commercial confidentiality. For projects with a reasonable degree of certainty, the Consultant has assumed that projects currently at the construction phase will proceed in 2004/05 and, projects at either the application or enquiry phases will proceed over the remainder of the period. The total costs for the major project categories are shown in the following table:

**Table 9-31: Major Customer Expenditure**

| | 04/05 | 05/06-09/10 |
|---|---|---|
| **Category 1: Known projects – reasonable certainty** | 83.4 | 38.0 |
| **Category 2: Known projects – uncertain** | | 107.0 |
| **Category 3: Unknown projects** | | 66.4 |

The Consultant has reduced Ergon Energy's forecasts in line with the above described approach, and has allocated the costs to reduce from $9.4M in 2005/06 to $6.8M in 2007/08 and for the remainder of the period. However, the $107M for known projects of uncertain timing (Category 2) could be expected to form part of a pass-through mechanism developed by the QCA. The estimated $66M of unknown projects (Category 3) could also be expected to dealt with by the pass-through mechanism.

A comparison between Ergon Energy's forecasts and that of the Consultant is shown in the following table:

**Table 9-32: Ergon Energy and Consultant's Major Customer Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Ergon Energy | **$ M** | 83.0 | 41.8 | 42.0 | 41.8 | 42.6 | 43.1 | 211.4 |
| Consultant | **$ M** | 83.0 | 9.4 | 8.1 | 6.8 | 6.8 | 6.8 | 38.0 |

*All forecast and historical figures are in June 2004 dollars.*

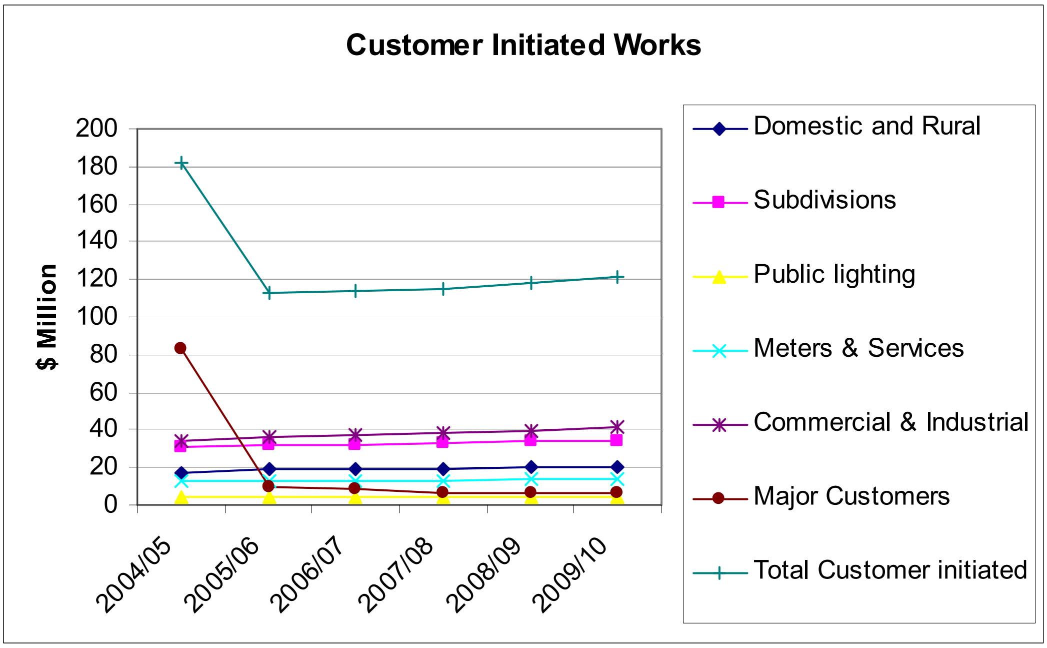
### 9.9.3.7 Total Customer Initiated Works

The Consultant considers that Ergon Energy's forecast for Customer Initiated capital expenditure, for the roll-forward period 1 July 2004 to 30 June 2005, to be reasonable with the exception of Subdivisions, which has been reduced by $1.5M by the Consultant.

The Consultant considers that Ergon Energy's forecast for Customer Initiated capital expenditure, for the next regulatory period to be reasonable with the exception of Subdivision and Major Customers, which have been reduced by $10.8M and $173.4M respectively by the Consultant.

The total Customer Initiated CAPEX is shown in the following graph:

**Figure 9-11: Consultant' s Customer Initiated – CAPEX**




*All forecast and historical figures are in June 2004 dollars.*

### 9.9.4 Reliability Improvement

A comparison between Ergon Energy's actual (for 2001/02 and 2002/03) and budget (for 2003/04 and 2004/05) expenditure (in $ millions) and the QCA allowance for Reliability CAPEX is shown in the following table:

**Table 9-33: QCA Determination and Ergon Energy Demand Related – Reliability Improvement CAPEX**

| | | 01/02 | 02/03 | 03/04 | 04/05 | TOTAL |
|---|---|---|---|---|---|---|
| QCA Determination | $ M | 13.5 | 11.0 | 9.9 | 9.5 | 43.8 |
| Ergon Energy Actual/Budget | $ M | 9.9 | 10.8 | 8.6 | 7.5 | 36.8 |

*All forecast and historical figures are in June 2004 dollars.*

It can be seen that expenditure has consistently been slightly lower than that allowed in the Determination. The Consultant considers that Ergon Energy's forecast for Reliability Improvement capital expenditure, for the roll-forward period 1 July 2004 to 30 June 2005, to be reasonable.

In the absence of externally defined targets, Ergon Energy has established its own targets based on general improvements to current performance, mostly focussing on problem hotspot areas and the poorest performing feeders. Ergon Energy has gained a more comprehensive understanding of the required levels of service quality through considerable analysis, customer survey work and consultancy input.

Ergon Energy has taken the three tiers of the Service Quality Incentive scheme (refer to Section 5.6.3) as three separate alternatives, rather than three layers as intended by the QCA.

Tier (a) of the Service Quality Initiative scheme proposed by Ergon Energy is to maintain the current levels of service quality. The view taken by Ergon Energy is that other programs contained in their expenditure forecasts will steadily improve the service quality, as measured by SAIDI and SAIFI, over time to a level close to that shown in Table 9-35. This is due to improvements expected from maintenance recovery programs and from expenditure for replacement and augmentation load growth programs. The only Reliability Improvement expenditure under this first tier is expected to be $7.8M over the next regulatory period to cover a special network monitoring program and some momentary outage mitigation works that are not addressed by other programs.

**Table 9-34: Quality Service Initiative – Tier (a) Expenditure**

| | | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|
| Monitoring program | $ M | 1.5 | 1.6 | 1.5 | 1.6 | 1.6 | 7.8 |

*All forecast and historical figures are in June 2004 dollars.*

The SAIDI target for Tier (a) is:

**Table 9-35: Quality Service Initiative – Tier (a) SAIDI Targets**

| | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL Reduction |
|---|---|---|---|---|---|---|
| SAIDI (minutes) | 490 | 489 | 497 | 470 | 453 | -37 |

The expenditure for Tiers (b) and (c) are discussed in Section 11.

### 9.9.5 System – Other and Load Energy Management

A comparison between Ergon Energy's actual (for 2001/02 and 2002/03) and budget (for 2003/04 and 2004/05) expenditure (in $ millions) and the QCA allowance for System Other CAPEX is shown in the following table:

**Table 9-36: QCA Determination and Ergon Energy Demand Related – System Other CAPEX**

| | | 01/02 | 02/03 | 03/04 | 04/05 | TOTAL |
|---|---|---|---|---|---|---|
| QCA Determination | $ M | 23.0 | 17.9 | 14.0 | 13.4 | 68.3 |
| Ergon Energy Actual/Budget | $ M | 3.0 | 1.0 | 5.2 | 17.8 | 27.0 |

*All forecast and historical figures are in June 2004 dollars.*

It can be seen that Ergon Energy has significantly underspent the allowance in the Determination to date, but proposes to increase spending in 2004/05. The increase in 2004/05 is attributed to the replacement of the SCADA Master Station. The Consultant considers that Ergon Energy's forecast for System Other capital expenditure, for the roll-forward period 1 July 2004 to 30 June 2005, to be reasonable.

The forecast expenditure is shown in the following table:

**Table 9-37: System Other and Load Energy Management Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Sub-Transmission | $ M | 13.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Zone Substation | $ M | 0.0 | 4.6 | 4.7 | 4.6 | 4.7 | 4.8 | 23.5 |
| Distribution | $ M | 2.5 | 3.6 | 3.6 | 3.6 | 3.2 | 2.5 | 16.6 |
| Load Energy Management | $ M | 1.9 | 0.4 | 1.4 | 1.3 | 1.3 | 1.4 | 5.8 |
| Ergon Energy - Total | $ M | **17.8** | **8.6** | **9.8** | **9.5** | **9.3** | **8.7** | **45.9** |

*All forecast and historical figures are in June 2004 dollars.*

Ergon Energy has allowed $5M per year for six years to bring substation fences up to the standard required for the draft new specifications / guidelines. This estimate is based on advice from other Australian utilities of the cost per meter for the modifications and replacements of fencing to the new standard to be between $800 and $1,000 per meter.

The expenditure for distribution is for protection and control works including:

- Augment Isolate SWER schemes;
- Augment Feeder protection (safety review);
- Install Sensitive Earth Fault ("SEF") protection on distribution feeders;
- Install Distribution transformer LV fuses; and
- Install New RTU in zone substations.

The expenditure for load energy management includes:

- Install Turtle Remote meter reading (remote sites); and
- Remote Read of meters (Proximity or Probe).

The Consultant considers the forecast expenditure to be reasonable.

### 9.9.6 Non-System

A comparison between Ergon Energy's actual (for 2001/02 and 2002/03) and budget (for 2003/04 and 2004/05) expenditure (in $ millions) for Non-System CAPEX is shown in the following table:

**Table 9-38: QCA Determination and Ergon Energy Non- System Expenditure**

| | | 01/02 | 02/03 | 03/04 | 04/05 | TOTAL |
|---|---|---|---|---|---|---|
| QCA Determination | $ M | 76.9 | 70.5 | 37.8 | 37.2 | 222.4 |
| Ergon Actual/Budget | $ M | 56.2 | 56.5 | 60.0 | 69.5 | 242.2 |

*All forecast and historical figures are in June 2004 dollars.*

The QCA Determination figures are taken from the QCA Final Determination and Capital Expenditure Study - Ergon Energy by PB Associates. All figures are June 2004 dollars.

It can be seen that Ergon Energy's expenditure is expected to be slightly above that allowed in the previous Determination, with underspending in the first two years and overspending in the final two years. The increase in 2004/05 is due to a new computer system and is considered by the Consultant to be reasonable.

**Table 9-39: Non - System Expenditure**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| Change Program | $ M | 14.6 | 22.4 | 17.5 | 17.5 | 17.5 | 17.5 | 92.4 |
| Computer Facilities | $ M | 6.2 | 14.3 | 8.1 | 9.1 | 8.2 | 7.1 | 46.8 |
| Vehicles & Mobile Plant | $ M | 27.3 | 25.0 | 25.0 | 25.8 | 26.3 | 21.7 | 123.7 |
| Land & Buildings | $ M | 15.4 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 60.0 |
| Other Fixed Assets | $ M | 5.9 | 1.2 | 1.1 | 0.9 | 0.9 | 1.1 | 5.3 |
| Other Unclassified Acquisitions | $ M | 0 | 1.0 | 1.0 | 1.0 | 2.0 | 2.0 | 7.0 |
| **ERGON ENERGY - Total** | **$ M** | **69.5** | **75.8** | **64.7** | **66.3** | **66.9** | **61.4** | **335.2** |

*All forecast and historical figures are in June 2004 dollars.*

The "Change program" incurs additional expenditure in 2004/05 and 2005/06 for implementation of a new ERP. The other expenditure for this category includes:

- Joint working arrangements with other organisations;
- Joint working arrangements with other organisations;
- Changes in corporate vision;
- Changes in government policy; and
- Compliance issues.

The "Computer facilities" includes:

- Desktops, laptops and workstations;
- Network and Citrix servers;
- Printers;
- Data Centre;
- Software systems and applications;
- Office equipment; and
- Telecommunications equipment.

Part of the Computer facilities expenditure is to install a DMS System ($9.850M).

The "Land & Buildings" category includes:

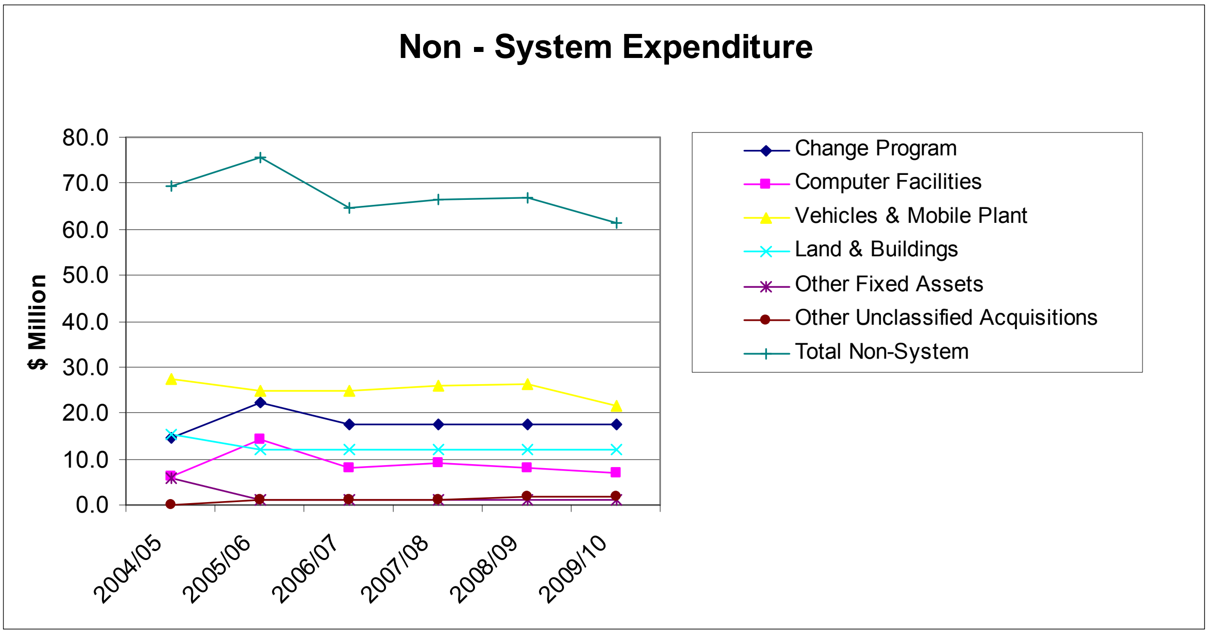
- Buildings;
- Office Machines; and
- Furniture & Equipment.

The "Other Fixed Assets" category includes:

- Replace Mobiles;
- Replace Batteries;
- Replace Solar Equipment;
- Replace Rectifiers;
- Replace Repeaters;
- Replace Buildings;
- Replace Bases;
- Replace Towers; and
- Replace Links.

The "Other Unclassified Acquisitions" consists of Research and Development to apply new technology to achieve efficiencies necessitated by the CPI-X regulatory approach. This has been estimated at $1M initially and increasing to 1% of CAPEX and OPEX over a 15 year period.

**Figure 9-12: Non – System Expenditure**




*All forecast and historical figures are in June 2004 dollars.*

The Consultant considers the forecast expenditure to be reasonable.

## 9.10 Consolidated CAPEX Program

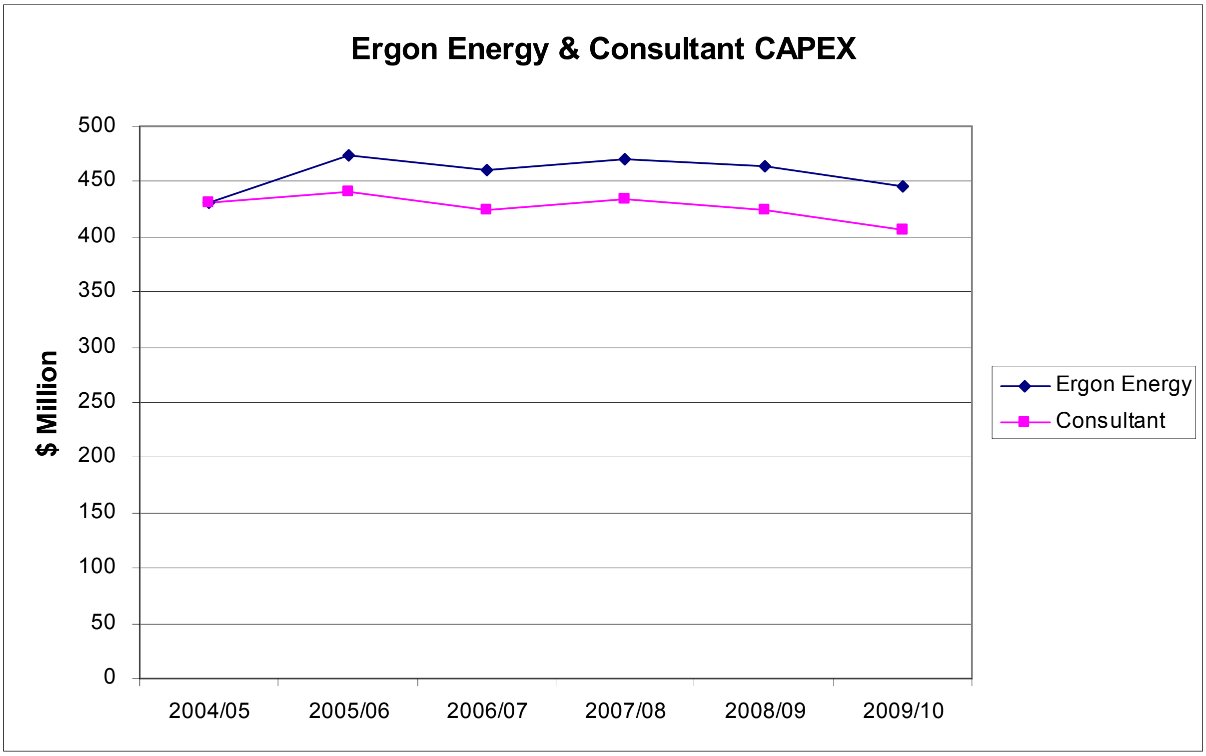
The total CAPEX expenditure proposed by Ergon Energy and by the Consultant are summarised in the table and graph below and detailed in the attached Appendix 14.10:

**Table 9-40: Ergon Energy and Consultant's Consolidated CAPEX**

| | | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|---|
| **Ergon Energy** | | | | | | | | |
| Asset Replacements | $ M | 98.4 | 136.0 | 130.4 | 131.6 | 128.3 | 129.1 | 655.4 |
| Corporate Initiated | $ M | 55.9 | 105.3 | 104.7 | 110.6 | 100.7 | 83.7 | 505.2 |
| Customer Initiated | $ M | 183.9 | 146.8 | 149.8 | 151.2 | 156.5 | 160.8 | 765.1 |
| Reliability Improvement | $ M | 7.5 | 1.5 | 1.6 | 1.5 | 1.6 | 1.6 | 7.8 |
| System Other | $ M | 17.8 | 8.6 | 9.8 | 9.5 | 9.3 | 8.7 | 45.9 |
| Non System | $ M | 69.5 | 75.8 | 64.7 | 66.3 | 66.9 | 61.4 | 335.1 |
| **Total CAPEX** | $ M | 433.0 | 474.0 | 460.9 | 470.9 | 463.3 | 445.4 | 2,314.4 |
| | | | | | | | | |
| **Consultant** | | | | | | | | |
| Asset Replacements | $ M | 98.4 | 136.0 | 130.4 | 131.6 | 128.3 | 129.1 | 655.4 |
| Corporate Initiated | $ M | 55.9 | 105.3 | 104.7 | 110.6 | 100.7 | 83.7 | 505.2 |
| Customer Initiated | $ M | 182.4 | 112.7 | 114.0 | 114.5 | 118.2 | 121.5 | 580.9 |
| Reliability Improvement | $ M | 7.5 | 1.5 | 1.6 | 1.5 | 1.6 | 1.6 | 7.8 |
| System Other | $ M | 17.8 | 8.6 | 9.8 | 9.5 | 9.3 | 8.7 | 45.9 |
| Non System | $ M | 69.5 | 75.8 | 64.7 | 66.3 | 66.9 | 61.4 | 335.1 |
| **Total CAPEX** | $ M | 431.6 | 440.0 | 425.1 | 434.1 | 425.0 | 406.0 | 2,130.2 |

*All forecast and historical figures are in June 2004 dollars.*

**Figure 9-13: Ergon Energy and Consultant Total CAPEX**




*All forecast and historical figures are in June 2004 dollars.*

# 10 CAPEX/OPEX TRADE-OFFS

There is a relationship between CAPEX and OPEX. Increased CAPEX can lead to a reduction in OPEX in the short term (for example, the installation of new equipment would reduce the requirement for maintenance) and a reduction in CAPEX may result in a short term increase in OPEX (for example, the deferral of a capital project may lead to increased maintenance costs). In the longer term, expenditure on CAPEX to install additional assets will result in an increase in operation and maintenance activity and thus an increase in OPEX. When developing expenditure proposals for CAPEX and OPEX, the whole-of-life costs should be considered, so for a capital project, the impact of the project on OPEX should be identified and vice versa.

In the Consultant’s experience, this issue of CAPEX/OPEX trade-offs is not handled well by Australian distributors. The review of capital projects (refer to Section 9.5) indicates that Ergon Energy is fairly typical in this regard.

The following CAPEX items have been identified as resulting in reductions in OPEX:

- SCADA upgrade with associated RTUs and control equipment;
- Rationalisation of control centres from 5 to 2 (this will result in an initial increase in OPEX to cater for the transition period);
- Increased meter replacements;
- Replacement of small copper and rusty steel conductors;
- Replacement of aged XLPE and sub-transmission underground cables;
- Replacement of line switchgear; and
- Replacement of electronic and electro-mechanical relays.

The Consultant considers that all of these items have been appropriately recognised in Ergon Energy’s forecasts of OPEX and therefore the Consultant does not expect any further changes to either CAPEX or OPEX due to trade-offs.

It is the Consultant’s experience that reductions in OPEX due to CAPEX programs are of a lower magnitude than the CAPEX involved – the driver for the expenditure is generally capacity, reliability or safety rather than reducing maintenance/operating expenditure.

An issue here is the approach to capitalisation of assets. Ergon Energy capitalises replacement works on a line only when a number of minor projects are packaged together and forms a significant block of work at a feeder level. This is because of the limitations imposed by Ergon Energy’s financial system which is not set up to handle individual projects such as the replacement of a single pole (the system is set up on a HV feeder basis). This is not in line with general industry practice, where the replacement of a single pole, for example, is capitalised and the old pole retired. As a result, the financial register is not updated for individual small projects, resulting in some undervaluing of the asset base (the asset inventory is updated). This would be offset to some extent by the practice of capitalising some minor maintenance items (eg. stay wire and insulator replacements) when carrying out major feeder works. The Consultant considers the net financial impact to be minimal

# 11 IMPROVEMENTS TO SERVICE QUALITY

As discussed in Section 9.9.4, Ergon Energy has taken the three tiers of the Service Quality Incentive scheme as three separate alternatives, rather than three layers. Ergon Energy has conducted a comprehensive and detailed analysis of network performance as a sound foundation for establishing performance targets and expenditure forecasts.

## 11.1 Tier (a)

Ergon Energy has forecast OPEX of $1,064M and CAPEX of $2,314M for the period 2005/06 to 2009/10, and has projected an improvement in SAIDI performance as shown in Table 11-1:

**Table 11-1: Quality Service Initiative – Tier (a) SAIDI Targets**

| | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL Reduction |
|---|---|---|---|---|---|---|
| SAIDI (minutes) | 490 | 489 | 497 | 470 | 453 | -37 |

## 11.2 Tier (b)

For Tier (b) of the Service Quality Incentive scheme, Ergon Energy have utilised the results of a customer “willingness to pay” survey to arrive at an expenditure budget, although the resultant service quality does not achieve the targets demanded by customers as determined by the survey. This expenditure is expected to be $38.2M over the next regulatory period and is targeted to achieve a 16 SAIDI minute improvement over the next regulatory above the normal SAIDI improvements. Of this expenditure, $7.9M is for the special network monitoring programme and momentary outage mitigation works allowed for under the Tier (a) with an additional $28.5M for improvement works.

The expenditure for Tier (b) (which includes the work for Tier (a)) is as follows:

**Table 11-2: Quality Service Initiative – Tier (b) Expenditure**

| | | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|
| Monitoring program | **$ M** | 1.6 | 1.6 | 0.0 | 0.0 | 0.0 | 3.2 |
| MAIFI mitigation program | **$ M** | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 4.7 |
| Unallocated | **$ M** | 5.7 | 5.7 | 5.7 | 5.7 | 5.7 | 28.4 |
| Total | **$ M** | **8.2** | **8.2** | **6.6** | **6.6** | **6.6** | **36.3** |

*All forecast and historical figures are in June 2004 dollars.*

The SAIDI target for Tier (b) is:

**Table 11-3: Quality Service Initiative – Tier (b) SAIDI Targets**

| | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL Reduction |
|---|---|---|---|---|---|---|
| SAIDI (minutes) | 490 | 485 | 489 | 458 | 437 | -53 |

### 11.3 Tier (c)

For Tier (c) of the Service Quality Incentive scheme, Ergon Energy has again used the customer survey results to determine the appropriate expenditure budget. This expenditure is expected to be $138.5M over the next regulatory period and is targeted to achieve an 80 SAIDI minute improvement above the normal SAIDI improvements.

The expenditure is to be allocated to projects in three areas:

- Feeder threshold program – Feeders on which customers, on specifically identified feeders, are willing to fund improvements.
- Community threshold program – This program is aimed at communities which have a frequency of outages above a threshold and are prioritised based on the gap between the current performance and the threshold target. This program aims improvements to feeders upstream of the community by augmentation of the major distribution feeders and/or sub-transmission system which are not covered by normal augmentation or other projects.
- Rising customer expectations program – This program is based on the premise that customer expectations will continue to rise during the next regulatory period and thus this program is aimed at meeting those rising expectations.

The expenditure for Tier (c) (which includes the work for Tiers (a) and (b)) is shown below:

**Table 11-4: Quality Service Initiative – Tier (c) Expenditure**

| | | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|
| Feeder threshold program | **$ M** | 7.3 | 7.3 | 7.3 | 7.3 | 7.3 | 36.6 |
| Community threshold program | **$ M** | 11.2 | 10.1 | 12.8 | 37.5 | 9.5 | 81.0 |
| Rising customer expatiations program | **$ M** | 4.2 | 11.0 | 3.3 | 2.1 | 0.0 | 20.7 |
| Monitoring program | **$ M** | 1.6 | 1.6 | 0.0 | 0.0 | 0.0 | 3.2 |
| MAIFI mitigation program | **$ M** | 1.0 | 1.0 | 1.0 | 1.0 | 0.9 | 4.8 |
| Total | **$ M** | **25.3** | **31.0** | **24.4** | **47.9** | **17.7** | **146.3** |

*All forecast and historical figures are in June 2004 dollars.*

The SAIDI target for Tier (c) is shown in the following table:

**Table 11-5: Quality Service Initiative – Tier (c) SAIDI Targets**

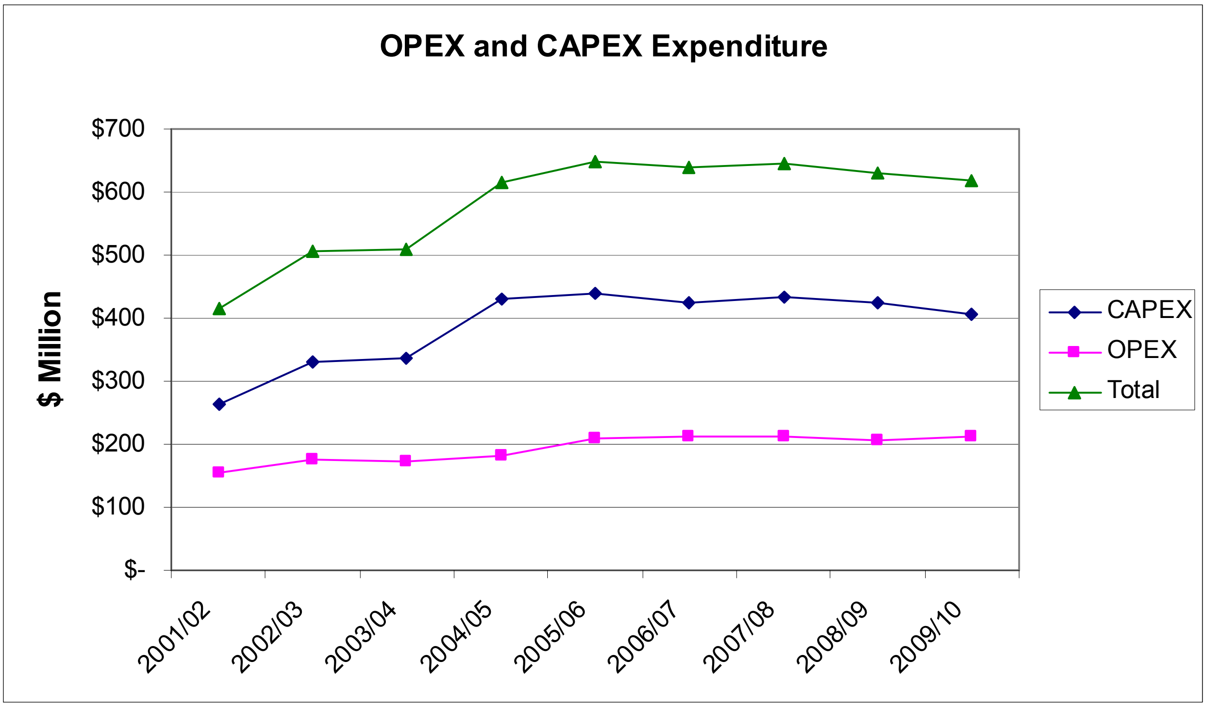
| | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | TOTAL Reduction |
|---|---|---|---|---|---|---|
| SAIDI (minutes) | 490 | 476 | 462 | 421 | 373 | -117 |

The Consultant considers that the expenditures and expected results for Tiers (a), (b) and (c) appear to be reasonable. The Consultant would also expect to see some reduction in OPEX associated with the improvements to the network with Tiers (b) and (c).

# 12 RESOURCE CAPABILITY

The Consultant has forecast significant increases in the level of CAPEX and OPEX spending, above current levels for the period commencing 2004/05.

**Figure 12-1: Consultant's Total OPEX and CAPEX Expenditure**




*All forecast and historical figures are in June 2004 dollars.*

Ergon Energy has prepared a comprehensive resource plan which details the organisation's capacity to find the resources (internal and external) required for the delivery of the 2004/05 works program and outlines the proposals for delivery of the five year works program. The plan identifies the current resource levels, the future resources required and the source of additional resources to deliver the 2004/05 program. This analysis has taken into account the skills required, attrition rates, overtime and training requirements.

Ergon Energy does not consider that the provision of materials will be an issue, based on the satisfactory result achieved with recent increases in requirements.

## 12.1 Internal Resources

Ergon Energy conducted a detailed review of its resources last year and commenced a national recruitment campaign early this year. Ergon Energy has filled many of the internal positions and is well on the way to filling the remainder. Apprenticeships and specialist traineeships are being utilised to develop the resource capability. The level of recruitment of internal resources has been based on the experience with recruiting in 2003/04.

Ergon Energy has already significantly increased its contract and project management resources in order to effectively manage the significant increase in external work.

## 12.2 External Resources

Over the last 12 months, Ergon Energy has been gearing up for a significant increase in external workload by establishing a panel of external resource providers, concentrating on large companies.

With regard to external resources, Ergon Energy has contacted its major service providers to determine their resource capabilities. Ergon Energy has been dealing with the larger companies who have the capability to ramp up resource levels, and has established long-term contracts. Ergon Energy proposes to offer larger blocks of work to external service suppliers, thus increasing the likelihood of the suppliers gearing up their resource levels.

Ergon Energy has also liaised with Energex to ensure that both distributors will not be counting on the availability of the same resources. Ergon Energy believes that they have already established a strong relationship with the external resource suppliers and feels confident that the resources will be made available, based on detailed discussions held with the suppliers. Ergon Energy also proposes to offer a significant number of projects as “turnkey” projects.

## 12.3 Resourcing for 2004/05 to 2009/10

Ergon Energy proposes to take a similar approach to meet the forecast increase in 2005/06, after which there is a slight decline in resource requirements. The specific initiatives proposed include:

- A continuation of internal staff development and growth strategies; and
- Further development of the relationships with external service providers to enable improved matching of obligated resource supply to forecast demand.

The actions taken to meet the increased workload in 2004/05 will lay the foundation for the developing and procuring adequate resources for 2005/06 and beyond.

## 12.4 Conclusion

The Consultant is aware of increasing demands in Australia and New Zealand for skilled electricity supply personnel, covering trades, technical and professional areas, particularly in the light of the increasing average age of such personnel and significant workload increases arising from recent and current pricing reviews in other jurisdictions. Notwithstanding this, the Consultant is reasonably confident of Ergon Energy’s capability to resource the forecast workload for 2004/05, but considers there is an increased risk with regard to 2005/06. This is not seen as a great concern, as it is the first year of the Regulatory period and is followed by a forecast decrease in resource requirements. Delays in obtaining the additional resources would thus result in a shift of some expenditure to later years, but are unlikely to impact on the total spending over the full regulatory period.

# 13 GLOSSARY

| | |
|---|---|
| AAAC | All Aluminium Alloy Conductor |
| AAC | All Aluminium Conductor |
| ABB | ASEA Brown Boveri |
| ABOM | Automatic Bill of Materials |
| ABS | Air Break Switch |
| ACR | Auto Reclosers |
| ACSR | Aluminium Conductor Steel Reinforced |
| AEF | Asset Energy Factor |
| AIDM | Asset Identification and Defects Management |
| BTH | British Thomson Houston |
| BRW | Burns and Roe Worley Pty Ltd |
| CAIDI | Customer Average Interruption Duration Index |
| CAPEX | Capital expenditure |
| CARS | Corrective Action Requests |
| CB | Circuit Breaker |
| CNS | Change Notification System |
| CPM | Capital Project Management |
| CT | Current Transformer |
| DC | Direct Current |
| DGA | Dissolved Gas Analysis |
| DLA | Dielectric Loss Angle |
| DMS | Distribution Management System |
| DNSP | Distribution Network Service Provider |
| DSA | Distribution System Automation |
| DUOS | Distribution Use of System |
| EBA | Enterprise Bargaining Agreement |
| EDMS | Ergon Drawings Management Solution |
| EPA | Environmental Protection Authority |
| EPV | Elevating Platform Vehicle |
| ERP | Enterprise Resource Planning |
| EUF | Energy Utilisation Factor |
| FMC | Field Mobile Computing |
| GEC | General Electric Corporation |
| GIS | Geographic Information System |
| GRASS | Grouped Assemblies |
| GSL | Guaranteed Service Level |
| HDBC | Hard Drawn Bare Copper |
| HV | High voltage |

| | |
|---|---|
| IR | Industrial Relations |
| IRC | Investment Review Committee |
| IT | Information Technology |
| IVR | Interactive Voice Recording |
| KPI | Key Performance Indicator |
| kV | Kilo volts i.e. 1,000 volts |
| LIMS | Load Information Management System |
| LMP | Line Maintenance Planning |
| LV | Low voltage |
| MAIFI | Momentary Average Interruption Frequency Index |
| MD | Maximum Demand |
| MDA | Metering Data Agency |
| MDI | Maximum Demand Indicators |
| MIMS | Management Informational Maintenance System |
| MMA | McLennan Magasanik Associates Pty Ltd |
| MVA | Mega volt amps i.e.1,000,000 volt amps |
| MV90 | Multi Vendor 90 |
| MWh | Mega watt hours i.e. 1,000,000 watt hours |
| MW | Mega watts i.e.1,000,000 watts |
| NEC | National Electricity Code |
| NEMMCO | National Electricity Market Management Company |
| NIER | National Institute of Economic and Industry Research |
| NIRC | Network Investment Review Committee |
| NLF | Network Load Factor |
| NR&E | Natural Resources, Mines and Energy |
| OPEX | Operating expenditure |
| PLC | Programmable Logic Controller |
| POE | Probability of Exceedance |
| PM | Plant Management |
| PUF | Plant Utilisation Factor |
| QCA | Queensland Competition Authority |
| RAP | Reliability Assessment Planning |
| RCM | Reliability Centred Maintenance |
| RMU | Ring Main Unit |
| RTU | Remote Terminal Unit |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCADA | Substation Control and Data Acquisition |
| SCAMS | Substation Contingency Asset Management System |
| SEF | Sensitive Earth Fault |

| | |
|---|---|
| SF6 | Sulphur Hexafluoride |
| SFU | Static Frequency Unit |
| SKM | Sinclair Knight Mertz |
| SVC | Static VAR Compensator |
| SWER | Single Wire Earth Return |
| TaDS | Transmission and Distribution Services |
| TUOS | Transmission Use of System |
| UG | Under Ground |
| UPS | Uninterruptible Power Supply |
| URD | Underground Residential Distribution |
| VAr | Volt Amp Reactive |
| VRLA | Valve Regulated Lead Acid |
| VT | Voltage Transformer |
| WIP | Work in Progress |
| XLPE | Cross-linked Polyethylene |
| YOM | Year of Manufacture |
| ZSS | Zone Substation |

# 14 APPENDICES

## 14.1 Site Visits and Interviews

| DATE & LOCATION | CONSULTANT PERSONNEL | KEY ERGON ENERGY PERSONNEL | TOPIC |
|---|---|---|---|
| 23/3/04<br>Brisbane | Bob Coulter<br>Ian Marks<br>Graham Batcheler<br>Jeff Randles | Terry Effney<br>Neil Lowry<br>Tony Pfeiffer<br>Peter Brennan<br>Gary Hunter<br>Denis Harris<br>Mike Dougan<br>Ken Ash<br>David Neilson<br>Bob Minchin<br>Leigh D'Arcy | Overview & Strategic Perspectives |
| 24/3/04<br>Various Locations | Bob Coulter<br>Ian Marks<br>Graham Batcheler<br>Jeff Randles | Neil Lowry<br>Tony Pfeiffer<br>Leigh D'Arcy<br>Denis Harris<br>Elton Ross<br>Steve Harris | Site Visits – Maryborough, Bundaberg, Emerald |
| 25/3/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | Denis Harris<br>Tony Loveday<br>Perry Tonking | Planning |
| 26/3/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | Mark Steindl<br>Denis Harris<br>Ken Ash | Zone Substation Design |
| 26/3/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | Ken Ash<br>Jim Brooks<br>Greg Chapman | Transmission & Distribution Line Design |
| 26/3/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | David Neilson<br>Paul Roberts | Metering |
| 26/3/04<br>Rockhampton | Bob Coulter<br>Ian Marks<br>Graham Batcheler<br>Jeff Randles | Neil Lowry<br>John Passaris<br>Tony Pfeiffer<br>Mark Lawrence | Visit Control Centre & National Contact Centre |
| 27/3/04<br>Townsville | Ian Marks<br>Graham Batcheler | Neil Lowry<br>Mike Dougan<br>Leigh D'Arcy | Capital Contributions, Project Approval & Project Ranking |
| 27/3/04<br>Townsville | Bob Coulter<br>Ian Marks<br>Graham Batcheler<br>Jeff Randles | Neil Lowry<br>John Christensen | Visit Control Centre |

| DATE & LOCATION | CONSULTANT PERSONNEL | KEY ERGON ENERGY PERSONNEL | TOPIC |
|---|---|---|---|
| 30/4/04 | Bob Coulter<br>Jeff Randles<br>Erika Twining | Leigh D'Arcy<br>David Neilson<br>Ken Ash<br>Allan Vollmerhause<br>Tony Pfeiffer<br>Paul Asnicar<br>Leon Powell<br>Telephone hook-up:<br>• Sam Nicdosi | OPEX Budget |
| 3/4/04 & 5/5/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | | Capital Project Review |
| 4/5/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | Paul Asnicar<br>Leigh D'Arcy<br>Dennis Harris<br>Phillip Spencer | Capital Budget - Growth |
| 4/5/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | Paul Asnicar<br>Mike Dougan | Capital Budget – Customer Projects |
| 4/5/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | Paul Asnicar<br>Peter Brennan | Capital Budget – System Other |
| 4/5/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | Paul Asnicar<br>Peter Brennan<br>Leon Powell<br>David Neilson<br>Telephone hook-up:<br>• Ken Ash<br>• Keith Norris<br>• Tony Sanders | Capital Budget - Replacement |
| 4/5/04<br>Rockhampton | Ian Marks<br>Graham Batcheler | Gary Hunter<br>Peter Brennan | Capital Budget - Reliability |
| 5/5/04 | Jeff Randles<br>Erika Twining | Telephone hook-up:<br>John Christensen | Network Operations Budget |
| 6/5/04<br>Townsville | Ian Marks<br>Graham Batcheler | | Capital Project Review |

## 14.2 Key Documents Accessed

Ergon Energy Submission to BRW Number 1 - 10/2/04

Ergon Energy Submission to BRW Number 2 - 29/4/04

20 Year Vision for Asset Management

Managing Escalated Internal Complaints Procedure

Environmental Strategic & Operational Objectives & Targets Register

Network Planning Criteria – Deliverable NP02

Five Year Sub-transmission Network Augmentation Plans

Regional Capability & 5 Year Distribution Augmentation Plan- Summary Report & Regional Reports

Policy Relating to New Connections

New Capital Contributions Methodology Supporting Information

Ergon Energy Corporate Governance Policy

Network Investment Review Committee Guidelines

Distribution Business 2003/04 Budget Guidelines

Risk Management Methodology Reference Guide

Asset Management Drivers in Ergon Energy

Review of Demand Forecasts Information Request

Distribution Business Plan 2003/04

Network Asset Management Strategies

Corporate Property Budget 2004/05

Distribution Monthly Reports

Distribution Information Framework

Consumer Preferences for Service Standards in Electricity Distribution (KPMG Report)

Review of Ergon Energy's Measurement & Reporting of Network Reliability (PBA Report)

Fleet Replace Program

Information Systems Strategy

Network Asset Maintenance & Replacement Plans (& Supporting Spreadsheets)

Final Determination – Regulation of Electricity Distribution May 2001 – QCA

Service Quality Incentive Scheme for Electricity Distribution Services in Queensland Feb 2004 – QCA

Customer Service Quality Expectations and Network Performance

Major Customer Connections CAPEX Pass Through

Resource Plan Summary

Ergon Energy Control Centre Strategy Project – Future Vision

Ergon Energy Control Centre Strategy Project – Current State Report

SCADA Strategy

Network Operations Emergency Management Plan

## 14.3 Organisation Structure

**Figure 14-1: Ergon Energy Corporation Organisational Structure**

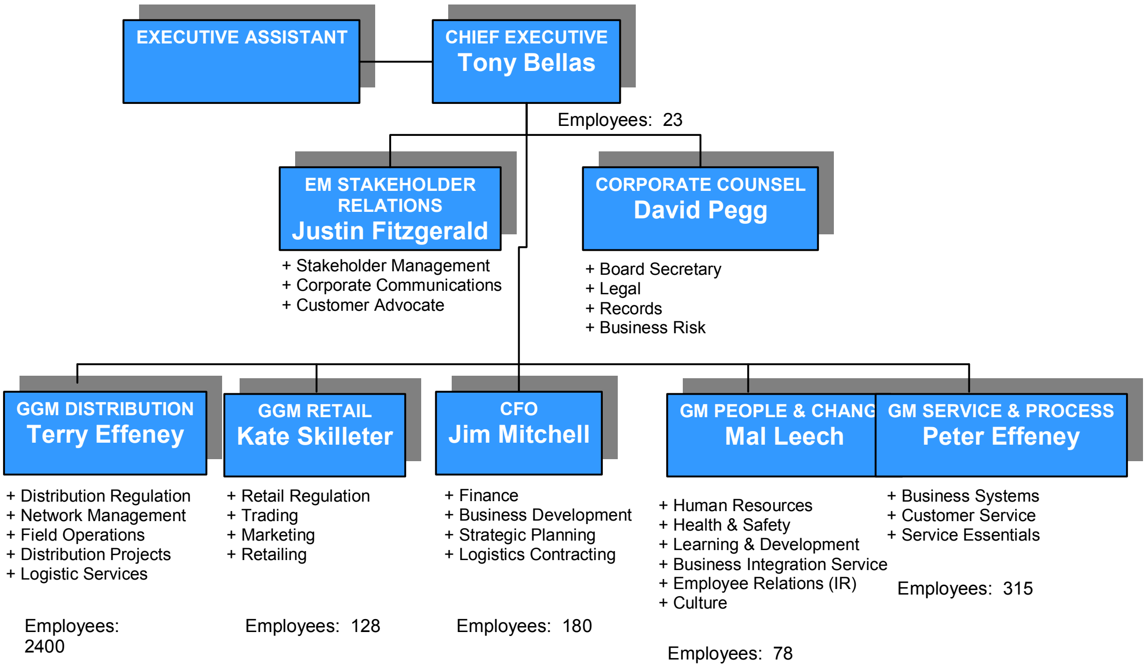
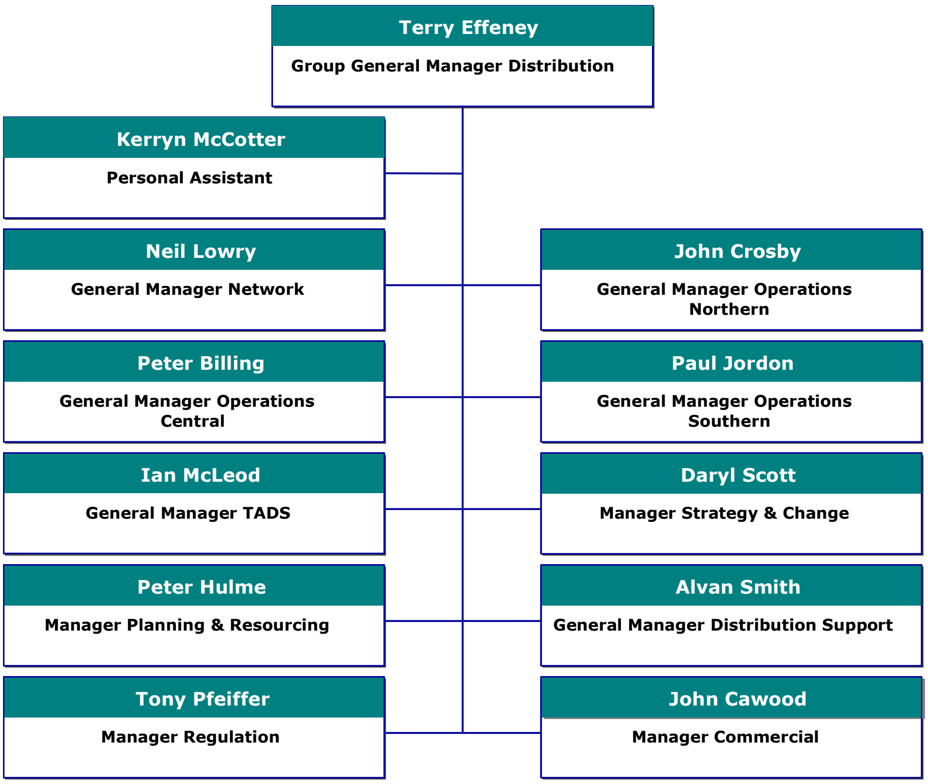



**Figure 14-2: Ergon Energy Electricity Distribution Organisational Structure**



### 14.4 Areas of Overhead Expenses

The overhead and corporate support costs cover the follow range of areas:

- Finance and Administration, covering the following range of activities:
    - Audit Regulation;
    - Claims Personnel;
    - Business Risk & Compliance;
    - Business Advisory Services;
    - GST;
    - FBT;
    - Tax General;
    - Treasury;
    - Planning;
    - Audit (internal);
    - Legal;
    - Energy Risk Management;
    - Accounts Receivable;
    - Group Management;
    - Board Reporting;
    - Accounting Processing;
    - System Accounting;
    - Group Financial Controller;
    - Tax Consolidations;
    - Tax Reform;
    - Tax Return; and
    - Payroll.
- Business System and Processes, covering the following range of activities:
    - Telecommunications;
    - Data Network;
    - Business Report Support;
    - Help Desk & Desktop;
    - Customer Systems Franchise;
    - Customer Systems Contestable;
    - HR Systems;
    - Logistics (Purchasing, Inventory & Fleet);
    - Asset Systems;
    - Works Systems;
    - Office Systems;
    - Ecommerce;
    - Corp. share Business process support & ref info;
    - Customer Services Contestable; and

  - Share of Corporate portion of HR Systems.
- Human Resources, covering the following range of activities:
  - Career Transition;
  - HR Services;
  - Employee Relations;
  - Training;
  - Workplace Health & Safety;
  - Change Management - Program Office;
  - Change Management - share of Corporate portion of Change costs;
  - Share of Corporate portion of Career Transition costs;
  - Share of Corporate portion of HR Services costs;
  - Share of Corporate portion of Employee Relations costs;
  - Share of Corporate portion of Training costs; and
  - Share of Corporate portion of WH&S costs.
- CEO Board and Stakeholder relations, covering the following range of activities:
  - Chief Executive Officer;
  - Board; and
  - Secretarial.
- Network Regulatory Services:
- Insurance Premiums, covering the following range of expenses:
  - Industrial & Special Risk;
  - Combined Liability;
  - Professional Indemnity;
  - Supplementary Legal Expense;
  - Statutory Liability;
  - Crime;
  - Contract Works;
  - Motor Vehicle (material damage);
  - Marine (Transit);
  - Travel;
  - Aviation (Hull);
  - Non-owned Aviation; and
  - Brokerage Fee.
- Insurance Claims;
- Telecommunications, covering the following range of expenses:
  - Mobile data;
  - Mobile voice;
  - Outbound voice (desk, onramps);
  - Inbound voice (1800*, 13* numbers etc);
  - Video conference (ISDN, conferlink);

  - Satellite phones;
  - Internet; and
  - Data network services (wide area network).
- Brisbane Office, covering the following range of expenses:
  - Brisbane office rent & occupancy costs;
  - Repairs & maintenance - buildings & equipment; and
  - Other Office Costs eg. Amenities, First Aid etc.
- Property Services, covering the following range of expenses:
  - Substations;
  - Generators;
  - Depots;
  - Residences; and
  - Administration.

## 14.5 Summary of Current Maintenance Practices

**Table 14-1: Summary of Inspection and Preventative Maintenance Intervals**

| | Asset | Inspections | Preventative Maintenance | Industry Practice |
|---|---|---|---|---|
| **Transmission and Distribution** | **Overhead Assets** | | | |
| | Sub-transmission lines | 3 yrs. *<br>Annual patrols prior to storm season for critical sub-transmission lines. | N/A | 6 yrs |
| | Pole top <66 kV | 3 yrs.* | | 6 yrs |
| | Pole top > 66kV, wood poles | On request to address chronic reliability or age related problems | | 6 yrs |
| | Pole tops > 66 kV, transmission towers | - None for first 15 yrs.<br>- Climb reference sample every 5 yrs between 15 yrs and 30 yrs.<br>- After 30 yrs climb same reference sample every 2 yrs. | | 6 yrs |
| | Poles | 3 yrs. * | 3 yrs. * | 6 yrs<br>Queensland legislation states 5 yrs. |
| | Service lines | 3 yrs. | N/A | 6 yrs |
| | Line Thermovision | 3 yrs. | N/A | 3 yrs |
| | **Underground Assets** | | | |
| | UG Cables | N/A | Condition monitoring tests every 5 yrs for cables aged over 10 yrs and 15 yrs depending on criticality | Reactive maintenance only.<br>XLPE 2 yearly sheath test. |
| | 11 kV & LV including pillars. | 3 yrs | | Inspection with line and station assets. |
| **Distribution Network** | Ring Main Units (RMU) | 3 yrs | N/A | 12 yrs |
| | Reclosers | 6 months | As per manufacturers recommendations. | 6 & 12 yrs |
| | Load break switches / Sectionalisers | Run to fail | | 6 yrs |
| | Distribution Earthing Systems | SWER earths – 3 yrs.<br>Non-SWER earths – 9 yrs | | 6 yrs |
| | **Distribution Transformers** | | | |
| | Enclosed substation - major | 6 mths | Replace / overhaul as required | Indoor and enclosed - 6 yrs<br>Outdoor – 2 yrs |
| | Enclosed substation - minor | 12 mths | | |
| | Padmount - large | 12 mths | | |
| | Padmount – small | 3 yrs | | |

| | Asset | Inspections | Preventative Maintenance | Industry Practice |
|---|---|---|---|---|
| **Zone Substations** | Zone Substation Inspections | 6 mths (minor) & 12 mths (major) | N/A | 1 mth & 6 mths |
| | Zone Substation property | Small site – 6 mths<br>Large site – 4 mths | N/A | 1 year |
| | Thermo-scan | 2 yrs | | 2 yrs |
| | **Power Transformers** | | | |
| | General Maintenance | Zone Sub Insp. | 4 yrs. | At substation inspection. |
| | DGA | 2 yrs | | 2 yrs |
| | OLTCs (33/110/132 kV) | Zone Sub Insp. | 4 yrs (time based only) | Maintenance after designated operations only |
| | **Circuit Breakers** | | | |
| | Oil CBs | Zone Sub Insp. | 4 yrs | 6 years |
| | Vac / Gas CBs | Zone Sub Insp. | 6 yrs | |
| | CB Maintenance after faults | - | At scheduled maintenance | Maintenance according to points system based on fault currents. |
| | **Ancillary Equipment** | | | |
| | Exposed Busbars | Zone Sub Insp. | 4 yrs | 6 yrs |
| | ABS / Isolators | Zone Sub Insp. | 4 yrs | 6 yrs |
| | Earth switch | Zone Sub Insp. | 4 yrs | |
| | Instrument transformer | | Oil sample and DGA – 3 yrs | <66 kV - 4 yrs, oil test, incl.DGA<br>>66 kV - 2 yrs oil test incl. DGA |
| | Earth Mats | | Test resistance every 10 yrs | 1 yr |
| | Portable earthing equipment | | Test every 6 mths | |
| | Battery banks | | Impedance test every 1 yr | |
| | Protection schemes | | 4 yrs | Interval depends on points allotted according to age, customer impact and relay performance. |
| **Vegetation** | Fast pre-storm patrol | | | |
| | Planned vegetation management | | | 3 years |

## 14.6 Consolidated OPEX program

**Table 14-2: Ergon Energy OPEX Expenditure (incl. overheads)**

| | | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Maintenance** | | | | | | | | | | | |
| Lines | $M | 36.386 | 56.217 | 77.497 | 87.085 | 92.878 | 94.067 | 93.795 | 78.312 | 79.576 | 34.264 |
| Vegetation | $M | 36.142 | 41.596 | 41.262 | 41.399 | 49.054 | 49.359 | 49.108 | 55.771 | 56.282 | 34.034 |
| Substations | $M | 36.709 | 34.475 | 19.920 | 19.208 | 22.646 | 22.969 | 23.030 | 23.818 | 24.391 | 34.568 |
| Meters | $M | 2.794 | 2.709 | 2.338 | 1.983 | 2.924 | 3.523 | 3.556 | 3.899 | 4.493 | 2.631 |
| **Total Maintenance** | **$M** | **112.031** | **134.997** | **141.017** | **149.675** | **167.502** | **169.917** | **169.489** | **161.799** | **164.742** | **833.449** |
| **Operations** | | | | | | | | | | | |
| Network Operations | $M | 8.744 | 9.628 | 10.255 | 12.759 | 11.920 | 11.994 | 11.933 | 12.228 | 12.424 | 60.499 |
| Customer Service | $M | 33.030 | 25.877 | 23.063 | 21.787 | 32.275 | 33.038 | 33.439 | 34.859 | 36.030 | 169.641 |
| **Total Operations** | **$M** | **41.774** | **35.505** | **33.318** | **34.546** | **44.195** | **45.032** | **45.372** | **47.087** | **48.454** | **230.140** |
| **Total OPEX** | **$M** | **153.804** | **170.501** | **174.335** | **184.221** | **211.697** | **214.949** | **214.861** | **208.887** | **213.196** | **1,063.590** |

**Table 14-3: Consultant's Revised OPEX Expenditure (incl. overheads)**

| | | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|
| **Maintenance** | | | | | | | |
| Lines | $M | 91.949 | 93.126 | 92.857 | 77.529 | 78.780 | 434.241 |
| Vegetation | $M | 48.564 | 48.865 | 48.617 | 55.213 | 55.720 | 256.979 |
| Substations | $M | 22.419 | 22.739 | 22.800 | 23.580 | 24.147 | 115.684 |
| Meters | $M | 2.895 | 3.488 | 3.520 | 3.860 | 4.448 | 18.210 |
| **Total Maintenance** | **$M** | **165.827** | **168.218** | **167.794** | **160.181** | **163.095** | **825.115** |
| **Operations** | | | | | | | |
| Network Operations | $M | 11.801 | 11.874 | 11.814 | 12.106 | 12.300 | 59.894 |
| Customer Service | $M | 31.952 | 32.707 | 33.105 | 34.511 | 35.670 | 167.944 |
| **Total Operations** | **$M** | **43.753** | **44.581** | **44.919** | **46.616** | **47.970** | **227.839** |
| **Total OPEX** | **$M** | **209.580** | **212.799** | **212.713** | **206.798** | **211.064** | **1,052.954** |

*All forecast and historical figures are in June 2004 dollars*

## 14.7 Ergon Energy OPEX forecasts

### 14.7.1 Meters

**Table 14-4: Metering Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Revenue Meters | No. (M) | 1.13 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Inspect & Test Metering | Units | 1,175 | 4,501 | 6,002 | 5,897 | 7,044 | 7,251 | 7,572 | 8,238 | 36,001 |
| | $M | 0.32 | 0.68 | 0.88 | 0.80 | 1.13 | 1.19 | 1.30 | 1.58 | 6.00 |
| Contract Test Metering | Units | 13 | 47 | 68 | 13 | 14 | 13 | 14 | 13 | 67 |
| | $M | 0.06 | 0.20 | 0.29 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.34 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair / Replace Faulty Metering | Units | 6271 | 6811 | 6835 | 7347 | 5854 | 5899 | 5517 | 5436 | 30053 |
| | $M | 0.55 | 0.87 | 0.96 | 0.96 | 0.94 | 0.92 | 0.95 | 0.98 | 4.75 |
| **Emergency** | | | | | | | | | | |
| Repair Faulty Metering | Units | 346 | 295 | 349 | 395 | 368 | 333 | 358 | 357 | 1,811 |
| | $M | 0.05 | 0.05 | 0.05 | 0.06 | 0.05 | 0.05 | 0.05 | 0.05 | 0.27 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | **0.98** | **1.79** | **2.18** | **1.88** | **2.20** | **2.23** | **2.37** | **2.67** | **11.36** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.2 Poles

**Table 14-5: Pole Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Poles | No. (M) | 0.85 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Pole Inspection | Units (M) | | 0.28 | 0.29 | 0.29 | 0.29 | 0.29 | 0.18 | 0.18 | 1.23 |
| | $M | | 16.72 | 17.62 | 17.16 | 17.43 | 17.88 | 10.70 | 10.75 | 73.92 |
| | $/unit | | 59 | 60 | 60 | 60 | 60 | 60 | 60 | 60 |
| **Deferred Corrective** | | | | | | | | | | |
| Guy Maintain | Units (M) | | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.03 | 0.03 | 0.19 |
| | $M | | 0.63 | 0.65 | 0.63 | 0.64 | 0.66 | 0.39 | 0.39 | 2.71 |
| | $/unit | | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| Pole Straighten | Units | | 333 | 344 | 334 | 340 | 349 | 209 | 210 | 1,441 |
| | $M | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.01 | 0.01 | 0.08 |
| | $/unit | | 55 | 55 | 55 | 55 | 55 | 55 | 55 | 55 |
| Chemical Treatment | Units (M) | | 0.20 | 0.21 | 0.21 | 0.21 | 0.21 | 0.13 | 0.13 | 0.89 |
| | $M | | 3.37 | 3.48 | 3.38 | 3.44 | 3.53 | 2.11 | 2.12 | 14.59 |
| | $/unit | | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| Notifiable Pole Nailing | Units | | 126 | 130 | 127 | 129 | 132 | 79 | 79 | 545 |
| | $M | | 0.10 | 0.11 | 0.10 | 0.10 | 0.11 | 0.06 | 0.06 | 0.44 |
| | $/unit | | 813 | 813 | 813 | 813 | 813 | 813 | 813 | 813 |
| Notifiable Pole Replacement | Units | | 559 | 577 | 561 | 571 | 585 | 350 | 352 | 2,420 |
| | $M | | 0.75 | 0.77 | 0.75 | 0.76 | 0.78 | 0.47 | 0.47 | 3.25 |
| | $/unit | | 1342 | 1342 | 1342 | 1342 | 1342 | 1342 | 1342 | 1342 |
| **Emergency** | | | | | | | | | | |
| Guy Maintain | Units | | 341 | 352 | 342 | 348 | 357 | 214 | 215 | 1,476 |
| | $M | | 0.14 | 0.15 | 0.14 | 0.15 | 0.154 | 0.09 | 0.09 | 0.62 |
| Notifiable Pole Nailing | Units | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $M | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Notifiable Pole Replacement | Units | | 671 | 692 | 674 | 685 | 703 | 421 | 423 | 2,904 |
| | $M | | 1.19 | 1.23 | 1.20 | 1.22 | 1.25 | 0.75 | 0.75 | 5.18 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **22.92** | **24.02** | **23.39** | **23.77** | **24.38** | **14.59** | **14.66** | **100.79** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.3 Pole Tops

**Table 14-6: Pole Top Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Pole top structures | No. (M) | 1.221 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Inspect Pole Top | Units | | 8,377 | 22,000 | 52,118 | 52,118 | 52,118 | 52,118 | 52,118 | 260,590 |
| | $M | | 0.43 | 2.11 | 5.00 | 5.00 | 5.00 | 5.00 | 5.00 | 25.02 |
| | $/unit | | 51 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| Clean Insulation | Units | | 616 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 7,500 |
| | $M | | 0.03 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 0.41 | 2.03 |
| **Deferred Corrective** | | | | | | | | | | |
| Straighten Crossarm | Units | | 58 | 93 | 93 | 91 | 89 | 88 | 86 | 447 |
| | $M | | 0.003 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.02 |
| Maintain Pole Top | Units | | 865 | 865 | 865 | 822 | 781 | 742 | 705 | 3,914 |
| | $M | | 0.11 | 0.11 | 0.11 | 0.10 | 0.10 | 0.09 | 0.09 | 0.49 |
| | $/unit | | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 |
| Replace Pole Top | Units | | 434 | 449 | 449 | 440 | 431 | 423 | 414 | 2,157 |
| | $M | | 0.18 | 0.40 | 0.40 | 0.39 | 0.38 | 0.37 | 0.37 | 1.92 |
| | $/unit | | 427 | 890 | 890 | 890 | 890 | 890 | 890 | 890 |
| **Emergency** | | | | | | | | | | |
| Make pole tops safe after fires | Units | | 312 | 312 | 312 | 296 | 282 | 268 | 254 | 1,412 |
| | $M | | 0.05 | 0.05 | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.22 |
| Maintain Pole Top | Units | | 994 | 994 | 994 | 944 | 897 | 852 | 810 | 4,497 |
| | $M | | 0.18 | 0.18 | 0.18 | 0.17 | 0.16 | 0.15 | 0.14 | 0.80 |
| Replace Pole Top | Units | | 643 | 643 | 643 | 611 | 580 | 551 | 524 | 2,909 |
| | $M | | 0.57 | 1.15 | 1.15 | 1.09 | 1.03 | 0.98 | 0.93 | 5.18 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | 1.621 | 4.469 | 7.360 | 7.275 | 7.193 | 7.116 | 7.042 | 35.985 |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.4 Line Conductor and Hardware

**Table 14-7: Line Conductor Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| OH Subtransmission | km | 13,984 | | | | | | | | |
| OH Distribution | km | 43,903 | | | | | | | | |
| OH SWER | km | 62,500 | | | | | | | | |
| OH LV | km | 15,234 | | | | | | | | |
| **OH Total** | **km** | **135,621** | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Thermo-scan | km | | 37,081 | 37,060 | 37,060 | 37,060 | 37,060 | 37,060 | 37,060 | 185,300 |
| | $M | | 0.37 | 0.37 | 0.37 | 0.37 | 0.37 | 0.37 | 0.37 | 1.86 |
| | $/km | | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **Deferred Corrective** | | | | | | | | | | |
| Maintain Connectors | Units | | 1,100 | 1,635 | 1,635 | 1,635 | 1,635 | 1,635 | 1,635 | 8,175 |
| | $M | | 0.17 | 0.26 | 0.26 | 0.26 | 0.26 | 0.26 | 0.26 | 1.31 |
| Maintain Statutory Clearance | Units | | 320 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $M | | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Replace Conductor | Units | | 1,674 | 2,143 | 2,143 | 2,143 | 2,143 | 2,143 | 2,143 | 10,715 |
| | $M | | 0.44 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 2.79 |
| **Emergency** | | | | | | | | | | |
| Maintain Connectors | Units | | 1,755 | 1,915 | 1,915 | 1,915 | 1,915 | 1,915 | 1,915 | 9,575 |
| | $M | | 0.49 | 0.53 | 0.53 | 0.53 | 0.53 | 0.53 | 0.53 | 2.66 |
| Maintain Statutory Clearance | Units | | 220 | 539 | 539 | 539 | 539 | 539 | 539 | 2,695 |
| | $M | | 0.07 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.92 |
| Replace Conductor | Units | | 3,833 | 5,339 | 5,339 | 5,339 | 5,339 | 5,339 | 5,339 | 26,695 |
| | $M | | 1.22 | 1.65 | 1.65 | 1.65 | 1.65 | 1.65 | 1.65 | 8.26 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **2.82** | **3.56** | **3.56** | **3.56** | **3.56** | **3.56** | **3.56** | **17.79** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.5 Underground Cables and Joints

**Table 14-8: Underground Cables and Joints Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| UG Sub-transmission | km | 25 | | | | | | | | |
| UG Distribution | km | 726 | | | | | | | | |
| UG LV | km | 2,000 | | | | | | | | |
| **UG Total** | **km** | **2751** | | | | | | | | |
| **UG Pillars** | **No.** | **42,000** | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Inspect U/G Pillars | Units | | 11,063 | 29,952 | 30,538 | 31,136 | 31,746 | 32,367 | 33,002 | 158,789 |
| | $M | | 0.21 | 1.35 | 1.37 | 1.39 | 1.42 | 1.45 | 1.48 | 7.13 |
| | $/unit | | 19 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| Maintain Enclosed U/G Pad | Units | | 1,118 | 1,140 | 1,163 | 1,186 | 1,210 | 1,234 | 1,259 | 6,053 |
| | $M | | 0.34 | 0.35 | 0.35 | 0.36 | 0.37 | 0.37 | 0.38 | 1.83 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair U/G Cable & Joints | Units | | 193 | 233 | 238 | 242 | 247 | 252 | 257 | 1,237 |
| | $M | | 0.09 | 0.11 | 0.11 | 0.11 | 0.11 | 0.12 | 0.12 | 0.58 |
| Repair Pillar | Units | | 347 | 514 | 524 | 535 | 545 | 556 | 567 | 2,728 |
| | $M | | 0.040 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.31 |
| Repair Trench / Duct | Units | | 100 | 89 | 91 | 93 | 94 | 96 | 98 | 472 |
| | $M | | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.04 | 0.17 |
| Repair Enclosed U/G Pad | Units | | 52 | 131 | 134 | 136 | 139 | 142 | 145 | 695 |
| | $M | | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.10 |
| **Emergency** | | | | | | | | | | |
| Repair U/G Cable & Joints | Units | | 430 | 722 | 736 | 733 | 738 | 744 | 750 | 3,702 |
| | $M | | 0.21 | 0.35 | 0.36 | 0.35 | 0.36 | 0.36 | 0.36 | 1.79 |
| Repair Pillar | Units | | 628 | 655 | 668 | 681 | 695 | 709 | 723 | 3,477 |
| | $M | | 0.09 | 0.10 | 0.10 | 0.10 | 0.10 | 0.11 | 0.11 | 0.52 |
| Repair Trench / Duct | Units | | 24 | 28 | 29 | 29 | 30 | 30 | 31 | 149 |
| | $M | | 0.004 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 | 0.005 | 0.02 |
| Repair Enclosed U/G Pad | Units | | 45 | 90 | 92 | 94 | 96 | 97 | 99 | 478 |
| | $M | | 0.009 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.10 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **1.04** | **2.38** | **2.43** | **2.47** | **2.51** | **2.56** | **2.60** | **12.57** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.6 Distribution Substations

**Table 14-9: Distribution Substation Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Distribution Transformers | No. | 78,687 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Inspect & Test | Units | 735 | 1,692 | 4,441 | 5,026 | 5,342 | 4,801 | 4,808 | 4,815 | 24,792 |
| | $M | 0.00 | 0.05 | 0.05 | 0.26 | 0.26 | 0.26 | 0.26 | 0.26 | 1.31 |
| Maintain Enclosed | Units | 1,177 | 1,488 | 1,495 | 1,503 | 1,510 | 1,518 | 1,526 | 1,533 | 7,590 |
| | $M | 0.00 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 1.07 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair Distribution | Units | 623 | 718 | 757 | 761 | 765 | 768 | 772 | 776 | 3,842 |
| | $M | 0.00 | 0.07 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.42 |
| **Emergency** | | | | | | | | | | |
| Repair Distribution | Units | 701 | 703 | 725 | 729 | 732 | 736 | 740 | 743 | 3,680 |
| | $M | 0.00 | 0.13 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.62 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **0.47** | **0.47** | **0.68** | **0.68** | **0.68** | **0.69** | **0.69** | **3.42** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.7 Other Distribution Equipment

**Table 14-10: HV Enclosed Switchgear Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Distribution substation switchgear | No. | 221 | | | | | | | | |
| ACR | No. | 858 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Inspect ACR's | Units | | 2,918 | 2,933 | 3,080 | 3,234 | 3,395 | 3,395 | 3,395 | 16,499 |
| | $M | | 0.19 | 0.19 | 0.19 | 0.21 | 0.22 | 0.22 | 0.22 | 1.05 |
| Maintain HV Enclosed SG | Units | | 367 | 371 | 389 | 409 | 429 | 429 | 429 | 2,085 |
| | $M | | 0.06 | 0.06 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.37 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair HV Enclosed SG | Units | | 141 | 233 | 233 | 233 | 233 | 233 | 233 | 1,165 |
| | $M | | 0.12 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.95 |
| **Emergency** | | | | | | | | | | |
| Reset HV Enclosed SG | Units | | 534 | 855 | 855 | 855 | 855 | 855 | 855 | 4,275 |
| | $M | | 0.003 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.02 |
| Repair HV Enclosed SG | Units | | 238 | 313 | 313 | 313 | 313 | 313 | 313 | 1,565 |
| | $M | | 0.11 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.70 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **0.48** | **0.59** | **0.60** | **0.61** | **0.63** | **0.63** | **0.63** | **3.10** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-11: Line ABS Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| ABS | No. | 8,990 | 8,990 | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Maintain ABS | Units | | 1,591 | 1,600 | 1,600 | 1,600 | 1,600 | 1,600 | 1,632 | 8,032 |
| | % of total | | 17.70 | | | | | | | |
| | $M | | 1.11 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.14 | 5.62 |
| | $/unit | | 700 | 700 | 700 | 700 | 700 | 700 | 700 | 700 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair ABS | Units | | 141 | 197 | 201 | 205 | 209 | 209 | 209 | 1,033 |
| | % of total | | 1.57 | | | | | | | |
| | $M | | 0.12 | 0.16 | 0.16 | 0.17 | 0.17 | 0.17 | 0.17 | 0.85 |
| | $/unit | | 820 | 820 | 820 | 820 | 820 | 820 | 820 | 820 |
| **Emergency** | | | | | | | | | | |
| Repair ABS | Units | | 309 | 285 | 285 | 285 | 50 | 51 | 52 | 723 |
| | $M | | 0.33 | 0.30 | 0.30 | 0.30 | 0.05 | 0.05 | 0.06 | 0.77 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **1.56** | **1.59** | **1.59** | **1.59** | **1.34** | **1.35** | **1.37** | **7.24** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-12: Line Fuse Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| LV Fuses | No. | 100,000 | | | | | | | | |
| HV Fuses | No. | 500,000 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| N/A | | | | | | | | | | |
| **Deferred Corrective** | | | | | | | | | | |
| Maintain HV Fuse | Units | | 455 | 353 | 353 | 353 | 353 | 353 | 353 | 1,765 |
| | $M | | 0.11 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.41 |
| Maintain LV Fuse | Units | | 713 | 921 | 921 | 921 | 921 | 921 | 921 | 4,605 |
| | $M | | 0.16 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 | 1.03 |
| Replace LV Fuse | Units | | 367 | 367 | 367 | 367 | 367 | 367 | 367 | 1,835 |
| | $M | | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.20 |
| **Emergency** | | | | | | | | | | |
| Maintain HV Fuse | Units | | 1,477 | 1,007 | 1,007 | 1,007 | 1,007 | 1,007 | 1,007 | 5,035 |
| | $M | | 0.45 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 0.31 | 1.53 |
| Maintain LV Fuse | Units | | 4,987 | 4,863 | 4,863 | 4,863 | 4,863 | 4,863 | 4,863 | 24,315 |
| | $M | | 1.51 | 1.48 | 1.48 | 1.48 | 1.48 | 1.48 | 1.48 | 7.39 |
| Replace LV Fuse | Units | | 5,904 | 6,352 | 6,352 | 6,352 | 6,352 | 6,352 | 6,352 | 31,760 |
| | $M | | 0.83 | 0.89 | 0.89 | 0.89 | 0.89 | 0.89 | 0.89 | 4.48 |
| Replace HV Fuse | Units | | 8,430 | 6,632 | 6,632 | 6,632 | 6,632 | 6,632 | 6,632 | 33,160 |
| | $M | | 1.86 | 1.46 | 1.46 | 1.46 | 1.46 | 1.46 | 1.46 | 7.32 |
| | $/unit | | 221 | 221 | 221 | 221 | 221 | 221 | 221 | 221 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **4.96** | **4.47** | **4.47** | **4.47** | **4.47** | **4.47** | **4.47** | **22.36** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-13: Lightning Arrestors**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Lightning Arrestors | No. | 194,000 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| *n/a* | | | | | | | | | | |
| **Deferred Corrective** | | | | | | | | | | |
| *n/a* | | | | | | | | | | |
| **Emergency** | | | | | | | | | | |
| Replace LAs | Units | 1,073 | 1,127 | 1,183 | 1,242 | 1,304 | 1,369 | 1,438 | 1,510 | 6,864 |
| | $M | 0.17 | 0.18 | 0.19 | 0.19 | 0.21 | 0.22 | 0.23 | 0.24 | 1.09 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | **0.17** | **0.18** | **0.19** | **0.19** | **0.21** | **0.22** | **0.23** | **0.24** | **1.09** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-14: Line Earth Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Preventative** | | | | | | | | | | |
| Inspect & Test SWER Earths | Units | | 8,538 | 8,538 | 8,559 | 8,581 | 8,602 | 8,624 | 8,645 | 43,011 |
| | $M | | 0.64 | 0.64 | 0.64 | 0.64 | 0.65 | 0.65 | 0.65 | 3.23 |
| Inspect & Test Non SWER Earths | Units | | 10,701 | 10,701 | 10,996 | 11,301 | 11,614 | 11,936 | 12,269 | 58,116 |
| | $M | | 0.77 | 0.77 | 0.79 | 0.81 | 0.83 | 0.85 | 0.87 | 4.15 |
| **Deferred Corrective** | | | | | | | | | | |
| Reinstate SWER Earths | Units | | 295 | 1,351 | 1,297 | 1,250 | 720 | 679 | 630 | 4,574 |
| | $M | | 0.13 | 0.51 | 0.48 | 0.47 | 0.27 | 0.25 | 0.23 | 1.71 |
| Reinstate Non SWER Earths | Units | | 4,100 | 2,140 | 2,140 | 2,140 | 2,140 | 2,140 | 2,140 | 10,701 |
| | $M | | 1.25 | 0.64 | 0.64 | 0.64 | 0.64 | 0.64 | 0.64 | 3.21 |
| **Emergency** | | | | | | | | | | |
| Reinstate SWER Earths | Units | | 278 | 1,491 | 1,472 | 1,457 | 1,234 | 918 | 730 | 5,812 |
| | $M | | 0.11 | 0.58 | 0.58 | 0.57 | 0.48 | 0.36 | 0.29 | 2.28 |
| Reinstate Non SWER Earths | Units | | 121 | 1,454 | 1,454 | 1,454 | 1,454 | 1,454 | 1,454 | 7,271 |
| | $M | | 0.06 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 0.56 | 2.79 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **2.96** | **3.70** | **3.69** | **3.69** | **3.43** | **3.31** | **3.24** | **17.37** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-15: Line Regulator, Capacitor and Reactor Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Reactors | No. | 915 | | | | | | | | |
| Regulators | No. | 358 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Inspect RCR | Units | | 562 | 515 | 991 | 1,037 | 1,085 | 1,085 | 1,085 | 5,282 |
| | $M | | 0.07 | 0.06 | 0.12 | 0.12 | 0.13 | 0.13 | 0.13 | 0.62 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair RCR | Units | | 112 | 219 | 219 | 219 | 219 | 219 | 219 | 1,095 |
| | $M | | 0.05 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.41 |
| **Emergency** | | | | | | | | | | |
| Repair RCR | Units | | 146 | 221 | 221 | 221 | 221 | 221 | 221 | 1,105 |
| | $M | | 0.08 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.71 |
| Remove RCR | Units | | 29 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $M | | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Replace RCR | Units | | 11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $M | | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **0.24** | **0.28** | **0.34** | **0.35** | **0.35** | **0.35** | **0.35** | **1.74** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-16: LV Services Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| LV Services | No. | 536,179 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| N/A | | | | | | | | | | |
| **Deferred Corrective** | | | | | | | | | | |
| Maintain LV Services | Units | | 2,294 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 2,283 | 11,415 |
| | $M | | 0.55 | 0.54 | 0.54 | 0.54 | 0.54 | 0.54 | 0.54 | 2.72 |
| | $/unit | | 239 | 239 | 239 | 239 | 239 | 239 | 239 | 239 |
| **Emergency** | | | | | | | | | | |
| Maintain LV Services | Units | | 6,429 | 7,101 | 7,101 | 7,101 | 7,101 | 7,101 | 7,101 | 35,505 |
| | $M | | 1.32 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 7.27 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **1.86** | **2.00** | **2.00** | **2.00** | **2.00** | **2.00** | **2.00** | **9.99** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-17: Street Lights Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Street lights | No. | 110,000 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Street light patrol | Units | | 68,180 | 95,550 | 97,461 | 99,410 | 101,398 | 103,426 | 105,495 | 507,191 |
| | $M | | 0.12 | 0.17 | 0.17 | 0.17 | 0.18 | 0.18 | 0.18 | 0.89 |
| | $/unit | | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Bulk Lamp Replacement | Units | | 18,179 | 17,981 | 18,880 | 19,824 | 20,816 | 21,232 | 21,656 | 102,409 |
| | $M | | 0.39 | 0.39 | 0.41 | 0.43 | 0.45 | 0.46 | 0.47 | 2.23 |
| | $/unit | | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| **Deferred Corrective** | | | | | | | | | | |
| Street Light Repair or Replace | Units | | 14,792 | 11,715 | 9,525 | 9,328 | 9,231 | 9,133 | 9,037 | 46,254 |
| | $M | | 1.47 | 1.14 | 0.93 | 0.89 | 0.87 | 0.85 | 0.83 | 4.35 |
| Watchman Lights Adjust or Repair | Units | | 343 | 477 | 482 | 487 | 491 | 496 | 501 | 2,458 |
| | $M | | 0.02 | 0.02 | 0.02 | 0.03 | 0.03 | 0.03 | 0.03 | 0.13 |
| **Emergency** | | | | | | | | | | |
| N/A | | | | | | | | | | |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **2.00** | **1.73** | **1.53** | **1.52** | **1.52** | **1.51** | **1.51** | **7.59** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-18: Line Site Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| OH Subtransmission | km | 13,984 | | | | | | | | |
| OH Distribution | km | 43,903 | | | | | | | | |
| OH SWER | km | 62,500 | | | | | | | | |
| OH LV | km | 15,234 | | | | | | | | |
| **OH Total** | **km** | **135,621** | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Feeder Ground Patrol | Units | | 29,300 | 29,300 | 29,300 | 29,300 | 29,300 | 29,300 | 29,300 | 146,500 |
| | $M | | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.46 |
| | $/km | | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Feeder Aerial Patrol | Units | | 40,043 | 40,043 | 40,043 | 40,043 | 40,043 | 40,043 | 40,043 | 200,215 |
| | $M | | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 2.23 |
| | $/km | | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| **Deferred Corrective** | | | | | | | | | | |
| Gate Repair | Units | | 74 | 139 | 139 | 139 | 139 | 139 | 139 | 695 |
| | $M | | 0.03 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.27 |
| Environment cleanup | Units | | 260 | 260 | 260 | 260 | 260 | 260 | 260 | 1,300 |
| | $M | | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.62 |
| Access Track Reinstatement | Units | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $M | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Feeder Ground Patrol | Units | | 23,600 | 28,750 | 28,750 | 28,750 | 28,750 | 28,750 | 28,750 | 143,750 |
| | $M | | 0.08 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.52 |
| Feeder Aerial Patrol | Units | | 16,250 | 17,501 | 17,501 | 17,501 | 17,501 | 17,501 | 17,501 | 87,505 |
| | $M | | 0.17 | 0.18 | 0.180 | 0.18 | 0.18 | 0.18 | 0.18 | 0.90 |
| **Emergency** | | | | | | | | | | |
| Feeder Ground Patrol | Units | | 103,651 | 98,074 | 98,074 | 98,074 | 98,074 | 98,074 | 98,074 | 490,370 |
| | $M | | 1.05 | 0.99 | 0.99 | 0.99 | 0.99 | 0.99 | 0.99 | 4.99 |
| Feeder Aerial Patrol | Units | | 52,898 | 47,370 | 47,370 | 47,370 | 47,370 | 47,370 | 47,370 | 236,850 |
| | $M | | 0.55 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 0.49 | 2.45 |
| Environment cleanup | Units | | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 425 |
| | $M | | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.20 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **2.58** | **2.53** | **2.53** | **2.53** | **2.53** | **2.53** | **2.53** | **12.64** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.8 Zone Substation Transformers

**Table 14-19: Zone Substation Transformer Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| ZS Transformers | No. | 573 | | | | | | | | |
| ZS Reactor | No. | 60 | | | | | | | | |
| ZS Regulator | No. | 25 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Condition Monitoring | Units | 454 | 397 | 474 | 554 | 554 | 560 | 560 | 581 | 2,807 |
| | $M | 0.06 | 0.06 | 0.07 | 0.08 | 0.08 | 0.08 | 0.08 | 0.09 | 0.42 |
| | $/unit | 143 | 143 | 147 | 149 | 149 | 148 | 148 | 149 | 143 |
| Service Transformer / Tap Change / Reactor / Regulator | Units | 271 | 291 | 266 | 271 | 271 | 271 | 276 | 283 | 1,373 |
| | $M | 0.78 | 0.82 | 0.65 | 0.68 | 0.68 | 0.68 | 0.69 | 0.71 | 3.44 |
| | $/unit | 2,823 | 2,810 | 2,445 | 2,513 | 2,513 | 2,513 | 2,496 | 2,494 | 2,823 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair Transformers / Tap Change / Reactor / Regulator | Units | 761 | 695 | 757 | 757 | 757 | 757 | 757 | 749 | 3,777 |
| | $M | 0.81 | 0.71 | 0.78 | 0.78 | 0.78 | 0.78 | 0.78 | 0.78 | 3.92 |
| **Emergency** | | | | | | | | | | |
| Repair Transformers / Tap Change / Reactor / Regulator | Units | 58 | 50 | 67 | 67 | 67 | 67 | 67 | 66 | 334 |
| | $M | 0.09 | 0.08 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.51 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | **1.76** | **1.67** | **1.61** | **1.65** | **1.65** | **1.65** | **1.66** | **1.67** | **8.28** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.9 Zone Substation Circuit Breakers

**Table 14-20: Zone Substation Circuit Breaker Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| ZS Circuit Breakers | No. | 2,528 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Condition Monitoring | Units | | 0 | 0 | 0 | 0 | 22 | 22 | 22 | 67 |
| | $M | | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.01 | 0.02 |
| | $/unit | | 0 | 0 | 0 | 0 | 250 | 250 | 250 | |
| Service Oil CBs | Units | 347 | 299 | 264 | 298 | 293 | 290 | 288 | 281 | 1,450 |
| | $M | 0.91 | 0.75 | 0.67 | 0.75 | 0.74 | 0.73 | 0.73 | 0.71 | 3.67 |
| | $/unit | 2,545 | 2,509 | 2,526 | 2,531 | 2,533 | 2,534 | 2,533 | 2,521 | 2,545 |
| Service Vac / Gas CBs | Units | 128 | 132 | 184 | 167 | 170 | 173 | 174 | 179 | 862 |
| | $M | 0.17 | 0.13 | 0.21 | 0.18 | 0.18 | 0.18 | 0.18 | 0.19 | 0.91 |
| | $/unit | 1,311 | 1,018 | 1,136 | 1,066 | 1,057 | 1,054 | 1,064 | 1,049 | 1,311 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair CBs | Units | 475 | 442 | 515 | 515 | 515 | 515 | 515 | 510 | 2,570 |
| | $M | 0.58 | 0.51 | 0.58 | 0.58 | 0.58 | 0.58 | 0.58 | 0.58 | 2.90 |
| **Emergency** | | | | | | | | | | |
| Repair CBs | Units | 41 | 35 | 47 | 47 | 47 | 47 | 47 | 47 | 235 |
| | $M | 0.07 | 0.06 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.38 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | **1.73** | **1.46** | **1.53** | **1.59** | **1.58** | **1.58** | **1.58** | **1.55** | **7.88** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.10 Zone Substation Site and Equipment

**Table 14-21: Zone Substation Instrument Transformer Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Instrument Transformers | No. | 5200 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Condition Monitoring | Units | 1,059 | 882 | 872 | 952 | 952 | 942 | 956 | 955 | 4,757 |
| | $M | 0.27 | 0.21 | 0.26 | 0.29 | 0.29 | 0.28 | 0.29 | 0.29 | 1.42 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair Instrument Transformer | Units | 190 | 177 | 185 | 185 | 185 | 185 | 185 | 183 | 923 |
| | $M | 0.19 | 0.17 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.89 |
| **Emergency** | | | | | | | | | | |
| Repair Instrument Transformer | Units | 18 | 15 | 18 | 18 | 18 | 18 | 18 | 18 | 90 |
| | $M | 0.02 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.08 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | **0.46** | **0.39** | **0.46** | **0.48** | **0.48** | **0.48** | **0.48** | **0.48** | **2.40** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-22: Zone Substation Switches Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Isolators | No. | 2855 | | | | | | | | |
| Earth Switches | No. | 681 | | | | | | | | |
| Fault Throw Switches | No. | 54 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Service Isolator / Earth Switch / Fault Throw Switch | Units | 809 | 723 | 766 | 974 | 974 | 974 | 974 | 1,008 | 4,904 |
| | $M | 0.49 | 0.42 | 0.45 | 0.57 | 0.57 | 0.58 | 0.57 | 0.59 | 2.86 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair Isolator / Earth Switch / Fault Throw Switch | Units | 273 | 264 | 274 | 274 | 274 | 274 | 274 | 271 | 1,367 |
| | $M | 0.22 | 0.20 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 1.10 |
| **Emergency** | | | | | | | | | | |
| Repair Isolator / Earth Switch / Fault Throw Switch | Units | 30 | 27 | 38 | 38 | 38 | 38 | 38 | 38 | 190 |
| | $M | 0.03 | 0.02 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.17 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | **0.74** | **0.65** | **0.70** | **0.82** | **0.82** | **0.82** | **0.82** | **0.84** | **4.12** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-23: Zone Substation Capacitor Bank and SVC Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Capacitor Banks | No. | 128 | | | | | | | | |
| SVCs | No. | 4 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Test SVC Bushing & Service Capacitor Bank | Units | 29 | 21 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | $M | 0.03 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair SVC / Capacitor Bank / Compensator | Units | 81 | 76 | 77 | 70 | 70 | 70 | 70 | 69 | 349 |
| | $M | 0.14 | 0.12 | 0.14 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.61 |
| **Emergency** | | | | | | | | | | |
| Repair SVC / Capacitor Bank / Compensator | Units | 6 | 5 | 7 | 7 | 7 | 7 | 7 | 7 | 35 |
| | $M | 0.01 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.08 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | **0.20** | **0.16** | **0.16** | **0.14** | **0.14** | **0.14** | **0.14** | **0.14** | **0.69** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-24: Zone Substation Site Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Preventative** | | | | | | | | | | |
| Test Gapped Surge Diverter | Units | 298 | 278 | 542 | 300 | 300 | 300 | 300 | 360 | 1,560 |
| | $M | 0.04 | 0.03 | 0.06 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.19 |
| Test Earthing Resistance Earth Mats | Units | 44 | 43 | 30 | 30 | 30 | 30 | 30 | 30 | 150 |
| | $M | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.04 |
| Test Portable Earthing Devices and Tools | Units | 1,314 | 1,302 | 1,201 | 1,218 | 1,234 | 1,250 | 1,266 | 1,282 | 6,250 |
| | $M | 0.65 | 0.63 | 0.58 | 0.58 | 0.59 | 0.60 | 0.61 | 0.62 | 3.00 |
| Infrared Scan Site | Units | 131 | 111 | 150 | 152 | 154 | 156 | 158 | 160 | 780 |
| | $M | 0.08 | 0.07 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.10 | 0.47 |
| Service Polution Control Systems | Units | 209 | 181 | 360 | 370 | 380 | 390 | 400 | 410 | 1,950 |
| | $M | 0.06 | 0.05 | 0.11 | 0.11 | 0.11 | 0.12 | 0.12 | 0.12 | 0.58 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair Gapped Surge Diverters | Units | 103 | 184 | 170 | 170 | 170 | 170 | 170 | 170 | 850 |
| | $M | 0.03 | 0.13 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.69 |
| Repair Miscellaneous Plant & Equipment | Units | 464 | 441 | 446 | 446 | 446 | 446 | 446 | 446 | 2,230 |
| | $M | 0.33 | 0.30 | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 1.64 |
| Repair Polution Control Systems | Units | 168 | 184 | 166 | 166 | 166 | 166 | 166 | 166 | 830 |
| | $M | 0.13 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.59 |
| **Emergency** | | | | | | | | | | |
| Repair Gapped Surge Diverters | Units | 14 | 12 | 16 | 16 | 16 | 16 | 16 | 16 | 80 |
| | $M | 0.02 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.10 |
| Repair Miscellaneous Plant & Equipment | Units | 91 | 78 | 108 | 108 | 108 | 108 | 108 | 108 | 540 |
| | $M | 0.07 | 0.06 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.42 |
| **Operations** | | | | | | | | | | |
| Inspect Data Recorder | Units | 504 | 472 | 249 | 249 | 249 | 249 | 248 | 247 | 1,241 |
| | $M | 0.15 | 0.14 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.37 |
| Investigate Fault/Alarms | Units | 245 | 405 | 558 | 558 | 558 | 558 | 558 | 558 | 2,790 |
| | $M | 0.15 | 0.24 | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 1.67 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | **3.38** | **3.30** | **3.45** | **3.46** | **3.49** | **3.52** | **3.55** | **3.59** | **17.61** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.11 Zone Substation Secondary Equipment

**Table 14-25: DC System Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Battery Systems | No. | 360 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Impedence Test Battery Bank | Units | 184 | 193 | 243 | 296 | 300 | 304 | 308 | 312 | 1,520 |
| | $M | 0.02 | 0.02 | 0.03 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.18 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair Battery Bank | Units | 250 | 243 | 237 | 237 | 237 | 237 | 237 | 235 | 1,183 |
| | $M | 0.24 | 0.21 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 0.22 | 1.09 |
| Repair Battery Charger | Units | 154 | 139 | 146 | 146 | 146 | 146 | 146 | 145 | 729 |
| | $M | 0.13 | 0.11 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.61 |
| **Emergency** | | | | | | | | | | |
| Repair Battery Bank | Units | 19 | 18 | 25 | 25 | 25 | 25 | 25 | 25 | 125 |
| | $M | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.11 |
| Repair Battery Charger | Units | 18 | 15 | 19 | 19 | 19 | 19 | 19 | 19 | 95 |
| | $M | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.06 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | **0.41** | **0.38** | **0.40** | **0.41** | **0.41** | **0.41** | **0.41** | **0.41** | **2.05** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-26: Communications Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Pilot cable | km | 293 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Pilot Cable Ground Patrol | Units | | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 10 |
| | $M | | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.04 |
| Test & Service Comms Equipment | Units | | 1,812 | 1,929 | 2,019 | 2,088 | 2,210 | 2,337 | 2,431 | 11,084 |
| | $M | | 0.46 | 0.48 | 0.49 | 0.51 | 0.53 | 0.56 | 0.57 | 2.67 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair Pilot Cable | Units | | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 490 |
| | $M | | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.79 |
| Repair Battery Systems | Units | | 154 | 154 | 154 | 154 | 154 | 154 | 154 | 770 |
| | $M | | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.38 |
| Repair DSA Equipment | Units | | 25 | 27 | 30 | 33 | 36 | 40 | 43 | 182 |
| | $M | | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.20 |
| Repair Protection Signalling | Units | | 50 | 50 | 50 | 80 | 80 | 80 | 80 | 370 |
| | $M | | 0.02 | 0.02 | 0.02 | 0.03 | 0.03 | 0.03 | 0.03 | 0.14 |
| Repair Telephone Equipment | Units | | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 250 |
| | $M | | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.02 |
| Repair VHF/UHF Equipment | Units | | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 660 |
| | $M | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.10 |
| **Emergency** | | | | | | | | | | |
| Repair Fibre Optic | Units | | 13 | 16 | 18 | 18 | 18 | 18 | 20 | 92 |
| | $M | | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.18 |
| Repair MUX | Units | | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 15 |
| | $M | | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.05 |
| Repair Pilot Cable | Units | | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 175 |
| | $M | | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.14 |
| Repair Battery Systems | Units | | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 230 |
| | $M | | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.14 |
| Repair DSA Equipment | Units | | 13 | 13 | 13 | 14 | 14 | 14 | 14 | 69 |
| | $M | | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.06 |
| Repair Protection Signalling | Units | | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 150 |
| | $M | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.09 |
| Repair Telephone Equipment | Units | | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 160 |
| | $M | | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.06 |
| Repair VHF/UHF Equipment | Units | | 68 | 68 | 68 | 68 | 68 | 68 | 68 | 340 |
| | $M | | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.19 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **0.95** | **0.98** | **0.99** | **1.03** | **1.05** | **1.08** | **1.10** | **5.25** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-27: Protection Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Protection relays | No. | 5,200 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Test Meters & Indicators | Units | | 785 | 770 | 755 | 739 | 718 | 704 | 684 | 3,600 |
| | $M | | 0.23 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.75 |
| Test Protection Systems | Units | | 1,881 | 1,884 | 1,910 | 1,923 | 1,935 | 1,947 | 1,960 | 9,675 |
| | $M | | 1.70 | 1.12 | 1.13 | 1.13 | 1.14 | 1.15 | 1.16 | 5.71 |
| Test Reclosers | Units | | 0 | 0 | 180 | 203 | 225 | 248 | 270 | 1,125 |
| | $M | | 0.00 | 0.00 | 0.07 | 0.08 | 0.09 | 0.10 | 0.10 | 0.43 |
| Replace Recloser Batteries | Units | | 0 | 0 | 360 | 405 | 450 | 495 | 540 | 2,250 |
| | $M | | 0.00 | 0.00 | 0.14 | 0.16 | 0.17 | 0.19 | 0.21 | 0.87 |
| Data Collection | Units | | 0 | 0 | 69 | 74 | 78 | 83 | 87 | 390 |
| | $M | | 0.00 | 0.00 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.15 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair Protection Systems | Units | | 805 | 311 | 312 | 314 | 315 | 316 | 317 | 1,575 |
| | $M | | 0.73 | 0.19 | 0.19 | 0.19 | 0.19 | 0.19 | 0.20 | 0.96 |
| Repair Meters & Indicators | Units | | 460 | 66 | 66 | 66 | 66 | 66 | 66 | 330 |
| | $M | | 0.28 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.13 |
| Repair Recloser Protection | Units | | 0 | 14 | 36 | 38 | 40 | 42 | 43 | 199 |
| | $M | | 0.00 | 0.46 | 0.12 | 0.13 | 0.14 | 0.14 | 0.15 | 0.68 |
| **Emergency** | | | | | | | | | | |
| Repair Protection Systems | Units | | 105 | 160 | 160 | 160 | 161 | 161 | 161 | 803 |
| | $M | | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.39 |
| Repair Meters & Indicators | Units | | 69 | 40 | 40 | 40 | 40 | 40 | 40 | 200 |
| | $M | | 0.04 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.08 |
| Repair Recloser Protection | Units | | 0 | 0 | 27 | 28 | 29 | 30 | 30 | 143 |
| | $M | | 0.00 | 0.00 | 0.10 | 0.11 | 0.11 | 0.12 | 0.12 | 0.56 |
| Repair Sectionaliser Protection | Units | | 0 | 0 | 6 | 6 | 6 | 6 | 6 | 30 |
| | $M | | 0.00 | 0.00 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.12 |
| **Operations** | | | | | | | | | | |
| Change Recloser Settings | Units | | 350 | 350 | 350 | 350 | 350 | 350 | 350 | 1,750 |
| | $M | | 0.10 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.69 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **3.18** | **2.17** | **2.21** | **2.26** | **2.30** | **2.35** | **2.40** | **11.53** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-28: Control Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Population** | | | | | | | | | | |
| Master station control systems | No. | 8 | | | | | | | | |
| **Preventative** | | | | | | | | | | |
| Service & Test Ripple Injection & SVC Plant | Units | | 14 | 19 | 56 | 59 | 61 | 62 | 63 | 301 |
| | $M | | 0.02 | 0.02 | 0.04 | 0.05 | 0.05 | 0.05 | 0.05 | 0.24 |
| Test Control Systems | Units | | 201 | 184 | 188 | 193 | 197 | 202 | 206 | 986 |
| | $M | | 0.11 | 0.06 | 0.06 | 0.07 | 0.07 | 0.07 | 0.07 | 0.34 |
| Inspect Operator Interface | Units | | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 265 |
| | $M | | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.05 |
| Control Battery Change | Units | | 40 | 41 | 42 | 42 | 43 | 44 | 45 | 217 |
| | $M | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.08 |
| **Deferred Corrective** | | | | | | | | | | |
| Repair Ripple Plant | Units | | 99 | 18 | 18 | 18 | 17 | 17 | 17 | 87 |
| | $M | | 0.14 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.28 |
| Repair Operator Interface | Units | | 276 | 10 | 10 | 10 | 11 | 11 | 11 | 53 |
| | $M | | 0.12 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.17 |
| Repair Control Systems | Units | | 650 | 149 | 149 | 150 | 150 | 150 | 151 | 750 |
| | $M | | 0.52 | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 0.34 | 1.67 |
| **Emergency** | | | | | | | | | | |
| Repair Ripple Plant | Units | | 11 | 3 | 3 | 3 | 3 | 3 | 3 | 15 |
| | $M | | 0.01 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.39 |
| Repair Operator Interface | Units | | 21 | 5 | 5 | 5 | 5 | 5 | 6 | 27 |
| | $M | | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.03 |
| Repair Control Systems | Units | | 238 | 76 | 76 | 75 | 75 | 75 | 75 | 376 |
| | $M | | 0.13 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.47 |
| **Operations** | | | | | | | | | | |
| Maintain System Control Room Equipment | Units | | 501 | 347 | 348 | 349 | 350 | 352 | 353 | 1,752 |
| | $M | | 0.32 | 1.48 | 1.48 | 1.49 | 1.49 | 1.50 | 1.51 | 7.47 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | *n/a* | **1.43** | **2.19** | **2.22** | **2.24** | **2.24** | **2.25** | **2.26** | **11.22** |

*All forecast and historical figures are in June 2004 dollars.*

### 14.7.12 Vegetation Management

**Table 14-29: Vegetation Management Operational Budget**

| | | 02/03 | 03/04 | 04/05 | 05/06 | 06/07 | 07/08 | 08/09 | 09/10 | Total 05/06 – 09/10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Preventative** | | | | | | | | | | |
| Inspect Vegetation | Units (MHr) | 0 | 7,875 | 32,648 | 32,648 | 32,648 | 32,648 | 34,125 | 34,125 | 166,195 |
| | $M | 0.00 | 0.70 | 2.71 | 2.71 | 2.71 | 2.71 | 2.83 | 2.83 | 13.79 |
| Preventative Clear / Remove Trees Urban | Units (tree) | 122,272 | 123,981 | 145,362 | 145,362 | 145,362 | 145,362 | 156,755 | 155,555 | 748,398 |
| | $M | 6.06 | 6.67 | 7.37 | 7.37 | 7.37 | 7.37 | 7.99 | 7.93 | 38.04 |
| Preventative Clear / Remove Trees Rural | Units (tree) | 182,846 | 152,213 | 143,624 | 143,624 | 143,624 | 143,624 | 165,471 | 165,371 | 761,713 |
| | $M | 15.58 | 13.77 | 11.76 | 11.76 | 11.76 | 11.76 | 13.65 | 13.65 | 62.58 |
| Preventative Corridor Clearing | Units | 1,180 | 1,440 | 1,610 | 1,610 | 1,610 | 1,610 | 1,743 | 1,683 | 8,254 |
| | $M | 1.77 | 2.32 | 2.41 | 2.41 | 2.41 | 2.41 | 2.61 | 2.52 | 12.38 |
| Maintain Access Tracks | Units (km) | 0 | 0 | 13,419 | 13,419 | 13,419 | 14,968 | 15,710 | 15,710 | 73,225 |
| | $M | 0.00 | 0.00 | 1.88 | 1.88 | 1.88 | 2.10 | 2.20 | 2.20 | 10.25 |
| Install / Repair Gates | Units (gate) | 0 | 0 | 170 | 170 | 170 | 202 | 212 | 212 | 965 |
| | $M | 0.00 | 0.00 | 0.11 | 0.11 | 0.11 | 0.12 | 0.13 | 0.13 | 0.59 |
| Supervision & Audits | Units (Mhr) | 10,616 | 11,348 | 13,429 | 13,429 | 13,429 | 13,429 | 14,036 | 14,036 | 68,358 |
| | $M | 0.55 | 0.61 | 0.67 | 0.67 | 0.67 | 0.67 | 0.70 | 0.70 | 3.42 |
| **Deferred Corrective** | | | | | | | | | | |
| Reactive Clear / Remove Trees | Units (tree) | 27,606 | 37,714 | 31,248 | 30,377 | 29,535 | 28,723 | 27,937 | 27,178 | 143,750 |
| | $M | 1.70 | 2.63 | 2.20 | 2.14 | 2.08 | 2.03 | 1.97 | 1.92 | 10.14 |
| Reactive Corridor Clearing | Units | 1 | 4 | 4 | 4 | 4 | 4 | 4 | 3 | 18 |
| | $M | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.03 |
| Maintain Access Tracks | Units (km) | 0 | 0 | 2,832 | 2,832 | 2,832 | 1,416 | 1,416 | 1,416 | 9,912 |
| | $M | 0.00 | 0.00 | 0.40 | 0.40 | 0.40 | 0.20 | 0.20 | 0.20 | 1.39 |
| Install / Repair Gates | Units (gate) | 0 | 0 | 60 | 60 | 60 | 28 | 28 | 28 | 204 |
| | $M | 0.00 | 0.00 | 0.03 | 0.03 | 0.03 | 0.01 | 0.01 | 0.01 | 0.09 |
| **Emergency** | | | | | | | | | | |
| Reactive Clear / Remove Trees | Units (tree) | 652 | 680 | 592 | 562 | 534 | 508 | 482 | 458 | 2,545 |
| | $M | 0.07 | 0.07 | 0.06 | 0.05 | 0.05 | 0.05 | 0.05 | 0.04 | 0.25 |
| Reactive Corridor Clearing | Units | 0 | 0 | 6 | 6 | 5 | 5 | 5 | 5 | 26 |
| | $M | 0.00 | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.04 |
| Maintain Access Tracks | Units (km) | 0 | 0 | 142 | 142 | 142 | 8 | 8 | 8 | 307 |
| | $M | 0.00 | 0.00 | 0.02 | 0.02 | 0.02 | 0.00 | 0.00 | 0.00 | 0.04 |
| **Total OPEX** | | | | | | | | | | |
| **Total** | **$M** | 25.78 | 26.97 | 29.41 | 29.41 | 29.41 | 29.41 | 32.60 | 32.38 | 153.21 |

*All forecast and historical figures are in June 2004 dollars.*

## 14.8 Projects Reviewed

**Table 14-30: Projects Reviewed**

| PROJECT TYPE | NUMBER | TITLE |
|---|---|---|
| AGEING ASSET REPLACEMENT | NL00013 | R-Rebuild EHB-RLSS Feeder, Raglan |
| | CV00665 | Upgrade Streetlights Stage 3, Rockhampton & Gracemere |
| | NQ32411 | Ingham Substation CT Replacement |
| | NC04189 | IN MA HSC Rotary Park, Ingham |
| | NS0061 | Install Sec Distance Relays |
| | NS00130 | East End Quary Transponder Replacement |
| | CV00669-01 | Replace Ageing Services, Rockhampton - Stage 5 |
| AUGMENTATION | NN00237 | TV Alan Sherriff 11kV Feeders |
| | NC04660 | Aug 156 Fullham Rd Gulliver |
| | NA01390 | New 11kV Feeder Augmentation PH106 |
| | CV00448 | Bungandarra SWER Upgrade |
| | NQ32328 | Stuart – Ross Plains 66kV |
| | NS00099 | MLC Ripple Control Installation |
| | NA00686 | Feeder Upgrade Glendale Rd, Parkhurst |
| NETWORK REFURBISHMENT | NC04237 | CB-05 Cranbrook No 5 11kV Feeder |
| OTHER CORPORATE INITIATED | NC00024 | Pole Dump Hartley St Bunding |
| | NC04778 | TV NL Black River 66kV ABS |
| RELIABILITY | NP10037 | TV – Stuart No 5 Performance Improvement |
| | NP10339 | R – Stanwell Feeder Performance Improvement |
| | NP10265 | BD – AY10 Ayr Feeder Performance Improvement |
| COMMERCIAL INDUSTRIAL | NC05005 | TV Coles Ogden St City |
| | NC04394 | TV Cableway Apartments |
| | NL01419 | R-Modify SWER Undercrossings |
| | NA00890 | Q-Mag New Line, Kunwarara |
| | MK15090 | APC Moorvale Coal Mine |
| | WC20551 | Hyne & Son (Tuan Sawmill) |
| | NC04758 | In CI Milton Stone River |
| | NC04913 | IN Orpin 43 Mt Cudmore Rd |
| DOMESTIC & RURAL | CV01271 | R – Williams Delrosa Rd A/Downs |
| OTHER CUSTOMER REQUESTED | NC04753 | TV CI Crestbrook Stage 4 |
| | NC04540 | TV URD Range Drive In Estate |
| | NA01255 | Y-URD 47 Lot S/D Pacific Palms |
| CHANGE PROGRAMS | CG02001 | AIDM Project |
| | CG10005 | Finance CSS |
| | CG10002 | Common Core Processes |
| COMPUTER FACILITIES | LP01950 | E-Commerce Strategy |
| | LP01907 | Exe Video Conference Project |
| | LP01892 | Virtual Private Network |
| LAND & BUILDINGS | FA20830 | Lake St Refurbishment |

## 14.9 Review Pro-forma

PROJECT NO ………………...PROJECT CATEGORY………………………………… PROJECT NAME………………………………………………………………………………

| CRITERION | RATING | COMMENTS |
|---|---|---|
| Consideration of impact on demand | | |
| Current & projected capacity/asset utilisation | | |
| Asset condition & renewal requirements | | |
| Demographic circumstances | | |
| Non-network alternatives | | |
| Safety & service quality standards | | |
| Accepted planning standards | | |
| Policies re environmental requirements etc. | | |
| Minimising life cycle cost/economic evaluation | | |
| Risk analysis | | |
| Correct project categories | | |
| Correct allocation of overheads | | |
| Efficient design/planning approach | | |

PROJECT DESCRIPTION…………………………………………………………………………………………………………………………………………………

…………………………………………………………………………………………………………………………………………………………………………

BUDGET COST……………..…ACTUAL COST…………………APPROVED BY………………………………..…..DATE………………..

PROJECT REVISION YES /NO REVISION DATE…..………APPROVED BY……………………………BASIS ……………………………………………………………

COMPLETIONDATE……………… POST IMPLEMENTATION REVIEW DATE…………….

PIR COMMENTS…………………………………………………………………………………………………………………………………………………

…………………………………………………………………………………………………………………………………………………………………………

PROJECT CLOSURE DATE……………..AUTHORISED BY……………………………..

BASIS FOR COSTING ………………………………………………………………………………………………………………………………………….

OVERALL ASSESSMENT……………………………………………………………………………………………………………………………………

……………………………………………………………………………………………………………………………………………………

## 14.10 Consolidated CAPEX program

**Table 14-31: Ergon Energy CAPEX Program**

| | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|
| **Customer contribution** | | | | | | | |
| Cash contributions | 25.000 | 25.000 | 24.000 | 23.000 | 22.000 | 21.000 | 115.000 |
| In kind contributions | 0.000 | 1.000 | 2.000 | 4.000 | 5.000 | 7.000 | 19.000 |
| Total Customer Contribution | **25.000** | **26.000** | **26.000** | **27.000** | **27.000** | **28.000** | **134.000** |
| | | | | | | | |
| **Asset replacements** | | | | | | | |
| Poles and pole tops | 25.767 | 28.516 | 28.769 | 28.981 | 28.701 | 28.857 | 143.824 |
| Power and Distribution transformers | 15.441 | 16.534 | 15.599 | 17.370 | 17.903 | 17.448 | 84.853 |
| Meters | 1.232 | 2.694 | 5.231 | 5.016 | 5.873 | 3.931 | 22.744 |
| Line conductors | 18.568 | 29.538 | 31.104 | 32.418 | 33.627 | 34.034 | 160.520 |
| Underground cables | 5.210 | 4.644 | 4.670 | 3.158 | 1.800 | 1.534 | 15.806 |
| Distribution line and zone substation equipment | 17.999 | 25.544 | 25.126 | 24.987 | 25.102 | 24.734 | 125.493 |
| Zone substation sites | 7.010 | 10.218 | 9.527 | 7.245 | 8.241 | 11.025 | 46.256 |
| Control and communication systems | 7.200 | 18.299 | 10.368 | 12.447 | 7.009 | 7.574 | 55.697 |
| **Total Asset replacements** | **98.427** | **135.987** | **130.393** | **131.622** | **128.255** | **129.136** | **655.393** |
| **Augmentations** | | | | | | | |
| Transmission | 4.233 | 17.973 | 18.489 | 25.602 | 20.143 | 17.835 | 100.042 |
| Sub Transmission | 26.460 | 12.980 | 12.761 | 10.433 | 5.273 | 9.465 | 50.913 |
| Zone Substations | 0.000 | 35.033 | 31.888 | 31.655 | 31.208 | 22.922 | 152.706 |
| Distribution | 25.229 | 39.337 | 41.609 | 42.954 | 44.111 | 33.480 | 201.492 |
| **Total Corporate Initiated** | **55.921** | **105.323** | **104.747** | **110.645** | **100.736** | **83.702** | **505.152** |
| **Customer initiated** | | | | | | | |
| Domestic and Rural | 17.448 | 18.666 | 19.098 | 19.324 | 20.051 | 20.648 | 97.788 |
| Subdivisions | 32.519 | 33.337 | 34.193 | 34.683 | 36.075 | 37.242 | 175.531 |
| Public lighting | 4.098 | 4.202 | 4.310 | 4.372 | 4.548 | 4.694 | 22.126 |
| Meters & Services | 12.410 | 12.449 | 12.769 | 12.952 | 13.471 | 13.907 | 65.549 |
| Commercial & Industrial | 34.417 | 36.301 | 37.379 | 38.062 | 39.744 | 41.187 | 192.673 |
| Major Customers | 82.986 | 41.800 | 42.033 | 41.800 | 42.625 | 43.141 | 211.399 |
| **Total Customer Initiated** | **183.878** | **146.756** | **149.782** | **151.192** | **156.514** | **160.820** | **765.065** |
| **Total Reliability Improvement (Tier (a))** | | | | | | | |
| Monitoring program | 0.000 | 1.544 | 1.552 | 1.543 | 1.574 | 1.593 | 7.807 |
| Sub-Transmission | 2.078 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| Distribution | 5.461 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| **Total Reliability Improvement** | **7.540** | **1.544** | **1.552** | **1.543** | **1.574** | **1.593** | **7.807** |

| | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|
| **System - Other** | | | | | | | |
| Sub-Transmission | 13.439 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| Zone Substations | 0.000 | 4.644 | 4.670 | 4.645 | 4.736 | 4.794 | 23.489 |
| Distribution | 2.471 | 3.624 | 3.644 | 3.624 | 3.222 | 2.495 | 16.610 |
| Load Energy management | 1.889 | 0.355 | 1.449 | 1.280 | 1.348 | 1.379 | 5.810 |
| **Total System - Other** | **17.798** | **8.624** | **9.763** | **9.548** | **9.307** | **8.667** | **45.908** |
| | | | | | | | |
| **Non-System** | | | | | | | |
| Change Program | 14.634 | 22.357 | 17.500 | 17.500 | 17.500 | 17.500 | 92.357 |
| Computer Facilities | 6.244 | 14.250 | 8.100 | 9.100 | 8.200 | 7.100 | 46.750 |
| Vehicles & Mobile Plant | 27.317 | 25.000 | 25.000 | 25.780 | 26.265 | 21.700 | 123.745 |
| Land & Buildings | 15.415 | 12.000 | 12.000 | 12.000 | 12.000 | 12.000 | 60.000 |
| Other Fixed Assets | 5.854 | 1.179 | 1.089 | 0.933 | 0.933 | 1.132 | 5.266 |
| Other Unclassified Acquisitions | 0.000 | 1.000 | 1.000 | 1.000 | 2.000 | 2.000 | 7.000 |
| **Total Non-System** | **69.464** | **75.786** | **64.689** | **66.313** | **66.898** | **61.432** | **335.118** |
| **Total CAPEX** | **433.028** | **474.019** | **460.926** | **470.864** | **463.283** | **445.350** | **2,314.442** |

*All forecast and historical figures are in June 2004 dollars.*

**Table 14-32: Consultant's CAPEX Program**

| | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|
| **Customer contribution** | | | | | | | |
| Cash contributions | 25.000 | 25.000 | 24.000 | 23.000 | 22.000 | 21.000 | 115.000 |
| In kind contributions | 0.000 | 0.45 | 1.91 | 3.37 | 4.85 | 6.33 | 16.91 |
| Total Customer Contribution | **25.000** | **25.45** | **25.91** | **26.37** | **26.85** | **27.33** | **131.91** |
| | | | | | | | |
| **Asset replacements** | | | | | | | |
| Poles and pole tops | 25.767 | 28.516 | 28.769 | 28.981 | 28.701 | 28.857 | 143.824 |
| Power and Distribution transformers | 15.441 | 16.534 | 15.599 | 17.370 | 17.903 | 17.448 | 84.853 |
| Meters | 1.232 | 2.694 | 5.231 | 5.016 | 5.873 | 3.931 | 22.744 |
| Line conductors | 18.568 | 29.538 | 31.104 | 32.418 | 33.627 | 34.034 | 160.720 |
| Underground cables | 5.210 | 4.644 | 4.670 | 3.158 | 1.800 | 1.534 | 15.806 |
| Distribution line and zone substation equipment | 17.999 | 25.544 | 25.126 | 24.987 | 25.102 | 24.734 | 125.493 |
| Zone substation sites | 7.010 | 10.218 | 9.527 | 7.245 | 8.241 | 11.025 | 46.256 |
| Control and communication systems | 7.200 | 18.299 | 10.368 | 12.447 | 7.009 | 7.574 | 55.697 |
| **Total Asset replacements** | **98.427** | **135.987** | **130.393** | **131.622** | **128.255** | **129.136** | **655.393** |

| | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | TOTAL 05/06-09/10 |
|---|---|---|---|---|---|---|---|
| **Augmentations** | | | | | | | |
| Transmission | 4.233 | 17.973 | 18.489 | 25.602 | 20.143 | 17.835 | 100.042 |
| Sub Transmission | 26.460 | 12.980 | 12.761 | 10.433 | 5.273 | 9.465 | 50.913 |
| Zone Substations | 0.000 | 35.033 | 31.888 | 31.655 | 31.208 | 22.922 | 152.706 |
| Distribution | 25.229 | 39.337 | 41.609 | 42.954 | 44.111 | 33.480 | 201.492 |
| **Total Corporate Initiated** | **55.921** | **105.323** | **104.747** | **110.645** | **100.736** | **83.702** | **505.152** |
| **Customer initiated** | | | | | | | |
| Domestic and Rural | 17.448 | 18.666 | 19.098 | 19.324 | 20.051 | 20.648 | 97.788 |
| Subdivisions | 31.084 | 31.690 | 32.304 | 32.931 | 33.572 | 34.226 | 164.723 |
| Public lighting | 4.098 | 4.202 | 4.310 | 4.372 | 4.548 | 4.694 | 22.126 |
| Meters & Services | 12.410 | 12.449 | 12.769 | 12.952 | 13.471 | 13.907 | 65.549 |
| Commercial & Industrial | 34.417 | 36.301 | 37.379 | 38.062 | 39.744 | 41.187 | 192.673 |
| Major Customers | 82.986 | 9.410 | 8.120 | 6.820 | 6.820 | 6.820 | 37.990 |
| **Total Customer Initiated** | **182.443** | **112.718** | **113.980** | **114.460** | **118.206** | **121.483** | **580.848** |
| **Total Reliability Improvement (Tier (a))** | | | | | | | |
| Monitoring program | 0.000 | 1.544 | 1.552 | 1.543 | 1.574 | 1.593 | 7.807 |
| Sub-Transmission | 2.078 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| Distribution | 5.461 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| **Total Reliability Improvement** | **7.540** | **1.544** | **1.552** | **1.543** | **1.574** | **1.593** | **7.807** |
| **System - Other** | | | | | | | |
| Sub-Transmission | 13.439 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| Zone Substations | 0.000 | 4.644 | 4.670 | 4.645 | 4.736 | 4.794 | 23.489 |
| Distribution | 2.471 | 3.624 | 3.644 | 3.624 | 3.222 | 2.495 | 16.610 |
| Load Energy management | 1.889 | 0.355 | 1.449 | 1.280 | 1.348 | 1.379 | 5.810 |
| **Total System - Other** | **17.798** | **8.624** | **9.763** | **9.548** | **9.307** | **8.667** | **45.908** |
| | | | | | | | |
| **Non-System** | | | | | | | |
| Change Program | 14.634 | 22.357 | 17.500 | 17.500 | 17.500 | 17.500 | 92.357 |
| Computer Facilities | 6.244 | 14.250 | 8.100 | 9.100 | 8.200 | 7.100 | 46.750 |
| Vehicles & Mobile Plant | 27.317 | 25.000 | 25.000 | 25.780 | 26.265 | 21.700 | 123.745 |
| Land & Buildings | 15.415 | 12.000 | 12.000 | 12.000 | 12.000 | 12.000 | 60.000 |
| Other Fixed Assets | 5.854 | 1.179 | 1.089 | 0.933 | 0.933 | 1.132 | 5.266 |
| Other Unclassified Acquisitions | 0.000 | 1.000 | 1.000 | 1.000 | 2.000 | 2.000 | 7.000 |
| **Total Non-System** | **69.464** | **75.786** | **64.689** | **66.313** | **66.898** | **61.432** | **335.118** |
| **Total CAPEX** | **431.594** | **439.981** | **425.124** | **434.132** | **424.975** | **406.013** | **2,130.225** |

*All forecast and historical figures are in June 2004 dollars.*

## 14.11 GSL Comparison

| UTILITY | ERGON | ENERGEX | CITIPOWER | POWERCOR | TXU | UNITED ENERGY | ETSA UTILITIES | ENERGY AUSTRALIA | ACTEWAGL |
|---|---|---|---|---|---|---|---|---|---|
| **CONNECTIONS** | Supply available by the agreed date | Contact within 10 business days to advise what is required to make supply available | Supply connected by agreed date | Supply connected by agreed date | Supply connected by agreed date | Supply connected by agreed date | Supply connected by agreed date or within 6 working days | Supply connected by agreed date | If premises physically connected to network:<br>- same day if prior to 2 PM<br>- next day if after 2 PM If not physically connected - by agreed date. |
| **$** | 25/day | 20/day up to 200 | 50/day up to 250 | 100/day up to 500 | 50/day up to 250 | 50/day up to 250 | 50/day up to 250 | 60/day up to 300 | 60/day |
| **INTERRUPTION DURATION** | | | Duration > 12 hours | Duration > 12 hours | Duration > 12 hours | Duration > 12 hours | | | Duration > 12 hours |
| **$** | | | 80 | 80 | 80 | 80 | | | 50 |
| **INTERRUPTION FREQUENCY** | | | Excludes momentary interruptions > 9 times/calendar year - urban | Excludes momentary interruptions > 9 times/calendar year - urban > 15 times/calendar year - rural | Excludes momentary interruptions > 9 times/calendar year - urban > 15 times/calendar year - rural | Excludes momentary interruptions > 9 times/calendar year - urban > 15 times/calendar year - rural | | | |
| **$** | | | 80 | 80 | 80 | 80 | | | |
| **INTERRUPTION ADVICE** | Provide at least 4 business days' notice of planned interruptions | Provide at least 2 business days' notice of planned interruptions | | | | | | Provide at least 2 business days' notice. Duration not longer than specified | Provide at least 2 business days' notice of planned interruptions |
| **$** | 20 res 50 bus | 20 | | | | | | 20 | 50 |
| **APPOINTMENTS** | | More than 15 minutes late | More than 15 minutes late | More than 15 minutes late | More than 15 minutes late | More than 15 minutes late | More than 15 minutes late | More than 15 minutes late | More than 30 minutes late. Provide 24 hours notice of cancellation |
| **$** | | 20 | 20 | 40 | 20 | 20 | 20 | 25 | 20 |

| UTILITY | ERGON | ENERGEX | CITIPOWER | POWERCOR | TXU | UNITED ENERGY | ETSA UTILITIES | ENERGY AUSTRALIA | ACTEWAGL |
|---|---|---|---|---|---|---|---|---|---|
| **PUBLIC LIGHTING** | Repair by the agreed date | | Repair within 2 business days | Repair within 2 business days | Repair within 2 business days | Repair within 2 business days | Repair within 5 business days for nominated major areas and 10 days elsewhere - recurring for each time the target is not achieved | Repair on or before agreed date | |
| **$** | 10 | | 10 | 40 | 10 | 10 | 20 | 15 | |
| **QUALITY OF SUPPLY** | | Investigate & respond within 10 business days | | | | | | | |
| **$** | | | | | | | | | |
| **WRONGFUL DISCONNECTION** | | Disconnection in error | | | | | | | |
| **$** | | 100 | | | | | | | |
| **HOT WATER** | Attend to enquiry within 1 day where it is due to a fault in Ergon's control system | | | | | | | | |
| **$** | 20/day | | | | | | | | |
| **TREES & O/H POWERLINES** | Respond immediately if safety risk. If not urgent & not already on vegetation program, visit to assess within 20 business days | | | | | | | | |
| **$** | 20 | | | | | | | | |

| UTILITY | ERGON | ENERGEX | CITIPOWER | POWERCOR | TXU | UNITED ENERGY | ETSA UTILITIES | ENERGY AUSTRALIA | ACTEWAGL |
|---|---|---|---|---|---|---|---|---|---|
| **WRITTEN CUSTOMER ACCOUNT QUERIES** | | | | | | | | | Acknowledge within 10 business days and respond within 20 business days |
| **$** | | | | | | | | | 20 |
| **WRITTEN CUSTOMER COMPLAINTS** | | | | | | | | | If visit required or enquiries of 3rd party involved, then acknowledge within 10 business days & respond within 20 business days. In all other cases, respond within 10 business days. |
| **$** | | | | | | | | | 20 |
| **NOTIFICATION BY CUSTOMER OF PROBLEM** | | | | | | | | | If likely to affect public health or potential to cause substantial damage or harm to person or property, respond ASAP and within 6 hours. In all other cases, respond within 48 hours. |
| **$** | | | | | | | | | 60/day |
| **UPLANNED INTERRUPTIONS 24 HOUR TELEPHONE SERVICE** | | | | | | | | | Within 1 hour of advice, establish 24 hour telephone service |
| **$** | | | | | | | | | 20 |