Review of ENERGEX regulatory proposal for the period July 2010 to June 2015

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for Australian Energy Regulator

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Glossary

Previous regulatory control period	The period 1 July 2001 to 30 June 2005
Current regulatory control period	The period 1 July 2005 to 30 June 2010
Next regulatory control period	The period 1 July 2010 to 30 June 2015
Good electricity industry practice	Has the meaning given by the National Electricity Rules: The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the power system for the generation, transmission or supply of electricity under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments.

List of abbreviations

AER	Australian Energy Regulator
BMS	business management system
C&I	commercial and industrial
capex	capital expenditure
CBRM	condition-based risk management
COIN	company initiated augmentation
CPoW	consolidated program of work
D&C	design and construct
DM	demand management
DNR	domestic and rural (sub-divisions)
DNSP	Distribution Network Service Provider
EDSD	Electricity Distribution and Service Delivery Review
GFC	Global Financial Crisis
MAMP	Mains Asset Maintenance Policy[1]
MSS	Minimum Service Standard
NAMP	Network Asset Management Program
NER	National Electricity Rules
NMP	Network Management Plan[2]
NTC	Network and Technical Committee
opex	operating expenditure
PoE	probability of exceedance (in relation to forecast demand)
QME	Queensland Department of Mines and Energy
QCA	Queensland Competition Authority

1 ENERGEX July 2009, Regulatory Proposal for the period July 2010–June 2015, Appendix_4.7 Mains Asset Maintenance Policy

2 ENERGEX, July 2009, Regulatory Proposal for the period July 2010–June 2015, Appendix_9.2(1) Network Management Plan [Part 1]; Appendix_9.2(2) Network Management Plan [Part 2]

SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAMP	Substation Asset Maintenance Policy[3]
STPIS	Service Target Performance Incentive Scheme

Notes

All dollar values in this report are expressed as $m real 2009-10 unless stated otherwise.

Table N1 below provides the escalation rates (as advised by the AER) used to convert historical expenditures to the 2009-10 reference year for direct comparison with the forecasts presented by the businesses.

Table N1 Escalation rates used to convert historical expenditures to real 2009-10 advised by AER

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
Escalation rates	1.2478	1.2063	1.1829	1.1556	1.1222	1.0955	1.0509	1.0256	1.000

Source: AER, based on consumer price inflation

3 ENERGEX July 2009, Regulatory Proposal for the period July 2010–June 2015, Appendix _4.6 Substation Asset Mana

Executive summary

The Australian Energy Regulator, in accordance with its responsibilities under the National Electricity Rules, is required to conduct an assessment of the appropriate revenue determination to be applied to direct control services provided by ENERGEX for the period 1 July 2010 to 30 June 2015 (the next regulatory control period).

ENERGEX proposes to invest capital expenditure of $5902.0m in its electricity system, $563.7 of capital expenditure in non-system assets and spend $1843.2m on operations and maintenance. Parsons Brinckerhoff (PB) has been engaged to provide an independent view on the prudence and efficiency of these proposed expenditures, and to review the service standards proposed to be delivered for these expenditures.

In undertaking this review PB has adopted a phased approach to provide broad coverage of the expenditure proposal while enabling a more detailed examination of key issues — as required. The three stages of the PB review are: a high level 'portfolio' review; a more detailed, 'focused' review of specific areas identified in the high-level review; and a reporting stage.

Overall, PB has found that:

- The proposed total capital expenditure of $6465.7m is prudent and efficient, except for the proposed building program ($158.3m reduction), and the forecast in peak demand ($289m reduction based on McLennan Magasanik Associates demand forecasts[4]). PB recommends a prudent and efficient expenditure in the next regulatory period would be $6019m.

- The proposed operational and maintenance expenditure of $1843.2m is prudent and efficient, except for the demand and energy data capture and analysis program ($2.2m reduction). PB recommends a prudent and efficient expenditure in the next regulatory period would be $1841.0m.

- A reduction of $9.5m is recommended relating to the service charge from ICT service provider SPARQ. The service charge is treated as an overhead and the recommendation results in a $7.3m reduction in capex and a $2.2m reduction in opex.

PB's detailed findings for each expenditure category are set out below.

System capital expenditure

ENERGEX proposes to invest capital expenditure of $5,902m on its electricity system over the next regulatory control period. PB has found this level of expenditure to be prudent and efficient except for the forecast expenditures relating to growth. PB's key findings are as follows:

- ENERGEX's proposed capex for growth is reduced by $289m, based on a one year delay in the demand forecast as recommended by MMA.

- ENERGEX's capital governance is consistent with good electricity industry practice.

4 MMA, September 2009, Review of ENERGEX's maximum demand forecasts for the 2010 to 2015 price review, page 3.

- The processes and procedures ENERGEX has used are reflective of good electricity industry practice and implementation should lead to a prudent and efficient outcome.

- The electricity demand forecast set out in the ENERGEX Regulatory Proposal has been appropriately incorporated into forecast expenditures.

- ENERGEX's consideration of non-network solutions and demand management alternatives is consistent with good electricity industry practice.

- Increased expenditures are sought in all expenditure sub-categories:

  - Increased asset replacement and renewal expenditure is mostly driven by the EDSD review recommendations[5]

  - Increased expenditure for reliability and quality of service enhancement is driven by performance improvements required to meet the minimum service standards targets set out in the *Electricity Industry Code*. Projects included in the reliability investment plan are developed in line with the network reliability improvement strategy.

  - Increased expenditure for security compliance is driven by the EDSD review recommendations. The revised security standards that ENERGEX has proposed for the next regulatory control period represent good electricity industry practice.

PB recommends that the system capex allowance for the next regulatory control period should be adjusted from the levels proposed by ENERGEX as detailed in Table E1.

Table E1 Recommended system capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	1,047.0	1,144.9	1,203.5	1229.2	1277.5	5,902.2
PB adjustment	(37.3)	(43.8)	(60.5)	(66.9)	(80.0)	(288.6)
PB recommendation	1,009.7	1,101.1	1,143.0	1,162.3	1,197.5	5,613.6

Non-system capital expenditure

ENERGEX proposes to invest capital expenditure of $563.7m on non-system assets in the next regulatory control period, an average increase of 29%. PB has found this level of expenditure not to be prudent and efficient as follows:

- ENERGEX proposes expenditure of $12.8m for Information and Communications Technology (ICT) in the next regulatory control period, a reduction of 74% when compared to the current period (due to the establishment of SPARQ as their ICT service provider). Based on an assessment of historical expenditures, PB has assessed ENERGEX's proposed ICT expenditure as being prudent and efficient. In determining its forecast expenditure, however, PB notes that ENERGEX has applied a forecast CPI to its historical expenditure in financial year 2009-10 that is different to that recommended by the AER.

- ENERGEX proposes to spend $298.4m on land and buildings capex in the next regulatory control period, an increase of 128%. The need and timing for the extensive proposed building program was not sufficiently demonstrated to PB, and as such PB recommends a reduction of $158.3 for the next regulatory control period.

5 Office of Energy, Department of Natural Resources, Mines and Energy July 2004, *Electricity distribution and service delivery for the 21st century.*

- The proposed capex for tools and equipment, representing a real decrease of 16%, and for fleet, representing a real increase of 3.6%, are assessed as being prudent and efficient.

PB recommends that the non-system capex allowance for the next regulatory control period should be reduced by $158.3m (28%) from the levels proposed by ENERGEX. Table E2 presents PB's recommended non-system capital expenditure.

Table E2 Recommended non system capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	192.3	124.8	98.4	63.2	85.0	563.7
PB adjustment	(115.0)	(39.8)	(16.4)	9.5	3.3	(158.3)
PB recommendation	77.3	85.0	82.0	72.7	88.3	405.4

Operational and maintenance expenditure

ENERGEX proposes to spend $1843.2m on operations and maintenance in the next regulatory control period, an average increase of 36% when compared to the current period. PB has found this level of proposed expenditure to be prudent and efficient, except as follows:

- The proposed expenditure for demand management programs is assessed to be prudent and efficient except for the demand and energy data capture and analysis program. The impact of this recommendation is a reduction in the 2010-11 financial year expenditure forecasts of $2.24m.

PB's other key findings are as follows:

- ENERGEX's asset management principles, processes and procedures are prudent.
- The forecasting methodology ENERGEX has used to determine expenditure forecasts for the next regulatory control period is sound and is likely to result in accurate forecasts.
- The proposed expenditure for network operations is assessed as prudent and efficient given the business-as-usual trend and the detailed bottom-up approach ENERGEX used when forecasting expenditure for the next regulatory control period.
- The proposed expenditure for inspections based on a business-as-usual expenditure pattern is assessed as prudent and efficient.
- The proposed expenditure for planned maintenance is assessed as prudent and efficient given the detailed nature of the forecasting methodology used by ENERGEX and the overall reduction in proposed expenditure found through the top-down analysis.
- The proposed expenditure for corrective repairs based on a business-as-usual expenditure pattern is assessed as prudent and efficient.
- PB notes a $4.8m step change between the last year of the current regulatory control period and the first year of the next period for the introduction of reduced trimming cycles on low voltage (LV) urban lines. This increased proposed expenditure is assessed as prudent and efficient as this is required for regulatory compliance.
- The proposed expenditure for emergency response and storms, based on the average annual expenditure in the current regulatory control period, is assessed as being prudent and efficient.

- The proposed expenditure for customer service is assessed as being prudent and efficient as it is based on business-as-usual forecasts.

PB recommends that the opex allowance for the next regulatory control period should be reduced by $2.2m (0.1%) from the levels proposed by ENERGEX. Table E3 presents PB's recommended operations and maintenance expenditure.

Table E3 Recommended operations and maintenance expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	355.1	360.9	371.3	380.4	375.5	1843.2
PB adjustment	(2.2)	0.0	0.0	0.0	0.0	(2.2)
PB recommendation	352.9	360.9	371.3	380.4	375.5	1841.0

Overheads

PB has found the allocation of overheads is in accordance with the required cost allocation method.

PB has examined the service charge from ICT service provider SPARQ. PB considers that, with the exception of 'distribution management systems', the proposed expenditure associated with the 'new capability' initiatives capitalised within SPARQ has not been shown to be prudent and efficient and, as such, PB recommends a business-as-usual ICT expenditure forecast.

PB has estimated a $9.5m reduction, and recommends an ICT service charge totalling $170.8m for the next regulatory control period. The recommendation results in a $7.3m reduction in capex and a $2.2m reduction in opex.

Table E4 Reduction in overheads due to SPARQ service charge

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX/SPARQ Proposal	343.0	369.0	383.0	385.9	389.2	1,870.0
PB adjustment	(0.6)	(2.4)	(2.3)	(1.8)	(2.3)	(9.5)
PB recommendation	342.4	366.6	380.7	384.1	386.9	1,860.5

Service delivery

PB's review of the contracting strategies and the material procurement practices used by ENERGEX indicates that, in the view of PB, ENERGEX should be able to deliver its proposed operating and capital programs of work during the next regulatory control period.

Service standards

PB notes that the reliability of supply targets proposed by ENERGEX are required to meet the Minimum Service Standards mandated by the *Electricity Industry Code*. PB has assessed the expenditure proposed by ENERGEX for meeting these targets and considers the amount to be appropriate.

The values proposed by ENERGEX for the service target performance incentive scheme are generally found to be appropriate, with the exceptions noted below.

PB's findings for the reliability of supply parameter are:

- The proposed variation to the Value of Consumer Reliability is not consistent with the objectives of the scheme and the values set out in clause 3.2.2(b) of the scheme should apply.
- The SAIDI and SAIFI 2007-08 baseline performance and performance targets for the next regulatory control period (2010-15) are reasonable.
- ENERGEX did not provide additional information above that provided during the framework and approach process to justify a paper trial and incremental approach to revenue at risk. PB's view is that a revenue at risk cap of 2% as set out in the framework and approach paper should thus apply for the entire duration of the next regulatory control period.

PB's findings for the customer service parameter are:

- The proposed variation to the telephone answering parameter based on a measure of the Average Speed of Answer is not appropriate to include in the scheme.
- The structural break in call centre data is significant such that historical data before the change would not be reflective of future performance.
- No targets should apply for 2010-11. Targets for 2011-12 to 2014-15 should be set at the average performance of the three years of data from 2008-09 to 2010-11.
- An incentive rate of -0.040 should apply. Should the proposed alternative Average Speed of Answer definition of the telephone answering parameter be adopted, the incentive rate of -0.040 should apply.
- An overall revenue at risk cap of 2% should apply, with a revenue at risk cap of 0.14% for the telephone answering parameter.

In summary, PB recommends the values for the service performance parameters shown in Table E5 and the maximum revenue increment or decrement for the telephone answering parameter should be 0.14%.

Table E5 Recommended values for the service performance parameters

Parameter	Unit	Rate %	Targets				
			2010-11	2011-12	2012-13	2013-14	2014-15
SAIDI							
CBD	minute	0.0084	3.3	3.3	3.3	3.3	3.3
Urban	minute	0.0605	69.4	67.7	66.0	64.3	63.0
Short rural	minute	0.0128	173.2	164.4	158.0	152.4	147.6
SAIFI							
CBD	per interruption	0.7631#	0.032	0.032	0.032	0.032	0.032
Urban	per interruption	4.0437#	1.044	1.032	1.020	1.008	0.996
Short rural	per interruption	1.0459#	2.285	2.201	2.120	2.041	1.967
Customer service							
Telephone answering	%	-0.040	N/A	*	*	*	*

*Note: * Target to be determined based upon telephone answering data (2008-09 to 2010-11) when available.*

 # per 0.01 interruptions

Incentive rates for SAIDI and SAFI parameters are calculated using ENERGEX's proposed average energy consumption.

1. Introduction

In this section we describe the background to this review and provide details of the terms of reference. We also set out the structure of this report.

1.1 Background to the review

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (NER), is required to conduct an assessment of the appropriate revenue determination to be applied to direct control services provided by Distribution Network Service Providers (DNSPs) in South Australia and Queensland for the period 1 July 2010 to 30 June 2015 (the next regulatory control period).

As part of its assessment the AER has engaged the services of Parsons Brinckerhoff (PB)[6] to provide an independent view on the prudence and efficiency of the expenditure proposals from each of the three DNSPs — Ergon Energy and ENERGEX in Queensland, and ETSA Utilities in South Australia. The advice from PB will assist the AER in making its determination in respect of the expenditure proposals from each of the businesses.

This report concerns the review of the expenditure proposal from ENERGEX only. ETSA Utilities and Ergon Energy are the subject of separate reports by PB.

The ENERGEX Regulatory Proposal[7] was submitted to the AER on 30 June 2009. PB was provided with a copy of the proposal on 3 July 2009. The AER is expected to make its Draft Determination in by the end of November 2009 and its Final Determination by the end of April 2010.

1.2 Terms of reference

PB's terms of reference are contained in Appendix A of this report. The main objective of PB's review is to provide the AER with independent technical advice regarding the efficiency and prudence of the capital expenditure (capex) and operating expenditure (opex) proposals submitted by ENERGEX and also to provide input to assist the AER in its assessment of the opex and capex objectives, criteria and factors set out in clauses 6.5.6 and 6.5.7 of the NER. Specifically, this involves a review of ENERGEX's historical and forecast capex and opex, the associated policies and procedures, and the service standards proposals for the next regulatory control period.

PB's terms of reference do not include the review of external factors and obligations[8], cost pass-through items, or the review of submissions from interested parties on PB's report or the AER's draft or final determination. Reviews of equity raising and superannuation costs are also outside of the scope of PB's engagement.

PB's final report to the AER on the ENERGEX Regulatory Proposal was submitted on 9 October 2009.

6 Please refer to Appendix B for a summary about PB and PB's relevant experience
7 ENERGEX 2009, *Regulatory proposal for the period July 2010–June 2015.*
8 Other than to the extent required to develop an independent recommendation on the prudence and efficiency of the expenditure proposed by ENERGEX.

1.3 Report structure

In section 2 of this report we set out the overarching methodology PB adopted for this review. Section 3 discusses the application of cost escalation to the forecast expenditures and the allocation of overheads. Sections 4, 5 and 6 deal with the ENERGEX system capex, non-system capex, and opex proposals respectively. Section 7 provides details of PB's review of ENERGEX's deliverability proposals and in section 8 we provide our recommendations in respect of the ENERGEX proposed Service Standards. Generic limitations of the report are provided in section 9.

2. Review methodology

In this section we describe the overarching methodology PB adopted in its review of the ENERGEX Regulatory Proposal. This includes an outline of our approach to the review and details of aspects of the proposal that were examined.

2.1 PB's phased approach

PB has adopted a phased approach to review ENERGEX. The process has been specifically designed to provide broad coverage of the expenditure proposal while enabling a more detailed examination of key issues — as required. In summary, the three stages of the PB review are:

- a high level 'portfolio' review
- a more detailed, 'focused' review of specific areas identified in the high-level review
- a reporting stage.

The first two stages of the review process allow consideration of the complete expenditure proposal while supporting and facilitating a more detailed examination of selected aspects of the proposal. The process inherently recognises the need for a high-level review of the entire regulatory submission *before* it is possible to determine which aspects warrant further review effort and scrutiny.

In this way PB has been able to ensure that effort is expended in areas of the proposal likely to be important in providing credible and sound independent advice on the prudence and efficiency of the ENERGEX Regulatory Proposal.

This phased approach to the review is represented in Figure 2.1.

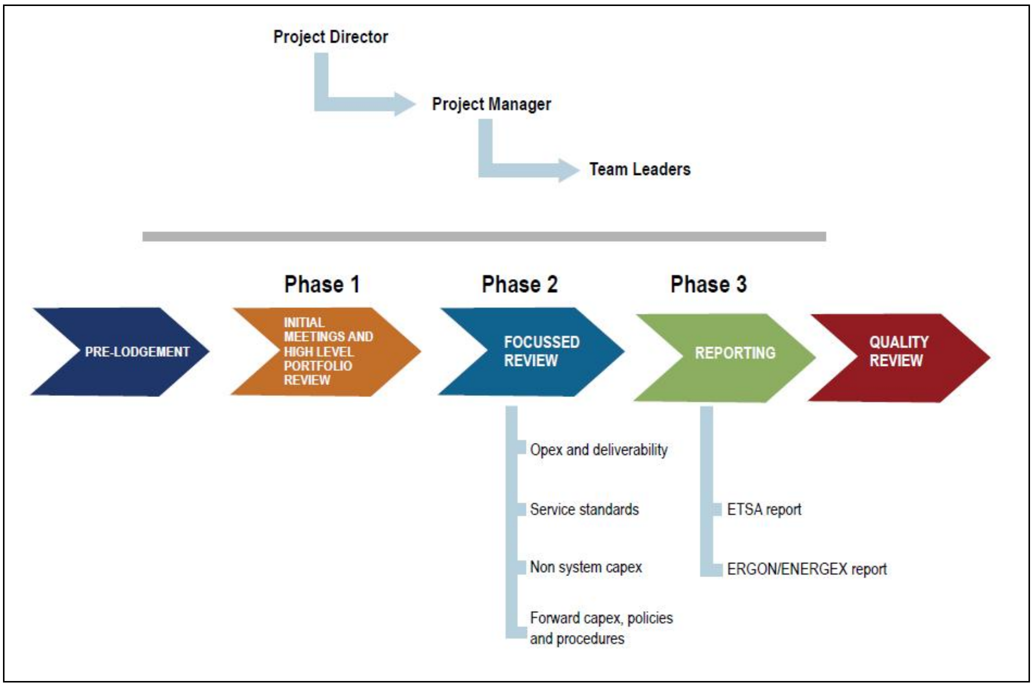

Figure 2.1 PB's approach to the review

The phased approach adopted by PB involved the following steps:

- a detailed desk-top review of the information provided in the Regulatory Proposal
- onsite meetings with ENERGEX staff to discuss essential elements of the Regulatory Proposal (PB provided ENERGEX with details of specific areas for discussion beforehand)
- development of a preliminary view on key issues at a portfolio level and discussion and agreement with the AER to a scope of works for the focused review stage
- formulation of detailed questions for ENERGEX on its expenditure proposals
- consideration of ENERGEX's responses
- a second on-site visit with ENERGEX to discuss key issues and PB's preliminary views and findings on the expenditure proposals
- further questions and responses to establish a full understanding of specific expenditure items.

In meeting its primary objective of providing an independent view on the prudence and efficiency of the ENERGEX expenditure proposal, PB has given due regard to the opex and capex objectives, criteria and factors set out in clauses 6.5.6 and 6.5.7 of the NER.

In assessing the prudence and efficiency of proposed expenditures, PB has considered the need or driver for the expenditure, the timing of the expenditure and, where appropriate, has used business-as-usual levels of recurrent expenditures to develop a view about the appropriate level of forecast expenditures. Given that ENERGEX is incentivised to be efficient by the nature of the incentive based CPI-x form of price regulation, PB considers that business-as-usual levels of expenditures can be considered as indicative of efficient expenditures.

PB notes that historical expenditures may differ from business-as-usual expenditures in that historical expenditures may contain abnormal under or over spends. Discussion with ENERGEX about historical expenditures has therefore occurred. Further information about PB's review of the capex and opex proposed by ENERGEX is set out in the following sections.

2.1.1 Capex review

In assessing whether proposed capital investments are prudent and efficient, PB has:

- assessed whether ENERGEX is acting efficiently in accordance with good electricity industry practice through a review of capital governance, policy and procedures, cost estimating practices, specific reviews of certain expenditures, and the deliverability of the proposed works program
- assessed whether there is a justifiable need for the proposed investment within each expenditure category
- after confirming the need for an investment, assessed whether all reasonable options have been considered and the most efficient investment selected to satisfy that need

- where an investment is based on assumptions about future conditions, assessed whether those assumptions are reasonable[9].

PB's review of ENERGEX's forecast capex allowance has specifically excluded the following matters from our scope of work:

- benchmarking of unit costs
- the level of forecast demand.

2.1.2 Opex review

PB's review of ENERGEX's proposed opex included an assessment of:

- the efficiency of the forecast opex for each year of the next regulatory control period, and whether there is any further scope for efficiencies
- the appropriateness of the allocation of opex costs to specific activities
- the effectiveness of operating practices, procedures, and asset management systems at ensuring only necessary and efficient opex occurs
- the major factors (drivers) that may affect the level of efficient opex required over the next regulatory control period
- the appropriateness of the opex forecasting methodology, including:
  - reviewing the opex by cost category in both the current and next regulatory control period, including trends and changes in each line item[10]
  - reviewing the variations between the opex in the final year of the current regulatory control period and opex in the first year of the next period (step changes in expenditures)
  - the reasonable application of escalation factors used to forecast expenditures
  - assessing the appropriateness of efficiency factors used to reflect the impact of economies of scale and scope
  - assessing the efficiency of labour and material costs used to forecast expenditures
  - whether insurance costs captured by self insurance have been appropriately excluded
- the impact of proposed capital works to be commissioned during the next regulatory control period on forecast opex.

A two-stage process has been carried out covering an initial high-level review, followed by a more detailed investigation into areas of particular materiality or variance. Fundamentally, the objective of the process has been aimed at:

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9 PB's review did not include assumptions made about the future demand for electricity.

10 This included escalating historical nominal costs to real 2009-10 dollars and removing the impacts of labour and material escalation in the next regulatory control period to test the sensitivity of the real labour and material escalation built into the forecasts, and to provide more insight into the volumes of work in the next regulatory control period compared with historical levels.

- reviewing and understanding the business-as-usual asset management approach and practice, including relevant policies and procedures, from both a technical and commercial perspective

- reviewing and understanding the expenditure forecasting methodology and modelling used, with a strong view to being informed of the scope of work proposed; understanding changes proposed by the business; and the drivers presented by the business for any notable and material changes

- forming an independent view on the prudence and efficiency of the proposed scope of work and expenditure, to advise and assist the AER in determining how the opex complies with the requirements and objectives of the NEL and the NER.

PB's review of ENERGEX's forecast opex allowance has specifically excluded the following matters from our scope of work:

- self-insurance arrangements and allowances ($15.1m included in the 'other opex' line item)

- non-system allowance for levies ($46.1m included as a specific opex cost category)

- costs of debt raising ($44.8m included as a specific opex cost category)

- costs of equity raising ($87.4m included as a specific opex cost category)

- the magnitude of the labour and material escalation factors applied to the forecast opex (noting that the application methodology is included in PB's review)

- high-level, inter-business comparative benchmarking — for example, opex/RAB, or opex/composite size ratios (to be undertaken by the AER)

- a high-level review of historical expenditure variations in the current period compared with regulatory allowances (to be carried out by the AER)

- a detailed review of the indentified external factors and obligations (to be carried out by the AER) and identification of external factors and obligations that have been omitted and may be material

- systematic and formal comparative review or analysis of unit costs informing opex

- review of submissions from interested parties.

2.1.3 Service standards

ENERGEX proposes to improve its reliability of supply service performance over the next regulatory control period in line with its regulatory obligations under the *Electricity Industry Code*. PB examines the costs associated with this improvement as a part of its capex review.

ENERGEX is also subject to a Service Target Performance Incentive Scheme (STPIS), including a reliability of supply component and a customer service component. The outcome of the PB review is the recommendation of appropriate reliability of supply and customer service performance targets to be applied to ENERGEX over the next regulatory control period. PB has assessed the STPIS values proposed by ENERGEX against both the principles outlined in the STPIS and clause 6.6.2 of the NER.

In determining the future performance targets, PB has given due regard to historical performance as required by the STPIS, as well as the impact that the proposed capex and opex programs may have on performance.

Specifically, in its review, PB has:

- examined any reliability improvements completed or planned to be completed within the current regulatory control period and any other factors that are likely to materially affect reliability performance
- ensured the defined exclusions to the scheme are appropriately removed from the performance data on which targets are based
- assessed the appropriateness of proposed targets, incentive rates and other values proposed for each parameter
- ensured the overall revenue at risk, and the revenue at risk for each customer service parameter, is limited as required by the scheme.

From this review, PB has provided its recommendations of appropriate reliability of supply and customer service performance targets to be applied to ENERGEX over the next regulatory control period.

2.2 Specific aspects under review

Significant aspects of PB's review of the proposed expenditures are the assessments of:

- capital governance
- business polices and procedure
- programs of work
- individual projects.

Each of these aspects is described below.

2.2.1 Capital governance

PB recognises sound capital governance as an important cornerstone of prudent and efficient asset management, as it acts to establish and define the business' investment approach. PB has undertaken a high level review of ENERGEX's capital governance framework as an integral element of assessing the prudence and efficiency of the proposed network capex for the next regulatory control period.

In our view, good practice capital governance in the context of an asset manager, involves both good practice asset management principles as well as good practice investment management principles. In forming a view on the soundness of capital governance practices, PB relies upon our industry experience and our knowledge of the broader principles of sound business management practice. We also draw upon the principles set out in asset management standards such as PAS 55, IIMM , and TAM , as well a range of Australian and International Standards . Broadly, these asset management standards define an approach that starts with the overarching strategy, devolving this through policies, procedures and plans into all aspects of the business' operations. PB anticipates that good asset governance practice, as set out through such standards, would be evidenced by a well developed and integrated framework of documentation that forms part of the business' culture.

Further to this, PB expects sound capital governance to embody the principles good practice investment management as evidenced through prudent business management practices. Specifically, formal delegations from the Board level through to business' operational levels, supporting policies and procedures to control capital investment (including audit practices), as well as control of capital investment as evidenced through business documentation which establishes the business case for investment throughout the entire asset lifecycle. These practices should be integral with the business' risk management practices, quality practices, compliance practices, OH&S practices, and environmental management practices amongst others.

2.2.2 Policies and procedures

ENERGEX has been asked to specify the policies and procedures by which it makes its operational and investment decisions. Such policies are expected to relate to, for example, augmentation, replacement, opex, cost allocation, capitalisation and demand management. PB has made a detailed review of these policies and procedures. This has included a review of network performance targets and associated forecasts, augmentation models, and opex and replacement models where applicable. In making its assessment and recommendation PB has considered the extent to which it believes ENERGEX's policies and procedures align with good electricity industry practice and clauses 6.5.6(c) and 6.5.7(c) of the NER.

PB considers this aspect of the review as critical to assessing the prudence and efficiency of expenditure. Electricity distribution businesses engage in a large volume of activities — particularly when compared with gas or electricity transmission businesses. This large volume of activities results in many investment decisions, particularly involving minor network augmentation and asset replacement activities. As it is impractical to individually assess the reasonableness of each of these expenditure decisions, it is necessary to review the framework in which the decisions are made to determine whether the approach taken by the business is likely to result in appropriate expenditure.

PB has developed its view on ENERGEX policies and procedures through a desk-top review of documentation, through discussions with ENERGEX staff and as an integral part of its more focused review of specific programs of work and projects. Reviewing policy and procedure in the context of proposed expenditure has also provided the opportunity to confirm appropriate application and implementation.

The review of policy and procedure has been for opex, capex and service standards.

2.2.3 Programs of work

It is recognised that there is a notable difference between the approach required for the review of electricity distribution and that for electricity transmission. A significant difference is the predominance of 'programs' of expenditure and the significantly higher number of lower value assets. PB's review recognises the importance of this difference in the context of reviewing the proposed ENERGEX expenditure. Planned programs of work can apply to high volume asset fleets and can extend over many years. The link between strategic priorities, policies and procedures, and programs of work is therefore an important aspect of developing an expert opinion on prudence and efficiency. Planned work programs can have a considerable influence on opex as well as on investment decision-making.

PB's review of the ENERGEX work programs has been informed by the Regulatory Proposal and supporting documentation as well as through further discussions with ENERGEX staff. Some work programs have been subject to a more focused examination following the portfolio level review of proposed expenditures.

2.2.4 Projects

A significant proportion of DNSP capex is associated directly with the implementation of major distribution projects. As distinct from programs of work, project work often results in large one-off expenditures to establish a large asset — such as new major substation site. Equally, project expenditure can comprise a large number of smaller discrete work activities.

PB's review of specific projects includes a high level review of all significant projects (Phase 1) and a focused review of a number of projects. PB's review has examined links between projects and larger work programs, and also the association with particular business strategies and policies.

3. Cost escalation and allocation of overheads

In this section we describe the method used by ENERGEX to escalate forecast costs to account for increases in materials and labour above CPI, and to allocate overhead costs across expenditure categories.

3.1 Cost escalation

To reflect the potential for ENERGEX's input costs to change at a different rate than CPI, ENERGEX has included the effect of real cost escalation in its determination of forecast expenditure. ENERGEX employed consultant KPMG to determine the relevant cost escalators as detailed in Appendices 12.6 and 12.7 of the ENERGEX Regulatory Proposal. The methodology used by ENERGEX to apply these escalators is described in RIN Supporting Document 2.3.10(1) Expenditure Escalation Process.

For each expenditure type, KPMG arrived at a single annual cost escalator for the next regulatory control period as shown in Table 3.1.

Table 3.1 Cost escalators

Expenditure type	Real cost escalator (%)	Nominal cost escalator (%)
Materials	0.00	2.45
Construction	10.20	12.65
Land	2.00	4.45
Motor vehicles	0.00	2.45
Plant and equipment	0.00	2.45
Labour	3.05	5.50
Contractors	3.05	5.50
CPI		**2.45**

Source: ENERGEX July 2009, Regulatory proposal for the period July 2010–June 2015, pp.176-178.

The materials escalator has been developed to represent all input materials used by ENERGEX and is applied equally to all materials types. The inherent conclusion of the KPMG analysis[11] is that due to a perceived high degree of uncertainty in forward looking commodity prices, CPI is the most reasonable forecast for each and every commodity. Therefore, no weightings are required to develop a materials escalator that represents the proportion of various commodities in ENERGEX's forecast expenditure. As such, commodity weightings do not form part of ENERGEX's application of a materials escalator.

While it is not within PB's scope of work to review the value of the actual raw escalators ENERGEX has incorporated into its expenditure forecasts, it is required to comment on the reasonableness and suitability of the application method used. This review is detailed in the following sections on capex and opex cost escalation.

[11] KPMG May 2009, *Development of Cost Escalation Rates* (Appendix 12.7 to ENERGEX's regulatory proposal)

3.1.1 Capex cost escalation

ENERGEX has described the process by which all cost escalators are applied within its cost estimating systems to the relevant expenditure type. As evidence of this process, ENERGEX has provided a model[12] to PB that provides the breakdown of the forecast system capex into asset categories (i.e. distribution transformers, sub-transmission lines and so forth), and the breakdown of each of these asset categories into expenditure types (i.e. materials, labour and so forth.). The relevant expenditure type escalator is then applied at the breakdown level such that the final total forecast capex includes the appropriate weighting of each of the expenditure type escalators. It should be noted ENERGEX built the model to demonstrate the application of escalators, and the escalators that are applied to the forecast expenditure within ENERGEX's enterprise systems cannot be directly verified.

PB's assessment and findings

PB has reviewed this model and found that:

- the cost escalators are applied to the correct expenditure type categories, and therefore the cost escalators are inherently weighted correctly according to the value of each expenditure type
- expenditures at the asset category level within the model sum to amounts that equal the total proposed expenditure.

According to these findings, PB is satisfied with the treatment of escalators within this model and has confidence that the model represents the impact of escalation within ENERGEX's enterprise systems. The impact of cost escalators on capex is not discussed further in this report.

3.1.2 Opex cost escalation

PB relied on reviewing ENERGEX's audit processes and results to decide if the methodology ENERGEX used to apply opex cost escalators was valid, reasonable and suitable.

The methodology ENERGEX used essentially consisted of taking the base opex program of works operating forecasts, the system capex and non-system capex forecasts (each expressed in 2008-09 dollars) and checking that they were all divided into labour, materials, land/easements or contractor/construction categories as appropriate.

ENERGEX then used an Excel spreadsheet model to represent how it had applied the appropriate escalation rates to each cost category within its Primavera software process. The escalation rates recommended by KPMG were consistent over the regulatory control period. Deloittes undertook an independent review of the modelling.

PB's assessment and findings

PB found the MS Excel spreadsheet methodology used by ENERGEX to apply real escalation to the four cost components of labour and materials appropriate and straightforward. In relation to the auditing the process, PB notes that Deloittes has audited the methodology applied. Whilst PB requested a copy of the internal audit report (conducted by Deloitte), it did not receive a copy to review. Hence, PB has relied on the Evans and Peck

12 ENERGEX, August 2009, PB.EGX.MW.37&38 Capex model - PB.xls

review of the ENERGEX submission to the AER for compliance with the NER[13]. This report finds the operating and maintenance forecast expenditures to be prudent and efficient and the review included an examination of the cost escalation process.

PB also reviewed and tested the MS Excel spreadsheet[14] developed by ENERGEX to show how it had applied its real input cost escalators. PB found the model confirmed that ENERGEX has correctly applied the real cost escalators in developing its opex forecasts.

A more detailed discussion of the impact of input cost escalation on ENERGEX's opex can be found in section 6.3.2 of this report.

3.2 Overhead allocations

ENERGEX allocates overheads to capex and opex to cover the cost of running the business. PB has reviewed the DNSP's overheads and has recommended adjustments based on this review. PB notes that overheads are applied to each of the expenditure categories and that any reductions made to these categories will require the overheads to be re-allocated across to remaining categories. The relationship between the overhead pool and the capital and operating expenditures was not considered part of PB's review.

3.2.1 Proposed overhead expenditure

ENERGEX has allocated a total of $2131m in overheads[15] for the next regulatory control period[16]. This is 33% of the total forecast capex. Table 3.2 shows the allocation of overhead by ENERGEX.

13 Evans & Peck ENERGEX Review of 2010/11 to 2014/15 Submission to the Australian Energy Regulator for Compliance with the National Electricity Rules June 2009

14 Refer to section 6.3.3 of this report for further discussion

15 The figure of $2,131m includes $261m of non capitalised costs (unregulated activities and alternative control services), PB's review has focused on the capital aspects of the overhead allocation.

16 ENERGEX, August 2009, PB.EGX.MW.37&38 Capex model.xls.

Table 3.2 Overheads allocation

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Customer Service (inc Accounts & Communications)	42.4	43.2	44.5	45.0	45.5	220.6
ICT	81.4	95.9	102.5	100.3	98.4	478.5
Property	39.1	44.5	46.6	46.2	45.8	222.2
Regulation & Compliance	4.4	4.5	4.6	4.7	4.8	23.0
Chief Executive & Chief Financial Officer	42.2	43.0	43.8	44.5	44.9	218.4
Legal	3.4	3.5	3.6	3.6	3.7	17.8
Audit	1.2	1.3	1.3	1.3	1.4	6.5
Human Resources	16.8	17.3	17.7	18.2	18.7	88.7
Procurement	7.4	7.8	7.7	7.4	7.3	37.6
RedEquip Assets	9.3	9.6	9.9	10.3	10.6	49.7
Esitrain	6.8	7.0	7.3	7.5	7.7	36.3
Network Performance	37.6	38.6	39.2	39.7	40.2	195.3
Energy Delivery	87.3	89.7	92.0	94.5	96.9	460.4
Network Programming & Planning	14.7	15.1	15.3	15.4	15.6	76.1
TOTAL	394.0	421.0	436.0	438.6	441.5	2,131.1

Source: ENERGEX, August 2009, PB.EGX.MW.37&38 Capex model.xls

[*]Note: This figure includes $261m of costs that are not regulated and therefore not capitalised. The total capitalised overheads is $1,870.1m

PB grouped the overheads in categories to help understand the allocation. Table 3.3 shows the grouping.

Table 3.3 Overhead cost categories

PB category	ENERGEX categories	
Business	Regulation & compliance	Legal
	CEO & CFO	Audit
Customer service	Customer services	
Network	Procurement	Energy delivery
	Network performance	Network programming & planning
RedEquip	RedEquip	
ICT	ICT	
Property	Property	
HR function	Human resources	Esitrain

Source PB

Figure 3.1 shows the allocation of overheads with similar groups combined to simplify the presentation.

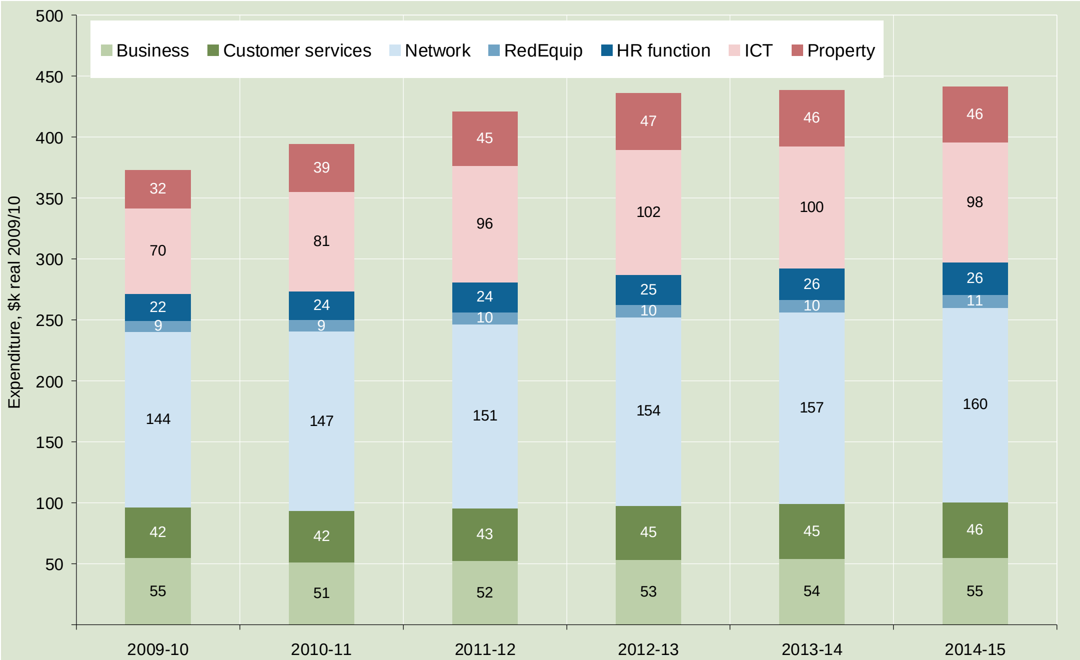

Figure 3.1 General allocation of overheads

Source: ENERGEX, August 2009, PB.EGX.MW.37&38 capex model.xls

ENERGEX formed the view that although using a cost allocation may result in less costs flowing to overheads, the benefits (in terms of improved reporting) do not justify the cost of redeveloping business systems or processing the additional data. ENERGEX intends to continue to apply its simple cost allocation method by aggregating indirect costs and distributing them as overheads.

3.2.2 Process and procedure

ENERGEX allocates overheads as per the AER's approved cost allocation method[17], resulting in a 77% allocation of overheads to capex and 23% to opex. The financial systems in ENERGEX have been set up to classify all expenditure that is not a direct spend on an operational or capex activity as an indirect spend and therefore an overhead.

3.2.3 Specific reviews

From the figures provided by ENERGEX, property increased by 23% in 2010-11 and 14% in 2011-12. In ICT the increase was 16% and 18% in 2010-11 and 2011-12 respectively. For the remaining areas of overheads, there were no significant step changes in expenditure. Therefore PB requested additional information on the drivers behind the increase in these two areas.

Property

Property overheads show a significant increase in the first two years of the next regulatory control period as shown in Table 3.4.

17 ibid.

Table 3.4 Overheads allocated to property

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	39.1	44.5	46.6	46.2	45.8	222.2
Variation (%)	23.2	14.0	4.5	(1.0)	(1.0)	

Source: ENERGEX, August 2009, PB.EGX.MW.37&38 Capex model.xls

ENERGEX provided supporting information[18] about the drivers for the increase in overheads. This information indicates that the proposed increase from 2009-10 to 2010-11 is mainly due to the additional expenses for the Newstead property lease costs and the additional government surcharge for land tax[18]. The proposed increase from 2010-11 to 2011-12 is mainly due to additional lease costs from the proposed Brisbane Metro North and South regional offices[18].

To assist its review, PB reduced the overhead in property as an ongoing additional charge in the years mentioned by ENERGEX[19] as relating to lease costs and to two property categories[20]. Table 3.5 shows the predominant costs as proposed by ENERGEX

Table 3.5 Overheads with annual lease costs separated out

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	39.1	44.5	46.6	46.2	45.8	222.2
Newstead property	(7.3)	(7.3)	(7.3)	(7.3)	(7.3)	(36.5)
Brisbane metro	-	(5.5)	(5.5)	(5.5)	(5.5)	(22.0)
Ongoing costs	31.8	31.7	33.8	33.4	33.0	163.7
Variation (%)		(0.3)	6.2	(1.2)	(1.2)	

Source: ENERGEX, August 2009, PB.EGX.MW.37&38 Capex model.xls

After removing the known increases, the ongoing costs show no significant step change and minimal variation. PB did not identify any changes to the processes or practices that would drive a change in the ongoing costs.

Based on a high level review, the step increase in overheads relates to an increase in ongoing lease costs for two properties, namely Newstead and Brisbane Metro. Once removed, the underlying ongoing costs show no significant step change and minimal variation. PB did not identify any other changes to the processes or practices that would cause a variation to the costs and PB is of the view that ongoing property overheads appear reasonable.

ICT

The proposed increase in ICT overheads is 16% in 2010-11 and 18% in 2011-12. For the remaining areas of overheads, there are no significant step changes in expenditure. Therefore PB requested additional information on the drivers behind the increase in these two areas.

18 ENERGEX, August 2009, PB EGX MW 49.doc
19 Ibid
20 PB estimated the value of the lease costs based in ENERGEX's response in ENERGEC, August 2009, PB.EX MW 49.doc and ENERGEX, August 2009, PB.EGX.MW.37&38 Capex model.xls

Table 3.6 Overheads allocated to ICT

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	81.4	95.9	102.5	100.3	98.4	478.5
Change (%)	16.2	17.8	6.9	(2.1)	(1.9)	

Source: ENERGEX, August 2009, PB.EGX.MW.37&38 Capex model.xls

ENERGEX provided supporting information[21] that the changes in the overheads are being driven by the asset usage fee expense from SPARQ Solutions. The asset usage fee is based on the forecast capex spend in 2008-09 and 2009-10 as well as the capex spend in the next regulatory control period which is based on the Joint ICT Roadmap Initiatives.

The allocation of ICT is reviewed under section 3.2.4, where PB recommends that a reduction is made in the allocation of the service charge from ICT service provider SPARQ.

3.2.4 PB assessment and findings

PB has assessed the prudence and efficiency of overheads as part of its review of capex and opex at an expenditure category level in sections 4, 5 and 6. We note that the AER agreed cost allocation method has been used.

PB has also examined the 2 categories of overheads expenditure that appear to have step changes in expenditure when compared to current levels. PB examined 'property' in detail as there was an increase proposed for the first two years of the next regulatory control period. ENERGEX commented that the main driver for the increase was due to government surcharges for land tax on existing properties and in PB considers that the property overhead expenditure would be at a similar level should this charge not be applied. Therefore, PB considers the business-as-usual expenditure to be reasonable.

PB has also examined the ICT category of overheads where an increase was proposed for the first two years of the next regulatory control period. ENERGEX contend that this is driven by asset usage fee expense from SPARQ Solutions. In the 2009-10 period the ICT overheads are stated as $70.1m and the increasing trend is shown in Table 3.7.

Table 3.7 Overheads allocated to ICT

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
ICT Overheads	70.1	81.4	95.9	102.5	100.3	98.4
Change (%)		16.1	15.1	6.4	(2.2)	(1.9)

Source: PB analysis

PB has taken the 2009-10 year as being reflective of the costs of incurred capex to the business and that the future increases in overheads are driven by the increase in capex expenditure in ICT.

Under the capex review of ICT in section 5.2.4, PB recommended a reduction in the SPARQ service charge relating to ICT expenditure capitalised by SPARQ. The recommendation is shown in Table 3.8.

21 ENERGEX, August 2009, PB EGX MW 48.doc

Table 3.8 Recommended capex for ICT expenditure – SPARQ

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
SPARQ Proposal	54.0	39.2	32.9	31.1	26.9	184.1
PB total adjustment	(3.1)	(3.7)	(2.3)	(1.9)	(2.2)	(13.3)
PB recommendation	50.9	35.5	30.6	29.2	24.7	170.8
Change %	(5.7)	(9.4)	(6.9)	(6.1)	(8.1)	(7.2)

Source: PB analysis

To calculate the reduction in the service charge associated with the SPARQ capex, PB has interpreted the increase in the ICT overhead from that incurred in 2008-09 to be predominately driven by the SPARQ asset usage fee[22] based on ENERGEX advice, and applied a proportional reduction. The reduction is reflective of the recommended percentile reduction made in PB's review of SPARQ capex. The calculation is shown in Table 3.9.

Table 3.9 Recommended reduction in ICT overheads expenditure – SPARQ

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ICT overheads	81.4	95.9	102.5	100.3	98.4	478.5
ICT baseline (09/10 year)	70.1	70.1	70.1	70.1	70.1	350.5
Increase in ICT ($m)	11.3	25.8	32.4	30.2	28.3	128.0
% change in SPARQ capex (see Table 3.8)	(5.7)	(9.4)	(6.9)	(6.1)	(8.1)	(7.2)
Proportional reduction in ICT overhead	(0.6)	(2.4)	(2.3)	(1.8)	(2.3)	(9.5)
PB recommendation	80.8	93.5	100.2	98.5	96.1	469.0

Source: PB analysis

PB's recommended overheads for ENERGEX are shown in Table 3.10.

Table 3.10 Recommended overheads for ENERGEX

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	343.0	369.0	383.0	385.9	389.2	1,870.0
PB adjustment	(0.6)	(2.4)	(2.3)	(1.8)	(2.3)	(9.5)
PB recommendation	342.4	366.6	380.7	384.1	386.9	1,860.5

Source: PB analysis

3.3 Capitalisation policy

ENERGEX has a fixed assets policy (capitalisation policy)[23], which sits below the Board Approved Group Accounting Policy. It provides guidance on the distinction between capex and opex at a conceptual and detailed level.

22 PB.EX.MW.48.doc

23 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, Appendix_17.1 ENERGEX Capitalisation Policy

At the conceptual level the policy indicates assets will be capitalised if:

- the asset has a cost that can be measured accurately
- the asset has physical substance and could be expected to be used over more that one accounting period
- the asset will be in the control of ENERGEX and will deliver future economic benefits to ENERGEX.

In regards to the detailed application of the policy, ENERGEX has provided a table in Appendix ‘A’ of the policy, which describes in detail those types of expenditures that are an expense and those to be capitalised. This appendix provides advice in plain English on how to apply the capitalisation policy in practice and from an asset management perspective.

A typical example of the information in Appendix ‘A’ applicable to overhead lines indicates the replacement of a single pole in a feeder or the replacement of conductor to repair a fault would be an expense. However, if a substantial portion of the conductor on a line was replaced or the work was carried out as part of a refurbishment project, then the costs would be capitalised.

As a result of several discussions PB had with ENERGEX finance and asset management staff to clarify the documented policies, as well as our review of the type of activities that have been included in the opex forecasts, PB found the capitalisation policy adopts a reasonable and pragmatic approach to classifying business expenditures, and is also applied throughout the organisation in a consistent manner.

4. System capex review

This section presents PB's review of ENERGEX's proposed system capex for the next regulatory control period. A high level review is provided, including an analysis of trends in expenditures. This is followed by factors affecting the forecast expenditures, an overview of the relevant processes and procedures, and discussion on specific expenditure categories. A summary of PB's findings and recommendations concludes the section.

4.1 High level review

ENERGEX has submitted a proposed system capex of $5,902m for the next regulatory control period, summarised in Table 4.1[24].

Table 4.1 Proposed system capex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Growth	416.7	457.0	533.0	569.3	637.2	2,613.2
Asset replacement/ renewal	160.5	255.7	212.9	280.2	256.0	1,165.3
Reliability & quality of service enhancement	85.8	50.6	72.6	51.6	45.7	306.3
Security compliance	384.0	381.6	385.0	328.1	338.6	1,817.3
Total system	1,047.0	1,144.9	1,203.5	1,229.2	1,277.5	5,902.1

Source: ENERGEX, July 2009, Regulatory proposal for the period July 2010–June 2015, p.19.

Note: includes customer capital contributions

Growth capex represents 44% of the total system capex proposed, while asset replacement/renewal represents 20%, reliability and quality of service represents 5%, and security compliance represents 31%.

In 2004, the Queensland Department of Mines and Energy (QME) made recommendations to ENERGEX on security standards that should be adopted by the business based on the findings of the EDSD review[25]. ENERGEX's Regulatory Proposal was based on proposed modifications to the security standards that were developed to reflect the EDSD recommendations.

The AER's review of historical expenditure[26] noted ENERGEX's total system capex allowance for the current regulatory control period represents a 50% nominal increase over the capex allowance approved for the previous regulatory control period. Furthermore, the AER identified the total system capex has been 9% above the QCA 2005 Final Determination forecast in the current regulatory control period (based on publicly available reports). The AER also notes that:

24 Unless otherwise stated, all expenditures are $m, real 2009-10.

25 Office of Energy, Department of Natural Resources, Mines and Energy July 2004, *Electricity distribution and service delivery for the 21st century*.

26 AER, July 2009, 20090728 – SA-QLD Historic capex review.doc

> “total capex across the current period … is comprised of some significant variances from forecasts in individual capex by purpose categories both within years and across the period.”[27]

The AER review notes the following significant events:

- Actual capex exceeded forecast capex in every year of the regulatory period, in total over the period by $360m (35%).

- Actual capex exceeded forecast capex significantly in 2003-04 (20%) and 2004-05 (106%). Explanations for these variances identified in Queensland Competition Authority (QCA) annual performance reports are as follows:

  - 2003-04: ENERGEX recorded higher than forecast demand related capex reflecting higher than forecast growth in network peak demand. Conversely, ENERGEX reduced expenditure on non-system assets as a result of a rationalisation of its IT function.

  - 2004-05: higher than forecast demand related capex ($230m or 125% above forecast) reflecting the implementation of an accelerated capital works program to address strong customer number growth and rapid growth in network peak demand. The higher-than-forecast aggregate capital expenditure also reflected a number of accounting adjustments, including capitalisation of both previously expensed costs and non-system assets depreciation during the year.

- A step change in capex allowances occurred through the QCA’s determination for the current regulatory control period. Forecast gross capex allowed for the current period (five years) is 268% higher than the previous period (four years) in nominal terms.

4.1.1 Trends and comparative analysis

PB reviewed historical variances between the QCA allowance and ENERGEX’s actual historical system capex[28].

Figure 4.1 shows the actual system capex for the previous and current regulatory control periods, the QCA allowance set in 2004 for the current regulatory control period, and the forecast capex for the next regulatory control period.

27 AER, July 2009, 20090728 – SA-QLD Historic capex review.doc, p. 4

28 The AER has made a comparative analysis of ENERGEX’s historical expenditure. Refer Australian Energy Regulator 2009, *Queensland and South Australia Electricity Distribution Determination 2010–15 Review of Historic Capital Expenditure*.

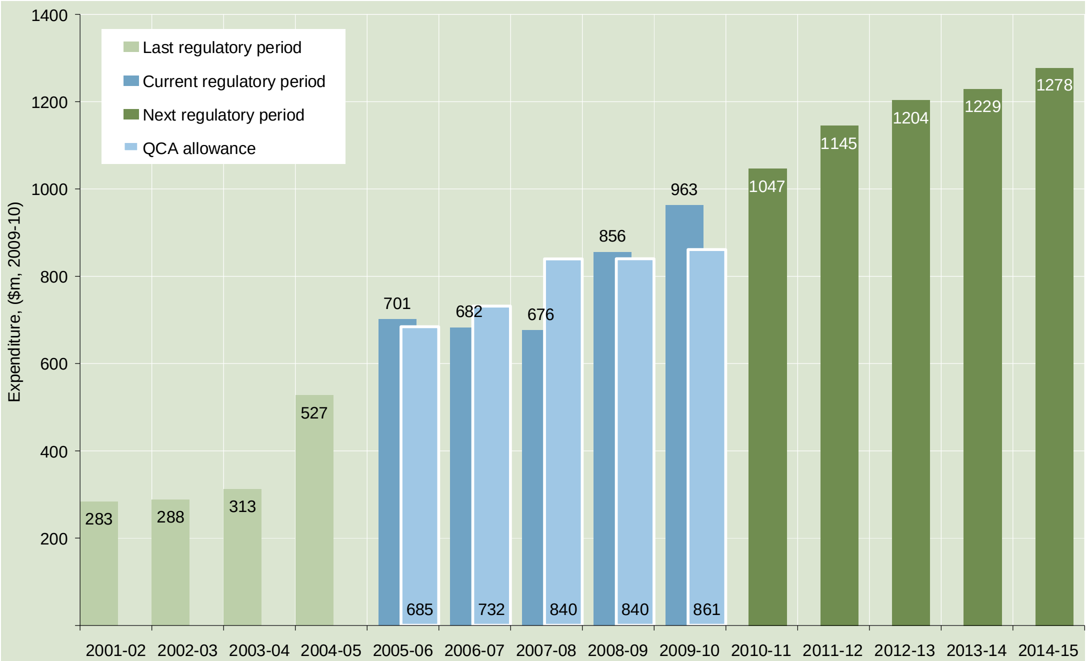

Figure 4.1 Total system capex from 2001 to 2015

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls; PB; AER, August 2009, SA – QLD historic capex review.doc

In the previous regulatory control period, ENERGEX expended a total of $1,411m, which increased to $3,878m in the current regulatory control period, and is forecast to increase to $5,902m in the next regulatory control period.

ENERGEX's allowance for system capex across the current regulatory control period was set by the QCA at $3,958m. Capital expenditure is forecast to increase in the final two years of the current regulatory control period, leading to a total system capex of $3,878m, 2% below the QCA allowance.

ENERGEX has requested $5,902m for the next regulatory control period, an increase of 52% over the actual expenditure in the current regulatory control period.

Figure 4.2 shows the total system actual expenditure and the forecast system expenditure split out into regulatory categories[29].

[29] The historical split between the regulatory categories has been calculated on a weighting basis (from the next regulatory control period) as the actual historical split is not available.

Figure 4.2 System capex by regulatory category

Source: ENERGEX July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls

Figure 4.2 shows a steady increase in expenditures across all regulatory categories. The largest increase relates to asset replacement and renewal, where in the current regulatory control period ENERGEX expects to spend $313m, and is proposing to expend $1,166m in the next regulatory control period. This is an increase of 273%. Table 4.2 shows the actual and forecast expenditures and the change across the current and next regulatory control periods.

Table 4.2 Total expenditures and change across the current and next regulatory control periods

Regulatory category	Regulatory control period		Change (%)
	Current	Next	
Growth	2,122.1	2,613.2	23
Asset replacement/renewal	312.7	1,165.3	273
Reliability and quality of service enhancement	137.2	306.3	123
Security compliance	1,127.7	1,817.3	61
Total	3,699.7	5,902.1	60

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls

Comparative Benchmarking

The AER also undertook some comparative benchmarking[30] and made the following observation with respect to ENERGEX:

[30] AER, July 2009, 2009 05 17- QLD-SA capex benchmarking.doc

> "ENERGEX's actual/forecast capex/RAB ratios is reasonably closely aligned to the benchmark ratios and [Ergon Energy] with both DNSPs' ratios trending down during the next regulatory control period"[31]

PB has considered this information during its review.

4.1.2 Capital governance framework

ENERGEX's capital governance framework is outlined in its Strategic Plan and clearly articulates the direction of the business. The Strategic Plan includes analysis of the drivers of the business and a risk assessment of those drivers to ENERGEX's goal. The analysis is aligned with ENERGEX's Enterprise Risk Management process.

The Plan links the direction of the business with six corporate strategies:

- Customer and Community Strategy
- Network Strategy
- Operational Excellence Strategy
- People and Safety Strategy
- Environment Strategy
- Financial Performance Strategy.

Each corporate strategy is discussed in terms of:

- strategic objective
- future state
- strategic response
- key result areas
- key performance indicators.

The strategic plan identifies five key performance indicators for the Network Strategy, namely:

- policy compliance
- demand under management
- forecasting accuracy
- load factor
- minimum services standards.

31 ibid., p. 2

The network strategy is contained in the Network Management Plan and has been reviewed as this document drives the system capex program. We found a clear connection in the network strategy with the Strategic Plan and a strong driver in the strategy towards the business meeting its key performance indicators. In addition the network management plan articulates the local and federal Codes and compliances that are applicable in a legislative framework.

PB also discussed with ENERGEX its process for making investment decisions. PB found that ENERGEX has:

- an appropriate involvement of the Board in investment decisions, both directly in approving investments exceeding $10m, and through consideration of issues brought to it by its Network Technical Committee
- clear delegations of authority to the CEO and lower levels of management to approve investment decisions
- sufficient information provided in documents submitted with requests for approval of investments to allow the approver to make an informed decision
- a range of management committees reviewing critical decisions, for example the Program of Works Governance Committee that reviews proposed changes to the annual works program, and the Property Governance Committee.

PB notes the high level of involvement and active interest of the Board in improvement initiatives, in particular those associated with technical innovation.

PB' concludes that ENERGEX has appropriate capital governance.

4.1.3 PB assessment and findings

ENERGEX has requested $5,902m for the next regulatory control period, an increase of 52% over the actual expenditure in the current regulatory control period. PB found that increased expenditures are sought in all expenditure sub-categories, driven by the EDSD review recommendations and increased volumes of assets requiring replacement.

PB's review of the network management plan identified a strong coherence between the businesses corporate strategy and strong connections with the key performance indicators. We believe that the suite of policies and plans presented represent good electricity industry practice.

PB found that the decision making process adopted by ENERGEX is consistent with good electricity industry practice and provides adequate assurance that investment decisions are likely to be prudent.

4.2 Growth capex

The growth category of capex relates to the growth portion of customer initiated capital works and the growth portion of corporate initiated augmentation[32].

4.2.1 Proposed expenditure

ENERGEX proposes to spend $2,613m on growth related capex over the next regulatory control period as shown in Table 4.3.

Table 4.3 Proposed capex for growth

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	416.7	457.0	533.0	569.3	637.2	2,613.2

Source: ENERGEX, July 2009, Regulatory proposal for the period July 2010–June 2015, Table 13.5.

Figure 4.3 shows the expenditure in the previous and current regulatory control period and the forecast expenditure on growth in the next regulatory control period for each of the categories — customer initiated capital works and corporate initiated augmentation.

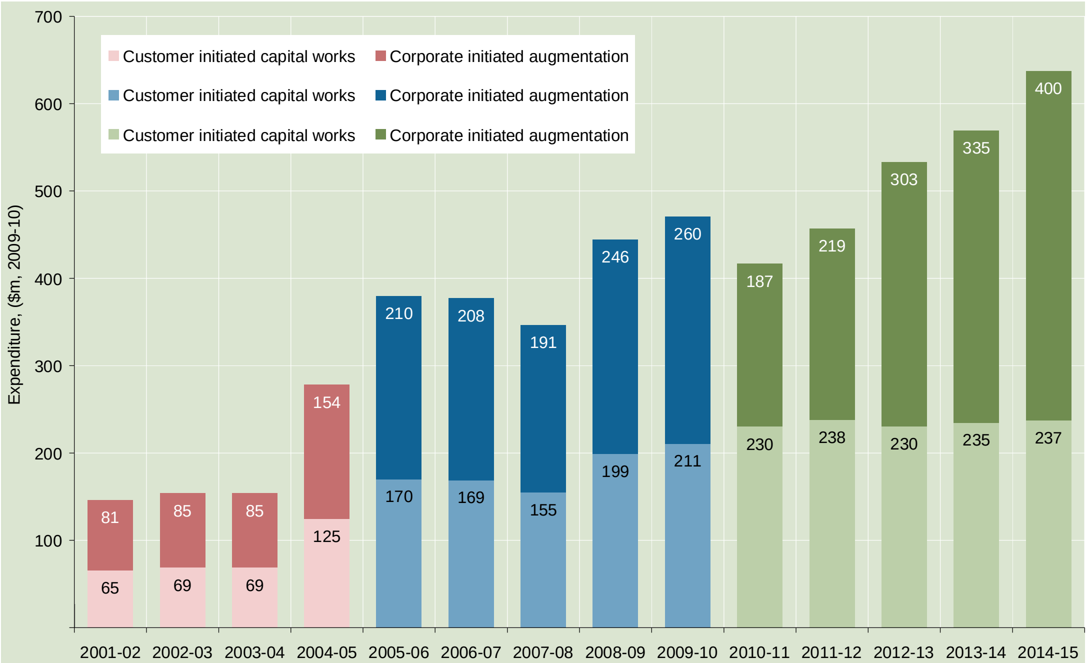

Figure 4.3 Total growth capex by major category

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls; PB; AER, August 2009, SA – QLD historic capex review.doc[32]

ENERGEX is proposing to expend, on average $523m a year in the next regulatory period on growth related works. This represents a real increase of 29% over the current regulatory control period.

32 Growth related expenditure is a combination of corporate initiated augmentation and customer initiated capital works. Growth-related corporate initiated augmentation has been calculated based on historical ratios at $1,443m (real 09/10), and customer initiated capital works has been calculated at $1,170m (real 09/10) based on historical ratios. The security compliance-related expenditure is discussed in section 4.5.

ENERGEX is proposing to expend approximately $235m a year in the next regulatory control period on growth-related customer initiated capital works and $1,443m on growth-related corporate initiated augmentation[33].

PB notes that ENERGEX has scaled back the forecast of the growth-related expenditure by $241.7m as a result of recent changes in the demand forecasts as outlined in the Regulatory Proposal[34]. This reduction is reduced by $16.0m due to redistribution of indirect cost to other capex categories, resulting in a net decrease of $225.8m in total system capex.

4.2.2 Drivers

The main driver of expenditure in this category is an increase in system demand. Figure 4.4 shows ENERGEX's forecast maximum demand in the next regulatory control period overlaid on top of the forecast expenditure on growth.

PB ran a correlation coefficient[35] on the two data sets and the result was ρ = 0.99 indicting a strong correlation.

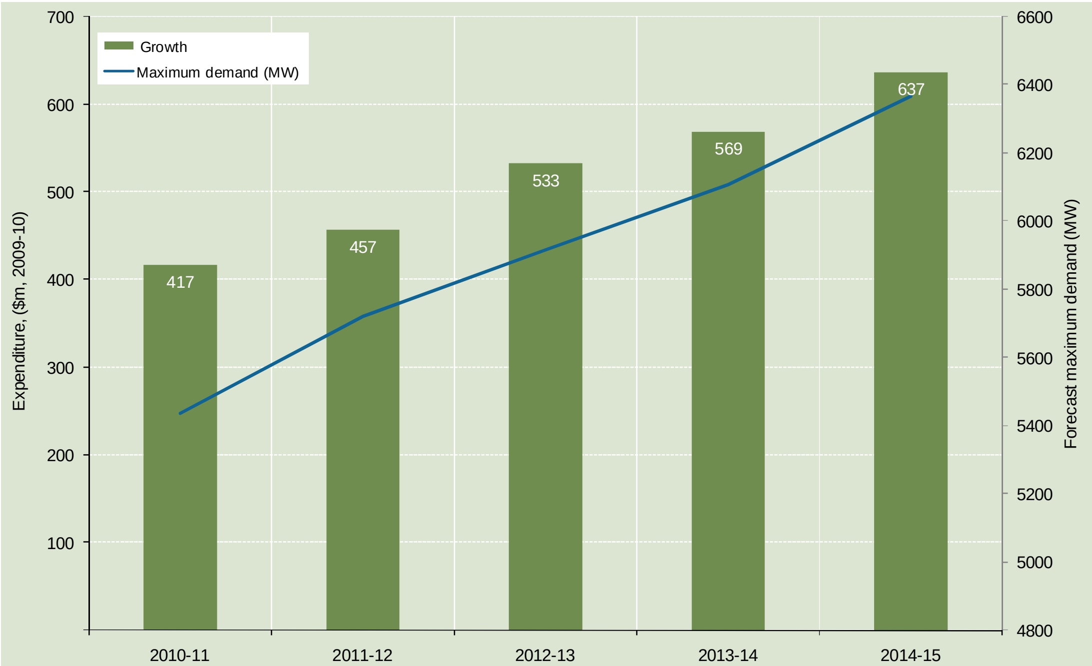

Figure 4.4 Total growth capex and maximum demand forecast

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls; PB; AER, August 2009, SA – QLD historic capex review.doc; ACIL Tasman, April 2008, System maximum demand, page 55

For customer initiated capital works the driver is the connection of customers to the network. PB has identified 20 specific projects within this category with a forecast expenditure of

33 ENERGEX, July 2009, RSD 2.2.1(2) CONFIDENTIAL Capital Expenditure Adjusted Program for SCS 2010-2015

34 op. cit., p. 193

35 A correlation coefficient (ρ)is a statistical technique that indicates the strength and direction of a linear relationship between two arrays of numbers where ρ=1 indicates a strong correlation and a ρ=0 indicates no correlation between the numbers

$1,517m and six generic programs of work at a total of $342m[36] (growth and security compliance programs of work).

For corporate initiated augmentation, expenditures are driven by planning guidelines. ENERGEX has implemented two planning guidelines for the network, one focused on transmission planning[37], the other on distribution planning[38]. Both documents describe the factors for consideration and activities involved in planning the network, as well as the network security standards[39] to be applied.

4.2.3 Policies and procedures

In this section, PB reviews ENERGEX's policies and procedures used to establish a forecast program of works. Specifically PB reviews the planning criteria, how options are analysed and how costs are estimated.

Planning criteria

ENERGEX has established a network development strategy that brings together demand forecasts, standards, and performance data to produce a network wide plan for the expansion and reinforcement of the electricity infrastructure. Figure 4.5 is a graphical representation of the planning process implemented by ENERGEX.

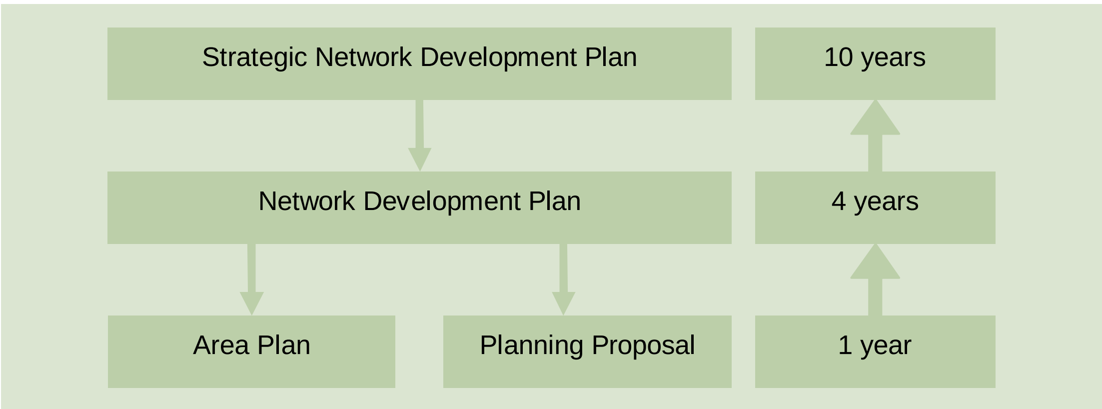

Figure 4.5 Representation of the planning process implemented by ENERGEX

Source: PB

The plans are discussed in detail below.

Strategic network development plan- The strategic network development plan identifies the long-term development for 20 years. Town planning data and load densities are used to evaluate the potential location of future substation sites and corridors along with the Security Planning Guidelines[40]. From the 20-year strategic overview a network development plan is established for three to ten years.

36 ENERGEX, July 2009, RSD 2.2.1(2) CONFIDENTIAL Capital Expenditure Adjusted Program for SCS 2010-2015

37 ENERGEX January 2009, *Transmission planning guidelines*, version 3

38 ENERGEX December 2008, *Distribution planning guidelines*, version 1

39 ENERGEX January 2009, *s*; p.4: ENERGEX December 2008, *Distribution planning guidelines*; p.7

40 PB discusses the implications of security compliance and standards in section 4.5.

Network development plan – After the post-summer load forecasts are complete, the network is reviewed to identify limitations. A strategy is developed to address the identified limitations, along with ensuring that forecast growth and security considerations are met. The solution to the network limitation is captured in a planning proposal document. Where projects are common to a single area, an area plan is constructed.

Area plan – Where multiple projects are proposed to overcome network constraints in a specific area an area plan is developed. Guided by the network strategic development plan, high level options and potential projects are identified and detailed planning either confirms the high level option analysis or provides a cost-effective alternative.

Planning proposal – The Network Development Planning Department generates a planning proposal that details the analysis identifying the preferred development for a particular project.

PB chose a cross-section of planning proposals to form a view on how ENERGEX has implemented the planning process. We observed that the processes and procedures employed by ENERGEX are common to all elements of the capital planning process and found strong links from the overarching strategy of the business that flowed down into individual projects.

PB reviewed the policy and guidelines employed by ENERGEX in developing the strategic network development plan and found the guideline and plan aligned. The policy allows for a long-term view (i.e. 20 years) in the strategic network development plan, which is adjusted each year based on actual growth in demand and customer interaction.

PB found that the processes were of a high standard and were correctly followed. Where the procedure required authorisation through internal panels or managerial approvals, the detail provided was sufficient to allow the approver to make an informed decision.

For the network development plans and the area plans, PB found a high level of detail contained in the plans that demonstrated the processes and procedures had been followed. PB also saw an appropriate approval had been sought and signed off on all the projects reviewed. We also found there to be a high level of detail in the options analysis and establishment of the costs.

Options analysis

PB anticipates that a prudent network planning process would require all practical options to be identified and assessed when determining the business's response to an identified constraint. Such options analysis would involve the application of net present value (NPV) analysis, risk assessment, consideration of the 'do nothing' case, as well as non-network (non-capex) alternatives. Options analysis is therefore a central plank in ensuring that proposed expenditure is the most efficient to meet the business's identified needs.

PB reviewed the option selection and analysis undertaken by ENERGEX in seven plans and associated proposals. PB found options presented included various solutions, including a do nothing option. The initial presentation of the options was an abridged table of an NPV analysis with the actual analysis available in appendices.

We also found that non network alternatives were mentioned in the options analysis and were discussed under a separate chapter. In the projects reviewed there were no viable non network alternatives. PB reviewed the nature of the projects and we concur with ENERGEX's that there are no viable non network options for these particular projects.

In addition to the NPV analysis, ENERGEX undertook a sensitivity analysis around the cost drivers of each option to ensure that the preferred option is robust to changes to scope or cost. PB notes that this analysis is not used as a preapproval of cost variations; should the project costs vary from the forecast, re-approval is required.

Cost estimation

ENERGEX uses an estimating computer program that is part of its Ellipse enterprise resource planning (ERP) package and has developed standard designs for substations, overhead power lines and underground cables. These designs are the building blocks used in the construction of the network. Individual components (i.e. civil works, isolators and so forth) are assembled to form compatible units (i.e. transformer bays), which in turn are built up into standard network building blocks (i.e. zone substations). This approach includes all labour, material and contract work in the compatible units.

The Ellipse estimation system is used to prepare specific estimates for various stages in the planning, design and construction process. Strategic estimates are prepared at the outset of the program, a project approval estimate is made and a further estimate is made if a variation from the approved estimate is required. Strategic estimates are used to produce forecast capital requirements in the next three to ten years.

Project approval estimates are developed from detailed planning analysis of individual network limitations and they are used for formal approval of capex. Risk factors are managed by detailed site investigation into soil condition or the amount of rock in the underground cable route. Project approval estimates are used to forecast capital requirements in the timeframe of zero to three years.

Variation estimates are used to seek re-approval for current projects where known factors make it likely that the original approval will be exceeded. Variation estimates are used to forecast capital requirements in the timeframe of zero to one year.

Projects are programmed and managed and the Primavera project management system monitors progress. The Primavera system consolidates individual projects and estimates into the works program that contributes to the overall capex forecast.

PB is of the opinion that the processes and procedures ENERGEX has used are reflective of good electricity industry practice and implementation should lead to a prudent and efficient outcome.

In reviewing the cost-estimating process, PB found a consistent approach had been applied to the reviewed projects. ENERGEX had included sensitivity analysis on changes in cost in the cost estimating.

4.2.4 Application of demand forecast

ENERGEX developed a baseline capex forecast using network demand forecasts prepared in July 2008, and published in the Network Management Plan[41] (NMP) in October 2008, in conjunction with the planning criteria to determine the emerging need and timing of system capex.

41 ENERGEX, August 2008, ENERGEX Network Management Plan – Part A 2008/09 – 2012/13, page 26

McLennan Magasanik Associates is conducting a review of the development and reasonableness of ENERGEX's demand forecast and these aspects of the forecast are not within PB's scope of work. This section provides PB's review of the application of the forecast in the development of the growth capex proposal. The potential implications of the McLennan Magasanik Associates' findings are discussed in section 4.2.6.

ENERGEX develops and publishes a twice yearly review of the 10 year zone substation, bulk supply substation and connection point demand forecasts for the 480 existing and planned substations. Connection point demand forecasts are an aggregation of the demand forecasts for bulk supply substations and for the direct transformation substations, while the demand forecasts for bulk supply substations are an aggregation of the zone substations they supply. The aggregated demand forecasts are reconciled with the total system demand forecast for summer and winter, day and night.

The process used by ENERGEX to produce the scenario 31 substation demand forecasts was developed and deployed over the past four years. The process uses a bottom up approach incorporating weather corrected starting demand, growth rates, block loads, and load transfers. ENERGEX is transitioning to a forecasting model that introduces a probabilistic approach. The revised forecasting method was recommended by ACIL Tasman[42] for zone substations to be used in the development of the post summer 2008-09 substation demand forecast. The ENERGEX System Maximum Demand Forecasts, in combination with the zone and bulk supply substation maximum demand forecasts, are used to identify network limitations that become key drivers for the network development process.

Due to the timing of ENERGEX's forecast, and the events surrounding the Global Financial Crisis (GFC), the baseline forecast does not include the impact of the GFC.

To account for the latest available information in relation to the GFC, ENERGEX made adjustments to the capex forecasts to reflect an expected reduction in the demand forecasts for the next regulatory period. ENERGEX did this by estimating that the economic slowdown will result in the deferral of $241m (3%) in growth related capex over the next regulatory control period. The corresponding reduction in demand is 549 MW (including 144MW of DM initiatives).

The forecast expenditures in this report have taken into account this revision by ENERGEX. Table 4.4 shows the adjustments made by ENERGEX to the July 2008 forecast capex.

Table 4.4 Adjusted capex forecast accounting for the GFC impact

Period	Baseline data ($m real 09/10)	Forecast after adjustment ($m real 09/10)
2010-11	1,283.0	1,239.5
2011-12	1,313.7	1,269.7
2012-13	1,346.8	1,301.9
2013-14	1,338.2	1,292.4
2014-15	1,407.9	1,362.5
Total	6,689.6	6,466.0

Source: ENERGEX, July 2009, Regulatory proposal for the period July 2010–June 2015; p.150

42 ACIL Tasman, October 2008, Forecasting maximum demand.

4.2.5 Consideration of non-network alternatives

In preparing its forecast capex, ENERGEX takes into account potential non-network alternatives in compliance with the NER. ENERGEX's planning process includes the application of the regulatory test and in line with the regulatory test, non-network solutions are considered.

As part of the non-network solutions, ENERGEX has a Demand Management Strategy that brings together a broad based demand management and energy efficiency initiatives that have the potential to deliver demand reduction through to 2020.

In addition to seeking non-network alternatives through the application of the regulatory test, ENERGEX is promoting a number of initiatives designed to reduce the peak demand – identified by ENERGEX as a key driver for network augmentation.

As part of the regulatory test, potential non-network alternatives are solicited, however this process for canvassing non-network alternatives has not generated interest. Therefore ENERGEX has actively pursued other non-network alternatives in the form of demand management.

ENERGEX formed a panel of potential suppliers for developing alternatives to network augmentation. From this panel ENERGEX has introduced a program of works for demand management through direct load control. This approach is exemplified in two schemes, namely.

- Off-peak water heating – 450 MW saving at peak in July 2008
- Summer preparedness program – 31 MVA in 2008/09

ENERGEX found that the regulatory test was not providing non-network alternatives to network augmentation and in a proactive step pursued other alternatives, namely demand management and peak management. This has lead to active non-network alternatives and through the Demand Management Strategy, ENERGEX intend to continue to grow these demand management activities.

During the specific review of three growth related projects discussed below in section 4.2.6. PB examined the options put forward specifically relating to non-network alternatives. We found that each project discussed non-network alternatives although no viable non-network alternatives were found. There was no detailed discussion, however, on the alternatives examined and therefore no discussion on why the alternatives were unsuitable. PB reviewed the nature of these specific projects and concurs that the predominant driver excludes a non-network alternative[43].

PB believes that despite the limited discussion of non-network alternatives in the planning proposals, ENERGEX's consideration of non-network solutions and demand management alternatives is consistent with good electricity industry practice.

43 ENERGEX, May 2009, convert 323 Parkwood 33/11kV zone substation to 110/11kV – the project resolves two issues where the security standards are not met.

4.2.6 Specific reviews

In examining ENERGEX's growth related capex, PB has specifically reviewed.

- potential impact of McLennan Magasanik Associates revised demand forecast
- high level review of customer numbers
- generic program of works relating to growth.

Potential impact of McLennan Magasanik Associates revised demand forecasts

PB has considered the implications of McLennan Magasanik Associates (MMA) revised demand forecasts with respect to the proposed growth related capex.

MMA has projected a maximum demand lower than the ENERGEX and NIEIR forecast by 200 MW to 300 MW[44]. This is reproduced in Table 4.5 below. PB has interpolated this reduction as an equivalent delay of approximately one year in growth expenditure; basically the demand will reach the forecast level one year later than initially predicted (5,828MW in 2015 instead of 5,797 in 2014).

Table 4.5 Forecast peak demand for the next regulatory period (MW)

	2010	2011	2012	2013	2014	2015
V31 Model	5,021	5,073	5,248	5,489	5,797	6,055
NIEIR	4,997	5,144	5,378	5,699	5,945	6,085
Revised V31 Model C	4,762	4,882	5,067	5,295	5,567	5,828

Source: MMA, September 2009 Review of ENERGEX's maximum demand forecasts for the 2010 to 2015 price review, page 3

PB's approach has been to identify the expenditure related to the growth in the corporate initiated augmentation categories, and to proportionally reduce the increase in growth by one fifth each year. This has the effect of smoothing the delay of one year over the 5-year regulatory control period.

This approach assumes that all expenditure related to achieving service obligations in the customer initiated capital works and the corporate initiated augmentation categories has been correctly identified as security compliance as set out in section 4.5.

Table 4.6 shows the original forecast capex provided by ENERGEX with the customer initiated capital work and corporate initiated augmentation separated into growth and security compliance.

44 MMA, September 2009, Review of ENERGEX's maximum demand forecasts for the 2010 to 2015 price review, page 3.

Table 4.6 Forecast capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Growth – customer initiated capital works	230.2	238.0	230.4	234.6	237.1	1,170.3
Growth – corporate initiated augmentation	186.5	219.0	302.6	334.7	400.1	1,442.9
Growth	416.7	457.0	533.0	569.3	637.2	2,613.2
Asset replacement / renewal	160.5	255.7	212.9	280.2	256.0	1,165.3
Reliability & quality of service enhancement	85.8	50.6	72.6	51.6	45.7	306.3
Security compliance	384.0	381.6	385.0	328.1	338.6	1,817.3
Total system	1,047.0	1,144.9	1,203.5	1,229.2	1,277.5	5,902.1
Total non system	192.3	124.8	98.4	63.2	85.0	563.7
Total	1,239.3	1,269.7	1,301.9	1,292.4	1,362.5	6,465.8

Source Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls

Table 4.7 shows the forecast capex with a one year delay in the expenditure relating to corporate initiated augmentation.

Table 4.7 Forecast capex with a delay in corporate initiated augmentation

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Growth – customer initiated capital works	230.2	238.0	230.4	234.6	237.1	1,170.3
Growth – corporate initiated augmentation	149.2	175.2	242.1	267.8	320.1	1,154.3
Growth	379.4	413.2	472.5	502.4	557.2	2,324.6
Asset replacement / renewal	160.5	255.7	212.9	280.2	256.0	1,165.3
Reliability & quality of service enhancement	85.8	50.6	72.6	51.6	45.7	306.3
Security compliance	384.0	381.6	385.0	328.1	338.6	1,817.3
Total system	1,009.7	1,101.1	1,143.0	1,162.3	1,197.5	5,613.5
Total non system	192.3	124.8	98.4	63.2	85.0	563.7
Total	1,202.0	1,225.9	1,241.4	1,225.5	1,282.5	6,177.2

Source Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls; PB

From the above analysis, a reduction in the demand forecast that results in a one year delay in the expenditure relating corporate initiated augmentation would reduce the total forecast capex over the period by $289.0m, or a reduction of 4.9% for the total forecast capex.

High level review of customer numbers

To establish a view on the extent to which the expenditure proposed by ENERGEX for the next regulatory control period is prudent and efficient PB undertook a high level review of the customer numbers and the proposed expenditure relating to connecting new customers. Figure 4.6 shows the proposed capex relating to customer connections and the proposed customer numbers over the next regulatory control period. From this review it can be seen that the proposed expenditure has a variation of approximately ±3% year on year, and an annual increase in customer numbers of 2.2% is predicted by ENERGEX[45]. This appears to be not unreasonable.

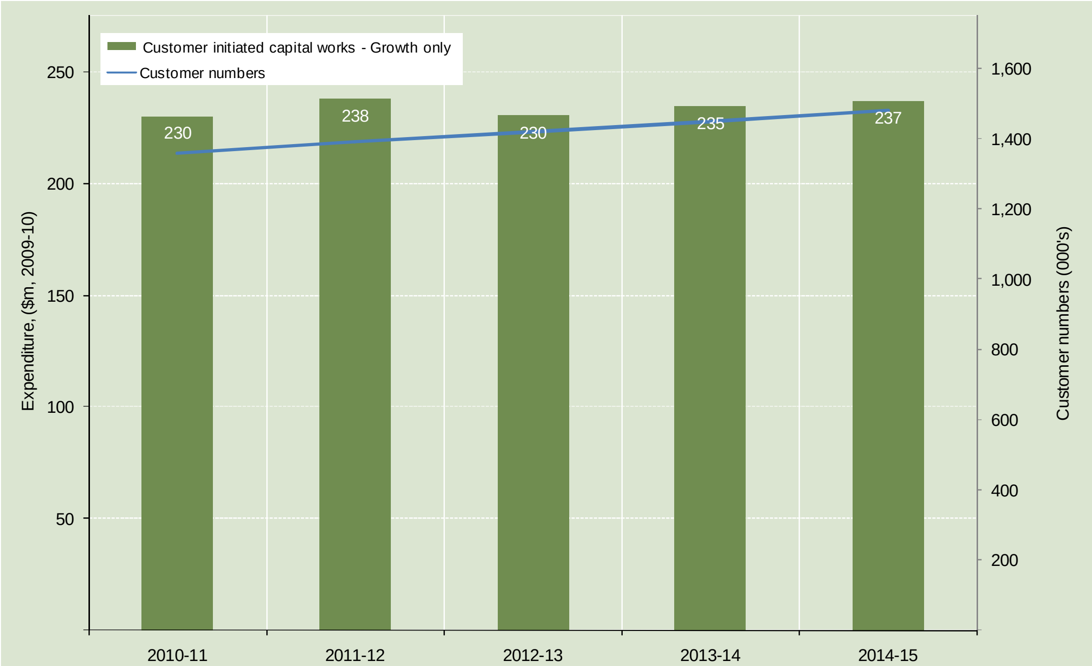

Figure 4.6 Forecast customer numbers and customer initiated capital works – growth related

Source: ENERGEX, July 2009, RSD 2.2.1(1) ENERGEX Network Capital Expenditure Baseline Program for SCS 2010-2015; ENERGEX July 2009, 2.3.8.Demand Forecast, Table 1; PB Analysis

PB has also reviewed in detail three generic programs of works, five specific projects in the customer initiated capital works and corporate initiated augmentation to establish how the policies and procedures have been applied.

Generic programs of works

The three generic programs reviewed were:

- domestic and rural (sub-divisions) (DNR) — customer initiated capital works
- commercial and industrial (CNI) — customer initiated capital works
- company initiated augmentation (COIN) — corporate initiated augmentation.

PB found the major driver of the generic programs work is the forecast of customer connections. ENERGEX has based the forecast on the number of historical connections — originally forecast in September 2008 to be 27,860 in 2010-11. To account for the GFC, ENERGEX reduced the forecast number of customer connections from 27,860 to 21,195[46], a drop of 23.9%.

45 ENERGEX, July 2009, Regulatory proposal for the period July 2010–June 2015, p.146.
46 ENERGEX, August 2009, PB.EGX.MW.34 – customer initiated capital works.doc

To benchmark ENERGEX's decrease in customer numbers, PB has taken the new approvals for dwellings in Queensland from the Australian Bureau of Statistics latest figures as a proxy for the change from June 2008 to June 2009, which was 20%[47].

ENERGEX has adjusted down its forecast of customer connections by a similar level to the relative reduction of new approved residential buildings stated by the Australian Bureau of Statistics.

4.2.7 PB assessment and findings

PB regards the ENERGEX planning standards as pragmatic, in that they are not 100% deterministic and they acknowledge a level of risk based on characteristics of the ENERGEX network[48].

PB has reviewed ENERGEX's planning standards and, based on the analysis of five specific projects and three generic programs of work, we believe that the standard represents good electricity industry practice and also reflects the specific conditions pertinent to ENERGEX's area and network.

PB examined how the growth had been applied to the forecast capital program by analysing three programs of works and five specific projects. We found that these programs of work and projects included supporting data that was thorough and had a consistent approach. The plans provided detail that addressed scope, options, timing and cost. The projects and programs of work also included evidence to support the main driver of the augmentation was and sensitivities around the driver of the augmentation. The packs highlighted interaction with other projects and programs of works in the area.

ENERGEX has used historical and government planning data to forecast the future requirements of generic programs of works. Owing to the timing of the GFC, ENERGEX applied a high level reduction to the forecast expenditure and when PB benchmarked this against data from the Bureau of Statistics the discount was of an equivalent volume.

Given the level of detail provided in the projects and area plans, PB regards ENERGEX's capex for growth as prudent and efficient.

4.2.8 PB recommendation

PB recommends that the proposed capex for the forecast regulatory control period is reduced by $289m, as set out in Table 4.8 based on a one year delay in the demand forecast as recommended by MMA.

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47 www.abs.gov.au; *Time series workbook 8731.0 Building Approvals, Australia*; Table 24. Dwelling Units Approved in New Residential Buildings, number and value, Original – Queensland

48 An example is the limit of load at risk has been assessed and load transfers can occur within two hours by remote switching (N-1(b) limit) based on a load transfer of no more than 15 MVA in rural areas, as 15 MVA is recognised as the available capacity on parallel feeders.

Table 4.8 Recommended capex for growth

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	416.7	457.0	533.0	569.3	637.2	2,613.2
PB adjustment	(37.3)	(43.8)	(60.5)	(66.9)	(80.0)	(288.6)
PB recommendation	379.4	413.2	472.5	502.4	557.2	2,324.6

Source: PB

4.3 Asset replacement and renewal capex

The replacement and renewal category of capex relates to assets that are replaced because of their condition.

4.3.1 Proposed expenditure

The proposed expenditure for replacement/renewal over the next regulatory control period is given in Table 4.9, while Figure 4.7 shows both the historical and forecast expenditure. ENERGEX is proposing to spend a total of $1,165m on replacement/renewal expenditure in the next regulatory control period.

Table 4.9 Proposed capex for asset replacement/renewal

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	160.5	255.7	212.9	280.2	256.0	1,165.3

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls

As shown in Figure 4.7, this represents a real increase of 273% over current period expenditure of $312.7m.

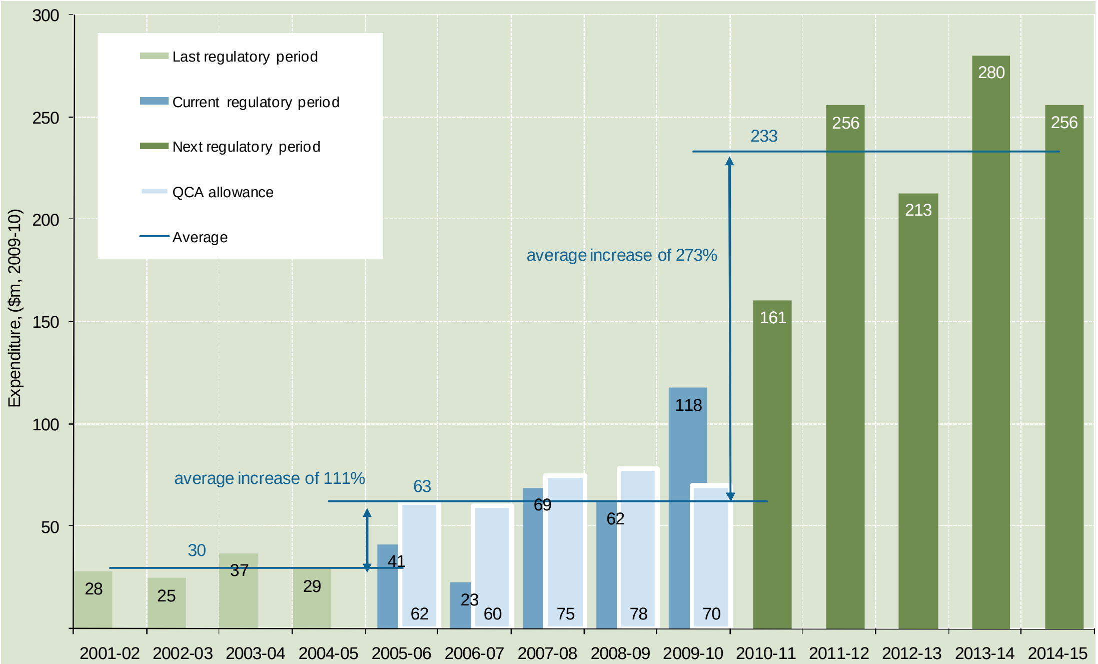

Figure 4.7 Asset replacement/renewal capex

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls; AER, August 2009, SA-QLD Historic Capex Review.doc

The two largest projects are to replace bush poles at $87m over the next regulatory control period and replace a specific type of underground cable that has been experiencing failures of the neutral sheath[49] at a total cost of $68m.

ENERGEX adopted a condition-based risk management approach in late 2007 for asset replacement and renewal. This leads to replacing higher risk assets before failure. The program of replacement works in the next regulatory control period arising from applying this new methodology consists of 581 individual projects at a total cost of $870.2m and 10 programs of works at a total cost of $295.1m

4.3.2 Drivers

The EDSD review made a recommendation[50] that ENERGEX ensure that sufficient amounts are spent to deliver an effective maintenance programme. In particular, attention needs to be given to its overhead network assets.

The outcome was the decision to adopt a Condition Based Risk Management (CBRM) model. The model was procured in 2007, and ENERGEX populated the database with information over the following six months.

4.3.3 Policies and procedures

The CBRM model is the main tool used to forecast the equipment that is to be replaced in the next regulatory control period. The model forecasts the date of replacement of single

49 ENERGEX July 2009, *AER Distribution Augmentation and customer capital program, NAMP detail 2006–2016; NAKP CA07 – replace LV Consac UG cable*; p.18.

50 ibid.

assets. The cost of replacing the asset is established under ENERGEX's standard cost-estimating process.

Where the CBRM model has predicted the replacement of an asset, initially the planning process allows for verification that the condition of asset is the driver of the replacement. Maintenance regimes that may extend the life, and therefore be a more efficient option, are considered at this stage.

In the short term — one to three years — individual replacement projects are confirmed as required and take place through ENERGEX's standard planning process. This allows for works at the same site to be aligned. Where work has been brought forward, a cost-benefit analysis is made to support the decision.

In the longer term — three to ten years — the CBRM model output is used to forecast which assets are required to be replaced. ENERGEX uses the same cost-estimating process for this term as for the short term.

PB is of the opinion that the processes and procedures ENERGEX has used are reflective of good electricity industry practice and implementation should lead to a prudent and efficient outcome.

4.3.4 Specific reviews

PB examined specific elements of the CBRM model to understand how these elements drive the results from the modelling. Specifically, PB examined the weighting applied in the model and the application and value of risk.

Finally, at PB's request ENERGEX ran an age-based replacement scenario for a class of assets for comparison with the CBRM model output.

Principle of the CBRM model

The CBRM model calculates when will be the most economical time to replace an asset. The economical time of replacement is calculated as being the point where the sum of the depreciated value of the asset and the cost of the increased risk associated with an aging asset at the same point in time is at a minimum.

ENERGEX has populated the database with 34 asset types and the database supporting the model collates data on an individual asset basis.

The inputs to the model are driven by three main factors:

- technical inputs
- constants
- risk-related inputs.

PB has discussed the technical inputs with ENERGEX and has established that the inputs are a combination of samples and condition information. Field staff collect information for each asset. ENERGEX has developed a formulaic data collection process to ensure that appropriate data are collected for assets as they are inspected by field staff.

Weightings applied in the CBRM model

The second class of inputs includes constants, for example, locality to the ocean, CBD, urban, rural or indoor versus outdoor. PB reviewed four of the location factors[51]. We reviewed the locality factors, ENERGEX provided data[52] and most of the weightings applied in the risk categories, which we found were EA Technology's recommended weightings. These have been developed over time across a large number of companies, and have been used to calibrate the model. PB notes that ENERGEX has made some additions to the model (in conjunction with EA Technology) to adequately describe its network. The additional categories are listed in Table 4.10 below.

Table 4.10 Additional weightings applied to the CBRM model

Asset class	Category	Description	Notes
Transformer/ circuit breaker	Nature of the load	Trade coast area	ENERGEX supplies customers within a specific area generally at the mouth of the Brisbane River where petrochemical type loads exist. This is a sensitive area in which a new risk category was warranted.
Outdoor equipment	Location factor	Within 5 km of coast	Different weightings applied based on zone approach. Zone 1 outside 5 km from coast, Zone 2 < 5 km from surf beach, Zone 3 < 5 km from non-surf beach. Note that similar factors are used by EA Technology; however, additional zones are added with relative weightings.

Source: ENERGEX, August 2009, PB.EGX.MW.40 – CBRM EA Technologies.doc

At an overall population level, the probability of failure of an asset generally increases with age, and cost of failure may also increase if the consequences are not reduced through management practices.

The development of risk

PB reviewed three risk elements of the model, specifically the value applied to risk, the application of risk to load areas, and the application of risk to CBD areas.

PB has found that ENERGEX applies two values to customer reliability in the form of $/SAIDI minute lost, and $/MWh of energy at risk. These values are given in Table 4.11. PB notes the values ENERGEX used were established for VENCORP[53] in 2003, and ENERGEX has chosen to apply these values without any escalation.

Table 4.11 Values of risk applied in the CBRM model

Constant	Value ($)
$/SAIDI minute lost	1,176,000
$/MWh at risk	29,600

Source: ENERGEX August 2009, PB.EGX.MW.25 – Value of risk.doc; VENCORP July 2003, Electricity transmission network planning criteria

51 ENERGEX, August 2009, PB.EGX.MW.40. CBRM EA Technology.doc
52 ibid.
53 VENCORP July 2003, *Electricity transmission network planning criteria.*

PB's enquiries have found that the $/SAIDI minute lost figure is applied to develop the dollar at risk figure for radial type distribution assets. That is, when loss of the asset will result in a direct loss of supply to customers. The $/MWh figure has been applied to develop the dollar at risk figure for sub-transmission or transmission assets where the N-2 security standard applies. That is, where loss of the asset will not result in a direct loss of supply to customers, but nonetheless puts the network at risk.

In order to quantify the risk in a way that can be related to SAIDI, a time component is included that describes how long the load is at risk and how long the asset is unavailable. This is represented schematically in Figure 4.8.

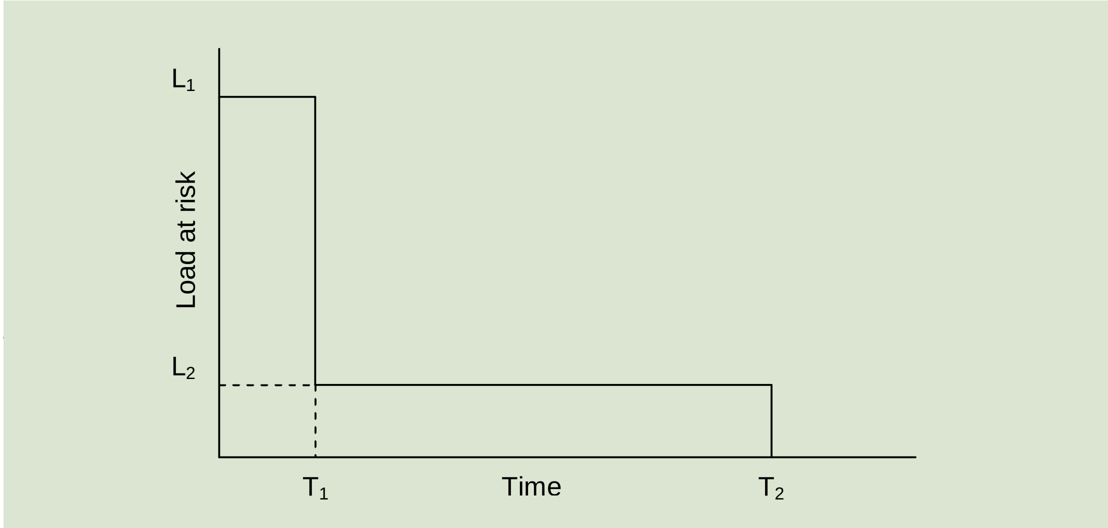

Table 4.12 Values for estimating load at risk

Asset type	L1 (MVA)	L2 (% of L1)	T1 (hrs)	T2 (hrs)
Overhead line	Rating of the line	30	4	8
Cable	Rating of the cable	30	4	16
Switchgear	Firm capacity of the substation	15	4	48
Transformer	Firm capacity of the substation	40	4	72

Source: ENERGEX August 2009, PB.EGX.MW.41 – CBRM analysis of transformer failures in the CBD.doc

Asset condition and remaining life

PB requested that ENERGEX make a comparative study of transformer replacements under a scenario only based on age[54]. The aim was to show that a condition-based approach would reduce the number of replacements and therefore the cost of replacements compared with a simplistic age-based approach. A comparison was made between an aged-based renewal program and CBRM for ENERGEX's 33 kV transformer population. The study results showed that 70 transformers would be replaced over the next regulatory control period under a condition risk-based approach, while 88 transformers would need to be replaced under an aged-based approach using a standard life of 50 years. That is, a 20% reduction was achieved using the CBRM model.

PB also requested information on transformer replacements that were to occur earlier than the age replacement would require[55], and where the replacement was to occur later than the

54 ENERGEX August 2009, PB.EGX.MW.21 – transformer replacement program.doc
55 Assuming a 50-year standard life.

age-based approach would require[56]. The first transformer was at Loganholme substation[57], installed in 1986. The CBRM indicated the end of life was due to the furan[58] level of 7.67 ppm where the permissible ENERGEX maximum is 4.75 ppm. The test indicated that the transformer will probably not withstand a fault and therefore proactive action was required. A further example is the transformer at Sunnybank substation[59] with a current age of 52 years, which would be classed as two years over the age-based standard life replacement of 50 years. CBRM indicates that this transformer's end of life will be in 2011 (i.e. in two years) when the transformer will have a nameplate age of 54 years, i.e. four years over the age-based standard life.

4.3.5 PB assessment and findings

PB has found the variable inputs to the CBRM model (specifically around the allocation of risk and the value of risk) were well supported and clearly identified. PB saw the source of the independent reports used to establish the value of lost load and value of customer reliability. PB found the values used were appropriate to ENERGEX's business.

PB examined the application of the risk and notes that the model predicted some replacements earlier than an age-based replacement approach. The model also predicted the replacement of equipment later than an age-based approach would allow. In addition, PB examined an age-based replacement strategy for a single class of transformers and found the CBRM model predicted 20% fewer replacements than an age-based approach would give.

In examining the weightings applied to the CBD, urban and rural classifications of customers, PB found that the weightings used were those established in conjunction with EA Technology — the producer of the CBRM model. ENERGEX also included additional weightings for certain areas within south-east Queensland. The additional weightings were established in conjunction with EA Technology and reflect the differing needs of these specific areas.

With the level of detail provided around the inputs to the model, supporting documentation on the establishment of the value of risk, the application of weightings, and load at risk, PB is of the view that the application of the CBRM model to ENERGEX's replacement and renewal program leads to a prudent and efficient expenditure proposal.

4.3.6 PB recommendation

PB recommends that the proposed capex for the asset replacement/renewal is accepted with no changes, as set out in Table 4.13.

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56 ENERGEX August 2009, PB.EGX.MW.26 – transformer replacement project.doc

57 ENERGEX July 2009, Loganholme transformer SSLHM/TR1 plant number TR32889

58 Furan is a heterocyclic organic compound that is typically derived by the thermal decomposition of pentose containing materials – for example cellulosic solids. An increase in furan levels in transformer oil indicates that the insulating layer (i.e. paper) is decomposing. The affect is the loss of the insulating property of the insulating layer that will lead to failure of the transformer.

59 ENERGEX July 2009, Sunnybank transformer SSSBK/TR3 plant number TR71695

Table 4.13 Recommended capex for asset replacement/renewal

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	160.5	255.7	212.9	280.2	256.0	1,165.3
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	160.5	255.7	212.9	280.2	256.0	1,165.3

Source: PB

4.4 Reliability and quality of service enhancement capex

The reliability and quality of service enhancement category of capex relates to improving the quality of electricity supply to customers. This includes work relating to reducing obligatory measures, such as SAIDI and SAIFI, along with improving problems identified by customers, such as voltage regulation at times of high peak demand.

4.4.1 Proposed expenditure

The proposed expenditure for reliability and quality of service enhancement over the next regulatory control period is given in Table 4.14, while the historical expenditure and forecast expenditure is shown in Figure 4.9.

Table 4.14 Proposed capex for reliability and quality of service enhancement

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	85.8	50.6	72.6	51.6	45.7	306.3

Source: ENERGEX July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls

Proposed expenditure on reliability and quality of service enhancements in the next regulatory control period is forecast to be a total of $306.3m. This represents a real increase of 115% over the expected expenditure of $142.6m in the current period.

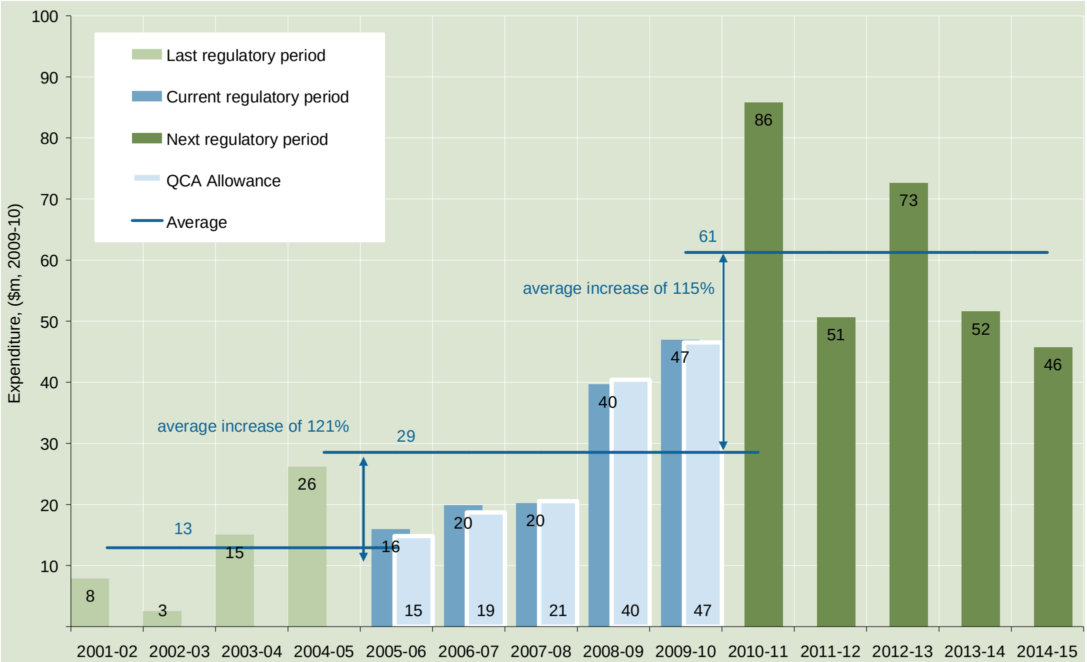

Figure 4.9 Capital expenditure on reliability & quality of service enhancement

Source: ENERGEX July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls

4.4.2 Drivers

The main driver for expenditure on reliability and quality of service enhancements is meeting the minimum service standards (MSS). The QCA introduced a MSS scheme following the EDSD review[60] in 2004. Discussion on the provisions of the MSS is discussed in section 8.

4.4.3 Policies and procedures

A reliability program has been developed by ENERGEX in accordance with their business procedure BMS 3171 – Produce a Network Reliability Investment Plan. The plan identifies specific projects that will improve the reliability based on investment decisions. This process involves the calculation of the gross reliability gap between current performance and future mandatory targets set by the QME[61], taking statistical variability into account. The benefits in reliability improvement are formed based on investment programs related to the capex program and the opex program. The projects that produce a net positive benefit are then developed.

PB's high level review of the reliability investment plan identified a consistent and repeatable approach had been adopted and the investment decisions were focused on delivering improvements. The process applied was repeatable and quantifiable.

PB is of the opinion that the processes and procedures ENERGEX has used are reflective of good electricity industry practice and implementation should lead to a prudent and efficient outcome.

60 Office of Energy, Department of Natural Resources, Mines and Energy July 2004, *Electricity distribution and service delivery for the 21st century*.

61 ENERGEX July 2009, *Regulatory proposal for the period July 2010–June 2015*, p.114.

4.4.4 PB assessment and findings

The projects included in the reliability investment plan are developed in line with the network reliability improvement strategy. Table 4.15 identifies the five categories of network reliability improvement.

Table 4.15 Schemes of works to improve network reliability

Scheme works	Forecast expenditure
Improve 11 kV reliability	171
Underground reliability	32
New reliability substations	39
Smart network	36
Other reliability works	28
Total	306

Source: ENEREGX August 2009, Reliability investment plan Chris dunn.ppt

Following the identification of projects to enhance the security and reliability of the network, the project is optimised with the existing capital works program and approved through the planning process.

The proposed capex for security and reliability of service enhancement is estimated at $306m in the next regulatory control period. This equates to 5.2% of the total capex.

To quantify the relative benefits of the proposed reliability improvements, PB compared the benefits under the current scheme with the proposed expenditures. In 2006, ENERGEX had applied for additional expenditure[62] of $124m to improve reliability by 13 SAIDI minutes for rural networks and 5.5 SAIDI minutes for urban networks. PB has apportioned the SAIDI minutes saved by the customer percentage and the expenditure to generate a weighted average cost of saving a SAIDI minute — calculated to be $19.5m per SAIDI minute saved. Table 4.16 shows the calculation.

Table 4.16 Calculation of cost of SAIDI improvement in 2006

	CBD	Urban	Rural
SAIDI improvement	0.0	5.5	13.0
Customers	3,469	864,485	294,159
Assumed customer share (%)	0.3	74.4	25.3
		Whole network	
Weighted SAIDI minute improvement		7.4	
Expenditure ($m)*		144.4	
$m per SAIDI minute saved		19.51	

Source: PB NOTE: For comparison purposes expenditure has been escalated from June 2004 to 2009-10*

PB used the same analysis for the forecast expenditure, shown in Table 4.17.

62 ENERGEX October 2006, *Application for additional capital expenditure*, p.14.

Table 4.17 Calculation of cost of SAIDI improvement in 2009

	CBD	Urban	Rural
SAIDI improvement	0.0	6.3	25.6
Customers	3,813	840,890	362,519
Assumed customer share (%)	0.3	69.7	30.0
		Whole network	
Weighted SAIDI minute improvement		12.1	
Expenditure ($m)*		306.0	
$m per SAIDI minute saved		25.3	

Source: PB

PB found the investment plan identified projects required to improve the reliability and quality of the service; that the benefits are quantified; and that the application of ENERGEX's standard planning and cost estimating process are likely to ensure a prudent and efficient outcome is reached.

Based on a cost per SAIDI minute saved, PB found that ENERGEX expenditure increases from $19.5m per SAIDI minute saved to $25.3m per SAIDI minute saved in the next regulatory period. PB considers this increasing in relative cost to be not unreasonable given that ENERGEX has been pursuing reliability improvements since 2005-06, and hence many of the low-cost improvements have been captured in the current regulatory control period. PB concludes that the overall program for reliability and quality of service enhancements forecast expenditure is prudent and efficient.

4.4.5 PB recommendation

PB recommends that the proposed capex for reliability and quality of service enhancement is accepted with no changes, as set out in Table 4.18.

Table 4.18 Recommended capex for reliability and quality of service enhancement

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	85.8	50.6	72.6	51.6	45.7	306.3
PB adjustment	0.0	0.0	0.0	0.0	0.0.	0.0
PB recommendation	85.8	50.6	72.6	51.6	45.7	306.3

Source: PB

4.5 Security compliance capex

ENERGEX has proposed capex to specifically address the security compliance issues that the business faces arising from the EDSD review findings. This section considers this proposed expenditure. It should be noted that ENERGEX's capital program for security compliance is included as part of the customer initiated capital works and corporate initiated augmentation, which is addressed under the growth element of the forecast capex.

4.5.1 Proposed expenditure

Table 4.19 shows the forecast capex on security compliance in the next regulatory control period.

Table 4.19 Proposed capex for security compliance

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	384.0	381.6	385.0	328.1	338.6	1,817.3

Source: ENERGEX July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls

Table 4.20 shows the expected expenditure at the end of the current regulatory control period, and the forecast capex in the next regulatory control period as defined under ENERGEX's growth related categories.

Table 4.20 Historical capex for security and compliance

Expenditure category	Previous period	Current period
Customer initiated capital works	407.5	860.3
Corporate initiated augmentation	0.0	450.6
Total	407.5	1310.9

Source ENERGEX July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls; PB

Figure 4.10 shows the historical and forecast expenditure for this category. ENERGEX is forecasting a 39% increase in security compliance expenditure over the expenditure in the current period.[63]

63 Security related expenditure is a combination of corporate initiated augmentation and customer initiated capital works. The security-related component of corporate initiated augmentation and initiated capital works has been calculated forecast ratios of growth at $2,613 (real 09/10) and security at $1,817m (real 09/10). The growth-related expenditure is discussed in section 4.2.

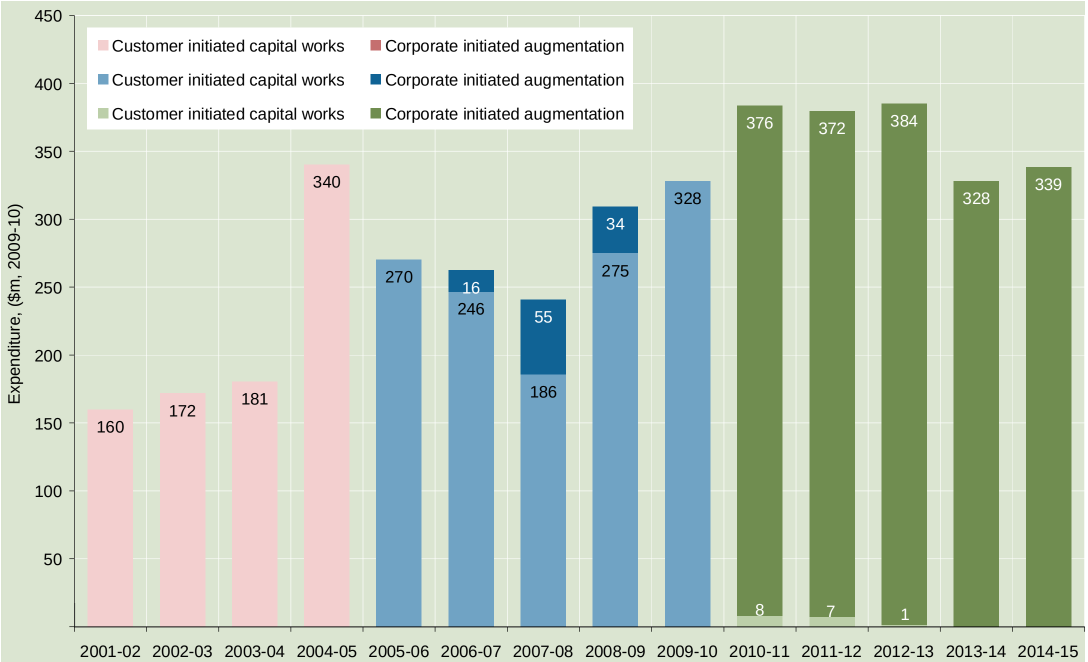

Figure 4.10 Security compliance capex[64]

Source: ENERGEX July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls; PB; AER, August 2009, SA – QLD historic capex review.doc

4.5.2 Drivers

The 2004 EDSD[65] review made two significant recommendations for improving the security of the network to system incidents. These were:

- that the [Queensland] Government require ENERGEX to meet a standard equivalent to 'N-1' for bulk and major zone substations, and for the sub-transmission system
- that ENERGEX's use of system assets is reduced to a generally accepted level of 60% to 65% from the 2004 level of 75%.

The AER has advised PB to only consider security standards that reflect accepted good electricity industry practice, and achieve these standards over a period of time that is consistent with an efficient business acting prudently[66].

4.5.3 Policies and procedures

In 2004, ENERGEX's network did not meet the recommended standard put forward following the EDSD review. Following this review, ENERGEX has been working towards improving the security of the network, and in 2008, along with Ergon Energy, engaged SKM Engineering Consultants to review the proposed N-1 Security of Supply Standards[67, 68]. SKM examined

64 Corporate initiated augmentation is a combination of growth-related expenditure and security compliance-related expenditure. Growth-related augmentation has been forecast at $1,443 m (real 09/10), and security compliance-related expenditure has been forecast at $1,798 m (real 09/10). The growth-related expenditure is discussed in section 4.2.

65 Office of Energy, Department of Natural Resources, Mines and Energy 2004, *Electricity distribution and service delivery for the 21st century*.

66 Australian Energy Regulator August 2009, email to PB.

67 ENERGEX August 2009, PB.EGX.MW.33 – N-1 security supply standards.doc

the standards that were being used by other national and international electricity distribution utilities and Evans and Peck was engaged to provide a review of the proposed standard to provide a link with the original EDSD report.

4.5.4 Specific reviews

Security related projects utilise the same governance process as other capex projects and programs of work. This is discussed in section 4.1.2 and PB found the governance processes implemented by ENERGEX would lead to a prudent and efficient outcome.

In reviewing security related expenditure, PB focused on the new security of supply standards[69] that were an outcome of the 2004 EDSD review rather than a detailed review of specific project expenditures. This is in line with PB's high level review methodology as outlined in section 2 of this report.

PB found that the security standards proposed by ENERGEX are less stringent than the standards recommended by the EDSD review. ENERGEX's proposed security standards[70] are shown in Table 4.21.

Table 4.21 Proposed security of supply standards

Name	Description
N-2	A system that can stand a credible single contingency with no interruption to supply and can be restored to a secure state within one hour.
N-1(a)	A system that has the capability to withstand a credible single contingency involving an outage of the largest most critical system element (transformer, feeder and so on) without an interruption to supply of greater than one minute for loads up to 50% PoE and 10% PoE for bulk supply points and zone substations.
N-1 (b)	As per N–1(a) except that all 50% PoE load can be restored in 30 minutes by remote switching
N-1 (c)	As per N–1(a) except that up to 6 MVA of load can be curtailed as long as it can be restored in three hours for urban and four hours for non-urban by remote or manual switching.
N	Possible loss of supply for single contingency of up to 8 hours for urban and 12 hours for non-urban while the network is reconfigured or repaired, or mobile equipment is deployed.

Source ENERGEX February 2009, Supply security standards; appendix 1, p.22

PB has discussed the limits in the proposed security standards with ENERGEX, and examined the justification of curtailment limits as well as the application of those limits. PB has found that additional contingency limits imposed are dependent on the residual load at risk. These additional criteria are shown in Table 4.22.

68 SKM November 2008, *ENERGEX and Ergon Energy: Security of Supply Standards.*

69 Office of Energy, Department of Natural Resources, Mines and Energy July 2004, *Electricity distribution and service delivery for the 21st century*.

70 At the time of writing, ENERGEX has put a proposed set of security standards to the Queensland Department of Mines and Energy, The proposed capital expenditure is based on the assumption that the revised security standards are accepted.

Table 4.22 Residual load at risk definitions

Name	Description
Staged supplies	The standards do not apply to interim or staged supplies
5 MVA	Residual load at risk must not exceed 5 MVA after load transfers have occurred.
0.75 of normal cyclic capacity	The 50% PoE forecast loads for distribution feeders will be limited to 75% of the expected maximum load based on a 50% PoE event.

Source: ENERGEX February 2009, Supply security standards; appendix 1, p.22

A limit of 5 MVA has been established on the technical limit of available portable generation. ENERGEX has verbally confirmed that it can connect portable generation to a faulted network within four hours, and that 5 MVA is the current limit of available portable generation.

We also discussed the use of the 75% normal cyclic capacity for distribution feeders. ENERGEX has confirmed[71] the policy for the 11 kV distribution feeder arrangements is based on this principle. This allows for one feeder to fail and the remaining load to be transferred to the remaining three adjacent feeders, thus loading the three remaining feeders to the maximum cyclic capacity.

4.5.5 PB assessment and findings

SKM made a comparative review of security of supply standards[72] internationally. ENERGEX has applied the proposed standards and included a technical assessment that reflects its specific circumstances. An example is the 5 MVA limit based on the fleet of portable generators accessible by ENERGEX field staff[73].

PB reviewed the SKM report of security standards along with the security standards initially recommended following the EDSD review[74]. We found that the revised security standards that ENERGEX has adopted represent a pragmatic approach to security in that the revised standards include a level of risk that ENERGEX identified can be managed though prudent management practices. PB found that the level of risk is accepted in other jurisdictions in Australia[75] and ENERGEX has analysed other DNSPs practices to reconcile these standards to their own environment. PB believes that this represents good electricity industry practice and therefore leads to a prudent and efficient expenditure.

4.5.6 PB recommendation

PB recommends that the proposed capex for security compliance is accepted with no changes, as set out in Table 4.23.

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71 ENERGEX, August 2009, C20 11 kV sub-transmission program.ppt
72 SKM, November 2008, ENERGEX and Ergon Energy: Security of Supply Standards
73 ENERGEX February 2009, *Supply security standards*, p.22
74 Office of Energy, Department of Natural Resources, Mines and Energy July 2004, *Electricity distribution and service delivery for the 21st century*.
75 SKM, November 2008, ENERGEX and Ergon Energy: Security of Supply Standards

Table 4.23 Recommended capex for security compliance

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	384.0	381.6	385.0	328.1	338.6	1,817.3
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	384.0	381.6	385.0	328.1	338.6	1,817.3

Source: PB

4.6 Summary of findings and recommendations

This section presents a summary of PB's key findings and recommendations relating to ENERGEX's proposed system capex for the next regulatory control period.

Key Findings

ENERGEX proposes to spend $5,902m on system capex in the next regulatory control period, an average increase of 60%.

An increase in expenditures is proposed across all regulatory categories. The largest increase relates to asset replacement and renewal, where ENERGEX propose to expend $1,165m, an increase of 273%.

PB reviewed ENERGEX's capital governance and found it consistent with good electricity industry practice.

Growth capex

The processes and procedures ENERGEX has used are reflective of good electricity industry practice and implementation should lead to a prudent and efficient outcome.

ENERGEX's consideration of non-network solutions and demand management alternatives is consistent with good electricity industry practice.

The application of the demand forecasts set out in the Regulatory Proposal has been appropriately incorporated into forecast expenditures.

The proposed capex for growth is reduced by $289m, based on a one year delay in the demand forecast as recommended by MMA.

Asset replacement and renewal

Increased expenditure is driven by the need to ensure that sufficient amounts are spent to deliver an effective maintenance programme. In particular, attention needs to be given to its overhead network assets.

The application of the CBRM model to ENERGEX's replacement and renewal program leads to a prudent and efficient expenditure proposal.

Reliability and quality of service enhancement

Increased expenditure is driven by performance improvements required to meet the MSS targets set out in the *Electricity Industry Code*.

Projects included in the reliability investment plan are developed in line with the network reliability improvement strategy.

The overall program for reliability and quality of service enhancements forecast expenditure is prudent and efficient.

Security compliance

Increased expenditure is driven by the need to improve the security of the network to faults and events.

The revised security standards that ENERGEX has proposed for the next regulatory control period represent good electricity industry practice and therefore lead to a prudent and efficient expenditure.

Recommendations

PB recommends that the system capex allowance for the next regulatory control period should be adjusted from the levels proposed by ENERGEX. Table 4.24 presents PB's recommended system capex.

Table 4.24 PB's recommendation for system capex

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Growth						
ENERGEX proposal	416.7	457.0	533.0	569.3	637.2	2,613.2
PB adjustment	(37.3)	(43.8)	(60.5)	(66.9)	(80.0)	(288.6)
PB recommendation	379.4	413.2	472.5	502.4	557.2	2,324.6
Asset replacement / renewal						
ENERGEX proposal	160.5	255.7	212.9	280.2	256.0	1,165.3
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	160.5	255.7	212.9	280.2	256.0	1,165.3
Reliability & quality of service enhancement						
ENERGEX proposal	85.8	50.6	72.6	51.6	45.7	306.3
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	85.8	50.6	72.6	51.6	45.7	306.3
Security compliance						
ENERGEX proposal	384.0	381.6	385.0	328.1	338.6	1,817.4
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	384.0	381.6	385.0	328.1	338.6	1,817.4
Total system capex						
ENERGEX proposal	1,047.0	1,144.9	1,203.5	1229.2	1277.5	5,902.2
PB adjustment	(37.3)	(43.8)	(60.5)	(66.9)	(80.0)	(288.6)
PB recommendation	1,009.7	1,101.1	1,143.0	1,162.3	1,197.5	5,613.6

Source: PB

5. Non-system capex review

This section presents PB's review of ENERGEX's proposed non-system capex for the next regulatory control period. A high level review is provided, including an analysis of trends in expenditures. This is followed by an overview of the relevant processes and procedures, and discussion on specific expenditure categories. A summary of PB's findings and recommendations concludes the section.

5.1 High level review

ENERGEX has submitted a proposed non-system capex of $563.7m for the next regulatory control period as summarised in Table 5.1. The proposed non-system capex for the next regulatory control period covers four main areas:

- end-use computing assets
- land and buildings
- fleet
- tools and equipment.

Table 5.1 Proposed non-network capex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Non-system capital expenditure						
End-use computing assets	3.2	4.3	1.3	1.8	2.2	12.8
Lands and buildings	143.0	67.8	44.4	18.5	24.7	298.4
Fleet	32.8	41.8	42.0	32.3	47.4	196.3
Tools and equipment	13.3	10.9	10.7	10.6	10.7	56.2
Total	192.3	124.8	98.4	63.2	85	563.7

Source: ENERGEX July 2009, Regulatory Proposal for the period July 2010 to June 2015, Table 13.5

In this report PB discusses ENERGEX's information and communication technology (ICT) function, which includes ENERGEX's end-use computing assets as set out in Table 5.1 and those functions provided by SPARQ Solutions[76]. This arrangement is examined in section 5.2.4. Table 5.2 outlines total non-system capex and SPARQ ICT expenditure for the next regulatory control period.

76 SPARQ Solutions is the jointly owned service provider to ENERGEX and Ergon Energy, a related service provider under the National Electricity Law. SPARQ provides ICT services to both businesses and recovers the costs of providing these services by a service charge to each business.

Table 5.2 ENERGEX proposed non-network capex for the next regulatory control period (including SPARQ ICT).

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Total non system – ENERGEX proposal	194.2	124.8	98.4	63.2	85.0	563.7
SPARQ ICT Expenditure	54.0	39.2	32.9	31.1	26.9	184.2
Total non system – including SPARQ ICT capex	246.3	164.0	131.4	94.3	111.9	747.9

Source: ENERGEX July 2009, Regulatory Proposal for the period July 2010 to June 2015, Table 13.5; PB analysis

Figure 5.1 provides a pie chart showing the breakdown of ENERGEX's proposed expenditure for non-system capex in the next regulatory control period. PB notes that Figure 5.1 includes ICT expenditure for SPARQ together with the end use computing forecast from the ENERGEX Regulatory Proposal.

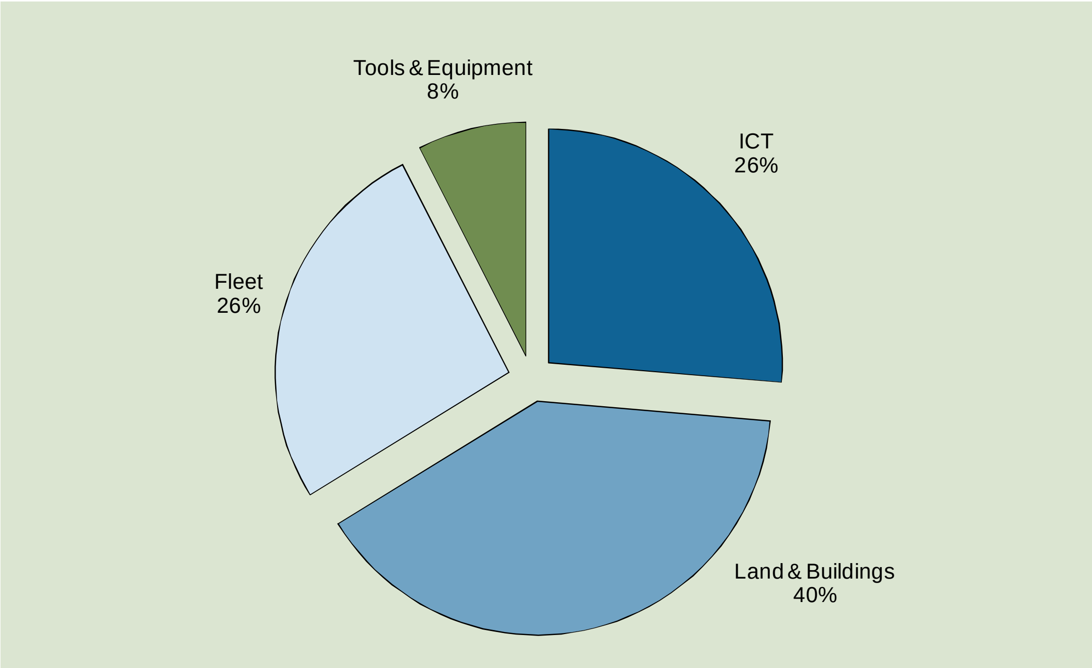

Figure 5.1 Breakdown of non-system capex forecast for 2010–2015 (including SPARQ ICT)

Source: ENERGEX July 2009, Regulatory Proposal for the period July 2010 to June 2015, Table 13.5

PB reviewed historical variances between the QCA allowance and ENERGEX's actual historical non-system capex. Figure 5.2 shows the actual non-system capex (including SPARQ ICT) for the previous and current regulatory control periods, the QCA allowance set in 2004 for the current regulatory control period, and the forecast capex for the next regulatory control period.

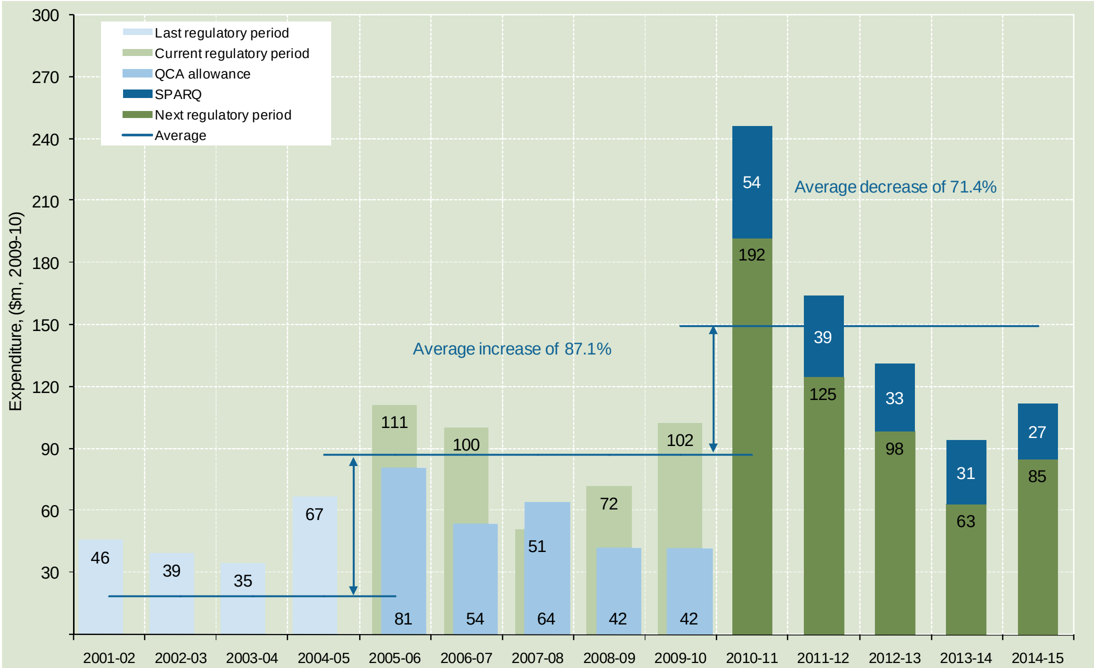

Figure 5.2 Comparison of total non-system capex

Source: ENERGEX July 2009, Regulatory Proposal for the period July 2010 to June 2015, Table 8.7; ENERGEX, July 2009, RIN 2.2.1 Capital Expenditure

ENERGEX's allowance for non-system capex set by the QCA was $282.8m for the current regulatory control period. ENERGEX spent a total of $436.3m on non-system capex in this period, an increase of 54% over the QCA regulatory allowance.

Forecast non-system capex expenditure

ENERGEX has proposed $563.7m for the next regulatory control period, an increase of 29% over actual expenditure in the current regulatory control period. Including SPARQ ICT the total capex proposed is $747.9m, a 72% increase over the current regulatory control period, as shown in Table 5.3. The trend in total non-system capex (including SPARQ ICT) between 2001 and 2015 is illustrated in Figure 5.3.

Table 5.3 Change in non-system capex between the current and the next regulatory control period

Regulatory category	Regulatory control period		Change
	Current	Next	%
Total Non-System Capex	436.2	563.7	29
Total Non-System Capex (including SPARQ ICT)	573.4	747.9	30

Source: PB analysis.

Figure 5.3 shows that the largest increase in the next regulatory control period relates to land and buildings, where ENERGEX proposes to spend $298.4m in the next regulatory control period, a 128% increase from $130.8m in the current regulatory control period.

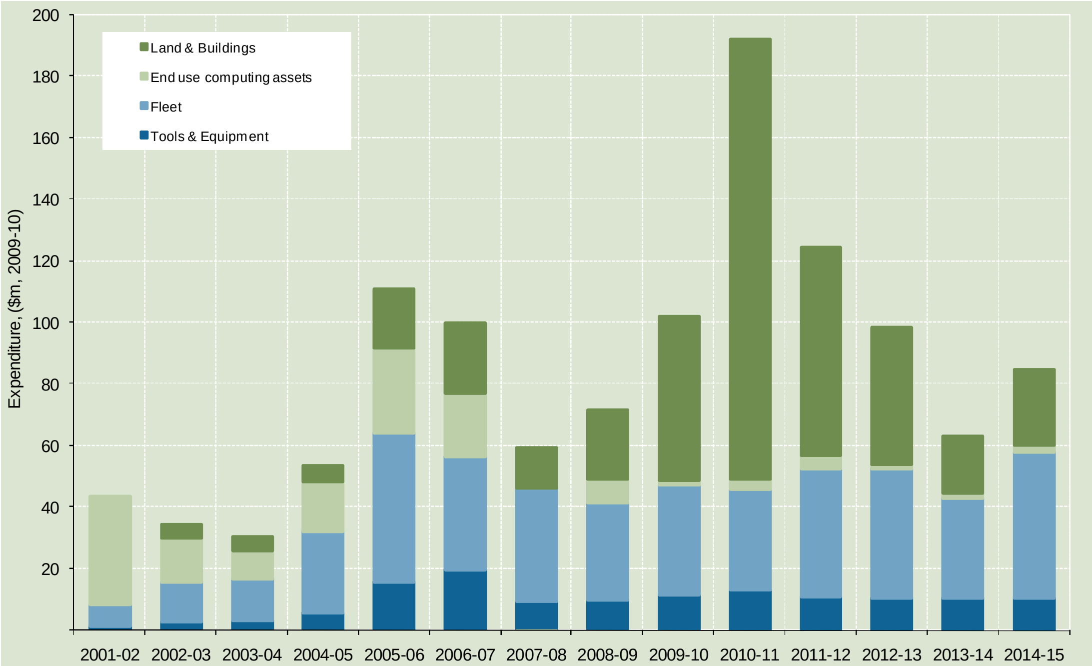

Figure 5.3 Non-system capex by category from 2001 to 2015

Source: PB analysis.

5.2 Information and communications technology (ICT) capex

The bulk of ENERGEX's ICT is delivered by SPARQ Solutions, an ICT service provider established on 1 July 2004, and jointly owned by Ergon Energy and ENERGEX. Under this arrangement, the provision of ICT services by SPARQ is covered by a service charge to each of the businesses. As a result, the capex that would otherwise be incurred by ENERGEX is capitalised by SPARQ, and amortised into SPARQ's service charge. This service charge is then recognised by ENERGEX as an opex-related charge.

To establish the underlying prudency and efficiency of the proposed forecast ICT expenditure (herein referred to as total ICT capex), PB has taken into account the ICT capex proposed by both ENERGEX and SPARQ (as it relates to ENERGEX[77]) and considered this as if they are one proposal. The conclusions of this section as they relate to ENERGEX's proposed ICT capex are then taken into account in our overall non-system capex recommendations. Similarly, the conclusions of this section as they relate to SPARQ's proposed ICT capex are then accordingly taken into account in this section of this report on page 60.

5.2.1 Proposed expenditure

The total ICT capex proposed is $197m over the next regulatory control period. Of this amount, $12.8m will be capitalised by ENERGEX, with the remaining $184.2m capitalised by SPARQ (see Table 5.4).

77 PB notes that not all of SPARQ's proposed capex relates to ENERGEX, and has only considered that portion that relates to ENERGEX.

Table 5.4 Summary of Total ICT expenditure – ENERGEX and SPARQ

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX ICT expenditure	3.2	4.3	1.3	1.8	2.2	12.8
SPARQ ICT expenditure	54.0	39.2	32.9	31.1	26.9	184.2
Total ICT expenditure	57.2	43.5	34.3	32.9	29.1	197.0

Note: Total ICT expenditure figures were provided in 2008-09 dollars and escalated by a factor of 1.045 by ENERGEX, as with ENERGEX reconciliation estimates provided to PB (August 2009, PB.EGX.JTK.14 – ENERGEX ICT reconciliation)

Source: ENERGEX Major Areas of ICT Expenditure – AER Submission 10 August 2009

Figure 5.4 shows the forecast expenditure of total ICT capex for ENERGEX and SPARQ, along with the historical actual expenditure. PB notes the expenditure figures have been sourced directly from ENERGEX's joint ICT capital forecast program, and include the capex of SPARQ and ENERGEX as outlined above. PB also notes that the current and historical figures (from 2004-05) were extracted from Audited Regulatory Accounts, and provided to PB by ENERGEX to represent its total ICT capex[78]. Figures for the remaining historical years (2001-02 to 2003-04) have been sourced from the Regulatory Information Notice (RIN) and reflect the ICT capex before SPARQ was established.

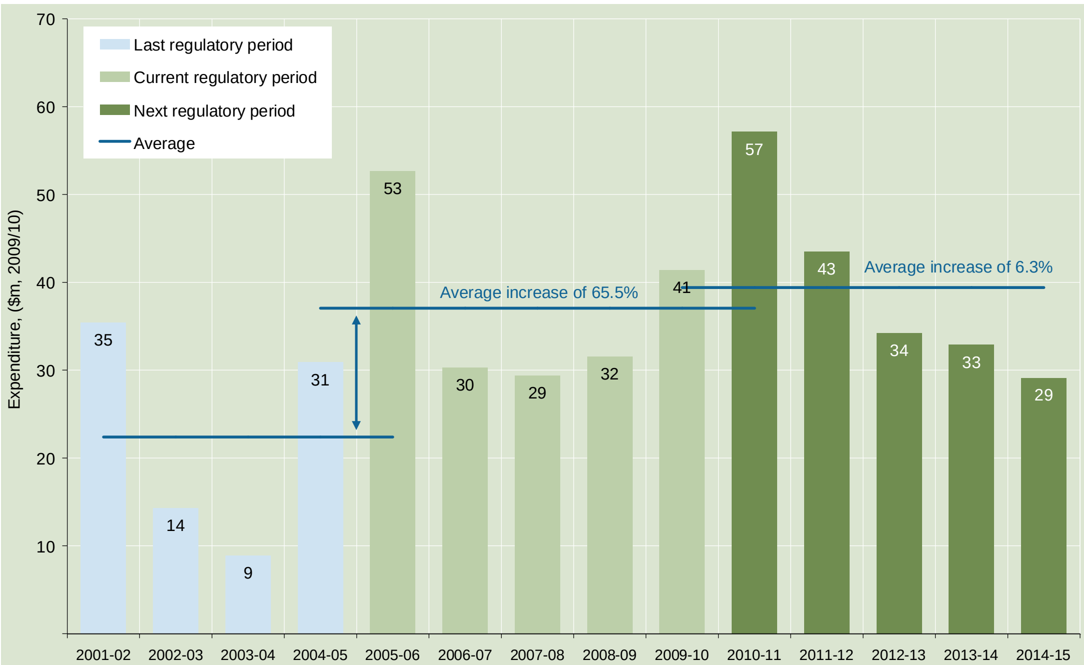

Figure 5.4 Total proposed ICT capex for ENERGEX and SPARQ

Source: PB analysis of ENERGEX and SPARQ ICT capital program

As shown in Figure 5.4, from the current to the next regulatory control period, the average yearly expenditure on ICT will increase from $37.1m to $39.4m, a real growth of approximately 6.3%. This compares to a change from $22.4m to $37.1m from the previous to the current regulatory control period, a significantly higher real growth of 65.5%.

ENERGEX's ICT capex is made up of items that ENERGEX, rather than SPARQ, will continue to purchase in the next regulatory control period, including end-use computing assets, such as desktop and laptop personal computers and smaller ICT devices.

78 ENERGEX August 2009, PB.EGX.JTK.08 to 09 - SPARQ IT

In reviewing the trend of ENERGEX's ICT capex (see Figure 5.5), it can be seen there is a clear reduction in expenditure from the current to the next regulatory control period. That is, ENERGEX estimates that its average yearly expenditure on ICT will decrease from \$9.8m to \$2.6m, a notable reduction of 74%. This compares to a change from \$18.7m to \$9.8m from the previous to current regulatory control periods, a smaller reduction of 47.4%.

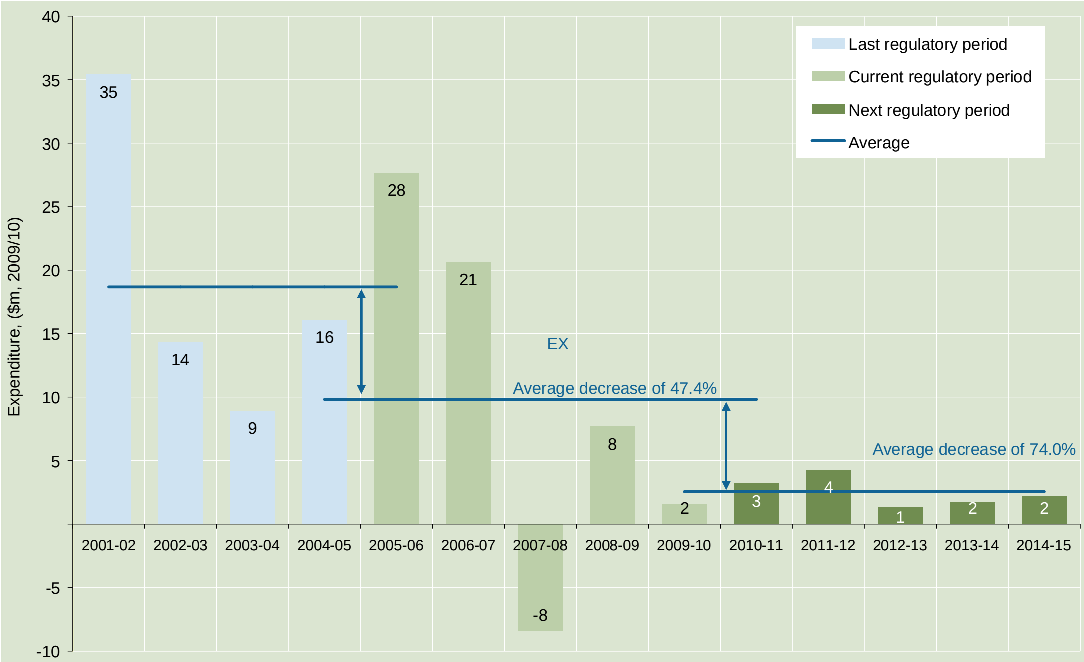

Figure 5.5 ENERGEX proposed ICT capex

Source: PB analysis of ENERGEX and SPARQ ICT capital program

SPARQ's ICT capex is made up of ten investment streams inclusive of governance, risk and compliance (GRC), knowledge management, market systems, customer servicing, energy management, workforce automation, enterprise resource planning (ERP), network model, planning and design, network operations and infrastructure and communications.

The ten investment streams outlined above can be further separated into three main areas of expenditure. These categories broadly include: (i) upgrades and replacement, (ii) continuous improvement and enhancements, and (iii) strategic initiatives. Within these expenditure categories, approximately \$117.3m is directed at upgrades and replacement (or approximately 60% of total expenditure), \$45.8m is directed at continuous improvement (or approximately 23% of total expenditure), and \$33.8m is directed at strategic change initiatives (or approximately 17% of total expenditure)[79].

5.2.2 Drivers

The drivers for total ICT capex are set out in the Joint ICT Investment Plan (herein referred to as the Plan) for the years 2010 to 2015. Within this Plan, it is stated that as a general rule, SPARQ will 'upgrade' existing applications on behalf of ENERGEX on a three-yearly basis. According to the Plan, this is driven by the need to maintain existing application in the face of:

- discontinuation of older versions of software

79 August 2009, PB.EGX.JTK.14 – Energex ICT reconciliation

- business changes
- technology changes.

The Plan also states that IT initiatives associated with replacement, retirement, or consolidation of existing applications would be undertaken within a six- to nine-year cycle. According to the Plan, this is driven by:

- the need to increase functional capabilities and performance
- business and technology changes
- the need to improve efficiencies through consolidating systems.

5.2.3 Policies and procedures

ENERGEX's ICT plan set out a blueprint to upgrade or replace existing ICT assets to meet operational needs, as well as enhance and develop new capabilities. The ICT plan guides ICT investment decision making for the near to medium term and is a direct input into the annual consolidated program of work (CPoW) planning process, which determines respective ICT operating budgets for ENERGEX.

5.2.4 PB assessment and findings

After reviewing ENERGEX's regulatory submission and supporting documentation, PB requested further information from ENERGEX and SPARQ to demonstrate the prudence and efficiency of the proposed ICT program. In particular, PB sought to substantiate the proposed expenditure through demonstration of the business case, and in the context of historical actuals. In response to PB's enquiries, ENERGEX and SPARQ provided the following information:

- a spreadsheet outlining the indicative operational benefits of a small sample of projects, and ICT capital forecast listing a breakdown of all projects for each of the 10 investment streams
- Information Management Steering Committee (IMSC) endorsement and discussion of the ICT program in relation to AER submission
- documentation and presentations outlining the links, dependencies and interrelationships between the Joint ICT Plan and AER ICT forecast
- a small sample of business cases, board papers, benefits management plan and other ad hoc documentation outlining the rationale for initiatives and their justification.

In particular, ENERGEX and SPARQ have indicated there are at least twelve new areas of capability in the next regulatory control period where an allowance is being sought above the steady state (business-as-usual)[80] expenditure. These are:

- DMS foundation platform — $15.5m

[80] ENERGEX January 2009, *AER Forecast Summary (IMSC)* Outline of Joint ICT planning, item 5a-2b – AER forecast.ppt.

- DINIS, PSSU and DMS integration — $1.1m
- holistic long-term forecasting — $0.9m
- Energy Information Management (EIM) Foundation — $0.8m
- energy enterprise integration — $2.6m
- protection design and analysis — $0.8m
- civil design tools and Integration — $0.9m
- external data integration — $0.7m
- emergency data integration — $0.6m
- performance management — $1.3m
- performance management upgrade — $2.5m
- operational report development — $1.1m.

Based on these new areas of capability, Table 5.5 shows a summary of ENERGEX and SPARQ's steady state and new capability expenditure, while Table 5.6 shows the corresponding breakdown of ENERGEX's proposed expenditure for new capability in the next regulatory control period.

Table 5.5 Total ICT expenditure – steady state and new capability

	2010-11	2011-12	2012-13	2013-14	2014-15	Total	% of total
Total steady state	46.3	32.1	32.0	31.0	26.9	168.2	85
Total new capability	10.8	11.4	2.3	1.9	2.2	28.7	15
Total ICT capex	57.2	43.5	34.2	32.9	29.1	197.0	100

Note: Figures may not sum precisely due to rounding

Source: PB analysis of ENERGEX Major Areas of ICT Expenditure – AER Submission 10 August 2009 and Joint ICT Panning – AER Forecast Summary (January 2009)

Table 5.6 ICT Expenditure – new capability Initiatives

Item	2010-11	2011-12	2012-13	2013-14	2014-15	Total
DMS foundation	7.7	7.7	0.0	0.0	0.0	15.5
DINIS, PSSU, DMS	0.0	1.1	0.0	0.0	0.0	1.1
Holistic forecasting	0.5	0.5	0.0	0.0	0.0	0.9
EIM foundation	0.8	0.0	0.0	0.0	0.0	0.8
Energy enterprise integration	0.3	0.6	0.6	0.6	0.3	2.6
Protect design and analysis	0.0	0.4	0.4	0.0	0.0	0.8
Civil design works	0.0	0.3	0.6	0.0	0.0	0.9
External data integration	0.0	0.2	0.2	0.2	0.0	0.7
Emergency services integration	0.0	0.4	0.2	0.0	0.0	0.6
Performance mgt	1.3	0.0	0.0	0.0	0.0	1.3
Performance mgt upgrade	0.0	0.0	0.0	0.8	1.7	2.5
Operational report development	0.2	0.2	0.2	0.2	0.2	1.1
Total new capability	10.8	11.4	2.3	1.9	2.2	28.7

Note: Figures may not sum precisely due to rounding

Source: PB analysis of ENERGEX Major Areas of ICT Expenditure – AER Submission 10 August 2009 and Joint ICT Panning – AER Forecast Summary (January 2009)

In assessing the appropriateness of the proposed ICT expenditure, PB has focused its examination on the new capabilities being proposed by the business. In this context, PB reviewed the appropriateness of these new capabilities having regards to:

- strategic alignment of individual ICT projects or program with the broader strategies, policies or other objectives and drivers of ENERGEX in the next regulatory control period
- project need, materiality and timing
- options analysis that considers a range of feasible options and unit cost estimates to address the identified needs and objectives with clear and logical explanation as to why the preferred option is the most efficient
- financial and/or economic appraisal that demonstrates value for money, cost savings and/or net benefits of the project or program
- procurement and delivery strategy that outlines an appropriate approach to delivering the proposed outcomes in the next regulatory control period.

The areas of assessment have been compiled on the basis of Treasury guidelines for capital business cases across several jurisdictions across Australia, and PB's previous experience in assessing business cases.

SPARQ ICT expenditure

To clearly demonstrate the proposed ICT capex is prudent and efficient, PB anticipates that, at a minimum, business cases would be available for major projects, particularly those proposed within the early years of the next regulatory control period. Where full business cases have not yet been developed, PB would anticipate that documentation setting out and demonstrating the business need, considering high level options, or presenting the cost benefit considerations would be available to support the capex proposals. PB requested such information for the high value initiatives, and ENERGEX was unable to produce these for the new capability initiatives outlined above[81]. Specifically, while it was found that the majority of projects had a clear description of need and purpose that PB found reasonable, expenditures were not supported by analysis that demonstrated prudence or efficiency.

An exception to this is the provision of the business case 'DMS Stage 2', which is reflective of the new capability DMS foundations[82]. In this instance, PB found the business case to be comprehensive with the need and net benefits of the project being clearly demonstrated, including a financial appraisal, quantification of efficiency gains, and cost savings associated with implementing the project based on staffing numbers.

To further supplement our enquiries, PB requested business cases for other large areas of expenditure that were not specifically related to new capabilities but which form an important part of the Plan. These included large expenditure categories, such as 'Core Technologies' ($22.1m), 'Infrastructure Renewal' for both SPARQ and ENERGEX ($25.8m) and 'ERP upgrades' ($13.4m)[83]. In particular, while the Plan contains a high level discussion of the ten investment streams that outline the current state, strategic drivers, investment intent and qualitative dot point summary of the benefits for each stream, actual quantification of the net economic benefits was not clearly demonstrated and appears to be made in a piecemeal fashion for certain initiatives. That is, a separate spreadsheet provided by ENERGEX that was compiled to quantify the net operational benefits that could result from the elements of the Plan indicated that little or no quantification was made (e.g. ERP – Finance, HR and HSE).[84] In certain cases where quantification was made, these estimates were based on expected 'hard-coded' benefits with no analytical assessment outlining the incremental or absolute net benefits of the proposed expenditure relative to the 'do-nothing' option. An example of this is initiatives associated with workforce automation[85].

From discussions with ENERGEX, PB understands that business cases will be developed closer to project realisation for major projects. However, this practice does not appear to be consistent, as PB viewed examples of business cases for other proposed ICT expenditures that directly reconciled with the ICT forecast (e.g. summer preparation and continuous improvement). Hence, PB would expect, at a minimum, business cases would also be available for major expenditure items, particularly that expenditure relating to new capability. Where full business cases have not yet been developed, PB would anticipate that documentation, in addition to that set out in the Plan, would be available to demonstrate the rationale for and timing of the proposed capital expenditures.

Taken together, it is PB's view that ENERGEX has not demonstrated that the proposed ICT expenditure for new capability is prudent or efficient. Similarly, it would be expected that a prudent operator, as part of its investment management would prepare business cases outlining the rationale behind the timing of expenditure in order to rank and efficiently execute its ICT capital delivery program.

Additionally, PB notes that ENERGEX has used an escalation factor of 4.5% to inflate its forecasts from 2008-09 dollars to 2009-10 dollars. This appears to be different to that

81 ENERGEX August 2009, PB.EGX.JTK.12
82 ENERGEX August 2009, Business Case - Data Centre Reconfiguration 0_3
83 ENERGEX August 2009, PB.EGX.JTK.10
84 ENERGEX August 2009, Strawman Biz Case 3 ER_160508_FHH_ENERGEXOnly
85 ENERGEX August 2009, Strawman Biz Case-WFA_V1.09_ENERGEXOnly

recommended by the AER[86]. PB recommends that the AER review the appropriate escalation factor.

ENERGEX ICT expenditure

In reviewing the appropriateness of ENERGEX's end-use computing assets specifically, PB notes there is a notable overall reduction in expenditure from previous to forecast regulatory control periods (see Figure 5.5 above). That is, an average yearly expenditure reduction from $9.8m to $2.6m, a reduction of 74%. This compares to a change from $18.7m to $9.8m from the current to previous regulatory control periods, a reduction of 47.4%. PB believes that this trend is appropriate given that the majority of assets owned by ENERGEX have gradually been transferred over to SPARQ and is therefore consistent with the forecast trend reduction.

5.2.5 PB recommendation

PB considers that, with the exception of DMS, the proposed expenditure associated with the 'new capability' initiatives capitalised within SPARQ has not been shown to be prudent or efficient and recommends a business-as-usual ICT expenditure forecast. Table 5.7 sets out PB's recommendations as they relate to ICT expenditure capitalised within SPARQ. PB notes that expenditure in this table is capitalised within SPARQ and passes through to ENERGEX as a service charge, as discussed in section 3.2.

Table 5.7 Recommended capex for ICT expenditure – SPARQ

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
SPARQ Proposal	54.0	39.2	32.9	31.1	26.9	184.1
PB adjustment to reflect steady state expenditure plus DMS	(3.1)	(3.7)	(2.3)	(1.9)	(2.2)	(13.3)
PB recommendation	50.9	35.5	30.6	29.2	24.7	170.8

Source: PB analysis

In relation to ENERGEX specifically, PB considers that the proposed expenditure is reasonable and recommends approval of the expenditure subject to review of the appropriate escalation factor used to adjust the ICT expenditure from 2008-09 to 2009-10. Table 5.8 sets out PB's recommendations for ENERGEX's ICT expenditure for the next regulatory control period.

Table 5.8 Recommended capex for ICT expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	3.2	4.3	1.3	1.8	2.2	12.8
PB adjustment	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
PB recommendation	3.2	4.3	1.3	1.8	2.2	12.8

Source: PB analysis

87 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, section 3.7.2, p.45, Discussions with ENERGEX referring to new urban areas in South East Queensland.

5.3 Land and buildings capex

The ENERGEX land and buildings expenditure category comprises the sub-expenditure categories:

- land
- buildings
- control centre – SCADA
- office equipment and furniture
- easements.

These expenditure categories are considered in the following sections.

5.3.1 Proposed expenditure

The proposed expenditure of $298.4m for land and buildings in the next regulatory control period includes $62.3m for land and $236m for buildings. No expenditure is proposed for the sub-expenditure categories of control centre — SCADA, office equipment and furniture, and easements.

The proposed expenditure for land and buildings has increased from $130.8m in the current regulatory control period to $298.4m in the next regulatory control period. This is an average increase of 128% between the two regulatory control periods. The trend in land and buildings expenditure between 2001and 2015 is illustrated in Figure 5.6.

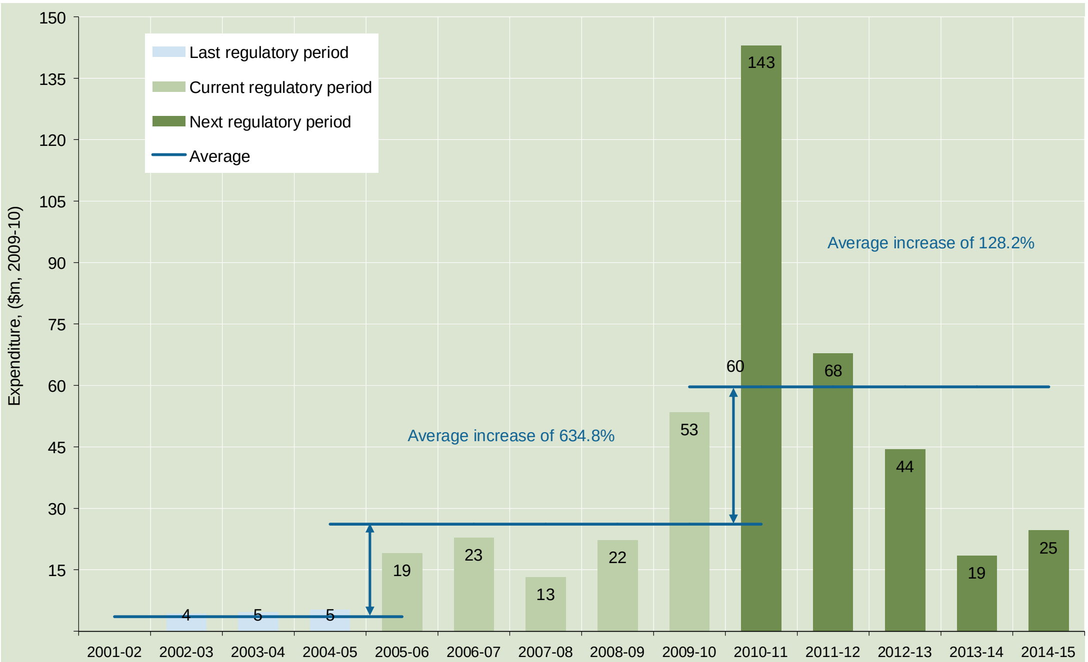

Figure 5.6 Land and building capex

Source: PB analysis

The major land and building expenditures proposed by ENERGEX are outlined in Table 5.9.

Table 5.9 Proposed capex for major land and building expenditures

Location	2010-11	2011-12	2012-13	2013-14	2014-15
xxxxxxxxxxx	xxxx	-	-	-	-
xxxxxxxxxxx	xxxx	-	-	-	-
xxxxxxxxxxxx	xxxx	-	-	-	-
xxxxxxxxxxx	-	xxxx	-	-	-
xxxxxxxxxxx	-	xxxx	-	-	-
xxxxxxxxxxxx	-	-	xxxx	-	-

Source: ENERGEX, PB.EGX.CA8&9 – Property Adjusted Program

5.3.2 Drivers

According to ENERGEX, the increase in proposed property expenditure is driven by several factors:

- alignment of property strategy with corporate strategy — facilities placement in growth areas[87]
- replacement or refurbishment due to overcrowding and/or facilities that no longer meet operational needs[88]
- increased safety risks resulting from multidisciplinary uses of existing depot and office facilities[89]
- aging and deteriorating assets[90]
- increasing operational efficiencies[91]
- acquisition of land in rural areas to enable secure storage of critical spare parts and heavy machinery in closer proximity to customers in remote locations[92].

5.3.3 Policies and procedures

ENERGEX's property strategy[93] sets out the plan to expand, upgrade or replace existing facilities to meet operational needs, alleviate overcrowding and improve field response capability. The purchase of land follows ENERGEX's operational business strategy of establishing a presence in developing areas[94]. As an integral part of PB's review process, the property strategy was discussed in meetings with ENERGEX.

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87 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, section 3.7.2, p.45, Discussions with ENERGEX referring to new urban areas in South East Queensland.
88 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, section 1.5.4, p.20, section 13.7.5, p.205, PB.EGX.CA.6.b – Program Scope + Commentary.pdf
89 ibid., section 13.7.5 p. 206, and CBRE report
90 ibid., section 13.7.5, p.206
91 ibid., section 13.7.5, p.205
92 ibid.,
93 ENERGEX July 2009, PB.EGX.CA.6.a - Property Strategic Plan.ppt
94 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, section 13.7.5, page 205, 206

The ENERGEX approval process requires an options paper to be provided to the executive committee followed by the development of a detailed business case to be provided to the Investment Review Committee and CEO where board approval is required to go to tender for the purchase of property[95].

5.3.4 PB assessment and findings

ENERGEX's forecast land and buildings expenditure of $298.4m over the next regulatory control period represents an average increase of 128% over the current regulatory control period.

ENERGEX's property strategy is driven by the need to manage the property portfolio and align it with the operational business strategy. The property strategy is based on the premise that each project will go through an approval process once a business case has been developed[96]. It is noted this process differs notably from that employed by the business in dealing with system capex, where ENERGEX has prepared business cases to justify the proposed expenditure. It is unclear why the property group practice differs markedly in this respect. PB notes that the property strategy has been signed by the ENERGEX Property Group but has not been approved by the Investment Review Committee or the CEO before Board approval[97] where an options paper and a detailed business case are required[98].

ENERGEX's property plan considers three high level options[99]:

- business as usual ($510m)
- alternative option strategy ($371m)
- property strategy ($250m).

As part of its review PB requested a breakdown of the expenditure behind each of these three options, but ENERGEX were only able to provide a breakdown of the $250m property strategy option[100]. ENERGEX provided a high level explanation for the other options: "The business as usual option was based on high level estimates and the alternative option strategy was based on a strategic shift and more rigorous cost planning including external consultant reports for land purchases and construction costs."[101] ENERGEX has stated that costing based on non-replacement of buildings has not been done[102], [redacted]

The need ENERGEX identified for the extensive building program is predicated on the following main factors:

95 ENERGEX August 2009, PB.EGX.CA.22 – PBEGX.CA.18 – 27.pdf
96 ENERGEX August 2009, PB.EGX.CA.36.tif, PB.EGX.CA.22 – PB.EGX.CA.18 – 27.pdf
97 ENERGEX August 2009, PB.EGX.CA.22 – PBEGX.CA.18 – 27.pdf. Note: The Investment Review Committee is newly formed.
98 ibid.
99 ENERGEX July 2009, PB.EGX.CA.6.a - Property Strategic Plan.ppt
100 ENERGEX July 2009, PB.EGX.CA.7.a – Explanation.doc, PB.EGX.CA.7.b – Energex Corp Property Strategy Extract, PB.EGX.CA.6.c – Program Budget.xls
101 ENERGEX July 2009, PB.EGX.CA.7.a – Explanation.doc; ENERGEX August 2009, PB.EGX.CA.30.tif
102 ENERGEX August 2009, PB.EGX.CA.43 – PB.EGX.CA.43, 44, 47.pdf

- high potential for a significant safety incident[103]
- sites not fit for purpose[104]
- addressing new growth areas[105]
- lack of long term planning in the past[106].

ENERGEX provided a Strategic Overview Report by consultant CBRE that recommends relocation or decentralisation [redacted] PB notes the report provides a perfunctory options treatment for refurbishment and recommends that a formal site options paper is developed for each site[107].

PB agrees with CBRE's recommendation of the development of a site options paper for each site as this is in line with industry practice.

The CBRE review includes an informal risk assessment[108] citing occupational health and safety, and security as a high to very high risk [redacted] High to moderate risks are cited for built environment, reputation and political, legislative and statutory compliance[109]. The 'risk assessment' presented in the CBRE review appears to be subjective in that little evidence of the steps taken within the AS4360/ISO 31000 process has been presented.

PB's concerns with the risk assessment are:

- the risk analysis does not show any review of current control integrity and the risk prioritisation shows insufficient rigour for such a large capex spend[110]
- no attempt has been made to demonstrate that ALARP[111] is achieved or genuinely assess the cost-benefit of potential risk treatments across limited options
- in regard to risk context, it is unclear if the task of the report is to identify areas for further review or to deliver the final recommendations
- there is no evidence of a risks identification process — the steps to conclude this generic list is appropriate and exhaustive are not evident
- there is no evidence of evaluation against the organisation's risk appetite or any defined acceptance criteria.

ENERGEX's strategy to mitigate the risks [redacted] is to vacate the existing site[112], and redesign depots based on a modular design that caters for expansion on an as-needed

103 ENERGEX July 2009, PB.EGX.CA.6.b – Program Scope + Commentary.pdf
104 ibid.
105 ENERGEX August 2009, PB.EGX.CA.30.tif , Discussions with ENERGEX 6/08/2009
106 Discussions with ENERGEX 6/08/2009
107 ENERGEX August 2009, PB.EGX.CA.30.tif
108 ENERGEX August 2009, PB.EGX.CA.30.tif p. 9 CBRE Strategic Overview Review
109 ibid.
110 Extract from the imminent global standard ISO 31000: 'In practice, qualitative analysis is often used first to obtain a general indication of the level of risk and to reveal the major risks. When possible and appropriate, one should undertake more specific and quantitative analysis of the risks as a following step.'
111 AS4360/ISO31000 – ALARP – As Low As Reasonably Practicable
112 ENERGEX July 2009, PB.EGX.CA.6.a – Property Strategic Plan.ppt

basis[113]. The resulting strategy includes among other things five major office fit-outs[114], three major facility replacements[115] and one major depot[116]. ENERGEX's property strategy proposes a separation of white and blue collar workers mainly based on:

- site not fit for purpose[117]
- unsuitable locations for industrial work ([redacted])[118]
- by separating white and blue collar functions, significant capital investment is avoided that would arise from heightened Council requirements on construction standards for office accommodation incorporated in industrial sites[119].

The proposed timing for the implementation of site building or upgrades was ranked through a risk assessment made by ENERGEX's property group[120]. The risk assessment classified properties into low, moderate and high risk categories, with projects deemed to be high risk placed in the early years because of their proposed risk ranking[121]. In making this risk analysis, PB notes that ENERGEX's risk management framework was not used, nor was a formal risk framework, and the criteria for how risk levels were assigned have not been clearly documented[122]. PB considers such an assessment to be inadequate as it is not verifiable or reasonably auditable, and does not employ a standardised method with respect to the principles of the AS4360/ISO31000 risk management standard. On this basis PB considers the proposed risk assessment is not rigorous and does not reasonably demonstrate the timing proposed by ENERGEX.

To clearly demonstrate the need for the expenditures proposed by the property plan, PB anticipates that, at a minimum, business cases would be available for major building projects, particularly those proposed within the early years of the next regulatory control period. Where full business cases have not yet been developed, PB would anticipate that documentation setting out and demonstrating the business need, considering high level options, or presenting the cost-benefit considerations would be available to support the capex proposals.

PB requested business case documentation or supporting documentation for the high value individual projects, and ENERGEX was unable to produce these. Through discussions with ENERGEX it was clear that business cases or supporting documentation for individual projects have not yet been developed, and that ENERGEX intends to develop such documentation closer to project realisation[123]. PB also notes that business case documentation or supporting documentation was not provided for proposed expenditure in the first year of the next regulatory control period (2010-11).

113 Discussions with ENERGEX 6/08/2009. Building refurbishment requires adherence to current building codes and could thus justify complete replacement of the asset depending on asset condition and fitness for purpose.
114 ENERGEX July 2009, PB.EGX.CA.6.a – Property Strategic Plan.ppt
115 ibid.
116 ibid.
117 ENERGEX July 2009, PB.EGX.CA.6.b – Program Scope + Commentary.pdf
118 ENERGEX August 2009, PB.EGX.CA.30.tif, Discussions with ENERGEX 6/08/2009
119 ibid.
120 ENERGEX August 2009, PB.EGX.CA.18 – PB.EGX.CA.18 – 27.pdf
121 ibid., and discussions with ENERGEX 6/08/2009
122 ibid.
123 ENERGEX August 2009, PB.EGX.CA.36.tif

ENERGEX has begun work [redacted][124] based on the risk assessment, but without a full options analysis[125]. On this basis PB considers the process employed by ENERGEX is not prudent when considering the large expenditures involved.

In relation to the treatment of revenue from the sale of land, the following is noted:

- ENERGEX has advised PB that revenue realised from asset disposal will be recorded on ENERGEX's profit and loss statement[126]
- ENERGEX does not offset potential net revenue from the sale of property, or recognise potential site remediation loses in its proposed building program[127]. PB would expect that remediation costs would have been taken into account for at least the major sites.

As previously noted, the land and building expenditure proposed represents a 128% increase over historical expenditure, with the majority of this expenditure proposed for the first two years of the period. PB is concerned the proposed program represents an ambitious increase in ENERGEX's building program that could be difficult to achieve given the imminent nature of the proposed expenditure and the current stage of planning.

In reviewing ENERGEX's forecast building expenditure for the next regulatory control period, PB found that that ENERGEX was unable to provide documentation that established the prudence of the proposed expenditure[128]. PB found that ENERGEX was unable to provide documentation that demonstrated consideration of options in relation to the business need or setting out the cost-benefits associated with the proposed building expenditure. The proposed expenditure represents a considerable increase over historic levels, and PB is concerned that ENERGEX has not demonstrated how this property development strategy will be delivered. This is particularly of concern in the first two years of the expenditure forecasts.

Consequently, PB concludes that the proposed land and buildings expenditure is not prudent and efficient.

5.3.5 Specific Reviews

PB specifically reviewed [redacted] the largest building project proposed. ENERGEX was able to provide much information regarding the [redacted] site, [redacted]

ENERGEX provided a consultant report that states the [redacted] facility will be untenable in the medium to long term[129]. The report concludes that ENERGEX should start the process of options analysis in the short term (to 2013) with a view to replacing the [redacted] facility in the medium (to 2018) to long term (to 2023). The report notes that [redacted] therefore relieving pressure on the site in the short term[130]. The report

124 ENERGEX August 2009, PB.EGX.CA.31.tif
125 ENERGEX August 2009, PB.EGX.CA.37.pdf, PB.EGX.CA.47 – PB.EGX.CA.43, 44, 47.pdf
126 ENERGEX August 2009, PB.EGX.CA.25 – PB.EGX.CA.18 – 27.pdf
127 ENERGEX August 2009, PB.EGX.CA.37.pdf
128 ENERGEX August 2009, PB.EGX.CA.36.tif
129 ENERGEX August 2009, PB.EGX.CA.48&49 – [redacted] Facility Constraints and Opps Analysis Final May 08.pdf
130 ENERGEX August 2009, PB.EGX.CA.48&49 – [redacted] Facility Constraints and Opps Analysis Final May 08.pdf, p.iii

recommends among other things a logistics study to most effectively use the site and to investigate options to reuse the site in the shorter term[131].

ENERGEX provided a consultant report that estimated the cost of upgrading the [redacted] facility over 10 years[132]. The total cost over 10 years is $31.5m for general renewal and $11m for selected roof renewals[133]. PB removed the 30% contingency and the 26.85% overhead included in this costing[134], bringing the adjusted total to $19.1m and $6.7m respectively over 10 years. PB has removed the contingency allowance because it is not related to a specific need and has not been demonstrated to be required. Similarly, PB has removed the overhead as it is considered to already be included in the property overheads (refer section 3.2.1).

Applying an average cost over 10 years, an appropriate annualised allowance for [redacted] would be $2.6m. PB considers this expenditure prudent and efficient for the [redacted] facility and this allowance has been made in the PB recommendations for land and buildings capex.

5.3.6 PB recommendation

As the proposed land and building expenditure has not been found to be prudent or efficient, PB recommends expenditures in line with ENERGEX's business-as-usual costs. An additional allowance of $2.6m per year should also be made for the [redacted] facility – a total of $13m in the next regulatory control period – based on the Davis Langdon estimates provided to refurbish the facility over 10 years.

To establish the business-as-usual costs, PB examined the impact of removing the proposed major building project expenditures that were found to be not prudent and efficient and compared this to the historical expenditures. The major building projects listed in Table 5.9 ([redacted]) amount to $171.3m. The impact of allowing only $13m for the [redacted] site and removing the other major building projects is a reduction of $158.3m. This compares with a reduction of $188.4m, based on the average historical expenditure in the current regulatory control period with the exclusion of the 2009-10 year[135], plus a $13m allowance for the [redacted] facility.

Given that ENERGEX has received independent consultant advice that indicates a need for some increase in expenditures to address the identified problems, PB considers that expenditures in the next regulatory control period are likely to be higher than for the current regulatory control period. Hence, PB is of the view that a minimum reduction of $158.3m, in line with the removal of the major projects, would lead to expenditures that are prudent and efficient.

Table 5.10 shows PB's recommended expenditure for land and buildings (combined) for each year of the next regulatory control period, including the allowance for the [redacted] site upgrade.

131 ibid.
132 ENERGEX August 2009, PB.EGX.CA.48&9 – Davis Langdon 1.pdf, Davis Langdon 2.pdf, Davis Langdon 3.pdf, Davis Langdon 4.pdf, Davis Langdon 6.pdf, Davis Langdon 6.pdf.
133 ENERGEX August 2009, PB.EGX.CA.48&9 – Davis Langdon 1.pdf, p4
134 ibid.
135 As expenditure in the current period is quite volatile, the 2009-10 expenditure is excluded as it is a forecast and our review process has not substantiated the current year expenditure. It also represents a considerable increase over the actual expenditure for the remainder of the current period. PB notes that the 2008-09 year expenditure also contains a portion that was forecast by ENERGEX at the time of submitting its Regulatory Proposal; however, this forecast was based on committed programs of work and is considered to be accurate.

Table 5.10 Recommended capex for land and buildings

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	143.0	67.8	44.4	18.5	24.7	298.4
PB adjustment	(115.0)	(39.8)	(16.4)	9.5	3.3	(158.3)
PB recommendation	28.0	28.0	28.0	28.0	28.0	140.1

Source: PB analysis

5.4 Fleet capex

The ENERGEX fleet expenditure category comprises the sub-expenditure category of motor vehicles. This expenditure category is considered in the following sections.

5.4.1 Proposed expenditure

The proposed expenditure for fleet has increased from $189.5m in the current regulatory control period to $196.3m in the next regulatory control period, representing a real increase of 3.6%. This trend in fleet expenditure is illustrated in Figure 5.7.

Figure 5.7 Fleet capex

Source: PB analysis

5.4.2 Drivers

ENERGEX stated the proposed fleet expenditure is based on business as usual. According to ENERGEX, the expenditure forecast for the fleet is derived by the replacement of existing vehicles, consistent with forecast staff requirements[136].

136 ENERGEX July 2009, *Regulatory proposal for the period July 2010–July 2015*, section 13.7.5.

5.4.3 Policies and procedures

ENERGEX has employed a business-as-usual approach to fleet management for the next regulatory control period. ENERGEX's 'Fleet Asset Management Plan'[137] provides an outline of the policies, processes and practices by which ENERGEX determines its current and projected vehicle fleet size and composition. This document also provides an overview of fleet assets and asset management strategies required to meet stakeholder and statutory requirements.

The timing of fleet expenditure is driven by a need in ENERGEX's motor vehicle replacement policy. This uses replacement criteria based on age[138] or kilometre[139]. In general, motor vehicles are replaced in accordance with the age replacement policy. PB verified adherence to this policy by comparing the replacement due date versus actual replacement date for ENERGEX's Landcruisers in 2008-09[140]. ENERGEX's replacement policy takes into account environmental, efficiency, operational reliability, safety, warranty, manufacturer specified design life, Australian standards and financial/resale factors[141].

5.4.4 PB assessment and findings

ENERGEX's forecast fleet expenditure of $196.3m over the next regulatory control period represents a 3.6% increase over the current period. PB notes that this expenditure is consistent with the historical level of expenditure for fleet.

PB expects that prudent fleet management would entail purchase of fleet on a need and timing basis in accord with the fleet strategy. ENERGEX demonstrated that proposed fleet expenditure is prudent, as motor vehicles are replaced on a need and timing basis in accord with its fleet strategy[142].

PB expects efficient fleet management to demonstrate cost efficiency in buying and selling motor vehicles. This includes evidence that motor vehicle costs have been compared by vehicle type. ENERGEX demonstrated that proposed fleet expenditure is efficient as the majority of fleet management is done by an external service provider (SG Fleet) contracted through a market tender process[143]. PB verified that SG Fleet were contracted through this process via review of their request for tender document. Furthermore, PB reviewed a 2007 benchmarking study of trucks by FleetAustralia, which compared the purchase costs and residual values for three trucks, demonstrating that alternative expenditure options are considered[144]. PB examined this report and, through discussions with ENERGEX, verified that this process occurs. PB thus concluded that ENERGEX's fleet services are run in a cost-efficient manner.

PB concludes ENERGEX's fleet management is prudent and efficient on the basis ENERGEX has demonstrated its replacement program follows its policy that forecast purchase and sale of motor vehicles for the next regulatory control period are aligned with its Fleet Asset Management Plan, and expenditure levels are in line with historic levels.

137 ENERGEX December 2008, *Fleet Asset Management Plan*.
138 ibid., p.6
139 Discussion with ENERGEX 6/08/2009.
140 ENERGEX, 2008-09 Landcruiser replacement spreadsheet.
141 ENERGEX December 2008, *Fleet Asset Management Plan*, p.6.
142 ENERGEX August 2009, PB.EGX.CA.45.doc, PB.EGX.CA.40.a – Explanation.doc, PB.EGX.CA.40.b – Fleet Replacement Program Aug09.xls
143 ENERGEX, Technical Specification: Provision of Light and Heavy Vehicle Operating Management and Reporting Services
144 FleetAustralia November 2007, Report to ENERGEX, Truck Comparison Report.

ENERGEX's outsourcing arrangement is market tested, the timing and expenditure is driven by a need in accordance with company policy.

5.4.5 PB recommendation

PB recommends that the proposed capex for fleet is accepted with no changes, as set out in Table 5.11.

Table 5.11 Recommended capex for fleet

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	32.8	41.8	42.0	32.3	47.4	196.3
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	32.8	41.8	42.0	32.3	47.4	196.3

Source: PB analysis, ENERGEX RIN – Capex (2.2.1)

5.5 Tools and equipment capex

The ENERGEX tools and equipment expenditure category comprises the sub-expenditure categories of:

- plant and equipment
- other.

5.5.1 Proposed expenditure

The proposed expenditure of $56.2m for tools and equipment in the next regulatory control period includes $56.2m for plant and equipment. Note that the sub-expenditure category of 'other' has no proposed capex.

Proposed expenditure for tools and equipment has decreased from $66.9m in the current regulatory control period to $56.2m in the next regulatory control period, representing a real decrease of 16%. Figure 5.8 outlines the expenditure trend between 2001 and 2015.

Figure 5.8 Tools and equipment capex

Source: PB analysis

5.5.2 Drivers

According to ENERGEX, the expenditure forecast for tools and equipment is derived from equipment testing and inspection management systems, and includes the acquisition and replacement of hand-held tools and safety equipment[145].

5.5.3 Policies and procedures

ENERGEX's policy in relation to tools and equipment outlines company processes and practices by which it determines its current and projected tooling and equipment levels[146]. ENERGEX uses a database to manage tools and equipment that computes predicted usage levels based on historical levels of usage[147].

5.5.4 PB assessment and findings

ENERGEX states the proposed tools and equipment expenditure is based on a business-as-usual approach[148]. Discussion with ENERGEX indicated that tools and equipment are selected using a number of criteria, including:

- safety and statutory obligations[149]
- operational reliability
- life-cycle cost efficiency[150]

145 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, section 13.7.5
146 ENERGEX July 2009, Fleet Tools Equip M Carroll PM.ppt
147 ENERGEX July 2009, AMPRO - Fleet Tools Equip M Carroll PM.ppt
148 ENERGEX July 2009, Fleet Tools Equip M Carroll PM.ppt
149 ibid., ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, p.21

- flat growth of workforce[151].

ENERGEX has stated the decrease in expenditure for tools and equipment in the next regulatory control period is driven by a flat workforce growth forecast[152], efficiency improvements in the use of plant and equipment across the business, and the significant purchase of long-lived items in the current regulatory control period[153] that will not require replacement in the next regulatory control period.

PB is satisfied by the explanations provided by ENERGEX as to the level of expenditure required and concludes the forecast expenditure on tools and equipment is prudent and efficient.

5.5.5 PB recommendation

PB recommends the proposed capex for tools and equipment is accepted with no changes, as set out in Table 5.12.

Table 5.12 Recommended capex for tools and equipment

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	13.3	10.9	10.7	10.6	10.7	56.2
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	13.3	10.9	10.7	10.6	10.7	56.2

Source: PB analysis & ENERGEX RIN – Capex (2.2.1)

5.6 Summary of findings and recommendations

This section presents a summary of PB's key findings and recommendations relating to ENERGEX's proposed non-system capex for the next regulatory control period.

Key Findings

ENERGEX proposes to spend $563.7m on non-system capex in the next regulatory control period, an average increase of 29%.

ICT Systems

ENERGEX proposes to spend $12.8m on ICT capex in the next regulatory control period, a reduction of 74% (due to the establishment of SPARQ as their ICT service provider).

PB assessed ENERGEX's proposed ICT capex as prudent and efficient.

Land and Buildings

ENERGEX proposes to spend $298.4m on land and buildings in the next regulatory control period, an increase of 128%.

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150 ENERGEX July 2009, Fleet Tools Equip M Carroll PM.ppt , Discussions with ENERGEX 15/08/2009
151 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015,* p.211
152 ibid.
153 Discussion with ENERGEX 15/08/2009

The need and timing for the extensive proposed building program was not sufficiently demonstrated and PB recommends a reduction of $158.3m.

Fleet

The proposed capex for fleet, representing a real increase of 3.6%, is assessed as prudent and efficient.

Tools and Equipment

The proposed capex for tools and equipment, representing a real decrease of 16%, is assessed as prudent and efficient.

Recommendations

PB recommends that the non-system capex allowance for the next regulatory control period should be reduced by $158.3m from the levels proposed by ENERGEX. PB's proposed adjustments are shown in Table 5.13.

Table 5.13 PB's recommended non-system capex

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ICT						
ENERGEX proposal	3.2	4.3	1.3	1.8	2.2	12.8
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	3.2	4.3	1.3	1.8	2.2	12.8
Lands and buildings						
ENERGEX proposal	143.0	67.8	44.4	18.5	24.7	298.4
PB adjustment	(115.0)	(39.8)	(16.4)	9.5	3.3	(158.3)
PB recommendation	28.0	28.0	28.0	28.0	28.0	140.1
Fleet						
ENERGEX proposal	32.8	41.8	42.0	32.3	47.4	196.3
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	32.8	41.8	42.0	32.3	47.4	196.3
Tools and equipment						
ENERGEX proposal	13.3	10.9	10.7	10.6	10.7	56.2
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	13.3	10.9	10.7	10.6	10.7	56.2
Total non-system capex						
ENERGEX proposal	192.3	124.8	98.4	63.2	85.0	563.7
PB adjustment	(115.0)	(39.8)	(16.4)	9.5	3.3	(158.3)
PB recommendation	77.3	85.0	82.0	72.7	88.3	405.4

Source: PB analysis

6. Opex review

This section presents PB's review of ENERGEX's proposed opex for the next regulatory control period. In undertaking its review, PB has provided technical advice regarding the efficiency and prudence of opex forecasts provided by ENERGEX, and aims to provide input to assist the AER in its assessment of the opex objectives, criteria and factors set out in clauses 6.5.6 of the NER.

6.1 Opex overview

ENERGEX has submitted an opex proposal of $1,843m for the next regulatory control period. During the current regulatory control period, ENERGEX expects the total opex to be $1,353m, based on three years of actual expenditure and estimates for the last two years of the period. The proposed opex for the next regulatory control period therefore represents a 36% increase in real terms over the current regulatory control period.

The profile of the opex spend over the ten years is shown in Figure 6.1.

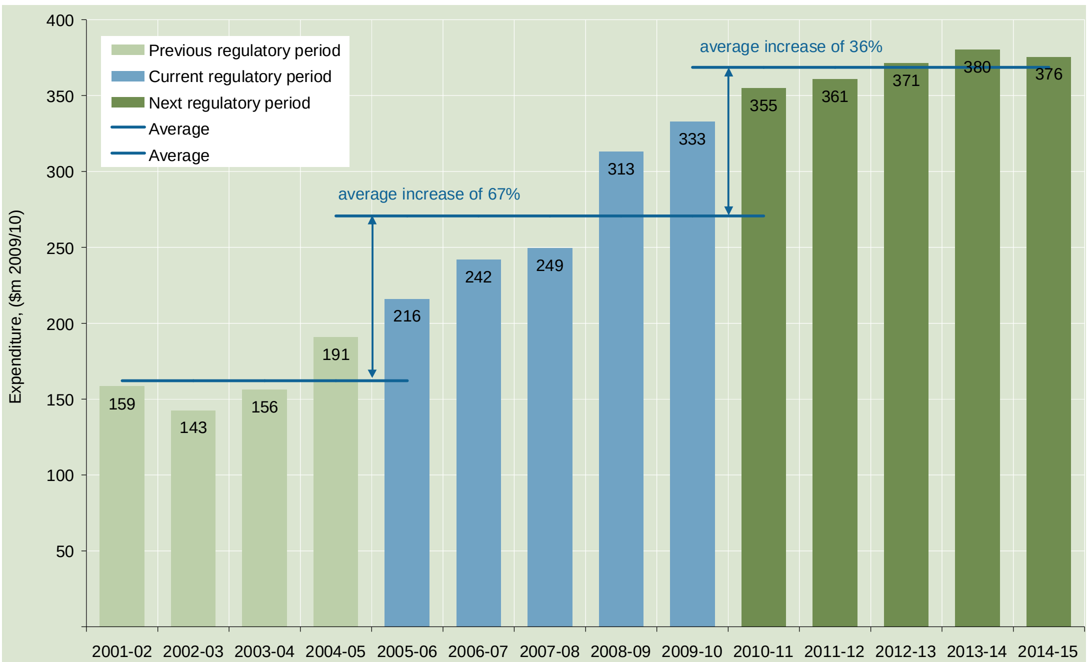

Figure 6.1 Opex over the 2005 to 2015 period

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

In accordance with ENERGEX's RIN submission proformas[154], the forecast opex comprises eleven main cost categories, including:

- network operating costs — related to those activities which enable the effective and efficient operation of the distribution network

154 EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, Table 1 (operating expenditure by category) in template 2.2.2, operating expenditure, 01/07/09.

- inspection maintenance — includes inspection of the electricity network such as feeder patrols, pole, substation and ring main unit (RMU) inspections, as well as those for underground cables
- planned maintenance — related to planned or programmed maintenance to reduce the probability of failure or performance degradation of a network asset; includes maintenance as a result of a component/sub-component going out of specification but still in service so maintenance can be scheduled for a future time
- corrective repair maintenance — which is repair work carried out following a network fault
- vegetation maintenance — related to tree clearing and trimming of trees on the network and customers' premises
- emergency response/storms maintenance — including efforts associated with storms and disaster coordination, and field costs to repair storm damage
- meter reading — includes the cost of reading meters
- customer service (including call centre) – related to call centre activities and other activities arising from specific requests by customers that require work on the ENERGEX network
- demand-side management initiatives — activities to manage customer demand by shifting or reducing demand for standard control services
- levies — including levies paid to regulatory bodies and other entities
- other operating costs — all other operating costs not captured above, including self-insurance costs.

6.1.1 Opex in the current regulatory control period

ENERGEX's opex in the current regulatory control period is estimated to be $1,353m, in accordance with the expense categories outlined in Table 6.1.

Table 6.1 Historical and estimated opex for the 2005-2010 regulatory control period

Expenditure category	2005-06	2006-07	2007-08	2008-09 (est.)	2009-10 (ext.)	Total
Network operations	12.81	14.47	16.29	23.74	24.95	92.26
Inspection	11.96	15.76	15.84	19.40	18.61	81.57
Planned maintenance	32.48	59.07	59.40	73.22	65.58	289.75
Corrective repair	26.61	26.58	35.86	36.37	40.03	165.45
Vegetation	62.37	57.21	56.54	64.40	70.29	310.81
Emergency response/ storms	10.76	4.07	4.77	20.32	8.21	48.13
Meter reading	15.66	14.62	14.88	13.62	15.87	74.65
Customer services	17.18	15.40	13.54	16.48	20.92	83.52
DSM initiatives	2.24	3.45	4.37	9.43	39.43	58.92
Total system opex	192.08	210.65	221.49	276.99	303.90	1205.11
Levies	6.10	6.31	6.42	7.94	8.31	35.08
Other operating costs	17.85	25.02	21.56	28.19	20.68	113.3
Total opex	216.02	241.96	249.47	313.11	332.88	1353.44

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

The expenditure numbers presented in Table 6.1 include an allocation of the business shared costs (overheads). These have been allocated in accordance with the AER's approved cost allocation method.

6.1.2 Forecast opex

ENERGEX propose opex in the next regulatory control period of $1,843m, as outlined in Table 6.2.

Table 6.2 Proposed opex for the next regulatory control period

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Network operations	25.54	26.79	27.43	28.30	28.91	136.97
Inspection	19.23	20.81	22.51	23.26	24.99	110.80
Planned maintenance	66.01	65.03	66.87	68.47	69.59	335.97
Corrective repair	39.95	41.08	41.41	41.88	42.11	206.43
Vegetation	77.21	79.52	81.10	82.21	82.53	402.57
Emergency response/ storms	8.56	8.91	9.07	9.27	9.43	45.24
Meter reading	14.61	15.19	15.81	16.45	17.13	79.19
Customer services	21.01	21.85	22.42	23.05	23.61	111.94
DM initiatives	24.60	23.23	25.28	30.58	23.18	126.87
Total system opex	296.71	302.43	311.90	323.48	321.48	1556.00
Levies	8.58	8.87	9.23	9.54	9.87	46.09
Other opex	22.05	21.71	22.40	21.81	20.89	108.86
Debt raising	7.16	8.06	8.97	9.87	10.72	44.78
Equity raising	20.61	19.79	18.79	15.66	12.59	87.44
Total non-system opex	58.40	58.43	59.39	56.88	54.07	287.17
Total	355.12	360.86	371.28	380.36	375.54	1843.16

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

The percentage contribution of each cost category, and the real increase compared with the current regulatory control period are summarised in Table 6.3.

Table 6.3 Proposed opex for the next regulatory control period proportions and increases from current period

Expenditure category	% of total forecast opex	Average % real increase from current period
Network operations	7	48
Inspection	6	36
Planned maintenance	18	16
Corrective repair	11	25
Vegetation	22	30
Emergency response/storms	2	(6)
Meter reading	4	6
Customer services	6	34
DM initiatives	7	115
Total system opex	84	29
Levies	2	31
Other opex	6	(4)
Debt raising	2	-
Equity raising	5	-
Total opex	100	36

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

The principal observations from Table 6.3 are that ENERGEX is proposing a significant increase in its DM initiatives (115%), in its network operations (48%), and in its vegetation management (30%). The continually increasing expenditure on inspections and associated planned maintenance (especially over the current period) are also indicative of a maintenance strategy informed by ongoing condition monitoring, as discussed further in section 6.2.

The profile of expenditure over the current and next regulatory control periods varies in real terms in accordance with Figure 6.2, which shows network related opex categories, and Figure 6.3, which shows non-network related opex categories.

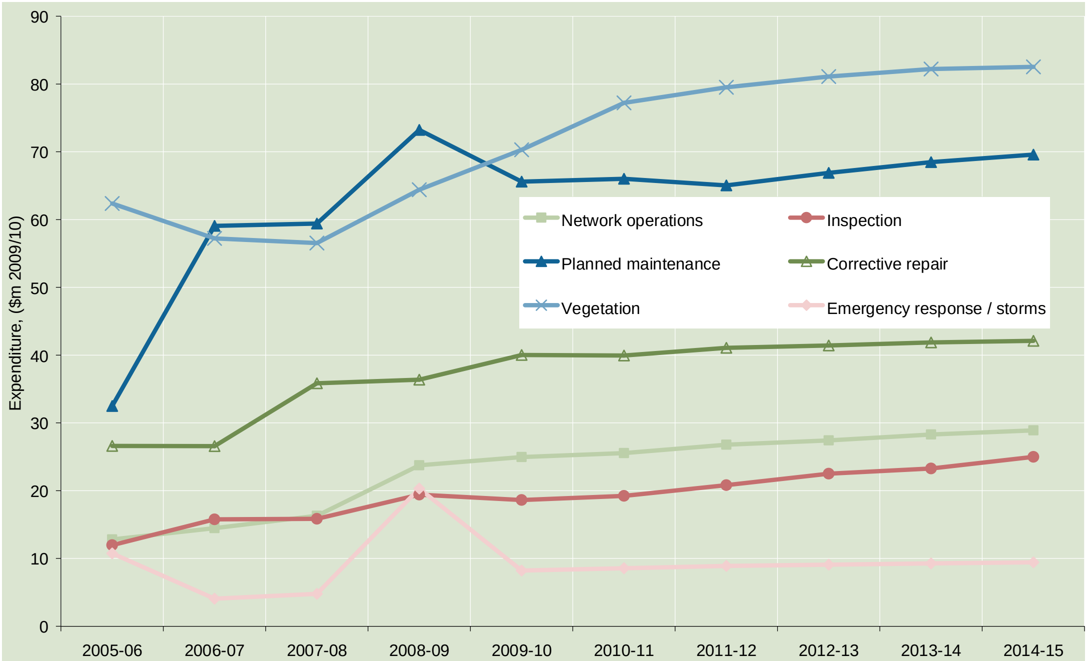

Figure 6.2 Opex trends – network operations, inspections, planned maintenance, corrective repair, vegetation and emergency response/storms

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

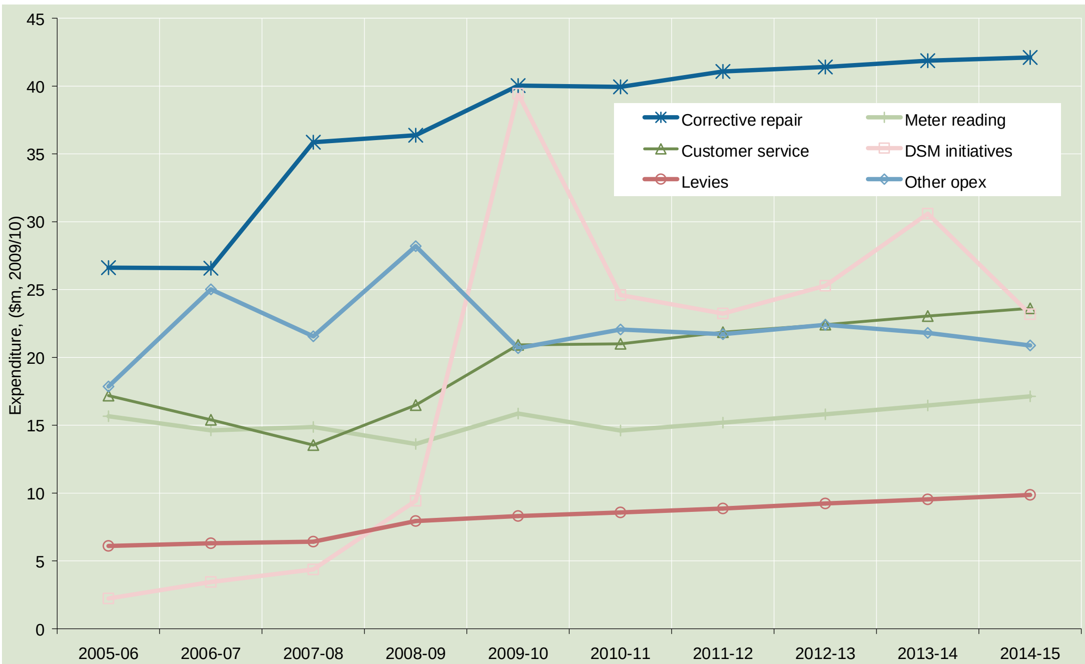

Figure 6.3 Opex trends – meter reading, customer service, DSM, levies, and other opex

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

A comparison between the opex in the current regulatory control period and the forecast opex proposed for the next regulatory control period is shown in Figure 6.4.

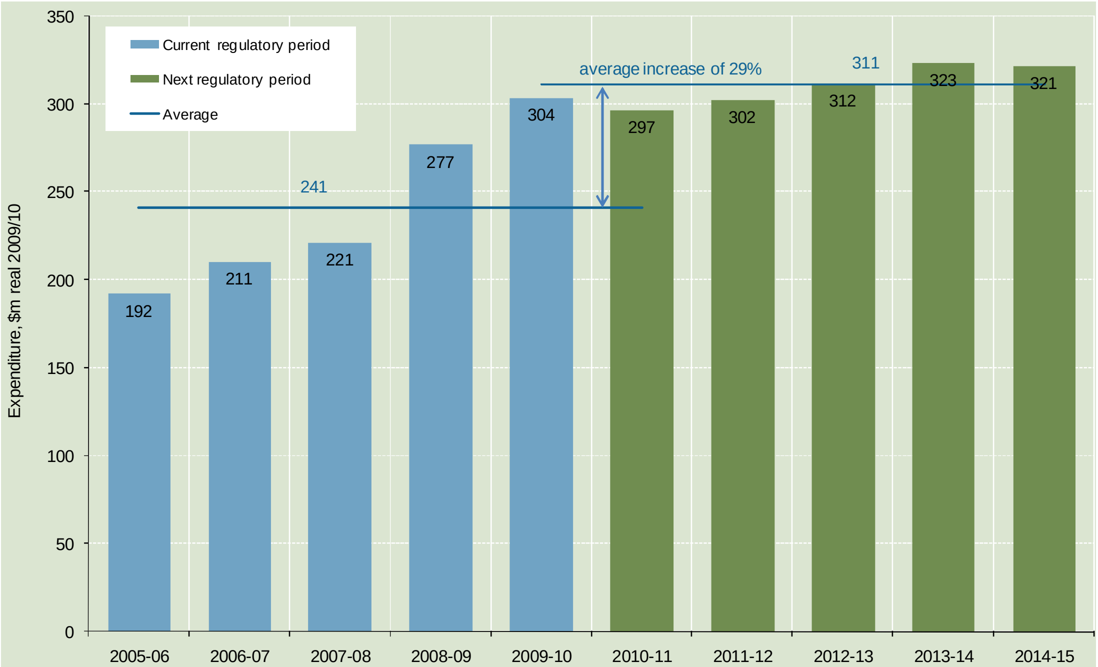

Figure 6.4 Historical and estimated system opex for the current regulatory control period and the proposed opex for the next regulatory control period

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

PB has formed the opinion the increasing system opex from 2005-06 to 2009-10 is largely a response to the findings presented as part of the 2004 EDSD review and the approach ENERGEX has taken to achieve these outcomes. Our opinion is mainly based on the review of ENERGEX's substation asset management and the mains asset management policies that detail the condition-based approach to asset maintenance ENERGEX has implemented. The major findings of the EDSD review that affect system operating costs include:

- *ENERGEX to improve worst performing feeders* – ENERGEX will target 10% of its worst performing feeders so that by 2010 its worst feeders will have outages no more than 1.5 times the ENERGEX system-wide average. This will provide a significant improvement in reliability for customers connected to those feeders. ENERGEX will publicise the 10% worst performing feeders and the annual improvements in reliability attained.

- *Reduce load and voltage constraints* – ENERGEX will identify load and voltage constraints and associated capex to address these constraints.

- *Effective maintenance program* **–** ENERGEX is increasing its operating and maintenance program, including increased preventative maintenance and effective vegetation management.

The introduction of a maintenance program based on condition monitoring is discussed further in section 6.2 and is demonstrated by the continual increasing expenditure on inspections and associated planned maintenance during the current regulatory control period.

6.2 Operations and maintenance approach and strategy

This section aims to identify and discuss the approach ENERGEX adopts and its business documentation relating to its asset management practices.

6.2.1 Key policies and documentation

The two documents that detail the maintenance philosophies and policies adopted by ENERGEX are its Mains Asset Maintenance Policy[155] (MAMP) and the Substation Asset Maintenance Policy[156] (SAMP).

The SAMP defines the minimum requirements for the condition monitoring inspection and maintenance of assets situated in zone and commercial and industrial (C&I) substations. These include assets such as transformers and on-load tap changers, circuit breakers, protection systems, ancillary equipment and the associated property assets.

The MAMP defines the minimum requirement for the inspection and maintenance requirements of sub-transmission and distribution overhead and underground assets, public lighting and vegetation in proximity to ENERGEX assets.

Specifically, the MAMP also clearly defines the minimum requirements in relation to the key area of vegetation management, including detailing the planned tree trimming program and specifying the vegetation clearing profiles for subtransmission, distribution and pilot cables. This particular aspect of the ENERGEX's proposed opex program was examined in detail due to the significant expenditures associated with the work and the proposal to decrease the trimming cycles on urban LV spur lines, aligning them with urban cycles for HV distribution lines. This issue is discussed in detail in section 6.8.

PB's review of these documents, which included direct discussions with asset maintenance managers, has indicated that essentially ENERGEX employs a condition-based approach to determine the timing of, and maintenance requirements for, each major asset class. This approach is referenced in section 1.3 Maintenance Procedures of the MAMP and section 1.1 Maintenance of the SAMP. It concentrates on the inspection, testing and recording of operations of plant to determine condition and hence the type and timing of routine or planned maintenance. Importantly, this approach allows for assets to be maintained based on performance, operation and location risk, with a safety net based on an extended inspection cycle, and the approach can therefore be fine tuned and informed through the regular monitoring.

The asset condition information is also a fundamental input used by the condition-based risk management (CBRM) program[157], which when analysed in conjunction with wider risk-based information (such as the likelihood and consequence of failure given locality issues) allows ENERGEX to develop a quantified, risk-based, and time-variant asset health index for each individual asset. The approach to developing a health index is described in section 2.1 Health Indices of the Full Application of CBRM with ENERGEX report[158]. The asset's specific

155 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, Appendix_4.7 Mains Asset Maintenance Policy

156 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, Appendix _4.6 Substation Asset Management Policy

157 Developed for ENERGEX by EA Technology using its framework, as established within the UK electricity network industry.

158 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, Appendix_4.5 Full Application of CBRM with ENERGEX (EA Technologies)

condition is an essential input into determining its health index. The relative health index forms the basis of ENERGEX's asset replacement and refurbishment program. PB's detailed review of this modelling, including the appropriateness of the assumptions and key inputs, is discussed in detail in section 4.3.4 of this report.

In some cases, assets are managed with a 'run-to-failure' approach. Run-to-failure assets are generally high volume, low cost assets used on high and low voltage distribution lines, such as drop-out fuses, links, low voltage switches, and so on. These assets are not specifically listed in the MAMP as being subject to condition monitoring. Where this is the case, ENERGEX maintains accurate records regarding asset specifications, manufacturer details, failure modes and so on. This informs procurement and purchasing of future assets in order to ensure long service lives. Typically, the cost to replace run-to-failure plant is considerably higher than the cost of replacing the plant under planned conditions. Given that well informed plant and equipment specifications play a material role in minimising whole-of-life costs, to this end accurate records are essential.

At a higher level, ENERGEX is currently developing its integrated strategic asset management and maintenance documentation. Whilst the SAMP and MAMP briefly outline how the practices align with the corporate strategy, they primarily focus on detailing very specific maintenance processes and procedures for each asset class. Hence, in drawing our conclusions in relation to the current roll out of condition bases maintenance practices within ENERGEX, PB has relied heavily on the MAMP and SAMP. EA Technology[159] has carried out a review of the SAMP and MAMP and whilst recommending the development of a high level asset management strategy document also found that the majority of asset classes have adequate inspection/maintenance intervals and task descriptions and did not identify any major omissions.

ENERGEX has a Demand Management strategy[160], which has as its key objective the transformation of the business into a customer focussed organisation providing sustainable energy solutions. The strategy requires ENERGEX to deploy demand management initiatives that will better utilise the network assets and over the long term reduce capital expenditure and benefit electricity customers. The strategy has a number of target outcomes in addition to reducing peak demand and they include minimising the impact of energy intensive living, enabling non-network solutions and assisting customers embrace energy efficiency. PB has reviewed a number of DM initiatives included in the Regulatory Proposal and these are discussed in detail in section 6.12.

ENERGEX has an Environment Strategy[161], which has as its key objective ensuring that ENERGEX delivers an environmental position responsive to the community's expectations whilst ensuring that environmental compliance, carbon management and environmental sustainability are recognised and targeted action plans improve overall performance. Specifically, this document addresses amongst other matters - pollution management, cultural heritage issues, and the biodiversity management of flora and fauna.

These key polices and strategy documents inform the opex forecast expenditure categories in accordance with Table 6.4.

159 Appendix 12.1 Maintenance Policy Review (EA Technologies), January 2008
160 Appendix 5.1 Demand Management Strategy.pdf, June 2009
161 Appendix 4.8 ENERGEX Environment Strategy.pdf, June 2009

Table 6.4 Policy document and expenditure mapping

	Network operations	Mains maintenance	Vegetation management	Substation maintenance	Customer services	Metering	Demand Management
MAMP	✓	✓	✓				
SAMP	✓	✓		✓			
Meter asset management plan					✓	✓	
Contracting strategy		✓	✓	✓	✓	✓	✓
Demand management strategy					✓		✓
Environment strategy	✓	✓	✓	✓	✓	✓	✓

Source: PB analysis

6.2.2 Asset management practices and performance

In reviewing ENERGEX's asset management documentation and how it has informed the opex forecasts, PB has reviewed the SAMP and MAMP in detail and also questioned ENERGEX asset managers to better understand the application of these two asset management plans. Whilst it is not possible to discuss every asset specific inspection and maintenance policy due to the sheer volume and numbers of these policies and practices, several of the key distribution asset class practices and polices are discussed in this section.

Detailed asset register

ENERGEX maintains a detailed asset management system to record all maintenance history. ENERGEX has developed specific maintenance record forms for each asset class. These are used to record and document the results of inspections, conditions found and actions taken during maintenance activities. These records are reviewed and analysed to assist in improving the maintenance process. ENERGEX uses a business management system (BMS) to record and control the maintenance procedures and the associated specific asset record forms. Each document is given a unique reference number so that revisions can be controlled. The system is used universally throughout ENERGEX and forms the basis for documenting and recording all policies, processes and procedures within the business.

Targeted approach

ENERGEX employs specialist maintenance planning engineers, with a customer and reliability focus, and it was evident to PB that ENERGEX seeks out contemporary asset management practices used by other organisations and deploys them within ENERGEX. For example, PB is advised that the introduction of the systems-based approach to asset inspection and subsequent asset defect rectification was introduced after identifying this practice in a NSW-based distributor.

With the use of the CBRM modelling, there is a clear framework of risk versus cost to inform investment decisions, and full-life cycle costing is implicit in processes used to standardise the purchase of plant and equipment.

The impact of the deployment of the condition-based approach to asset maintenance and asset replacement is evident in the significant increase in inspections and planned maintenance during the current regulatory control period and the fact that the forecast expenditures for emergency response are relatively constant during the next control period even though the asset size is increasing because of the proposed capital works programs.

Circuit breakers

ENERGEX currently maintains circuit breakers based primarily on the number of fault operations experienced — this is representative of leading practice in this area. For example the SAMP specifically details the number of fault operations for each of the 21 types of 33kV breakers in service in the ENERGEX network that would trigger a maintenance requirement, and also details the fall back time period of the maintenance if the operations threshold is not reached. This is to ensure continued serviceability of 33kV circuit breakers that have not experienced any operations for a considerable period of time. For example a GEC-K 33kV circuit breaker is maintained after 6 fault operations with a fall back maintenance period of 12 years if the circuit breaker does not operate 6 times under fault conditions during any 12 year period.

Typically, fault operations are recorded manually within ENERGEX as the majority of the existing protection relays cannot provide outputs of the fault current and the existing SCADA system cannot transfer this data back to the asset data base. However, in future when these assets are replaced with modern equipment, this information will be available in real time and will also detail the actual fault current interrupted. ENERGEX indicated that when this occurs it proposes to record both the number and severity of each fault operation. This will enable maintenance timing to be further refined, as currently all fault operations, even minor occurrences, are included in scheduling planned maintenance.

ENERGEX is implementing an intermediate step in the process by using the fault level at the location where the circuit breaker is situated as a surrogate for the fault current interrupted.

In relation to 66/110/132 kV switchgear and GIS, ENERGEX has a two stage approach to asset management. Inspections are triggered by the number of operations with a time based fall back, whilst maintenance is triggered by the number of fault operations with a time based fall back position. For example for the ABB-LTB type circuit breaker, inspections are triggered after 2000 operations with a fall back time period of 6 years and maintenance is triggered after 22 fault operations with a fall back period of 22 years.

Power transformers and tap changers

ENERGEX has detailed specific inspection and maintenance procedures for power transformers including transformer bushing testing, with additional requirements for power transformers with primary voltages of 110kV or greater, 11kV/415V transformers and tap changers.

For example, ENERGEX tests its high-voltage transformers for dissolved gas (oil) every 12 months for units with a primary voltage of 110kV or greater, and every two years where the primary voltage is lower than 110kV. The intervals are reduced if the power transformer shows signs of deterioration. The standard dissolved gas analysis includes analysis for dielectric strength, water content, loss tangent and resistivity, organic acidity and dissolved gasses.

Oil filled transformers and dry type 11kV to 415V distribution transformers are only inspected at 12 monthly intervals with the inspection results analysed within 1 month of the inspection, and defect rectification scheduled based on the defect severity and consequences of failure.

Tap changer diverter switches are maintained in accordance with the SAMP, which details the 36 different types of tap changers in service in the ENERGEX network. Tap changer diverter switches are maintained on the number of operations with a fall back time period. For example, a Reinhausen type B unit is maintained after 50,000 operations of the diverter switch with a fall back period of 6 years.

Aligned line inspections and routine feeder patrols

One visit by a trained inspector covers poles, tops, conductor, vegetation, etc. These inspections are carried out on a 5-year cycle which is relatively standard within distributors with a substantially wooden pole population. Also field data is captured on hand-held computer which interface and directly up-load into the asset management data base. The hand-held devices facilitate reasonableness testing on site and contain previous inspection results for operator analysis. Any calculations (such as pole strength/safety factor, etc) are preformed on site and results up loaded directly.

The MAMP also categorises any defect identified during line inspections into four categories, P1, P2, C3 and C4. P1 are defined defects that present an immediate safety hazard or the potential to cause a network failure and must be rectified within two days. P2 defines a defect or component that has reached the end of its useful life but is not at risk of imminent failure, and should be rectified within 3 months. C3 defines a physical condition that an item should be replaced or maintained within 12 months to prevent progression to a defective state. C4 defects are reported only and should be either replaced within two years or deterioration is observable suggesting end of serviceable life will be reached within approximately five years.

ENERGEX has classified its feeders into either category A or category B, and publishes a list annually of all category A feeders. Category A feeders are "*feeders for which an outage on this feeder alone will cause operational difficulties or loss of supply to customers or feeders where additional security is required to meet reliability or security objectives*". Whereas category B feeders are feeders where network redundancy exists to ensure alternate supply.

Feeders are patrolled routinely to identify hazards with the potential to cause injury or damage to property or affect the reliability of the line. In addition the patrols identify vegetation requiring attention. The MAMP specifies that category A feeders be patrolled every 6 months and category B feeders every 12 months.

Bundling work packages

Defects arising from inspections are combined into work orders allowing field staff to fix multiple issues on the feeder. In developing these work orders ENERGEX also reviews proposed capital works in the area and, if possible, combines the defect rectification and capital work into a single work order. Reviewing the proposed capital works program in an area also ensures that assets scheduled for replacement are not maintained.

Wood pole performance

Wood poles is one of the major asset categories in an electricity distribution network. Two standard measures used to determine the prudence of the pole maintenance practices are the percentage of unassisted pole failures and the condemnation rate expressed as a percentage of poles inspected. PB requested ENERGEX provide details of both these measures. Historical data on unassisted pole failures is detailed in Table 6.5.

Table 6.5 Historical unassisted pole failures.

Item	2003-04	2004-05	2005-06	2006-07
Pole population	587,967	595,928	596,770	612,638
Unassisted pole failures	12	11	8	12
Three-year rolling average	n/a	n/a	10	10

Source: ENERGEX, PB.EGX.VP.32, ENERGEX Network Management Plan 2008-09 to 2012-13, Page 13, 31 August 2008

The Queensland Government Code of Practice for Maintenance of Supporting Structures for Powerlines seeks as a prime objective a minimum three-year rolling average reliability against pole failure of 99.99% a year, provided that conditions do not exceed those likely to be experienced in service. This requirement is a generally accepted industry standard and ENERGEX's performance is well within this measure with the three-year rolling average of 0.002%. As an additional critical observation, there is no evidence the annual number of unassisted poles failures is increasing.

Table 6.6 displays the historical failure rate of poles inspected from 2005-06 to 2008-09. PB requested the data supplied excluded poles that were suitable for refurbishment (in the form of nailing), which resulted in an extension to their service life, or poles have not failed yet are replaced as part of an overall program of pole replacement. The average failure rate over the four-year period is 2.3%.

Table 6.6 Historical pole failure rate.

Item	2005-06	2006-07	2007-08	2008-09
No. of poles Inspected	115,111	117,990	119,120	128,513
No. of failed poles	2,728	2,132	3,202	3,008
Failure rate	2.4%	1.8%	2.7%	2.3%

Source: ENERGEX, PB.EGX.VP.47

Assuming a flat age profile, the average failure rate of 2.3% implies a wood pole service life of 1/0.023 = 43.5 years. When compared to the typical engineering life assigned to such assets of 40–50 years, this is a reasonable average service life for a pole population consisting of a mixture of natural round and treated poles.

6.2.3 Summary

PB considers that ENERGEX has documented and implemented well-established asset management and prudent risk management principles in formulating its current asset management practices. This should directly translate to the development of its opex forecasts. In particular, using the detailed, quantified, risk-based CBRM model to inform replacement and refurbishment capex and maintenance of plant is a leading edge practice in the Australian electricity distribution network industry. In adopting this approach ENERGEX appears to have appropriately tailored or adapted these principles to account for the age and condition of its assets, the degree of automation currently available, and the climatic conditions within which the assets operate.

ENERGEX, wherever possible, bases its maintenance decisions on asset condition, except for a proportion of low cost, high volume, run-to-failure (RTF) assets. This approach minimises unplanned asset failures, which minimises unplanned interruptions and consequently emergency response expenditures, while also improving network performance and customer satisfaction. PB considers this to be a prudent approach to distribution and sub-transmission asset management and ENERGEX appears to have deployed its condition-based risk management (CBRM) philosophy in a well-considered manner over the last two years.

PB acknowledges that ENERGEX can gain further improvements in asset management, particularly from a strategic level, by adopting an asset management framework such as PAS55[162], which defines asset management documentation, processes and communication paths. PB acknowledges that ENERGEX has already engaged EA Technology to assist in this process, including identifying and adopting a proved asset management methodology, such as reliability centred maintenance (RCM) or failure mode effects and criticality analysis (FMECA). However, PB believes these additional improvements would provide only incremental efficiency improvements, as the major gains over a time-based approach to asset management have already been achieved and hence are factored into the opex expenditure forecasts for the next regulatory control period.

PB considers the approach taken by ENERGEX in maintaining circuit breakers — a significant and important asset class — is transparent, comprehensive and in line with good electricity industry practice. The specific inspections, inspection triggers and cycles, maintenance and maintenance triggers and cycles are detailed in the SAMP. The SAMP also details the forms used to record the results of each inspection and maintenance operation.

PB considers the approach taken by ENERGEX in maintaining transformers and tap changers is transparent, comprehensive and in line with good electricity industry practice, the specific inspections, maintenance and maintenance triggers and cycles are detailed in the SAMP. The SAMP also details the forms used to record the results of each inspection and maintenance operation.

PB considers the approach taken by ENERGEX in inspecting and patrolling feeders is transparent, comprehensive and in line with good electricity industry practice, the specific inspections and patrols, inspection and patrol cycles, maintenance classifications rectification times are detailed in the MAMP.

The unassisted pole failure rate combined with the historical pole failure rate indicates that ENERGEX is managing its pole population in accordance with good electricity industry practice and in an efficient and prudent manner. This is evidenced by ENERGEX's 3-year rolling average unassisted pole failure rate being 20% better than that required by the Queensland Government *Code of Practice for Maintenance of Supporting Structures for Powerlines* as discussed in section 6.2.2. . In addition, the pole condemnation rate implies a satisfactory average wood pole service life.Given our discussions with ENERGEX asset managers, our review of the SAMP and the MAMP documents, our review of the EA Technology independent maintenance policy review (included as Appendix 12.1), and the written and verbal responses to our often detailed and specific questions relating to network performance and vegetation management, PB considers the forecast opex is based on prudent asset management principles, processes and procedures.

162 British Standards Institute, Publicly Available Specification (PAS) 55-1:2008, Specification for the optimised management of physical assets/

6.3 Forecasting methodology

Underpinning ENERGEX's opex forecasting methodology is a bottom-up estimate of future asset quantities based on existing quantities and those proposed as part of the capex programs. It has used its detailed asset management plans to determine the maintenance operations associated with each asset class and then used the actual unit costs to forecast future expenditures.

Importantly, ENERGEX has not adopted a forecasting approach that relies on top-down escalation models applied to an efficient base-year and hence PB's review has not focussed on establishing an efficient base year. Rather, PB focussed its review on the key assumptions made by ENERGEX under its forecasting methodology. In this respect, PB notes that where ENERGEX has based forecasts on historical expenditure trends, it has used periods extending back over the current regulatory period. In PB's view, this approach assists in incorporating the significant annual cost variations that occur in some opex activities. In addition, PB notes that corrective repair opex forecasts have been based on historical defect ratios (rather than expenditures) and hence are directly related to the quantity and type of asset inspections.

As discussed in section 12.5 of its submission, ENERGEX has used a two-part process to develop forecast opex for the next regulatory control period. This involved building up the opex work program using a bottom-up approach, and then assessing the resulting forecasts for relative efficiency using inter-business comparative benchmarking.

The first stage (bottom-up) opex program build included the following steps:

- prepare a network risk assessment to identify assets and services that require expenditure
- analyse the asset base to forecast asset quantities over the five-year period, taking into account the condition of the assets and the proposed growth and asset replacement capital works programs
- determine inspection and maintenance programs in accordance with the SAMP and MAMP
- forecast maintenance requirement using historical relationships between asset inspections and identified maintenance, historical failure rates and /or historical costs
- calculate and/or estimate unit costs, and incorporate real cost escalations as required
- align capital and operating programs of work (PoW) to ensure that the proposed works can be delivered
- identify opportunities for capital expenditure/operating expenditure trade-offs
- calculate the operating forecast expenditure for the regulatory control period.

In calculating the forecast opex, ENERGEX has used its normal business processes implicit in its Primavera scheduling and Ellipse programs to forecast opex costs and produce an achievable works program in conjunction with the proposed capital works programs. These systems implicitly incorporate the asset growth volumes related to the proposed growth capital works programs and the impact of the proposed asset replacement program within the opex forecasts as the volume of work is direct linked to asset quantities.

In determining the opex forecast, ENERGEX has used a combination of average unit costs in combination with the quantities that have been forecast (such as for inspections and planned/routine maintenance) or trended directly from historical costs where the quantities are not known (such as for emergency response). This latter approach is a less favourable one, but pragmatic as it does not decouple unit costs and quantities.

ENERGEX breaks each operational activity into network asset management program (NAMP) lines, with each line detailing individual programs within the activity. Where forecast asset quantities are used to develop the bottom-up estimate of costs, these annual quantities are incorporated into the opex modelling at the NAMP line level.

The methodology used to determine the maintenance unit costs employed by ENERGEX involved obtaining the end of year historical total costs booked to each NAMP line and also the quantity of units maintained. ENERGEX then reviewed this data to ensure that the cost and quantities align, to ensure there were no extraordinary issues during the period which could influence average cost calculations; such as significant changes in work practices, or a move to outsourcing. The total cost, including labour, material and contractor costs, but excluding any overheads, was then divided by the actual end of year unit numbers to determine the average cost. This methodology is a normal business process within ENERGEX and is carried out as part of the annual budgeting process. Hence it is documented in a BMS-controlled document[163].

A description of the forecast methodology used for each major cost category/activity adopted by ENERGEX is shown in Table 6.7.

Table 6.7 Opex cost category forecast methodology

Activity	Forecast methodology
Inspection	Forecast quantities at the NAMP line level, multiplied by average unit costs
Planned maintenance	Forecast quantities at the NAMP line level, multiplied by average unit costs
Corrective repair	Forecast based on historical costs
Network Operations	Forecasts based on historical quantities, multiplied by average unit costs
Emergency/ storms	Forecast based on historical costs
Vegetation	Forecasts based on vegetation management contracts
Metering	Forecasts are based on forecast quantities and units cost where available, otherwise historical expenditure
Customer services	Forecasts are based on forecast quantities and units cost where available, otherwise historical expenditure
DM initiatives	Individual projects

Source: PB analysis.

The second stage (benchmarking) part of the forecasting process included the following steps:

- compare forecast opex against industry benchmark

163 BMS 3177 Produce the OPEX Annual Plan and Five Year Deve.pdf

- determine the relative efficiency of the forecast opex
- investigate and justify any variance.

If the program fails to meet the objectives of Clause 6.5(a) of the NER, or does not satisfy the efficiency test or has unexplained variance it is resubmitted for a re-run of stage one of the process.

If the forecast opex is found to be relatively efficient with any variance justified, then the forecasts and non-system operating costs are submitted to the internal network technical committee (NTC) of the ENERGEX Board for endorsement, and ultimately to the ENERGEX Board for approval. Once approved by the board it is included in ENERGEX's Network Management Plan.

For the purposes of this second benchmarking stage of the forecasting process, ENERGEX has included information in its proposal[164] to support its contention that the forecast opex it proposed was efficient.

PB assessment and findings

Since ENERGEX has used a bottom up process to forecast its opex for the next regulatory control period, in order to review the prudence and efficiency of these forecasts PB has: reviewed the methodology and accuracy of the asset quantity forecasts; the cost efficiency of the unit costs; the defect ratios; and the methodology ENERGEX used to project historical expenditure trends.

PB also reviewed the compliance documents relating to the assumptions and calculations that support the development of the opex and capex programs of work which underpin the ENERGEX Regulatory Proposal.

ENERGEX has supplied an internal audit report dated 6 May 2006, and a report from an external auditor, NCS International, dated 24 July 2009, in respect of an audit in January 2009. PB has reviewed these documents and also discussed[165] the process used by the Performance Management Group, who internally reviewed the financial inputs into the program of work to provide assurances about the accuracy of the assumptions and the reasonableness of the calculations. The issues identified in the report by the Performance Management Group relate to automation of the process for developing estimates and entering them into the opex and C25 data bases. Although unrelated to the development of the programs of works, the report states that some costs are developed in real terms and others in nominal terms; the costs of the D & C projects in the C20 capex program could potentially be understated as ENERGEX has used internal costs plus contractor overheads to forecast project estimates; and the budgeted tax position and operating profit could be misstated. PB noted the findings of the internal audit but does not consider the issues identified placed the accuracy of the program of work at risk.

In conclusion, it is apparent that ENERGEX has used its normal business processes to develop its opex forecasts for the next regulatory control period. This approach not only provides opex forecasts but also produces a schedule of work aligned with available resources ensuring that the combined opex and capex program is in fact deliverable. In PB's

164 Based largely on the Wilson Cook & Co. revised benchmarking methodology used as part of its review on behalf of the AER of the ACT and NSW DNSP's.

165 Discussions were held with ENERGEX, AER and PB in Brisbane during weeks ending 17/7/2009 and 7/8/2009.

experience working with other DNSP's and TNSP's, the 'bottom-up' approach ENERGEX has used in developing its opex program of work is more accurate than ratio-type opex modelling, as calculating specific asset quantities based on the existing asset base and actual quantities identified from the augmentation and asset replacement programs will produce more accurate outcomes. PB has relied on the internal and external audits to verify the estimating process is sound and that the inputs used align with the information provided by the asset managers relating to quantities, average costs and defect ratio's and so on. As a result of our review, which included examining the documentation and discussing the process with ENERGEX staff, we believe the process is reliable and produces accurate forecasts.

PB also notes that the AER will require ENERGEX to re-run its normal business process opex modelling if any changes are recommended to the capex or opex programs, key inputs or real cost escalators in order to calculate the revised forecast opex over the next regulatory control period.

6.3.1 Workload estimation

The additional workload resulting from the commissioning of new growth assets during the next regulatory control period is implicitly incorporated into the ENERGEX opex modelling by using both the projected quantities of new assets and the appropriate maintenance cycles applicable to those assets that will be commissioned during the next regulatory control period. The method of calculating asset quantities varies depending of the type of asset. For example, the number of poles that need to be inspected each year to ensure all poles are inspected every five years will need to be adjusted to account for the number of new poles installed each year and the number of poles replaced each year, and also for the fact that new poles do not need to be inspected until the third five-year cycle after installation. Hence maintenance cycles also affect the number of assets requiring inspection annually.

For assets, such as transformers and circuit breakers, specific annual asset quantities are calculated based on existing quantities plus the additional assets commissioned as a result of the proposed growth and asset replacement programs. This data combined with the related inspection and maintenance programs as specified in the MAMP and SAMP enable the total opex workload associated with these assets to be calculated. This approach therefore implicitly includes the additional workload caused by the commissioning of new assets..

ENERGEX has divided its operating program of works into major cost categories called 'activities'. These activities align with the major cost categories detailed in the system operating forecasts and include inspections, planned maintenance, corrective repair and vegetation management. Each activity is further broken down into NAMP lines, with each line detailing individual programs within the activity. The impact of the proposed asset replacement programs are directly incorporated into the opex modelling at the NAMP line level, i.e. the unit quantity component used in developing metering opex estimates are the meter reads, and the unit quantity component for customer services related to call volumes. Table 6.8 shows the number of NAMP lines for each activity.

Table 6.8 NAMP lines for each activity.

Activity	NAMP lines
Inspection	32
Planned maintenance	49
Corrective repair	8
Network operations	10
Emergency/storms	2
Vegetation	6
Metering	N/A
Customer services	N/A
DM initiatives	10

Source: PB analysis.

The asset types have a direct relationship with forecast inspection quantities and planned maintenance as these are specified in the SAMP and the MAMP. These two documents define the inspection and maintenance periods or cycle times for each asset class based on statutory requirements, manufacturer's recommendations and ENERGEX's CBRM methodology. Typical examples of inspection and maintenance cycle times are the five-yearly pole inspection cycle, the annual power transformer dissolved gas analysis (DGA) oil testing program (or biennial depending on primary voltage), the 30 urban vegetation trimming cycles, the five-yearly tests of earth-mats at zone substations, the annual thermovision testing of zone substation connections, and the three-yearly inspection of disconnector links in zone substations.

Asset quantities also influence other opex cost categories, as historical defect ratios are used to forecast costs, such as planned maintenance.

PB assessment and findings

PB has reviewed the opex modelling by comparing the specific annual asset quantities used in the modelling, as presented in ENERGEX's document 'Distribution and Transmission Operating Programs 2006–2016', against the capital works programs, as detailed in the document 'Distribution Capital, Recoverable and Alternate Control Services 2006–2016'. PB's systematic review across the various asset classes and activities confirms these works programs are interrelated, with the asset quantities included in the opex programs reflecting the related capex programs.

In addition, during our meetings[166] with ENERGEX staff, PB reviewed a comprehensive sample of the individual NAMP line asset quantities and ENERGEX provided sufficient information for PB to confirm that the forecast asset quantities accurately reflect the current asset quantities and also the forecast additional asset quantities resulting from the proposed capex programs of work. ENERGEX also clearly demonstrated how the capex programs of work are reflected in the proposed NAMP line asset quantities.

Based on this review, PB has confirmed the forecast asset quantities ENERGEX has incorporated into its opex modelling are suitable for the purpose of forecasting expenditures. In addition, our review of the SAMP and MAMP confirms that specific inspection and

166 Meetings were held with ENERGEX, AER and PB in Brisbane during weeks ending 17/7/2009 and 7/8/2009

maintenance activities relating to specific assets are detailed, therefore enabling accurate work volumes to be forecast for the next regulatory control period.

6.3.2 Impact of input cost escalation

ENERGEX used its normal business operating systems (Oracle Primavera enterprise project portfolio management software) to develop its forecast opex for the next regulatory control period. To carry out a more targeted and transparent review of the proposed opex forecasts, PB requested ENERGEX develop an opex model in Microsoft Excel that would replicate the opex forecasts contained in its Regulatory Proposal so as to demonstrate the impact of the real labour and material escalators that had been incorporated. The spreadsheet model was checked by PB for reasonableness by running various scenarios, reviewing the outputs for correlation with the Regulatory Proposal, and by checking the outputs when various inputs (such as CPI) were modified.

PB mainly used this model to determine the base level of opex forecasts with the real cost escalators set to zero. This produced a version of the opex forecasts that were de-sensitised to cost escalation and showed more directly the need for opex as a result of the growth in asset volumes resulting from the corresponding capital works programs. Table 6.9 presents the contribution of real cost escalation on the total forecast system opex for the next regulatory control period.

Table 6.9 Base opex and the real annual cost escalation included in the forecast opex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Base system opex	289.2	287.3	288.8	292.3	282.3	1439.9
Real cost escalation	7.5	15.1	23.1	31.2	39.2	116.1
Total system opex	296.7	302.4	311.9	323.5	321.5	1556.0

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

This exercise indicated the impact of the real cost escalation ENERGEX had factored into the total opex forecasts for the next regulatory control period was $116.1m, or an uplift of 8.1% on the base system opex.

Figure 6.5 displays the real cost escalation included in each of the annual opex expenditure forecasts graphically.

Figure 6.5 Base opex and the real annual cost escalation included in the forecast opex for the next regulatory control period

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

Trends in each of the cost categories after removing real escalation over the outlook period are shown in Table 6.10 and graphically in Figure 6.6.

Table 6.10 Historical and forecast system opex – after real escalation has been backed out of the forecasts

	05-06	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14	14-15
Network operations	12.8	14.5	16.3	23.7	25.0	25.0	25.6	25.6	25.8	25.7
Inspection	12.0	15.8	15.8	19.4	18.6	18.7	19.7	20.8	20.9	21.8
Planned maintenance	32.5	59.1	59.4	73.2	65.6	64.4	61.9	62.0	61.9	61.4
Corrective repair	26.6	26.6	35.9	36.4	40.0	39.0	39.1	38.5	38.0	37.3
Vegetation	62.4	57.2	56.5	64.4	70.3	75.1	75.2	74.5	73.5	71.7
Emergency/ storms	10.8	4.1	4.8	20.3	8.2	8.4	8.5	8.4	8.4	8.3
Metering	15.7	14.6	14.9	13.6	15.9	14.2	14.4	14.7	14.9	15.1
Customer services	17.2	15.4	13.5	16.5	20.9	20.4	20.7	20.6	20.6	20.5
DM initiatives	2.2	3.5	4.4	9.4	39.4	24.0	22.2	23.7	28.3	20.5
Total system	192.2	210.8	221.5	276.9	303.9	289.2	287.3	288.8	292.3	282.3

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

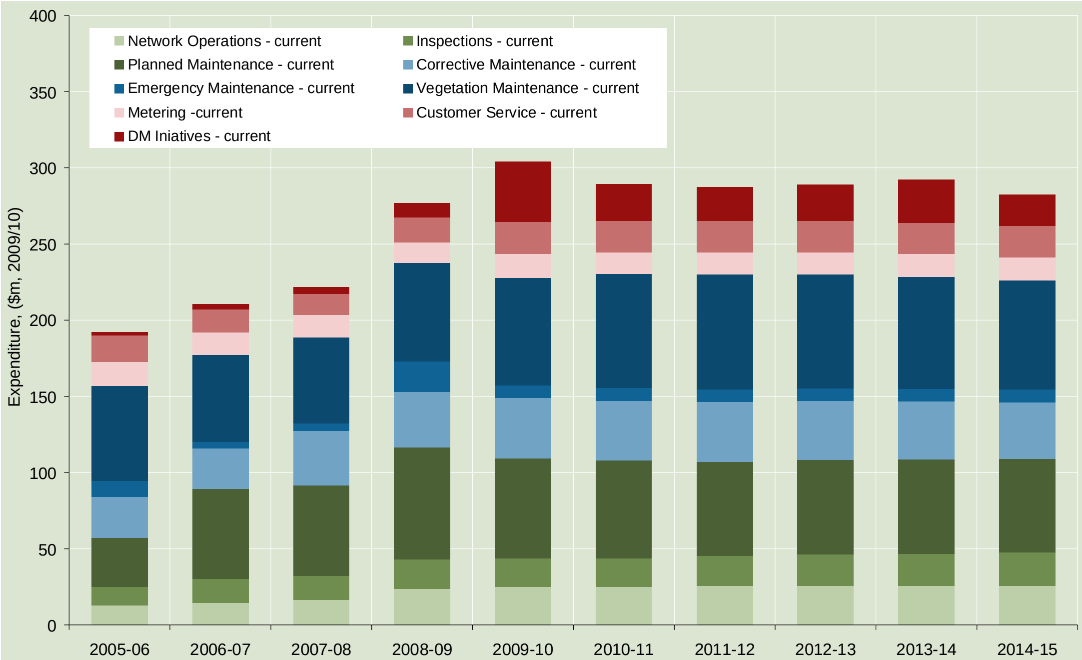

Figure 6.6 Historical and forecast system opex – after real escalation has been backed out of the forecasts

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

The analysis in Table 6.10 and Figure 6.6 shows that in all but two major opex cost categories there is no evidence of a material step change in the first year of forecast expenditures of the next regulatory control period compared with the final year of the current regulatory control period. The two categories where there is a notable step change in proposed opex, namely vegetation management and demand management initiatives, are examined in further detail in sections 6.8 and 6.12 of this report as part of PB's systematic review of the main cost categories.

PB relied on reviewing ENERGEX's audit processes and results to decide if the methodology ENERGEX used to apply opex cost escalators was valid, reasonable and suitable.

The methodology ENERGEX used essentially consisted of taking the base opex program of works operating forecasts, the system capex and non-system capex forecasts (each expressed in 2008-09 dollars) and checking that they were all divided into labour, materials, land/easements or contractor/construction categories as appropriate.

ENERGEX then used an Excel spreadsheet model to represent how it had applied the appropriate escalation rates to each cost category within its Primavera software process. The escalation rates recommended by KPMG were consistent over the regulatory control period. Deloittes undertook an independent review of the modelling.

PB found the MS Excel spreadsheet methodology used by ENERGEX to apply real escalation to the four cost components of labour and materials appropriate and straightforward. In relation to the auditing the process, PB notes that Deloittes has audited the methodology applied. Whilst PB requested a copy of the internal audit report conducted by Deloitte, it did not receive a copy to review. Hence, PB has relied on the Evans and Peck review of the ENERGEX submission to the AER for compliance with the NER[167]. This report finds the operating and maintenance forecast expenditures to be prudent and efficient and the review included an examination of the cost escalation process.

PB also reviewed and tested the MS Excel spreadsheet[168] developed by ENERGEX to show how it had applied its real input cost escalators. PB found the model confirmed that ENERGEX has correctly applied the real cost escalators in developing its opex forecasts.

6.3.3 Capex/opex trade-off

ENERGEX has directly incorporated the impact of the proposed asset replacement program into the opex forecasts at an asset category level. This has been accomplished by reducing the quantity of existing assets as they are replaced, and introducing additional assets as they are commissioned. This also influences the associated planned maintenance, as the new assets generally have different inspection and planned maintenance requirements compared with the older asset they are replacing.

ENERGEX has divided its opex work program into major cost categories called 'activities'. These activities align with the major cost categories detailed in the system operating forecasts and include inspections, maintenance, corrective repair and vegetation. Each activity is further broken down into NAMP lines, with each line detailing individual programs within the activity. The impact of the proposed asset replacement programs are incorporated into the opex modelling at the NAMP line level.

Specific examples of the impacts of the asset replacement program are as follows:

- tap changers – new units are vacuum and require less maintenance than oil insulated tap changers. ENERGEX proposes to replace 14 tap changers per annum due to network growth and a further 11 will be replaced under asset refurbishment programs.
- circuit breakers – asset refurbishment will result in lower maintenance requirements. ENERGEX has forecast a total of 370 circuit breakers will be replaced over a ten year period hence on average 37 are forecast to be replaced each year of the next regulatory control period.
- AFLC equipment - Asset refurbishment will result in less maintenance requirements. ENERGEX has forecast 1 AFLC unit to be replaced per annum over the next regulatory control period and acknowledges that the newer replacement electronic units are unlikely to require maintenance over the next regulatory control period
- cross arms – CBRM utilised to forecast cross arm numbers. ENERGEX has forecast 5,300 11kV cross arms to be replaced per annum over the next regulatory control period. 4,000 replaced as part of opex programs and a further 1,300 as part of end of life renewal projects
- pole hardware and access – reduced based on feeder refurbishment programs. ENERGEX bases maintenance on identified defects but last financial year 1,153 pole hardware and access maintenance tasks were completed
- maintain ground plant – reduced quantities based on replacement of end of life RMU's

167 Evans & Peck ENERGEX Review of 2010/11 to 2014/15 Submission to the Australian Energy Regulator for Compliance with the National Electricity Rules June 2009

168 Refer to section 6.3.3 of this report for further discussion

- maintain OH Services – reduced quantities of clamp replacements due to feeder refurbishment program. Each year of the next regulatory control period ENERGEX proposes to replace 112 km of LV mains with LV aerial bundled conductor (ABC) and in conjunction with this work, affected customers services and associated clamps are replaced. Based on an average span, each km of ABC replaced will result in the removal and replacement of 150 clamps, equivalent to 16,800 clamps for the 112km ABC replacement program

- OH earthing maintenance – reduced quantities at towers due to OPGW replacements.

PB assessment and findings

PB considers the approach of incorporating the impact of the proposed asset replacement programs at the NAMP line level to be an accurate methodology. It is likely to provide a more accurate result than the often applied financial modelling technique, which applies ratios to reduce the opex costs in proportion to the quantum of the proposed opex replacement relative to the current replacement cost of the existing asset base.

PB discussed with ENERGEX the relationship between the C20 and C25 capex programs of work and the forecast asset quantities[169]. The correlation between the capex programs of work and the forecast asset quantities was further reviewed and confirmed in written correspondence[170] between PB and ENERGEX. Based on this review, ENERGEX provided sufficient information for PB to confirm that the asset quantities on which the opex forecasts are based do accurately reflect the proposed capex programs of work.

It is PB's view that the opex forecasts inherently include the opex / capex trade off and that the approach adopted by ENERGEX has accurately and explicitly quantified the reduction in opex associated with the proposed asset replacement and refurbishment program of works.

6.3.4 Summary of findings and recommendations on forecasting methodology

PB found the forecasting methodology ENERGEX used to determine the opex forecasts for the next regulatory control period results in reasonable and accurate forecasts. This is based on the fact that ENERGEX used a bottom-up forecasting methodology for most expenditure categories, based on historical quantities adjusted to reflect the proposed capex programs. In addition, average unit costs were calculated based on historical costs and were reviewed to ensure the total costs aligned with the reported number of units maintained. Where ENERGEX has used historical expenditure trends to forecast future opex spends, the trends have been analysed over sufficient periods to counter the impacts of annual variability, such as how changing weather patterns affect emergency response expenditures.

PB has also reviewed the methodology ENERGEX used to escalate the opex forecasts for real increases in labour, material and services. We found the spreadsheet process to be appropriate and straightforward.

169 Meetings were held with ENERGEX, AER and PB in Brisbane during weeks ending 17/7/2009 and 7/8/2009.

170 PB maintained an Issues Register to record details of all questions posed to ENERGEX and the responses received.

6.4 Network operations opex

The most significant programs in the network operations activity are control centre operations, loss of supply, cold water and meter queries, network operations and works related to the operating project. Other minor programs included in this activity are the balancing of LV circuits, GSL payments, and voltage investigation.

6.4.1 Proposed expenditure

The proposed expenditure for network operating costs as presented in the ENERGEX Regulatory Proposal is shown in Table 6.11.

Table 6.11 Proposed opex for network operations

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	25.54	26.79	27.43	28.30	28.91	136.97
ENERGEX proposal – no escalation	24.96	25.58	25.59	25.79	25.72	127.64

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

6.4.2 PB assessment and findings

PB's top-down analysis of this activity involved backing out the real cost escalators from the estimates for the next regulatory control period and comparing them to the current period. PB found that the forecast activity expenditure in the final year of the current regulatory control period is very similar in real terms to the forecast network operations expenditure in 2011-12, namely $25m.

This indicates a business-as-usual expenditure pattern from 2008-09 onwards. PB notes that expenditures were forecast using historical quantities and average unit costs for the 2008-09 financial year.

6.4.3 PB recommendations

Given the business-as-usual trend and the detailed bottom-up approach ENERGEX used when forecasting capex for the next regulatory control period, PB considers the forecasts to be prudent and efficient.

PB recommends that the proposed opex for network operations is accepted with no changes, as set out in Table 6.12.

Table 6.12 Recommended opex for network operations

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	25.54	26.79	27.43	28.30	28.91	136.97
PB adjustment	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	25.54	26.79	27.43	28.30	28.91	136.97

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

6.5 Inspections opex

There are 32 NAMP lines in the inspection activity. The most significant programs are maximum demand indicators for distribution transformers, routine inspections of pole bases, diagnostic testing, pre-storm season feeder patrols and oil analysis/condition assessment, which account for approximately 65% of the activities costs. The remainder of the programs relate to 11, 33 and 132 kV feeder inspections and patrols, thermovision inspections of lines and substations, switchgear inspections and substation inspections.

6.5.1 Proposed expenditure

The proposed expenditure for inspections as presented in the ENERGEX Regulatory Proposal is shown in Table 6.13.

Table 6.13 Proposed opex for inspections

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	19.23	20.81	22.51	23.26	24.99	110.80
ENERGEX proposal – no escalation	18.72	19.72	20.77	20.90	21.84	101.95

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

6.5.2 PB assessment and findings

PB's analysis of this activity included backing out the real cost escalators for the forecast expenditures for next regulatory control period and comparing them to the current expenditures. PB has also reviewed the bottom-up process used to determine the forecast for this activity for the next regulatory control period.

The top-down review indicated a business-as-usual expenditure pattern from 2008-09 onwards with the forecast expenditure in the final year of the current regulatory period of $18.6m comparing to a forecast of $18.7m in real terms in 2010-11. The bottom-up review concentrated on the inspection quantities included in the opex modelling. PB noted a 16.5% increase in real terms in annual forecasts for inspections over the next regulatory control period. ENERGEX has advised this increase is because of the increase in the number of assets under management owing to the proposed capital works programs and a number of additional proposed inspections as follows:

- compliance-driven program to test substation earth mats on a five-year cyclic program (this program is detailed in the SAMP but not currently carried out)
- an extension of the thermoscan inspection program to LV switchboards based on increased failure rates
- renewed focus on testing protection equipment to achieve compliance
- increased inspection of LV pillars
- additional diagnostic sampling, testing and analysis to provide essential input into the CBRM modelling.

PB discussed each of these proposed additional inspection programs with ENERGEX who provided sufficient information to justify them. Two of the programs are linked to compliance issues, and hence are considered mandatory, while the remainder of the inspection programs have been included because the introduction of the CBRM program has identified assets where: additional inspections (such as thermoscanning) would identify assets prior to defects resulting in asset failure; and assets that may pose significant risks to the public (such as the high resistance neutral connections in LV pillars).

Based on our review, PB considers the proposed inspections are prudent and that the forecast expenditures are efficient.

6.5.3 PB recommendations

PB recommends the proposed opex for inspections is accepted with no changes, as set out in Table 6.14.

Table 6.14 Recommended opex for inspections

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	19.23	20.81	22.51	23.26	24.99	110.80
PB adjustment	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	19.23	20.81	22.51	23.26	24.99	110.80

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

6.6 Planned maintenance opex

The planned maintenance activity contains 49 NAMP lines. The important programs in this activity are to replace 11 kV cross arms, replace LV cross arms and maintain hardware and poles, 11 kV substation maintenance, 132/110 kV tower maintenance and maintain overhead services account for 25% of the forecast expenditure. Other less significant programs include maintaining UG pits and cables, 132/110 kV maintenance of insulators and hardware and transformer maintenance.

6.6.1 Proposed expenditure

The proposed expenditure for planned maintenance as presented in the ENERGEX Regulatory Proposal is shown in Table 6.15.

Table 6.15 Proposed opex for planned maintenance

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	66.01	65.03	66.87	68.47	69.59	335.97
ENERGEX proposal – no escalation	64.38	61.86	62.04	61.94	61.38	311.60

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

6.6.2 PB assessment and findings

PB's top-down analysis of this activity involved backing out the real cost escalators from the estimates for the next regulatory control period and comparing the resulting expenditures with those for the current period.

ENERGEX commenced a CBRM approach to asset management in 2007 and hence PB has compared the average annual planned maintenance opex since 2007 to the average annual planned maintenance forecast for the next regulatory control period. This analysis reveals that the average spend in the last three years of the current regulatory control period is $66.07m compared to an average forecast spend in the next period of $62.32m (prior to escalation). This is a reduction of 5.7% in average planned maintenance annual expenditures.

PB reviewed reasons for this expenditure pattern and ENERGEX advised that the expenditures for this activity were forecast using a combination of forecast maintenance based on the SAMP and MAMP, historical defect ratios associated with the quantity of forecast inspections and average unit costs for the 2008-09 financial year. The expenditure pattern is an outcome of the forecasting methodology ENERGEX has used to develop the forecasts. PB has reviewed the forecasting methodology in depth. Based on this review, PB considers the forecast to be based on prudent asset maintenance principles and the resultant activity opex forecasts are considered cost efficient.

In addition, the reducing expenditure trend in planned maintenance is indicative of a business that has adopted a condition based risk management approach to asset management, as evidenced by recent PB experience in undertaking regulatory proposal reviews of TNSPs such as Powerlink. This approach to asset management concentrates on inspection and testing and results in reduced planned maintenance expenditures. PB considers this to be further evidence that ENERGEX has adopted prudent and efficient asset management practices.

6.6.3 PB recommendations

Given the detailed nature of the forecasting methodology used by ENERGEX and the overall reduction in proposed expenditure found through the top-down analysis, PB recommends the proposed opex for planned maintenance is accepted with no changes, as set out in Table 6.16.

Table 6.16 Recommended opex for planned maintenance

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	66.01	65.03	66.87	68.47	69.59	335.97
PB adjustment	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	66.01	65.03	66.87	68.47	69.59	335.97

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

6.7 Corrective repair opex

The four programs in corrective repair are corrective maintenance LV, corrective maintenance 11 kV overhead, corrective maintenance 11 kV underground, and corrective maintenance to zone substation and relay operations. These four programs constitute approximately 94% of the total corrective maintenance expenditure.

6.7.1 Proposed expenditure

The proposed expenditure for corrective repairs as presented in the ENERGEX Regulatory Proposal is shown in Table 6.17.

Table 6.17 Proposed opex for corrective repairs

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	39.95	41.08	41.41	41.88	42.11	206.43
ENERGEX proposal – no escalation	38.99	39.15	38.51	38.01	37.30	191.96

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

6.7.2 PB assessment and findings

PB's top-down analysis of this activity involved backing out the real cost escalators from the estimates for the next regulatory control period and comparing the resulting expenditures with those for the current period. PB notes that the forecast expenditure for this activity in the final year of the current regulatory period is $40.0 compared to $39.0m in real terms in 2010-11. PB's review confirmed that the expenditures for this activity were forecast using historical expenditures and that ENERGEX has advised that the small reduction in real terms (i.e. before real cost escalators being applied) in forecast expenditures over the next regulatory control period of approximately $1.7m has been factored in to account for the further deployment of CBRM on asset replacement. That is, more of the assets with a higher risk of failure are scheduled for replacement over the same period.

The reducing expenditure trend in corrective repairs and planned maintenance is indicative of a business that has adopted a condition based risk management approach to asset management. Specifically, this approach to asset management results in additional inspections but these are accompanied by reduced opex costs in the longer term, associated with planned maintenance, corrective maintenance and emergency response.

It should be noted that due to the forecasting methodology used by ENERGEX, all forecast opex costs directly include the impact of the proposed growth capex program and the proposed asset replacement capex program. This is because the asset quantities which underpin the opex forecasts incorporate changes resulting from both of these capex programs. Given the forecasting approach adopted by ENERGEX, it is not possible to further examine the exact impact of either capex program as this would require remodelling all the opex forecasts with the assets quantities of each program backed out of the calculations. Hence further assessment of the real reduction of $1.7m over the next regulatory control period was not able to be undertaken.

In respect of comparing the forecast corrective repair expenditures to the historical expenditures in the current period, PB notes a further complication as stated in the Regulatory Proposal that the increase from 2007-08 "*represents a refinement of internal policy to collate costs previously allocated to storms and emergency to corrective repair* "[171].

Despite these review limitations, PB has formed the view that the proposed expenditures are based on sound forecasts that take into account the capex works program, and are therefore prudent and efficient.

6.7.3 PB recommendations

Based on this analysis, PB recommends the proposed opex for corrective repairs is accepted with no changes, as set out in Table 6.18.

Table 6.18 Proposed opex for corrective repairs

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	39.95	41.08	41.41	41.88	42.11	206.43
PB adjustment	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	39.95	41.08	41.41	41.88	42.11	206.43

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

6.8 Vegetation opex

The vegetation activity consists of 6 NAMP line programs. They are 132/110 kV feeder transmission, 11 kV sector-based distribution, 33 kV vegetation reliability improvement, 11 kV vegetation reliability improvement, LV customer requested and vegetation tree replacement.

6.8.1 Proposed expenditure

The proposed expenditure for vegetation management as presented in the ENERGEX Regulatory Proposal is shown in Table 6.19. The majority of the proposed expenditure is in the 11 kV sector-based programs that account for approximately 78% of the total forecast expenditures.

171 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015, p.*187

Table 6.19 Proposed opex for vegetation

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	77.21	79.52	81.10	82.21	82.53	402.57
ENERGEX proposal – no escalation	75.06	75.18	74.55	73.47	71.69	369.95

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

6.8.2 PB assessment and findings

Vegetation expenditures represent a considerable proportion of total opex and PB carried out an in-depth review of this activity. Our review included discussions with ENERGEX[172] and written requests for additional information.

PB noted a step increase in annual expenditures from 2007-08 to 2008-09 and to a lesser extent in 2009-10. The reason for this additional expenditure was due to the reduction in trimming cycles from 2.5 years in urban areas to 30 months for HV mains and 30 months LV spurs following a return to normal rainfall patterns in 2008. These rainfall patterns resulted in additional vegetation re-growth posing additional risks to the public and poor network reliability performance. ENERGEX introduced these reduced trimming cycles as a result of the EDSD review and to meet legislative compliance. PB is aware that the maintenance of vegetation clearance envelopes around HV and LV mains is a statutory requirement.

PB has also noted a $4.8m step change (in real terms before real labour and material escalators being applied) between the last year of the current regulatory control period and the first year of the next period. PB notes that the forecast expenditure for this activity in the final year of the current regulatory period is $70.3m compared to $75.1m in real terms in 2010-11. ENERGEX advised that the main reason for the additional expenditure related to the proposed introduction of reduced trimming cycles on low voltage (LV) urban lines.

ENERGEX advised that it proposes to reduce the trimming cycle for LV spur lines from the current 30 month cycle to a 15 month cycle. This will align all trimming cycles in urban areas to 15 months. The reduction in cycle times has been proposed as a return to normal rainfall patterns has resulted in trees growing into the LV clearance zones between trimming cycles. This has resulted in ENERGEX receiving improvement notice obligations from the technical regulator, the ESO, to maintain statutory clearances. Hence, this additional LV spur trimming is also considered to be a statutory requirement.

ENERGEX also advised that the additional trimming of the LV spur lines represented a step increase in the volume of work, represented as an increase in route length of 2,875 km a year. The cost to trim these spurs, based on the 2007-08 rates applicable and adjusted to reflect the cost allocation method approved by the AER for the next regulatory control period, is on average $10.95m a year. The step change is significantly smaller than the step change evident in the opex modelling because the LV spurs would be trimmed in conjunction with the HV and LV lines on each cycle and hence the contractors would be able to achieve economies of scale.

ENERGEX's contract management group have estimated that including an additional 2,875 km of trimming into the existing 13,000 km program will result in a 6% reduction in

172 Meetings were held with ENERGEX, AER and PB in Brisbane during weeks ending 17/7/2009 and 7/8/2009

trimming rates, which will reduce the additional costs for trimming the LV spurs to approximately $4.8m (2009-10) in real terms, i.e. excluding real cost increases.

PB also notes that all vegetation management is undertaken by contractors, which is subject to competitive open tendering arrangements, and that there appears to be sufficient competition to ensure that the tender costs represent current market costs and are hence efficient.

Additionally, ENERGEX provided a copy of the Evans & Peck review of the ENERGEX submission for compliance with the NER, which specifically reviewed ENERGEX's forecast vegetation opex. Evans & Peck states in relation to ENERGEX's forecast vegetation opex *"our analysis has not found deficiencies in ENERGEX's approach, and we therefore conclude that the levels proposed are prudent"*.

6.8.3 PB recommendations

As it is required for statutory compliance, PB considers the inclusion of this additional expenditure in the opex allowance for the next regulatory control period is based on a reasonable and prudent need. Hence, PB recommends the proposed opex for vegetation is accepted with no changes, as set out in Table 6.20.

Table 6.20 Recommended opex for vegetation

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	77.21	79.52	81.10	82.21	82.53	402.57
PB adjustment	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	77.21	79.52	81.10	82.21	82.53	402.57

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

6.9 Emergency response/storms opex

The emergency response/storms activity consists of two programs. They are emergency response and storms/emergency response.

6.9.1 Proposed expenditure

The proposed expenditure for emergency response/storms as presented in the ENERGEX Regulatory Proposal is shown in Table 6.21. The majority of the expenditure is related to emergency response associated with storms, which accounts for 92% of the emergency response expenditure proposed.

Table 6.21 Proposed opex for emergency response/storms

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	8.56	8.91	9.07	9.27	9.43	45.24
ENERGEX proposal – no escalation	8.35	8.47	8.41	8.38	8.31	41.92

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

6.9.2 PB assessment and findings

PB is aware that annual expenditures for this type of activity are variable as typically they are subject to the influence of external factors such as weather and storm activity. This is evident in the expenditure patterns in the current regulatory control period where the 2008-09 year shows very high levels of expenditure due to storm activity.

PB's top-down analysis of this activity involved backing out the real cost escalators from the estimates for the next regulatory control period and comparing the resulting expenditures to those in the current period. PB notes that the forecast expenditure for this activity in the final year of the current regulatory period is $8.2 m compared to $8.4m in real terms in 2010-11.

When asked how the forecasts were formulated, ENERGEX responded "Any forecast of storm/emergency events is also notably sensitive to severity. For 2008/09, a single storm accounted for expenditure in the order of $12.5m. The storm/emergency event forecast for the regulatory period (approx $8m pa) is based on an average over 8 years with no allowance for increased exposure through network growth."

PB also notes the reasonably constant forecast expenditure over the next regulatory control period in this category. This has to be considered in conjunction with the material increase in assets under management resulting from the proposed growth related capital program of works. Offsetting these potential additional emergency response costs associated with the commissioning of $5.9b of growth assets are the benefits associated with the reduced tree trimming cycles. PB is aware that the maintenance of statutory clearance envelopes has limited impacts once wind velocities reach those typical of severe storms, where they are capable of either moving tree limbs into the clearance zones and into contact with live mains, or blowing limbs off branches causing conductor clashes.

In view of the forecasting methodology adopted by ENERGEX and the fact that ENERGEX has maintained relatively constant emergency response expenditure forecasts over the next regulatory control period, PB considers the emergency response forecasts is prudent and efficient.

6.9.3 PB recommendations

Based on this analysis, PB recommends the proposed opex for emergency response/storms is accepted with no changes, as set out in Table 6.22.

Table 6.22 Recommended opex for emergency response / storms

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	8.56	8.91	9.07	9.27	9.43	45.24
PB adjustment	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	8.56	8.91	9.07	9.27	9.43	45.24

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

6.10 Meter reading opex

As part of its *standard control services,* ENERGEX reads meters, processes the associated metering data and undertakes network billing for more than 1.3 million residential and small to medium business customers with metered connections to the network.

The forecast opex incorporates the following metering activities:

Meter reading – includes physical visits to customer premises every three months in most cases and monthly for high usage customers.

Data processing and warehousing – involves the collection of interval data for type 1-4 and 5-7 customers and the conversion of data to consumption reads for network billing. Consumption data collected from the meter reads is uploaded, validated and published to retailers and the market in accordance with NEMMCO requirements.

Network billing – the Network Billing group within ENERGEX uses validated meter and consumption data to generate invoices against National Metering Identifiers, providing a monthly statement to retailers.

6.10.1 Proposed expenditure

The proposed expenditure for meter reading as presented in the ENERGEX Regulatory Proposal is shown in Table 6.23.

Table 6.23 Proposed opex for meter reading

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	14.61	15.19	15.81	16.45	17.13	79.19
ENERGEX proposal – no escalation	14.25	14.45	14.65	14.86	15.08	73.29

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

6.10.2 PB assessment and findings

PB's top-down analysis of this activity involved backing out the real cost escalators from the estimates for the next regulatory control period and comparing the resulting expenditures to those in the current period. PB notes that the forecast expenditure for this activity in the final year of the current regulatory period is $15.9 m compared to $14.2m in real terms in 2010-

11. This indicated the annual real forecasts before application of the real cost escalators is slightly lower on average in the next period compared to the current period.

PB also notes the largest component of costs for reading meters are meter reading activities, which are subject to a periodic open tendering process to ensure current market costs and service levels are maintained. The meter reading tender to start in 2010-11 has at this time not been finalised and expenditure is expected to increase from the end of the current regulatory control period to 2010-11. The meter reading forecast is based on forecast customer numbers, which explains the increasing expenditure trend over the next regulatory control period. As the majority of meter reading costs are subject to an open tendering process and ENERGEX has provided sufficient details for PB to form a view that there are sufficient contractors to ensure a competitive tendering process, PB considers that the tendered prices reflect current market conditions and prices.

Costs associated with *alternative control services*, including other non-cyclic meter reads, relate to fee-based services that are covered in Chapter 22 of ENERGEX's Revenue Proposal.

6.10.3 PB recommendations

Based on our review, PB recommends that the proposed opex for meter reading is accepted with no change, as set out in Table 6.24.

Table 6.24 Recommended opex for meter reading

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	14.61	15.19	15.81	16.45	17.13	79.19
PB adjustment	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	14.61	15.19	15.81	16.45	17.13	79.19

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

6.11 Customer service opex

The customer service category of ENERGEX's forecast opex includes the provision of customer services directly related to the planning, management and operation of the distribution network. It includes ENERGEX's Network Contact Centre, as well as customer initiated activities classified as *standard control services*. Descriptions of the activities are set out below.

Network Contact Centre – provides services to customers, contractors, retailers and other bodies on distribution-related enquiries and storm and major event responses, manages the administration of GSLs, provides telephone services to other parts of the business and manages customer compliments and complaints. The Network Contact Centre maintains three separate telephone numbers for customers to maximise service quality and provide effective communication to incoming callers. They are a general enquiries line for calls, such as metering, service order status, and new connections. A Loss of Supply (LOS) line supplies a 24-hour service covering calls about customers' loss of supply. It is also a 24-hour emergency line for emergency and life-threatening calls, such as electric shock and fallen power lines, and quality of supply issues, such as dim/flickering lights. In the year to 30

March 2009, ENERGEX's Network Contact Centre received more than 729,000 calls. The majority of telephone calls (48%) were received on the LOS line. The general enquiries line handled 36% and the emergency line 5%.

Other customer services – ENERGEX provides services that are initiated by customers and include loss of hot water supply and meter queries.

6.11.1 Proposed expenditure

The proposed expenditure for customer service as presented in the ENERGEX Regulatory Proposal is shown in Table 6.25.

Table 6.25 Proposed opex for customer service

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	21.01	21.85	22.42	23.05	23.61	111.94
ENERGEX proposal – no escalation	20.42	20.66	20.60	20.60	20.50	102.78

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

6.11.2 PB assessment and findings

The costs for customer service in the current period shows a step change in 2008-09 and a further step change in 2009-10, which are due to the fact that ENERGEX established a Network Contact Centre after the ENERGEX retail electricity and gas business was sold. The retail contact centre supplied these services to the network business prior to the sale, so after the expiry of the transition arrangements, ENERGEX had to develop and commission a Customer Management System (CMS), an Interactive Voice Response (IVR) and a call centre telephony system suitable for its needs going forward. The Network Contact Centre accounts for the majority of costs in customer service activities, and has operated since April 2008, after the completion of transition arrangements associated with the sale.

PB therefore considers the 2009-10 financial year costs are representative of the full costs associated with the customer services activity. PB's top-down analysis of this activity involved backing out the real cost escalators from the estimates for the next regulatory control period and comparing the resulting expenditures with those in the current period. PB notes that the forecast expenditure for this activity in the final year of the current regulatory period is $20.9 m compared to $20.4m in real terms in 2010-11. This analysis indicates that the annual forecasts before application of the real cost escalators aligns with the 2009-10 financial year costs and also remain constant throughout the next regulatory control period.

Based on this analysis, and the fact that ENERGEX has not increased its forecasts based on increasing customer numbers, PB has not recommended any adjustment to the forecast customer service expenditure estimates.

6.11.3 PB recommendations

PB recommends the proposed opex for customer service is accepted with no change, as set out in Table 6.27.

Table 6.26 Recommended opex for customer service

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	21.01	21.85	22.42	23.05	23.61	111.94
PB adjustment	0.00	0.00	0.00	0.00	0.00	0.00
PB recommendation	21.01	21.85	22.42	23.05	23.61	111.94

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

6.12 Demand management initiatives opex

ENERGEX's stated goal is to improve the balance between supply side management, involving building capacity to meet demand, and demand-side solutions that focus on reducing demand. ENERGEX has included a number of demand management (DM) programs during the next regulatory control period with the overall aim of reducing the overall system demand by approximately 144 MW. This proposed reduction in demand has been factored into the proposed capital works program.

6.12.1 Proposed expenditure

The proposed expenditure for demand management as presented in the ENERGEX Regulatory Proposal is shown in Table 6.27.

Table 6.27 Proposed opex for demand management initiatives

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	24.60	23.23	25.28	30.58	23.18	126.87
ENERGEX proposal – no escalation	24.05	22.24	23.67	28.32	20.50	118.78

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex

6.12.2 PB assessment and findings

Each of the DM programs proposed by ENERGEX has been supported by a preliminary business case, including cost-benefit analyses. Table 6.28 details each of the proposed DM programs in the ENERGEX proposal, including the forecast impact on peak demand, the forecast capital savings assuming they are only realised in 2020 (for generation, transmission and distribution deferrals), the initiative costs to 2015 and the relevant NAMP line applicable to each program.

Table 6.28 Proposed demand management programs.

DSM Programs	Peak reduction 2015 (MW)	Capital savings by 2020 ($m)	Cost to 2015 ($m)	NPV benefit to 2020 ($m)	NAMP Line
Air conditioning DLC	30	89	20	11	DM05
Pool filtration DLC	10	29	4	9	DM05
Conversion of HWS tariffs	7	21	5	7	DM06
Hot water optimisation	4	12	2	5	DM06
Reward-based tariffs	0	0	5	39	DM07
Centre of excellence	2	6	6	0	DM03
C & I demand management	77	231	35	86	DM08
Energy conservation communities	15	45	13	14	DM09
Demand and energy data capture and analysis	0	0	2	-1	DM10
Total	145	433	92	-	-

Source: ENERGEX , PB.EGX.VP.51

A brief description of each project is as follows:

Air conditioning DLC - Domestic and commercial air conditioning is a major contributor to peak demand. ENERGEX is running Cool Change trials in the northern suburbs of Brisbane from December that will continue to 2011 and involve more than 2000 residential volunteers. Cool Change is a technique that cycles the air-conditioning compressor while minimising any effect on customer comfort. Results demonstrate a capability to reduce peak demand by 17% without affecting customer comfort. The next phase of the program will involve distributing the technique of air-conditioning compressor 'cycling' more widely across south-east Queensland.

Pool filtration DLC - The Queensland government's Household Survey 2007 indicates that 24% of SEQ households have a swimming pool. Energy consultant Charles River Associates (CRA) estimates that pool pumps contribute to ENERGEX's system peak demand and confirms that there is benefit in shifting pool pumps from peak use time. In addition to continuing to offer and promote a better rate for electricity used by pool pumps at non-peak times through tariff 33, ENERGEX will be running further trials in 2009 to benefit from what was learnt from the Cool Change air-conditioning trials. The pool pump trial will use a new generation of audio frequency load control technology similar to that employed in the Cool Change air-conditioning trials. More than 500 households have already subscribed. The next phase of the program will involve spreading the program more widely across south-east Queensland.

Conversion of hot water service tariffs - ENERGEX will run a campaign across south-east Queensland to offer an incentive to householders to convert from a continuous supply tariff (tariff 11) to a cheaper off-peak tariff that provides supply for a minimum of eight hours a day (tariff 31) or 18 hours a day (tariff 33).

Hot water optimisation - ENERGEX's hot water load control system was developed at a time when the network was at a winter peak. With the advent of a summer peak, there is an opportunity to review and find the best switching times to identify and ensure network benefits while maintaining customer satisfaction. ENERGEX will analyse the optimum number of hours in a day for switching hot water loads to off-peak. Under the existing tariff arrangements, electricity supply is made available for a minimum of eight hours per day on tariff 31 and 18 hours per day on tariff 33. Preliminary analysis suggests that optimisation of the existing hot water switching program (through the optimisation of the hours of supply) may increase the load under control over the peak periods.

Reward-based tariffs - ENERGEX is committed to tariff reform as a means of encouraging more efficient use of the network as customers switch non-essential electricity use to off-peak periods, reducing peak demand and ultimately reducing capital expenditures. This project will run pricing trials and identify the benefits from Time of Use and Dynamic Pricing tariffs. In addition to research and analysis of load limiter technology (a device used to limit the maximum demand per household), these trials will help to understand customer acceptance and behavior towards tariffs of this nature and develop ENERGEX's understanding of the effectiveness of such tariffs.

Centre of excellence - To provide a single authoritative reference point for DM and energy conservation (energy efficiency), ENERGEX will work with the Queensland Government and leading electricity industry bodies to establish a Centre of Excellence (Centre). The rationale for the Centre is to:

- facilitate customer confidence in adopting DM initiatives through credible information
- consolidate DM information and advice
- address the 'lack of public information', which is often referred to as a barrier that prevents customers from implementing DM initiatives
- provide a single reference point for consistent data and advice for Queensland.

C & I demand management - This initiative will use the willingness of SME and C&I customers to participate in DM solutions and will initially focus on industry segments, such as refrigeration, hospitals, food manufacturing plants and so on, through a targeted, broad-based campaign. The technology solutions may include distributed generation, load control and shifting, improving building energy management systems, power factor correction, fuel substitution and improving energy conservation through an appropriate commercial delivery model.

Energy conservation communities - In addition to the residential and C&I DM programs described above, it is acknowledged that there are a range of other products that may be deployed in a community-based campaign. These may use community-based social marketing for changing to compact fluorescent lights, fuel substitution, home energy assessments and buy-back programs for second fridges. This initiative involves establishing energy conservation communities, enabling the deployment of residential and C&I energy conservation and DM policy initiatives in focused community areas, working with leading community stakeholders and varying in accordance with the particular demographics and characteristics of each community.

Demand and energy data capture and analysis - Improved energy demand and consumption data is essential for understanding changing customer energy needs and usage behavior. It also leads to the development of sound DM policy and allows the accurate modeling of DM potential initiatives. The data collected as part of this project will allow analysis by industry segments, socioeconomic groups, climatic region, building/residence types and feeder categories, and will be used to develop future DM programs and strategies.

PB has reviewed each of these programs, with specific attention to the NPV analysis for each program. PB has noted that in each NPV analysis the benefits attributable to each program have been factored into the analysis in the 2019/20 financial year and the discount factor used was 7.5%, hence producing conservative outcomes.

For clarity, all the DM proposed expenditures, including the capex components, are reviewed in this section of the report.

To test the sensitivity to input assumptions, PB requested ENERGEX to rework the NPV calculations by only including the distribution capex deferral benefits. ENERGEX has responded to this request as follows:

> "ENERGEX believes that any assessment of its demand management program should be consistent with the assessment included in the Regulatory Test under the National Electricity Rules, and as such consider market benefits to the whole electricity supply chain. ENERGEX has not provided any limited assessment of the NPV calculations.
>
> While ENERGEX put forward a value of $1.5M/MW (sourced from the Queensland Government's Review of the Climate Change Strategy, 2009) as part of its NPV analysis of demand management, the figure is conservative given the basis of its calculation (i.e. RAB divided by current peak demand). Further analysis undertaken on the forecast capital expenditure for the 2010-15 Regulatory Control Period confirms that the dollar/MW value put on distribution capital savings should be higher at just over $2M/MW. "

PB agrees with the statement that the amount used for valuing the generation, transmission and distribution deferrals in the NPV calculations is conservative and also notes the comments in relation to maintaining consistency with the Regulatory Test methodology.

PB recommends that those projects with a positive NPV and an impact on peak system demand be included in the works programme for the next regulatory control period. This recommendation is considered reasonable, as a positive NPV indicates that the benefits outweigh the project costs, and all the recommended projects have an identifiable positive reduction on peak system demand. In addition PB's recommendations will not have any impact on the forecast reduction in system peak demand, which has been factored into the capital works programs.

PB has recommended all the DM projects submitted by ENERGEX be incorporated into the programs of work except for the demand and energy data capture and analysis program which has a negative NPV and no reduction in peak system demand.

6.12.3 PB recommendations

PB recommends a reduction in the 2010-11 financial year opex expenditure forecasts of $2.24m. The recommendation has no impact on forecast capital DM expenditures.

Table 6.29 Recommended opex for demand management initiatives

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ENERGEX proposal	24.60	23.23	25.28	30.58	23.18	126.87
PB adjustment	(2.24)	0.00	0.00	0.00	0.00	(2.24)
PB recommendation	22.36	23.23	25.28	30.58	23.18	124.63

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

6.13 Specific review areas

6.13.1 Service delivery efficiency

ENERGEX has an efficient approach to internal staffing levels, which involves maintaining staffing levels such that they are always fully deployed, and where an outsourcing strategy is used to increase service delivery capacity when required. This approach applies to the opex and capex programs of works. In addition, ENERGEX also employs a systems-based approach to maintenance works, which minimises field trips to and from the assets in two ways. Firstly, asset inspectors have been trained to carry out all pole and line inspections concurrently and the results are loaded at the site into hand-held computer devices, and are then immediately uploaded into the asset maintenance data base. These field inspections are also programmed on a feeder (as opposed to individual pole or cross-arm) basis to minimise travelling, and are dispatched to the field directly from their home, saving travel time to depots where possible.

The asset managers review the field data results and combine defect rectification works into job lots so that the number of outages are minimised and the maximum amount of work achieved during the interruption for each outage. In addition, the opex work packages are combined with any proposed capital works to ensure that assets are repaired if they are programmed to be replaced shortly thereafter.

PB is aware of only two other Australian distributors that have trained their asset inspectors to carry out all onsite inspections while on location and then use a systems-based approach to program the rectification of the defects found. We consider this to be a very efficient way of managing distribution assets and contend that this approach should contribute to overall cost efficiency.

6.13.2 Inter-business benchmarking

The second part of the ENERGEX opex forecasting methodology involves comparing its forecasts developed using part one of the process against industry benchmarks to determine relative efficiency (top-down review). ENERGEX used the revised Wilson Cook and Co composite size measure variable to determine relative efficiency after adjusting the benchmark opex by a CPI of 2.4% to convert \$2008-09 to \$2009-10.

Wilson Cook, as part of its review of the proposed expenditure of the ACT and NSW electricity DNSPs for the revenue determination to be applied from 1 July 2009 to 30 June 2014, developed a methodology to compare different DNSPs based on a composite size factor. The Wilson Cook report, *ACT & NSW DNSPs Expenditure Review – Main Report*

FINAL, October 2008, compared opex between DNSPs using a number of different measures.

The composite size measure included customer numbers, total network line length and maximum demand to arrive at the best correlation factors. Wilson Cook subsequently reviewed its methodology, limiting the composite size variables for opex to only customer numbers and line length, as it was considered that demand or energy supplied should only have a secondary impact on projected opex levels. As stated earlier in this report, PB considers that line length and customer numbers are two of the primary drivers of distribution opex expenditure.

Wilson Cook found that applying the new method produced results that were not materially different from the original analysis[173].

ENERGEX plotted the efficiency frontier using the Wilson Cook equation composite size =0.131* customer numbers + 3.363 * line length. Plotting its forecast expenditure on the same graph indicated that the forecast opex is below the efficiency frontier, which indicates they are relatively efficient compared to the other Australian distributors. Figure 6.7 shows the Wilson Cook calculated efficiency frontier for ENERGEX and the historical and forecast total opex.

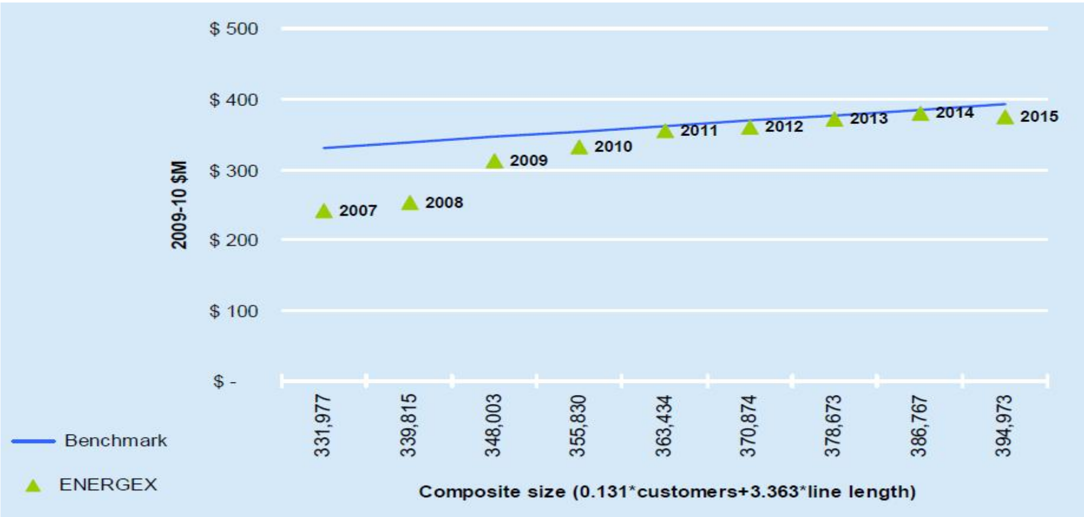

Figure 6.7 ENERGEX current and forecast total opex compared to the efficiency frontier calculated for ENERGEX (based on Wilson Cook methodology)

Source: ENERGEX, Regulatory Proposal, p.179

ENERGEX also referred to a SAHA report included in its proposal; however, PB does not consider this benchmarking report is relevant to the regulatory submission forecast as it only benchmarks DNSPs up until the 2006-07 financial year. Hence PB defers to the internal AER analysis provided to assist PB, as discussed below.

6.13.3 AER opex ratio analysis

The AER provided PB with a high level opex ratio analysis, based on a number of key assumptions. These assumptions give rise to limitations in the application and interpretation of the results, specifically, the AER study has not normalised for factors such as:

173 AER 2009, *Final Decision New South Wales distribution determination 2009–10 to 2103–14*, 28 April 2009, p.175

- differences in accounting/capitalisation policies
- network/age/condition profiles or other unique network operating characteristics.

Not withstanding these limitations, PB considers there are two studies within the AER analysis provided that are reflective indicators of distribution operational efficiency as they include customer numbers and line length, which may each be influential distribution cost drivers. The benchmarks include the *simple ratio of opex/km versus line length* refer to Figure 6.9 and the normalised study of *opex/km versus customer/line length* refer to Figure 6.8.

These studies are contained in the internal AER analysis provided to assist PB [174], which compares the QLD and SA distributors forecast opex for the next regulatory control period against an efficiency frontier calculated using ACT, NSW, QLD and SA distributors 2007-08 financial year actual opex and network statistics. PB prefers the use of actual (rather than regulatory approved 2007-08 financial year expenditures) as they are representative of the opex costs incurred by the distributors. In addition, it is observed by the correlation factors that these two benchmarks exhibit the most significant statistical relationship. For the simple ratio of *opex/km versus line length* the R squared is 0.7599 and for the normalised study of *opex/km versus customer/line length* the R squared is 0.9269.

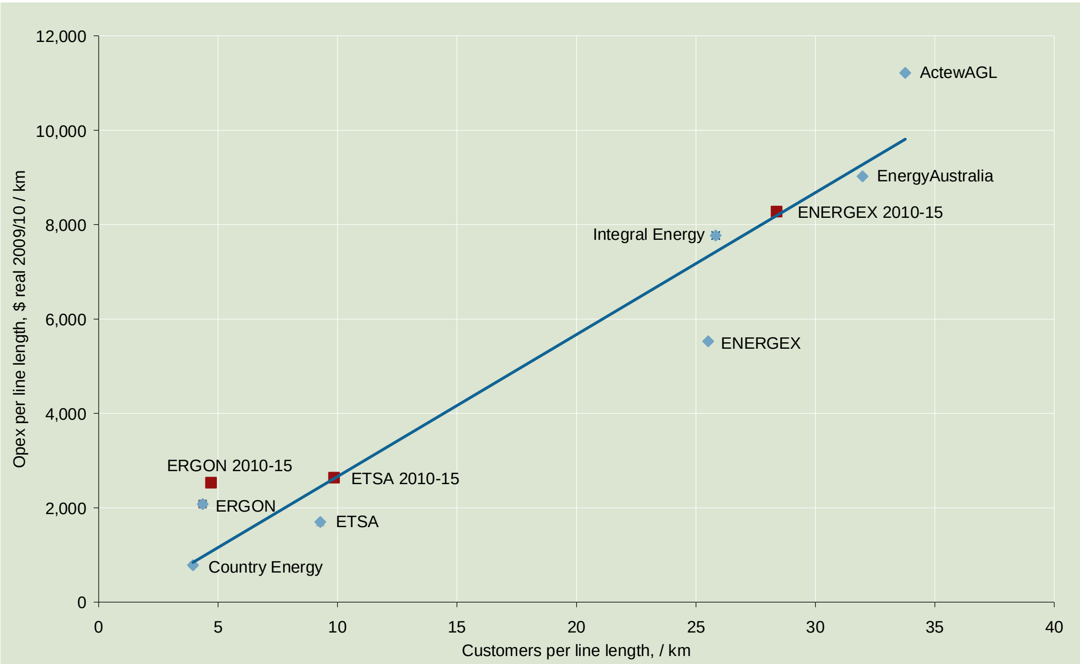

Figure 6.8 Normalised analysis of opex per km plotted against customers per line length

Source: AER Benchmarking Study

174 AER opex ratio analysis – staff working paper

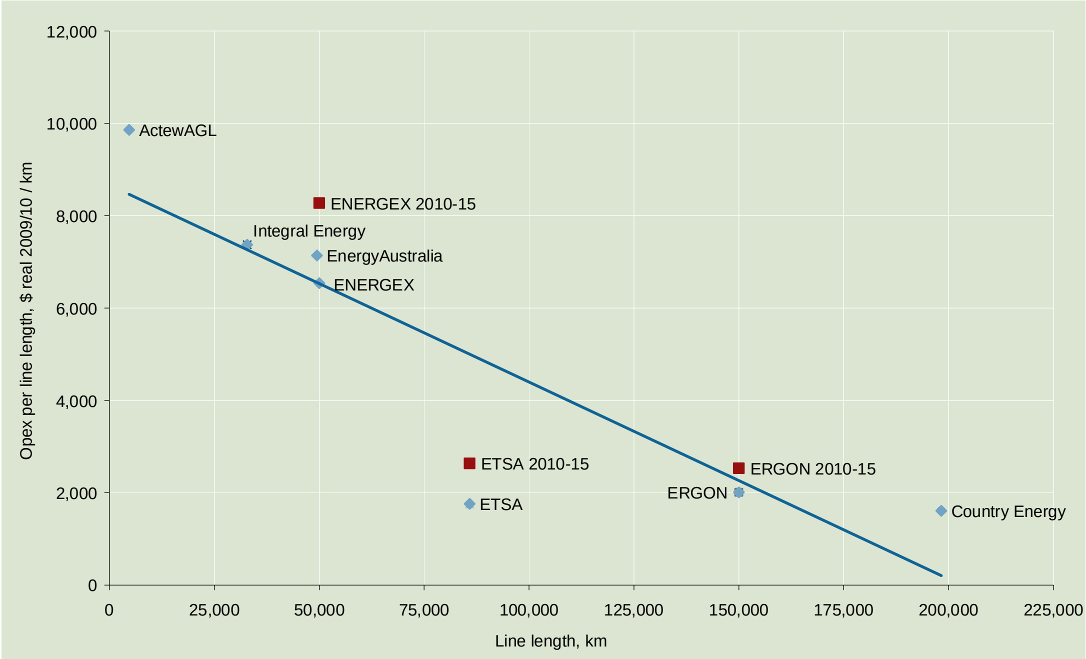

Figure 6.9 Simple ratio analysis of opex per km plotted against line length in km

Source: AER Opex Benchmarking

Both these studies place the ENERGEX forecast opex for the next regulatory control period between Energy Australia and Integral Energy, and on the relative efficiency frontier in the opex/km versus customer/line length study. In the simple ratio of opex/km versus line length study, ENERGEX is above the relative efficiency frontier.

PB believes the Wilson Cook benchmarking study and the AER benchmarking studies in combination indicate that ENERGEX's opex forecasts are relatively efficient from a top-down, inter-business comparative perspective.

6.14 Summary of findings and recommendations

This section presents a summary of PB's key findings and recommendations relating to ENERGEX's proposed opex for the next regulatory control period.

Key findings

ENERGEX proposes to spend $1843.2m on opex in the next regulatory control period, an average increase of 36%.

PB reviewed ENERGEX's asset management principles, processes and procedures and found them to be prudent.

PB found the forecasting methodology ENERGEX used to determine the opex forecasts for the next regulatory control period is sound and is likely to result in accurate forecasts.

Network Operations

The proposed expenditure for network operations is assessed as prudent and efficient given the business-as-usual trend and the detailed bottom-up approach ENERGEX used when forecasting capex for the next regulatory control period.

Inspections

The proposed expenditure for inspections based on a business-as-usual expenditure pattern is assessed as prudent and efficient.

Planned Maintenance

The proposed expenditure for planned maintenance is assessed as prudent and efficient given the detailed nature of the forecasting methodology used by ENERGEX and the overall reduction in proposed expenditure found through the top-down analysis.

Corrective repairs

The proposed expenditure for corrective repairs based on a business-as-usual expenditure pattern is assessed as prudent and efficient.

Vegetation management

PB notes a $4.8m step change between the last year of the current regulatory control period and the first year of the next period for the introduction of reduced trimming cycles on low voltage (LV) urban lines. This increased proposed expenditure is assessed as prudent and efficient as this is required for regulatory compliance. PB notes that ENERGEX has been receiving improvement notices in relation to vegetation encroaching on statutory clearances.

Emergency response/storms

The proposed expenditure for emergency response/storms based on the average annual expenditure in the current regulatory control period is assessed as prudent and efficient.

Customer service

The proposed expenditure for customer service is assessed as prudent and efficient as it is based on business as usual forecasts.

Demand management

The proposed demand management programs incorporated into the ENERGEX Regulatory Proposal are assessed to be prudent and efficient with the exception of the demand and energy data capture and analysis program, as it is presented by ENERGEX as having a negative NPV. The impact of this recommendation is a reduction in the 2010-11 financial year opex expenditure forecasts of $2.24m. The recommendation has no impact on forecast capital DM expenditures.

Self insurance

PB has not identified any evidence to suggest that ENERGEX has included opex costs associated with self insurance outside of the self insurance opex allowance.

Recommendations

PB recommends that the opex allowance for the next regulatory control period should be reduced by $2.2m from ENERGEX's proposal. PB's proposed adjustment is shown in Table 6.30.

Table 6.30 Recommended opex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
System opex						
ENERGEX proposal	296.7	302.4	311.9	323.5	321.5	1556.0
PB adjustment	(2.2)	0.0	0.0	0.0	0.0	(2.2)
PB recommendation	294.5	302.4	311.9	323.5	321.5	1553.8
Non-system opex						
ENERGEX proposal	58.4	58.4	59.4	56.9	54.1	287.2
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	58.4	58.4	59.4	56.9	54.1	287.2
Total opex						
ENERGEX proposal	355.1	360.9	371.3	380.4	375.5	1843.2
PB adjustment	(2.2)	0.0	0.0	0.0	0.0	(2.2)
PB recommendation	352.9	360.9	371.3	380.4	375.5	1841.0

Source: PB analysis and ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls, template 2.2.2 opex.

7. Deliverability

This section presents PB's review of ENERGEX's plans to deliver its proposed works program for the next regulatory control period.

ENERGEX proposes extensive opex and system capex programs of work (PoW) over the next regulatory control period, which in total are increasing from $1.27b in 2009-10 to $1.60b in 2014-15. (This excludes other opex costs and non-system capex that are not system-related.). This represents an increase of 26.2% over the period.

ENERGEX's internal staffing levels are forecast to remain relatively constant over the next regulatory control period so the increased work load will have to be addressed by a combination of strategies, such as outsourcing, standardised designs, design and construct contracts, and prefabrication. In addition ENERGEX will have to ensure delivery of materials necessary to construct the proposed capital works and deliver the asset replacement works, including long lead time assets, such as transformers and circuit breakers.

PB has reviewed the strategies ENERGEX has put in place to deliver the proposed PoWs during the next regulatory control period.

7.1 Expenditure across major asset categories

Table 7.1 shows the forecast system opex for the next regulatory control period.

Table 7.1 Proposed system opex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Inspection	19.2	20.8	22.5	23.3	25.0	110.8
Planned maintenance	66.0	65.0	66.9	68.5	69.6	336.0
Corrective repair	39.9	41.1	41.4	41.9	42.1	206.4
Network operations	25.5	26.8	27.4	28.3	28.9	136.9
Emergency/storms	8.6	8.9	9.1	9.3	9.4	45.3
Vegetation	77.2	79.5	81.1	82.2	82.5	402.5
Metering	14.6	15.2	15.8	16.5	17.1	79.2
Customer services	21.0	21.9	22.4	23.1	23.6	112.0
DM initiatives	24.6	23.2	25.3	30.6	23.2	126.9
Total system	296.7	302.4	311.9	323.5	321.5	1556.0

Source: *ENERGEX, July 2009, Actual & forecast figures* - EGX_*PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls*

Table 7.2 shows the forecast ENERGEX system capital expenditure for the next regulatory control period.

Table 7.2 Proposed system capex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Asset replacement	160.5	255.7	212.9	280.2	256.0	1165.3
Corporate initiated augmentation	562.4	591.3	686.5	662.8	738.7	3241.7
Customer initiated capital works	238.2	245.3	231.5	234.6	237.1	1186.8
Reliability/quality improvement	85.8	50.6	72.6	51.6	45.7	306.3
Other	0.2	1.9	0.0	0.0	0.0	2.2
TOTAL system	1047.1	1144.8	1203.5	1229.2	1277.5	5902.3

Source: ENERGEX, July 2009, Actual & forecast figures - EGX_PROD_n1075805_v1_ENERGEX_-_Pro_Formas_-_Final.xls

In total ENERGEX proposes to deliver $7.36b of system capital and operating works of the next five-year regulatory control period, compared to $5.084b in the current period. This is an increase of 45% over the total system operating and capital works delivered or proposed to be delivered during the current regulatory control period. PB questioned ENERGEX in relation to progress on delivering the 2009-10 programs of work and was advised that at this stage they were on track to deliver the majority of the proposed works.

7.2 Current service delivery performance

To form a view on ENERGEX's ability to deliver the system programs of works proposed for the next regulatory control period, PB performed a number of reviews. This included ENERGEX's performance during the current regulatory control period in increasing its delivery capability and the strategies it has put in place to continue to increase its service delivery capability.

In relation to ENERGEX's service delivery performance during the current regulatory control period PB notes that ENERGEX has increased its service delivery capability by 42% or $374m. This calculation is based on total actual system capex and opex of $893m in 2005-06 and an estimated total annual system capex and opex of $1,267.0m in 2009-10. The total annual system capex and opex in the first year of the next regulatory control period is forecast to be $1,343.8m, an increase of 6% over the estimated total system capex and opex for the current financial year.

7.3 Resourcing strategies (confidential)

[redacted]

[redacted]

[redacted]

[redacted]

	2010-11	2011-12	2012-13	2013-14	2014-15

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Zone substations

[redacted]

Sub-transmission lines

[redacted]

Underground sub-transmission cables

[redacted]

[redacted]

[redacted]

7.4 Materials procurement (confidential)

[redacted]

[redacted]

[redacted]

7.5 PB assessment and findings

PB's review of the contracting strategies ENERGEX has implemented indicates that ENERGEX can develop the capability to deliver the proposed operating and capital works programs during the next regulatory control period. PB also considers that a move to pre-qualification schemes will result in additional contracting efficiencies as the number of eligible contractors decreases and facilitates more effective contractor management.

In addition, PB considers the material procurement practices ENERGEX uses, particularly materials with long lead times, as opposed to stores items purchased on term contracts subject to CPI, should ensure that materials are available when required and unavailable materials should not result in delays to the delivery and subsequent commissioning of the proposed C25 projects.

PB also notes that ENERGEX has demonstrated an increase to its total system capex over the one-year period 2007-08 to 2008-09 by 27%, which is in excess of the largest annual step change of 9.4% anticipated over the next regulatory control period. This provides further confidence in ENERGEX's ability to deliver increasing capex programs of work.

7.6 PB recommendations

ENERGEX should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the next regulatory control period.

8. Service standards

ENERGEX proposes to improve its level of reliability of supply service performance to meet the MSS targets set out in the Queensland *Electricity Industry Code*. In section 4.4.4, PB has assessed that the proposed expenditure to achieve these changed levels of performance is appropriate. No other expenditure relating to a change in service performance is proposed.

In the remainder of this section, PB examines the Service Target Performance Incentive Scheme (STPIS) the AER established in June 2008 and revised in May 2009. The scheme has an objective to assist in setting efficient capex and opex allowances by balancing the incentive to reduce actual expenditure with the need to maintain and improve reliability for customers. This objective is met by establishing appropriate parameters to be included in the scheme and by setting appropriate values for targets and other attributes of the scheme.

The parameters forming the STPIS were fixed before ENERGEX was required to submit its Regulatory Proposal. In this section, we review ENERGEX's proposed values for the established parameters, including the recommendation of appropriate targets.

8.1 Framework and approach paper

In its Framework and Approach paper, the AER set out the likely approach to the application of the STPIS. The agreed matters in relation to this paper, as stated in ENERGEX's Regulatory Proposal, are as follows:

- The parameters to be included in the scheme are unplanned SAIDI and unplanned SAIFI (for CBD, urban and short rural feeder categories) and telephone answering.
- Parameter definitions are in accordance with the STPIS.
- The overall revenue at risk for years 3–5 of the next regulatory control period (2012-13 to 2014-15) is 2% (overall revenue at risk for 2010-11and 2011-12 is discussed in section 8.2.4 of this report).
- The events excluded from the reliability data are in accordance with the STPIS requirements[175] [176].

8.2 PB assessment and findings on the reliability of supply parameter

PB makes the following observations and findings regarding the reliability of supply parameter.

175 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, sections 17.5.2, 17.5.3.2 and 17.5.3.6

176 AER 2008, *Final Framework and Approach paper – Application of Schemes*, ENERGEX and Ergon Energy 2010-15, sections 2.5.2 and 2.5.4

8.2.1 Suitability of data

Reliability of supply data is available for the past five-year period. The QCA required ENERGEX to audit its data every three years[177]. In the current regulatory control period this entails data audits for the 2006-07 and 2009-10 financial years. In addition to this requirement, ENERGEX makes its own independent annual audits each year to enable continuous monitoring of performance.

ENERGEX's data was independently audited for the financial years of 2005-06, 2006-07 and 2007-08. The major findings reported by the external auditors for the 2006-07 financial year leading to the positive audit result were as follows:

- The overarching process adopted and described by ENERGEX is consistent with the principles for reporting reliability performance as envisaged by the *Electricity Industry Code*.
- ENERGEX has a strong business culture of documenting its critical processes and training staff to support its reliability reporting obligations — ensuring consistency in approach and fostering continuous improvements. In the auditors' view, the documentation reflects best practice in this area.
- The key reliability indicators have been calculated in accordance with the code requirements and could be reconciled using a bottom-up reconstruction from detailed individual outage records.
- The audit findings confirm that ENERGEX's reported reliability performance for the 2006-07 period is accurate to within ± 5%[178].

Based on the auditor's findings, PB concludes that the quality of ENERGEX's data forms a suitable base for performance targets.

The reliability data includes a data field that identifies the cause of the outage event. ENERGEX use this data field to identify the events that meet the exclusion criteria set out in clause 3.3(a) of the STPIS. These codes are used to filter the OMS data when calculating reliability performance under the scheme.

8.2.2 Incentive rates

ENERGEX proposes incentive rates based on a value of customer reliability (VCR) of $29,600/MWh for CBD, urban and short rural network segments[179]. This is different from the VCR of $95,700/MWh (adjusted for CPI) for the CBD segment and $47,850/MWh (adjusted for CPI) for all other parameter segments set out in clause 3.3.2(b) of the STPIS.

PB reviewed ENERGEX's proposal for an alternative VCR against section 2.2(b) of the STPIS, as outlined below:

- Section 2.2(b)(1) requires that a proposal made must include the reasons for and an explanation of the proposed variation.

177 ENERGEX August 2009, PB.EGX.AP.14
178 PB 2007, *Network Reliability Reporting Systems – An Independent Audit Review – 2006-07*
179 ibid. section 17.5.3.7

ENERGEX's reasons for an alternative VCR are based on its concerns about customers' willingness to pay for improved reliability and increasing energy prices, based on a report prepared for ENERGEX by KPMG. ENERGEX stated that it had instead applied the VCRs from STPIS Version 1 (based on the 2002 CRA study).

- Section 2.2(b)(2) requires a demonstration of how the proposed variation is consistent with the objectives of clause 1.5.

  ENERGEX engaged KPMG to carry out a study[180] to quantify and understand consumer preferences for electricity distribution service standards.

  PB reviewed the KPMG report and notes the following statements from the study:

  > 'Customers in the survey (South-East Queensland residents) showed a strong resistance to change propositions that involved a lower level of reliability. Conversely they showed a high demand for improved reliability. Similar trade-off scenarios have been put to other states by KPMG. By comparison, south-east Queensland consumers appear to be more demanding. In other states, customers with good to very good reliability typically trade for worse reliability. This is not the case for ENERGEX.' (p.1).
  >
  > 'Although customers generally agreed they had a reliable power supply, 40% overall indicated they required better reliability.' (p.1)
  >
  > 'A generally steady performance improvement over time would appear to be a satisfactory approach for customers.' (p.2)
  >
  > 'Only 25% of respondents indicated a willingness to pay "a little more" for a more reliable electricity supply, 47% were unwilling to pay more for improved reliability and 27% are open to persuasion.' (p.43).

  PB notes that the first three KPMG statements above indicate a clear demand by ENERGEX customers for improved reliability of supply. This suggests that a need exists to ensure that benefits to customers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme, as per clause 1.5(b)(1).

  The fourth statement by KPMG above relates to STPIS clause 1.5(b)(6). The statement indicates the cumulative total of respondents willing to pay "a little more" for more reliable electricity supply (25%) and those open to persuasion (27%) is greater than 50%. This implies that the majority of ENERGEX's customers are willing or open to pay more for improved performance in the delivery of services.

  In support of a lower incentive rate, ENERGEX also states in its Regulatory Proposal that:

  > 'Issues associated with the upward price effects of ENERGEX's significant investment in its distribution network over the course of the current regulatory control period and foreshadowed to continue in the 2010-15 regulatory control period. Consumer concerns about increasing electricity prices in Queensland due to the cost of this network investment, as well as higher electricity generation costs, have been evident during the QCA's consultation processes associated with its setting of the Retail Cost Benchmark Index for Queensland in 2007-08.' (p.260)

[180] KPMG 2008, *ENERGEX Regulatory Proposal 2010–15*, Appendix 17.3

In effect, ENERGEX is asking for a lower incentive rate so that potential price increases are restrained. PB notes that the STPIS scheme uses VCR to establish the efficient level of network investment in reliability. In PB's view, the rate at which service is improved is a separate matter.

- Section 2.2(b)(3) requires that if appropriate, include the calculations and/or methodology which differ to that provided for under the scheme.

  PB notes that ENERGEX has not carried out quantitative studies to determine an alternative VCR. ENERGEX instead proposed to apply the more conservative VCR's included in STPIS Version 1.0. ENERGEX has not explained why it has chosen to apply the VCR from STPIS Version 1 (based on the 2002 CRA study) instead of Version 1.1 (using the CRA 2007 study).

In conclusion, ENERGEX has not clearly demonstrated the need for a lower VCR and has not included calculations or a methodology to support the alternative proposed VCR. The proposed variation is thus not consistent with the objectives of Section 2.2(b)(2) or 2.2(b)(3) of the STPIS. PB therefore recommends that the VCR values set out in STPIS Clause 3.2.2(b) should apply. The recommended incentive rates are shown in Table 8.5.

8.2.3 Targets

The methodology ENERGEX used to develop targets for the reliability of supply parameters is set out in Appendix 17.4 of its Regulatory Proposal. PB examined the methodology as follows:

- Analyse 2003-04 to 2007-08 daily SAIDI and SAIFI values to represent the statistical variability in ENERGEX reliability performance. These were adjusted to reflect unplanned SAIDI and unplanned SAIFI.

  PB confirmed that the reliability data was net of events that meet the exclusion criteria set out in clauses 3.3 (a) and (b) of the STPIS. PB analysed the statistical variability of ENERGEX's reliability performance for the five years from 2003-04 to 2007-08, plus the 2008-09 data then provided in the review. PB is of the view that, due to the variability of unplanned SAIDI and SAIFI before 2003-04[181], data before this time is not appropriate for generation of 'average' unplanned SAIDI and SAIFI for urban or rural segments. In PB's view data should be based upon data from 2003-04 onwards.

- Adjust past and future outcomes to reflect the impact of capital and operating programs included in the regulatory determination.

  PB considered the interaction of historic and forecast capital and opex on service performance targets. PB concluded that historic improvement in urban SAIDI and SAIFI since 2003-04 accord with funded reliability improvements over the period. PB analysed the forecast reliability improvements from capital and operating expenditure in Tables 4.2 and 4.4 of Appendix 17.5 and concluded that the expenditure was correlated with ENERGEX's proposed urban and rural SAIDI and SAIFI targets. PB is satisfied that ENERGEX will not receive any benefit under the STPIS for improving service performance where this service performance has otherwise been funded through either the capex or opex allowances.

181 ENERGEX August 2009, PB.EGX.AP.10

- Establish a 2007-08 'baseline' performance (a statistical reliability) on which to develop ENERGEX's forward reliability programs to determine future targets. ENERGEX presented three methods to generate baseline performance:

  - A manually drawn 'line of best fit' on historical reliability of supply data prepared by Evans & Peck[182]. This line of best fit indicated that urban SAIDI and SAIFI performance improved 35% and 22.9% respectively over the four years from June 30, 2004 to June 30, 2008.

    PB notes that Evans & Peck rejected the 'line of best fit' method in favour of a methodology that considered only funded improvements.

  - 'Backwards extrapolation' of the MSS improvement from June 30, 2004 to June 30, 2008 prepared by Evans & Peck[183]. Through this method urban SAIDI and urban SAIFI are shown to have improved by 22.4% and 13.5% respectively over this four-year period[184]. Evans & Peck note that the MSS improvement programs have been funded[185].

    PB notes that actual reliability improvements in the current period have been assessed by Evans & Peck as being greater than the funded improvement[186]. PB is concerned that setting reliability of supply targets by back-casting the MSS levels rather than at the current performance will provide ENERGEX with cost recovery paths for improvement works though both tariff revenue and the STPIS. Hence it is PB's view that backward extrapolation of MSS requirements is not an appropriate method upon which to base targets.

  - An alternative analysis provided by ENERGEX subsequent to its Regulatory Proposal, involving separation of storm and non-storm components and application of a trend line (using the power function) to the non-storm component[187]. ENERGEX concluded the baseline performance resulting from this analysis is broadly similar to that established in the Evans and Peck report (Appendix 17.5) using the 'backwards extrapolation' of the MSS improvement.

    PB examined the 'non-storm' component and confirms the trending methodology adopted is sound. An error was found in the urban SAIDI figure of 58 minutes. The trend shown in the analysis is 61.4 minutes.

    PB notes that ENERGEX used reliability data from 1997-08 to 2008-09 to demonstrate the variability of the 'storm' component in its alternative analysis for the setting of STPIS targets. In PB's view, reliability improvement works made in response to the EDSD would be likely to improve average performance during storms (noting the major event days are excluded from the analysis) and that an improvement trend is evident in the urban storm component from 2005-06. PB is of the view that variability represented by the storm component from 2005-06 to 2008-09 would be likely to represent future performance, being the period in which reliability improvements were made and containing both years of severe and light

182 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, Appendix 17.5
183 ibid., Appendix 17.4
184 ENERGEX August 2009, PB.EGX.AP.9
185 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, Appendix 17.5, section 3.2.2
186 ibid., Appendix 17.5, section 3.2.2
187 ENERGEX August 2009, PB.EGX.AP.10

storm activity[188]. PB recommends that the average storm SAIDI and SAIFI values should not include the earlier period from 1997-98 to 2002-03. Table 8.1 shows annual and average urban storm SAIDI figures for the period 2003-04 to 2008-09.

Table 8.1 Annual and average (2003-04 to 2008-09) urban storm SAIDI

	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	Average
Urban SAIDI	29.95	14.74	19.37	12.38	13.14	6.85	16.07

Source: PB analysis.

PB notes that the average urban storm SAIDI of 16.1 in Table 8.1 (for the period 2003-04 to 2008-09) differs from the average of 20.5 (for 1997-98 to 2008-09) used in ENERGEX's analysis, as shown in Table 8.2.

Table 8.2 Comparison of urban SAIDI for 2007-08 baseline performance – PB, Evans & Peck and ENERGEX alternative analysis

Item	Evans & Peck	ENERGEX	PB
Power series	n/a	61.4*	61.4
Standard storm	n/a	20.5	16.1
Baselines	77.4**	81.9	77.5
Difference	-	4.5	0.1

*Note: *The figure of 58 contained in the ENERGEX report appears to be a typographical error.*

***Based on Evans & Peck Monte Carlo analysis.*

Source: PB analysis.

This analysis indicates that PB's estimate of a 2007-08 urban SAIDI baseline of 77.5 is very close to the Evans & Peck baseline performance of 77.4. The same analysis for urban and rural SAIFI indicated very similar results for urban and rural SAIDI.

- Superimpose the impact of the PoW programs and possible statistical variation around achievement of the forecasts on to the inherent variability of ENERGEX's reliability performance in a Monte Carlo model to assess the range of likely outcomes.

  PB verified that the outputs of the Mont Carlo model were used as the baseline performance figures.

In addition to the analysis above, PB compared ENERGEX's SAIDI and SAIFI STPIS targets against the MSS and the MSS less 10% probability of exceedance (PoE). Table 8.3 provides the comparative analysis for urban SAIDI.

188 ibid.

Table 8.3 Comparison of ENERGEX's proposed STPIS targets against MSS and MSS less 10% PoE for urban unplanned SAIDI

Item	2010-11	2011-12	2012-13	2013-14	2014-15
MSS less 10% PoE* [189]	82	79	76	73	70
ENERGEX proposed[190]	69.4	67.7	66.0	64.3	63.0
PB recommended	69.4	67.7	66.0	64.3	63.0

** MSS unplanned component (based on average historical proportion planned outages to total outages of 14%) less 10% PoE allowance*

Source: PB analysis.

Table 8.3 indicates that ENERGEX's proposed STPIS targets for urban SAIDI are below MSS less 10% PoE. PB's recommended urban SAIDI targets are in accord with ENERGEX's proposal.

Table 8.4 provides the comparative analysis for short rural SAIDI.

Table 8.4 Comparison of ENERGEX's proposed STPIS targets against MSS and MSS less 10% PoE for short rural unplanned SAIDI

Item	2010-11	2011-12	2012-13	2013-14	2014-15
MSS less 10% PoE*	160	158	156	154	152
ENERGEX proposed	173.19	164.44	157.95	152.37	147.60
PB recommended	173.19	164.44	157.95	152.37	147.60

** MSS unplanned component less 10% PoE allowance*

Source: PB analysis.

Table 8.4 indicates that ENERGEX's proposed STPIS targets for short rural SAIDI are above the MSS less 10% PoE for the first three years of the next regulatory control period, and below for the last two years. PB discussed this with ENERGEX who advised that they planned to meet the MSS targets by the end of the next regulatory control period. As the rate of improvement is consistent with proposed expenditures PB's recommended short rural SAIDI targets are in accord with ENERGEX's proposal.

In summary, PB confirms that the baseline performance determined by Evans and Peck is reasonable and that performance targets over the regulatory control period have then been set to match improvements expected from reliability improvement projects proposed in the forecast expenditures program. PB recommends that the targets proposed by ENERGEX as shown in Table 8.5 are adopted without change.

8.2.4 Revenue at risk

ENERGEX propose a staged and incremental approach to revenue at risk, with a paper trial for the first year (2010-11), and a second transitional year (2011-12) with 1% of revenue at risk[191]. PB analysed the level of revenue at risk considering ENERGEX's approach[192] in relation to the objectives of Clause 1.5(b) of the scheme as outlined below:

189 ibid., Appendix 17.4, Chart 2
190 ibid., section 17.5.3.8, Table 17.4
191 ibid., section 17.5.3.2.

- STPIS clause 1.5(b)(1) requires that the benefits to consumers resulting from the scheme should be sufficient to warrant any reward or penalty. ENERGEX states that a low powered and incremental approach during the initial introduction of the STPIS would allow ENERGEX to prudently manage its risks and protect the interests of its customers. ENERGEX states that it has not been subject to a service incentive scheme under any previous revenue determinations and the national STPIS is untested and was only very recently formulated.

  PB notes the AER's position in the Framework and Approach paper that 'the DNSP's (ENERGEX's) inexperience in implementing a scheme that places revenue at risk is not by itself a sufficient reason to apply the STPIS by way of a paper trial'. PB notes that ENERGEX did not provide any additional information in its regulatory submission to support its position that a low powered and incremental approach would allow ENERGEX to prudently manage its risk and protect the interests of its customers.

- STPIS clause 1.5(b)(2) requires consideration of any relevant regulatory obligation or requirement. ENERGEX states that under section 2.4 of the Electricity Industry Code, ENERGEX has MSS obligations and these must be considered in introducing the STPIS. ENERGEX states that it has a significant operational consideration in regard to the interplay between MSS and STPIS — namely the potential for them to operate counter to each other in the 2010–15 regulatory control period. ENERGEX states this could be an issue where the higher focus for improvement on rural feeders under MSS contrasts with the higher reward/penalty associated with the performance variation of urban feeders under STPIS.

  PB considered the interplay between ENERGEX's MSS obligations and the introduction of the STPIS[193]. In PB's view the higher focus for improvement on the rural feeders under MSS against the higher reward/penalty associated with urban feeders under STPIS is not particular to years 1–2 of the next regulatory control period (2010-11 to 2011-12) and thus should not prevent the application of a revenue at risk reward/penalty in these years.

PB notes that ENERGEX has not provided justification additional to that considered by the AER in the Framework and Approach process about the justification of a paper trial and incremental approach to revenue at risk. PB's view is thus that the revenue at risk reward/penalty of 2% should apply to ENERGEX's reliability of supply parameter for the entire duration of the next regulatory control period (2010–15), as with the AER's preliminary position in the Framework and Approach paper.

8.3 PB assessment and findings on customer service parameter

PB makes the following observations and findings regarding the customer service parameter.

8.3.1 Parameter definition

ENERGEX proposes a telephone answering parameter that is based on the Average Speed of Answer (ASA) rather than the STPIS definition, which ENERGEX refer to as a Grade of Service (GOS) measure.

192 Ibid.
193 ibid.

The ASA measure is based on the time from when the customer joins the queue to speak to an operator to when the call is answered. It excludes abandoned calls in the calculation. ENERGEX established the ASA measure when it enhanced its messaging capability on the fault call line in late 2004, including the capability to provide power outage updates to customers while they were waiting in the queue to be answered by an operator. Due to this functionality, customers are encouraged to abandon 'in queue' after receiving relevant outage information and before being answered by an operator.

ENERGEX considers the application of an ASA measure in the STPIS is appropriate. The reasons put forward by ENERGEX in appendix 17.2 of its Regulatory Proposal are discussed below.

- ENERGEX states that the choice of measure should reflect the DNSP's management decision regarding the best measure for its contact centre to achieve business objectives, any legislative requirements and customer service expectations.

  PB notes that achieving business objectives and customer service expectations are not part of the objectives for the STPIS. While the choice of parameter included in the STPIS will place revenue at risk, and hence place emphasis on achieving the performance standard as measured by the selected parameter, the call centre is likely to have a range of KPIs that cover the breadth of its operations. PB notes the parameter selected for the STPIS should meet the objectives of the STPIS rather than other objectives. PB acknowledges that ENERGEX is required to report on the ASA measure to the Queensland Government. In PB's view, establishing a different measure for the STPIS scheme is not inconsistent with the objectives of the scheme to take into account any regulatory obligation or requirement to which ENERGEX is subject.

- ENERGEX states the ASA measure provides a broader indication of the Contact Centre's performance in handling all calls to the fault call line compared with the GOS measure that indicates only the number of calls answered within a 30-second period. Under the GOS definition, all calls not answered within 30 seconds are excluded from the performance assessment. In this sense, it is a partial measure of telephone answering performance compared to the more complete ASA measure.

  PB notes that the GOS parameter does not exclude calls not answered within 30 seconds. It applies to all calls, the same as the ASA measure. It is simply a different measure of performance.

- ENERGEX states ASA is the primary driver for assessing performance on its fault call line as it is a broader measure and more reflective of the customer experience. It indicates the average waiting time of customers, hence the waiting time of all customers, not just a percentage of them.

  PB notes that because the ASA measure is an average of all calls, it provides no indication of the number of customers who have waited an unacceptable length of time. This is because the ASA measure does not consider the range of call response times that make up the average. Hence, it cannot be regarded as a 'broader' measure or 'more reflective of customer experience' when applied over a period of time when the maximum or minimum response could vary significantly from the average response.

- ENERGEX states GOS is not an effective indicator of service performance on the fault call line, as it fails to take into account the effect of positive abandons. This conflicts with the philosophy of ENERGEX's fault call line, which encourages abandonment of calls before contact with an operator.

PB notes the definition of the GOS parameter includes calls abandoned within 30 seconds, which are counted as answered calls, or if the length of time is not measured, then 20% of all abandoned calls are deemed to have been answered within 30 seconds. ENERGEX states that its telephone system does not provide the length of time before a call is abandoned. Hence the default of 20% of all abandoned call would apply.

ENERGEX has not shown that the provision of an updated message ‘in queue’ would have a material impact on performance as measured by the GOS parameter. The updated message would need to be constructed, heard by the caller and the call abandoned within 30 seconds of the caller being placed ‘in queue’ for the outcome to be affected. It seems more likely that calls in queue for longer than 30 seconds would benefit most from this ‘positive abandonment’ initiative.

PB has assessed the ASA measure against the relevant key objectives set out in clause 1.5 of the STPIS and the requirements of the NER and compared these with the GOS parameter:

- NER clause 6.6.2(a) requires that the STPIS provide incentives for DNSPs to maintain and improve service performance. PB notes the averaging nature of the ASA encourages improvements in average service performance, ignoring the range of call response times that make up the average. Applied over one year, the longer response times experienced during ‘busy’ periods would be balanced by shorter response times during ‘light’ periods, providing little indication of the actual service performance provided. Conversely, by selecting an appropriate threshold (30 seconds), the GOS parameter is focused on identifying how many callers were subject to a longer than optimum response time. Both would seem to meet the NER objective, but are focused on different aspects of service performance. In PB’s view, providing an incentive that ensures all callers to the fault call line can be answered within a reasonable period of time would seem to be more consistent with the nature of the service provided by a fault call line than encouraging an improvement in the average speed to answer.

  PB notes that the message applied to the IVR can change customers’ expectations of an acceptable response time. Indicating the network has suffered many incidents and that operators are ‘busy’ is likely to result in some callers abandoning the call immediately while others become prepared to wait a bit longer than they otherwise might. PB notes that the Queensland Government’s Department of Mines and Energy established different ASA targets for storm and non-storm periods.[194] For the GOS measure, this is unnecessary if the threshold value is set appropriately.

  PB also notes that overload events have occurred in the past where the call centre was unable to respond to the volume of incoming calls[195]. The ASA measure excludes abandoned calls and hence the inclusion of this measure in the STPIS would not encourage ENERGIX to maintain or improve this aspect of service performance.

- STPIS clause 1.5(b)(1) covers the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs. PB has not seen any indication that the ASA is of concern to electricity customers in Queensland and hence that information is available on which to establish an incentive rate.

194 ENERGEX 2009, *Service Target Performance Incentive Scheme Submission to the Australian Energy Regulator*, p.11

195 Queensland Government 2004, *An Action Plan for Queensland Electricity Distribution*, p.5

- STPIS clause 1.5(b)(5) covers the need to ensure the incentives are sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels. PB notes that under an ASA measure, the call centre operator has a strong incentive to reduce the time taken in talking to a caller, so as to be available to respond quickly to the next caller and hence improve the ASA performance outcome. The focus is on responding to the call rather than the customer. This incentive is reduced under the GOS measure, particularly during 'business-as-usual' periods when the call volume is light and most calls are easily answered within the threshold value of 30 seconds.

- STPIS clause 1.5(b)(6) covers the willingness of the customer or end user to pay for improved performance in the delivery of services. PB has not seen any indication that customers are willing to pay for improvements to ASA. Anecdotal evidence is available to indicate that callers to fault call lines do not want to wait an excessive length of time. Hence, PB is of the view that the ASA measure is less likely to meet customers' willingness to pay for service improvements than a GOS measure.

PB concludes the ASA is not an appropriate parameter to include in the STPIS.

8.3.2 Suitability of data

ENERGEX states that telephone answering data is only available for one full year because of downsizing the Retail/Network Contact Centre to form a Network Contact Centre in 2007[196]. PB discussed the structural break in the performance history of the Network Contact Centre associated with its operation as a network only contact centre and confirms the change in the call centre facility is significant and historical data before the change would not reflect future performance.

8.3.3 Incentive rates

ENERGEX proposed adjusting the telephone answering incentive rate of -0.040 as set out in the STPIS (Clause 5.3.2(a)) by removing the negative sign.[197] This incentive rate would apply to the ASA measure proposed by ENERGIX. PB has not seen any information on which to establish an incentive rate associated with the ASA measure and notes that ENERGEX has applied the same value as for the GOS measure on the basis that the GOS and ASA measures are broadly comparable ways of measuring performance[198].

Given the lack of better information, PB supports ENERGEX's view that an incentive rate of 0.040 should be applied for an ASA measure. Alternatively, should the GOS parameter be adopted, the incentive rate of -0.040 would apply.

8.3.4 Targets

The STPIS requires that targets are based on the average performance over the past five financial years. As only one year of data is available, insufficient data is available to inform the setting of targets at this time.

196 ENERGEX July 2009, *Regulatory Proposal for the period July 2010–June 2015*, section 17.5.1
197 ibid., section 17.5.3.5
198 ibid., appendix 17.2

ENERGEX propose that no telephone answering targets be applied in 2010-11 and 2011-12 and that targets for 2012-13, 2013-14 and 2014-15 should be derived from the three years of data from 2008-09 to 2010-11.

PB has examined the data for Jan-08 to Jan-09 and notes that service performance outcomes as measured by the ASA or GOS measures are not driven by call volume as might occur during periods of high storm activity. Given that storm activity is the major external influence on call centre activity, PB is of the view that a limited data set of three years should contain sufficient diversity of events to provide a sound basis for informing the setting of targets. PB has confirmed that no expenditures to improve call centre performance are included in the Regulatory Proposal and hence no adjustments for funded improvements over the period are required.

PB concludes that ENERGEX's proposal is sound and recommends that targets for 2011-12 to 2014-15 should be set at the average performance of the three years of data from 2008-09 to 2010-11.

8.3.5 Revenue at risk

ENERGEX proposes a staged start to the customer service parameter, with a paper trial in years 2010-11 and 2011-12 and the application of 0.05% of revenue at risk for 2012-13 to 2014-15[199].

Noting the lack of data on which to set targets, PB supports a paper trial in years 2010-11 and 2011-12.

ENERGEX states the amount of revenue at risk (0.05%) has been set to equal approximately 10% of the annual operating cost of the call centre[200]. PB notes this amount excludes capital investments that are required from time to time to replace equipment or to fund service performance improvements. A cap set at 0.05% is reached for a change in performance of about 1.8% (assuming an average performance of 70% of calls answered in 30 seconds and aggregate revenue of $1,423.5m). PB considers this change in performance is too small for the scheme to provide an appropriate incentive to improve performance.

Conversely, the maximum amount of revenue at risk allowed by the STPIS for the telephone answering parameter of 0.5% (about $7m) would equate to a change in performance of about 18%. This seems too high to be consistent with the transitional matters set out in NER clause 11.16.5, which require the AER to consider the application of the STPIS by way of a paper trial or a lower powered incentive scheme.

PB considers the requirements of the NER would be met by maintaining the value of the customer service parameter in the scheme at about 10% of the total incentive (i.e. 0.5% divided by 5%). For an overall cap of 2%, this equates to a cap on the telephone answering parameter of 0.14% and a change in performance of about 7%.

199 ibid., section 17.3.3
200 ibid., section 17.5.3.3

8.4 Summary of findings and recommendations

This section summarises PB's findings and recommendations in relation in relation to service standards.

PB's findings in relation to ENERGEX's reliability of supply parameter are as follows:

- The quality of ENERGEX's data is suitable for target setting.
- The proposed variation to the VCR is not consistent with the objectives of clause 1.5. The VCR values set out in STPIS clause 3.2.2(b) should thus apply.
- The SAIDI and SAIFI 2007-08 baseline performance and performance targets for the next regulatory control period (2010–15) are reasonable.
- ENERGEX did not provide additional information above that provided in the F&A to justify a paper trial and incremental approach to revenue at risk. A revenue at risk cap of 2% should thus apply for the entire duration of the next regulatory control period (2010–15).

PB's findings in relation to ENERGEX's customer service parameter are as follows:

- The proposed variation to the telephone answering parameter based on a measure of the Average Speed of Answer is not appropriate to include in the STPIS.
- The structural break in call centre data is significant such that historical data before the change would not be reflective of future performance.
- No targets should apply for 2010-11. Targets for 2011-12 to 2014-15 should be set at the average performance of the three years of data from 2008-09 to 2010-11.
- The incentive rate of 0.040 should be applied for an ASA measure. Alternatively, an incentive rate of -0.040 would apply should the STPIS telephone answering parameter definition be adopted.
- An overall revenue at risk cap of 2% should apply, with a revenue at risk cap of 0.14% for the telephone answering parameter.

In summary, PB recommends the values for the service performance parameters shown in Table 8.5 and the maximum revenue increment or decrement for the telephone answering parameter should be 0.14%.

Table 8.5 Recommended performance incentive scheme

Parameter	Unit	Rate %	Targets				
			2010-11	2011-12	2012-13	2013-14	2014-15
SAIDI							
CBD	minute	0.0084	3.3	3.3	3.3	3.3	3.3
Urban	minute	0.0605	69.4	67.7	66.0	64.29	63.0
Short rural	minute	0.0128	173.2	164.4	158.0	152.4	147.6
SAIFI							
CBD	per interruption	0.7631#	0.032	0.032	0.032	0.032	0.032
Urban	per interruption	4.0437#	1.044	1.032	1.020	1.008	0.996
Short rural	per interruption	1.0459#	2.285	2.201	2.120	2.041	1.967
Customer service							
Telephone answering	%	-0.040	N/A	*	*	*	*

*Note: * Target to be determined based upon telephone answering data (2008-09 to 2010-11) when available. Incentive rates for SAIDI and SAFI parameters are calculated using ENERGEX's proposed average energy consumption.*

 # per 0.01 interruptions

Source: PB Analysis

9. Generic limitations of this report

9.1 Scope of services and reliance of data

This report has been prepared in accordance with the scope of work/services set out in the contract, or as otherwise agreed, between PB and the client. In preparing this report, PB has relied upon data, surveys, analyses, designs, plans and other information provided by the client and other individuals and organisations, most of which are referred to in the report (the data). Except as otherwise stated in the report, PB has not verified the accuracy or completeness of the data. To the extent that the statements, opinions, facts, information, conclusions and/or recommendations in this report (conclusions) are based in whole or part on the data, those conclusions are contingent upon the accuracy and completeness of the data. PB will not be liable in relation to incorrect conclusions should any data, information or condition be incorrect or have been concealed, withheld, misrepresented or otherwise not fully disclosed to PB.

9.2 Study for benefit of client

This report has been prepared for the exclusive benefit of the client and no other party. PB assumes no responsibility and will not be liable to any other person or organisation for or in relation to any matter dealt with in this report, or for any loss or damage suffered by any other person or organisation arising from matters dealt with or conclusions expressed in this report (including without limitation matters arising from any negligent act or omission of PB or for any loss or damage suffered by any other party relying upon the matters dealt with or conclusions expressed in this report). Other parties should not rely upon the report or the accuracy or completeness of any conclusions and should make their own inquiries and obtain independent advice in relation to such matters.

9.3 Other limitations

To the best of PB's knowledge, the facts and matters described in this report reasonably represent the conditions at the time of printing of the report. However, the passage of time, the manifestation of latent conditions or the impact of future events (including a change in applicable law) may have resulted in a variation to the conditions.

PB will not be liable to update or revise the report to take into account any events or emergent circumstances or facts occurring or becoming apparent after the date of the report.

Appendix A

PB's Terms of Reference

A. PB Terms of Reference

In this section we set out PB's proposed terms of reference for the review of regulatory submissions made to the AER by ETSA Utilities, Ergon Energy and ENERGEX.

Exclusions

For the avoidance of doubt, under the revised PB proposal – and as agreed with the AER – PB will not be undertaking the following items which were originally anticipated in the original PB proposal (March 2009):

- pre-lodgement meetings with the businesses
- unit cost benchmarking
- comparative business benchmarking (including historical versus forecast)
- review of external factors and obligations
- cost pass-through items
- the review of submissions from interested parties

A.1 Introduction

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (NER), is to conduct an assessment of the appropriate distribution determination to be applied to direct control services provided by DNSPs in South Australia and Queensland for the period 1 July 2010 to 30 June 2015. Previous regulatory reviews for ETSA Utilities, Ergon Energy and Energex were undertaken by the Essential Services Commission of South Australia (ESCOSA) and the Queensland Competition Authority (QCA). Relevant documents for these determinations, including submissions, consultancies and the final determination, are available at www.escosa.sa.gov.au and www.qca.org.au.

As part of the AER's assessment, an appropriately qualified consultant is required to review the DNSPs' forecast capital expenditure (capex), operating and maintenance expenditure (opex), associated policies and procedures, and service standards proposals. Consultants interested in providing these services may submit a separate quotation for one or each of the determinations or a single quotation covering both determinations.

The AER is required to establish that the capex and opex forecasts of the electricity distribution businesses comply with the requirements of the National Electricity Law (NEL) and the National Electricity Rules (NER), particularly chapter 6 of the NER[201]. The consultant would be primarily concerned with providing technical advice regarding the efficiency and prudence of capex and opex forecasts provided by the distributors. The AER takes into consideration its consultant's views in making its assessments under the NER.

The AER's determinations are subject to merits review by the Australian Competition Tribunal and judicial review in the Federal Court. The consultant's analysis and reports must be produced at a standard that is commensurate with this context.

201 Clause 6.5.6 of the NER relates to opex and clause 6.5.7 of the NER relating to capex. Clause 6.5.6(a) sets out the opex objectives, clause 6.5.6(c) sets out the opex criteria and clause 6.5.6(e) sets out the opex factors. This structure is mirrored in clause 6.5.7 with respect to capex.

A.2 Services required

The services required for the primary engineering assessment and cost review covered by these terms of reference are described below. Within its report, the consultant must have regard to the opex and capex objectives, criteria and factors set out in clauses 6.5.6 and 6.5.7 of the NER. The consultant is to undertake an assessment of the DNSP's regulatory proposal to enable the AER to interpret and apply the NER. For example, the opex and capex factors include items such as:

- benchmarking the level of expenditure that would be incurred by an efficient DNSP;
- substitution possibilities between opex and capex; and
- the provision for efficient non-network alternatives such as demand management.

The consultant will be required to provide an explanation for its decisions in regards to its assessment of the relevant considerations required for the AER to apply the opex and capex objectives, criteria and factors set out in clauses 6.5.6 and 6.5.7 of the NER.

The AER requires a thorough assessment, including the provision of a high standard of detailed information in order to for it to evaluate the NER requirements. The AER expects that the consultant's assessments will be based on more than past experience and that the consultant will substantiate and justify its conclusions with references to data and information sources. For example, where the consultant uses sample testing, the samples must be statistically significant.

The AER expects that the consultant will have adequate resources to undertake the review in the time required and will be familiar with the AER's previous determinations in regards to Chapter 6 of the NER.

A.2.1 General pre-lodgement work

The consultant will be required to meet with the AER prior to receipt of the proposals to discuss in more detail the approach to the review and the AER's expectations.

A.2.2 High-level review of historic opex and capex

The AER will review actual and forecast capital and operating expenditures that have occurred or are forecast to occur over the current regulatory period compared with the expenditure levels forecast at the time of the last determination. It will also examine material variances between forecasts and actuals and the drivers for the differences. This information will assist in assessing clauses 6.5.7(e)(5) and 6.5.6(e)(5) respectively of the NER.

The purpose of this review is not to assess whether the expenditures in the current regulatory period are prudent but to establish the context in which the expenditure forecasts have been made and provide an indication of areas of the forecast expenditures that require more detailed analysis. Historic capex and opex will be assessed separately for each DNSP.

The consultant is required to use the findings from the review of forecast and actual expenditures in the current regulatory period in its assessment of forecast capex and opex.

The AER will share with its consultant its high level historic opex and capex review and any other relevant comparative analysis it undertakes. The AER will aim to provide this information to its consultant in a timely manner so that it can be used in the development of the consultant’s advice.

A.2.3 Forecast demand and cost escalators

External factors such as those affecting the future demand for electricity and the future cost of labour and materials will have a significant influence on the DNSPs’ expenditure forecasts.

The AER intends to engage a separate consultant to review the DNSPs’ demand forecasts. The AER requires the primary engineering consultant to verify the effect of any revised maximum demand forecasts that are developed as a consequence of the recommendations of the demand consultant.

The AER anticipates that the DNSPs will propose real cost escalators for labour and materials for the next regulatory period. The AER intends to engage a separate consultant to undertake an independent review of labour costs over the next regulatory period. In addition, the AER will undertake its own assessment of material cost escalators over the next regulatory period. As such the primary engineering consultant will not be required to provide a view in relation to labour and material cost escalators proposed by the DNSPs. However, the consultant will be required to review the application of the escalators and advise whether they are appropriate. The consultant will also need to review the process by which the DNSP’s escalators have been applied and whether the process, including the weightings used, is appropriate.

A.2.4 Review of policies and procedures

The DNSPs have been asked to provide the key policies and procedures by which their operational and investment decisions are made. Such policies are expected to relate to, for example, augmentation, replacement, opex, cost allocation, capitalisation and demand management. The consultant shall undertake a review of these policies and procedures. This work is to include a review of network performance targets and associated forecasts, augmentation models and opex and replacement models.

The consultant shall report on its review of these policies and procedures, noting, where relevant, any policies and procedures that it considers unreasonable or inappropriate having regard to good electricity industry practice and clauses 6.5.6(c) and 6.5.7(c) of the NER. Should the consultant find any such policies or procedures, it is to specify alternative policies or procedures; substantiate why they are reasonable and appropriate with reference to clauses 6.5.6 and 6.5.7 of the NER; and provide an estimate of the impact on the proposed allowances.

A.2.5 Review of forecast capex and opex

The consultant is to test the magnitude of the capex and opex forecasts submitted by the DNSPs by examining the application of the submitted policies and procedures (see section 2.4 above) to the DNSPs’ networks for the next regulatory period.

The consultant is also to review the expenditure projections for consistency with the demand forecasts accepted by the AER.

For these purposes, the DNSPs will be asked to provide details of their forecast augmentation, replacement, opex and non-network expenditure programs as part of their regulatory proposals. This information is to include a listing of all major projects and programs above a specified threshold.[202]

The consultant shall review the application of the DNSPs' policies and procedures (and, where relevant, shall check for consistency with the demand forecasts) with regard to:

- the major projects and programs identified in each of the regulatory proposals;
- areas of expenditure where there is a substantial deviation, upwards or downwards, from expenditure in the current period and/or agreed to in the previous determination (the preliminary high-level review of expenditure during the current regulatory period to be conducted by the AER may also highlight areas for testing the application of relevant policies and procedures); and
- a representative sample of projects and programs to be agreed with the AER. In recommending the sample, the consultant shall include forecast expenditure on a range of assets, time, magnitude and location for the DNSPs, sufficient to demonstrate consistency of application of the DNSPs' stated policies.

The focus of the assessment is identifying whether there are any systemic flaws in the DNSPs' practices. The consultant is to identify the projects and programs reviewed in its report and present well-reasoned and substantiated conclusions as to whether the relevant policies and procedures have been applied appropriately.

Should the consultant identify relevant policies and procedures that it considers have not been applied appropriately, it shall identify the problem and recommend appropriate adjustments where considered necessary to correct the situation. In such an instance, in consultation with the AER, the consultant may be required to investigate whether the application problems are systemic in nature. If found to be the case, this would likely involve the assessment of additional projects and programs of a similar nature. Again, well-reasoned and substantiated recommendations must be made, including the recommendation of appropriate adjustments to the opex and capex allowances resulting from amendments to the relevant policies and procedures where considered necessary.

The consultant is required to comment on the deliverability of the DNSP's proposed capex program, having regard to capex delivered in the current regulatory period and the DNSP's capex delivery framework and policies for the next regulatory control period. It is expected that the consultant will substantiate the factors considered in its conclusions on deliverability.

Clauses 6.5.6(e)(10) and 6.5.7(e)(10) of the NER require the AER to have regard to the extent the DNSPs have considered, and made provision for, efficient non-network alternatives. The consultant is required to assess whether the businesses are actively considering demand management and what may be some of the obstacles to the take up of demand management by the DNSPs.

The consultant shall also make such other recommendations to the AER as the consultant considers necessary to ensure that the expenditure levels are prudent and efficient.

[202] The RIN for South Australian and Queensland DNSPs specified that a project or program would be considered material if cumulative expenditure on it exceeded 2% of the annual revenue requirement in the final year of the current regulatory control period.

A.2.6 Service standards

The DNSPs will be subject to a Service Target Performance Incentive Scheme (STPIS), including a reliability of supply component and a customer service component. The consultant shall recommend appropriate reliability of supply and customer service performance targets to be applied to each DNSP over the next regulatory period.

The consultant must assess the STPIS values proposed by the DNSPs against both the principles outlined in the AER's STPIS and clause 6.6.2 of the NER.

In recommending the future performance targets, the consultant must have regard to the DNSPs past performance, as outlined in the STPIS, as well as the impact that the capex and opex programs may have on its performance.

A.3 Liaison with DNSPs and the AER

Without affecting the independence of the review, the consultant is expected to liaise closely with the DNSPs, and related parties if required, during the course of the review. This liaison is expected to include meetings with the DNSPs at their respective offices with AER staff in attendance and the preparation of written requests for additional information and documentation.

The consultant shall also liaise closely with AER staff and provide regular updates on:

- progress towards achieving deliverables;
- any impediments that have arisen to achieving those deliverables; and
- any significant issues that have been identified.

The consultant will also be required to liaise with the AER's secondary engineering consultant.

A.4 Pre-determination conferences

The consultant shall attend the pre-determination conferences to be held by the AER during the review process. The conferences are to be held in Brisbane on 8 December 2009 (Energex and Ergon Energy) and in Adelaide on 9 December (ETSA Utilities). The purpose of these conferences is to provide the AER with the opportunity to explain its draft distribution determinations. The consultant is not required to attend the public forums to be held in August 2009 in Brisbane and Adelaide.

A.5 Project deliverables – South Australian and Queensland determinations

To comply with the NER, the AER is required to publish its final determination two months before the commencement of the DNSPs' next regulatory control period (that is, by 30 April 2010). The consultant is to note that the timeframe in the NER does not allow for flexibility in the dates and that there are no 'stop the clock' provisions. The consultant is therefore required to meet the timeframe specified in the terms of reference to ensure compliance with the requirements of the NER.

The DNSPs are to submit their regulatory proposals by 1 July 2009. Given the timing requirements set out in the NER, the AER must release its draft determination by late November 2009 and thus the consultant will be required to meet the following deadlines:

- preliminary meetings with the AER in June 2009 and other pre-lodgement work where possible;
- meetings with the DNSPs following the submission of their regulatory proposals;
- provision of preliminary reports and presentations to AER staff on key issues identified from the consultant's high level review by late July 2009;
- provision of draft written reports on its findings by close of business 15 September 2009 (one report for the Queensland DNSPs and one for ETSA Utilities);
- presentation to the AER Board of the findings of draft reports (proposed to be 25 September 2009);
- provision of final written reports on its findings by close of business 9 October 2009 (one report for the Queensland DNSPs and one for ETSA Utilities); and
- attendance at the AER's predetermination conferences on 8 and 9 December 2009.

In addition to its draft and final reports, the consultant must provide supporting spreadsheets and analysis relied upon in its report to ensure the AER can meet the requirements set out in clause 6.12.2 of the NER. The consultant must also be available for follow-up questions from the AER.

A.6 Merits and judicial review

The regulatory determinations made by the AER under the NEL are subject to merits review by the Australian Competition Tribunal and judicial review in the Federal Court. Accordingly, the consultant's final report must be written to a professional standard with well-reasoned analysis and recommendations. The consultant's report will be published alongside the AER's determinations as part of the public consultation process.

Any work required as a result of a merits review would be the subject of a separate contract.

A.7 Timeline – South Australian and Queensland determinations

Event	Rule	Date
Regulatory proposals submitted	**6.8.2(b)**	**1 July 2009**
Preliminary examination of proposals completed		10 July 2009
PB 1st meeting with Energex and Ergon		13-15 July 2009
Publish proposals and call for submissions		17 July 2009
PB preliminary report (Energex and Ergon)		17 July 2009
PB 1st meeting with ETSA		20-22 July 2009
PB preliminary report (ETSA)		24 July 2009
PB 2nd meeting with Energex and Ergon	Wk begin	3 August 2009
Public forum on regulatory proposals (Brisbane)		**3 August 2009**
Public forum on regulatory proposals (Adelaide)		**6 August 2009**
PB 2nd meeting with ETSA	Wk begin	10 August 2009
Submissions on regulatory proposals close*	**6.9.3(c)**	**28 August 2009**
PB's draft report due		15 September 2009
PB's draft report to DNSPs for review		22 September 2009
PB presentation to board		25 September 2009
PB's final report due		9 October 2009
Publish draft determination	**6.10.2**	**27 November 2009**
Pre-determination conference – Bris/Adelaide	**6.10.2(b)**	**8/9 December 2009**
DNSPs to lodge revised proposals	6.10.3(a)	14 January 2010
Submissions on draft determinations close*	**6.10.2(c)**	**16 February 2010**
Publish final determination	**6.11.2**	**30 April 2010**

* Proposed cut off dates for information provision by the DNSPs.

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Appendix B

About PB

B.1 About PB

Parsons Brinckerhoff ("PB") is one of the world's oldest continuously operating consulting engineering firms, and one of the world's leading planning, environmental, engineering, and program and project management firms. PB is an employee owned company with over 12,000 professional and technical staff operating from 250 offices in 50 countries. This enables us to provide leading edge consultancy services from the latest standards and trends in Europe, North America and the Asia Pacific region to the benefit of our clients.

PB operates in all major cities of Australia. Using the combined capabilities of PB we are able to provide the comprehensive services required for specialised and informed advice on utilities and associated matters anywhere in Australia.

The PB strategic and management consulting group has a leading role in the provision of strategic management services in the utility, infrastructure and energy sectors, focusing on areas of industry and regulatory reform, energy economics, strategic planning, project finance, valuations, and advice on mergers and acquisitions.

The group builds on the experience PB has gained internationally as advisors to governments and utilities on the unbundling and restructuring of electricity supply undertakings around the world, and knowledge of the market structures within which privatised electricity utilities, generators, network operators and suppliers trade. This has included review and advice on various aspects of the electricity supply industry in England, Wales and Scotland since privatisation in 1990. The experience has been built on and extended into other countries, including New Zealand, Ireland, Poland, Portugal, Argentina, Venezuela, the Dominican Republic, United Arab Emirates and the Philippines.

The PB team consists of senior engineering, economic and financial professionals. In addition, we have access to an enormous network of professionals interstate and around the world.

PB can deliver a dedicated project team to the AER, each having relevant and recent experience, in order to ensure its objectives are met with high quality outcomes and within the required timeframes.

We remain acutely aware that the needs and drivers of utility regulators are different from the needs of utility managers, governments and shareholders. From this perspective, PB has an extensive history of delivering reports and outcomes that are of direct value and use to utility regulators. We note a significant potential for failure is to consider the review as an engineering study. Although PB will draw on a significant level of engineering resources, we recognise that an engineering report will not meet the needs of this study. The project team for this project has significant regulatory experience and will ensure that the project outcomes are aligned with the regulatory needs of the AER.

The team has a detailed knowledge of distribution (and transmission) networks – both in Australia and overseas. It also has extensive experience in working with economic regulators in reviewing optimal capital and operating expenditure requirements of monopoly utility businesses – particularly in gas and electricity where regulation is often more evolved. Team members have also worked directly for regulated electricity network businesses. PB believes that this experience provides a sound base for assisting the AER in undertaking this regulatory review the South Australia and Queensland DNSPs' revenue proposals for the period 1 July 2010 to 30 June 2015.

B.2 Summary of relevant experience

In this section we provide a summary of the PB experience which is relevant to this assignment. More detailed information on PB international and local experience is available on request.

The strategic and management consulting group of PB focuses on regulatory advice for the international electricity, gas and water utility industries, and has done so for an extended period of time, as reflected in the following referenced projects.

The teamwork which operates among the different disciplines and skill centres in the company provides an excellent mechanism for the cross-fertilisation of both individual and company experience. The approach has been successfully used to leverage off previous experience that PB has gained as a firm globally, and applied to provide solutions to the challenges facing regulators and electric utilities in an increasingly dynamic marketplace.

PB has considerable experience in the many aspects of utility industry reform, privatisation, regulation and restructuring. The company has advised on a number of wide-ranging privatisation, restructuring and regulation issues, beginning with its appointment in 1987 as technical advisor to the UK Government on privatisation of the electricity supply industry in England and Wales, and also under separate contract in Scotland. This experience has since been built on and extended to other countries including Australia, New Zealand, Argentina, Portugal, Italy, Ireland, Chile, Venezuela, Philippines, and India.

PB has advised the AER on similar revenue proposals, most recently TransGrid's 2009-10 to 2013-14 revenue proposal.

PB has been involved in numerous projects directly related to the AER's request for proposal for the South Australia and Queensland DNSPs, these include the following:

- Review of the TransGrid (transmission) revenue reset submission for the Australian Energy Regulator (AER), 2008/09
- Provision of strategic regulatory advice to the management team at Country Energy as part of the company's preparations for the 2009 distribution price determination
- Provision of technical and commercial advice to the management team at Integral Energy as part of the company's preparations for the 2009 distribution price determination
- Review of the SP AusNet and VENCorp (transmission) revenue reset submissions for the Australian Energy Regulator (AER), April 2007
- Strategic commercial, technical and regulatory advice to TransEnd as part of its preparation for the 2009/10 – 2013/14 regulatory review, 2008
- Provision of expert advice to Western Power in the preparation of its Access Arrangement proposal to the Economic Regulation Authority (ERA), 2008
- Provision of expert regulatory advice to the senior management team as part of the company's preparations for the 2008 distribution price determination – engaged by Aurora Energy (Tasmania), Australia, September 2006
- Powerlink (QLD) Revenue Reset for the Australian Energy Regulator (2006)

- Price reviews for three distribution businesses for the Philippines Energy Regulatory Commission (2006)
- Development of the Technical Rules for the South West Interconnected Network in WA (2006)
- Regulatory submission reports for Western Power (2008 and 2005)
- Review of the TransGrid forward transmission capex for ACCC (2005)
- Review of the Energy Australia forward transmission capex for ACCC (2004)
- DirectLink Regulatory Test Review undertaken for the ACCC (2004)
- distribution price review of ETSA undertaken for ESCoSA (2004)
- reliability incentive review for IPART (2004)
- MurrayLink Regulatory Test Review undertaken for the ACCC (2003)
- SPI PowerNet and VENCorp transmission review for the ACCC (2002)
- distribution price review of Aurora Energy undertaken for OTTER (2002)
- review of NSW distribution and retail competition costs for IPART (2001)
- distribution price reviews of Ergon Energy & ENERGEX for the QCA (2001)
- PowerLink Transmission Review undertaken for the ACCC (2000)
- distribution price reviews of all 5 Victorian DNSPs for the ESC (2000)
- TransGrid transmission review undertaken for the ACCC (1998).

Specifically, all of the key team members for this review have directly participated in work for the AER as part of the recent TransGrid transmission revenue review, or have been associated with providing advice on service target performance incentive schemes.