Electricity Network Costs Review
Final Report

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Preamble

Electricity networks are capital intensive, monopoly utilities designed to deliver an inherently dangerous product that cannot be stored. Electricity supply is an essential service. Value for both customers and shareholders is driven by network performance and cost.

The focus of network business managers must therefore be to sustainably:

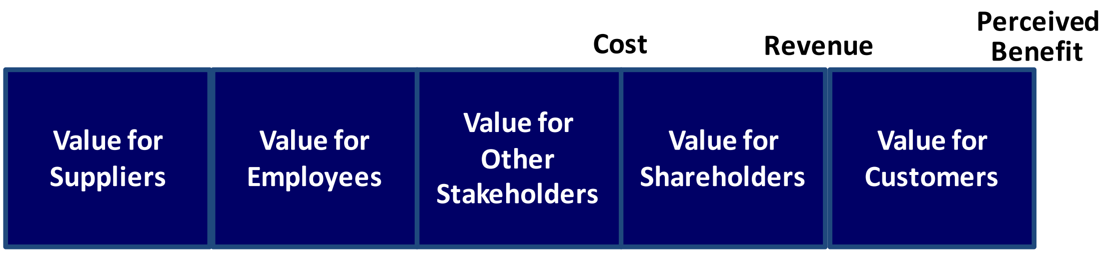
- create network capability, at an economic cost, which meets the forecast requirements for security and reliability of supply for existing customers now and for new customers as they connect to the network in the future; and
- exercise stewardship of the network assets to maintain network performance and preserve the assets over their design life through efficient maintenance, repair and augmentation.

Electricity transmission and distribution assets are spread over an extensive geographic area in an interconnected network. This presents challenges in monitoring network performance and diagnosing asset faults. It also places a premium on effective logistics to deliver resources to the right place at the right time. Supplies of materials, equipment and labour must be moved to locations on the network wherever work is required.

Wide geographic coverage leads to variations in customer density and load and hence the service cost per customer or unit cost of product supplied. Uniform retail, and sometimes network, tariff policies designed for social or equity reasons obscure these differences and constrain economic decision making in network investment and energy use decisions.

Industrial, commercial, rural and residential customers of the network constitute the general community so that each customer is, at the same time, a representative of 'the community'. Stakeholder management can be complicated by conflicts arising from this dual role of community member and customer.

The diagram below illustrates how stakeholder value is created and shared in a business enterprise.



The evolution of the National Electricity Market (NEM) in the eastern states has led to the creation of three national market management and regulatory bodies and the promulgation of well over 2,000 pages of legislative and regulatory instruments at both Federal and State levels.

As a result, the management of electricity network entities is now overlaid by complex legal and regulatory processes and policy interventions which can blur the accountabilities of boards and executives. The role of economic and technical regulators in determining how value is shared between customers and shareholders is constantly being reviewed, with each change triggering significant cost to industry.

The essential capabilities of an electricity network business are:

- a transmission or distribution authority (licence);
- right of access to easements;

- reliable primary network infrastructure (poles, wires and substations) and secondary systems (protection and communications infrastructure);
- a skilled multi-disciplinary workforce;
- access to capital;
- constructive customer and community relationships; and
- positive relationships with shareholders and regulators.

The key enablers of these capabilities in an efficient, effective network business are:

- load forecasting and network planning;
- primary and secondary network technologies;
- effective operation of the network;
- logistics management;
- contract administration;
- field work resourcing and management;
- regulatory management;
- network diagnostic and technical;
- asset management;
- project management;
- relationship management; and
- financial management.

The Panel has assessed the essential capabilities, processes and outcomes of the NSPs against industry benchmarks and has made 45 recommendations to better meet customer, community and shareholder expectations.

Executive Summary

In response to the recent history of rising electricity prices, the Queensland Government instituted a freeze on the standard residential tariff for 2012/13 and established the Independent Review Panel on Network Costs (IRP or the Panel) to develop options to address the impact of network costs on electricity prices in Queensland.

The review is focussed on the Government-owned electricity distribution and transmission corporations, which are:

- Ergon Energy (Ergon Energy Corporation Limited), which owns and operates the electricity distribution network in regional Queensland and the north-west Queensland network around Mount Isa, as well as 34 isolated networks (including 33 small-scale generators) in more remote locations across Queensland;
- Energex (Energex Limited), which owns and operates the electricity distribution network in south-east Queensland; and
- Powerlink (Queensland Electricity Transmission Corporation Limited), which owns and operates the high voltage transmission network across Queensland, and the main interconnection to the NEM.

Ergon Energy and Energex are registered distribution network service providers (DNSPs) and Powerlink is a registered transmission network service provider (TNSP) within the NEM under the National Electricity Rules (the Rules). The NSPs are incorporated under the *Corporations Act 2001* (Cth) and are Government Owned Corporations (GOCs) wholly owned by the Queensland Government under the *Government Owned Corporations Act 1993* (Qld) (GOC Act).

The GOC Act requires GOCs to operate as commercial entities. It also imposes requirements for transparency, accountability, probity in commercial dealings, high standards of ethical behaviour and comprehensive reporting, consistent with their public ownership. Boundaries are set on the extent of Government control and direction, with the Boards and management responsible for implementing specified expectations of the Government as shareholder of the companies. Where Government mandates the provision of specific services that are not commercial, there is a requirement for explicit Community Service Obligation (CSO) payments to be recognised.

The Panel has found a trend towards higher levels of involvement by Government in the operations of the GOCs. The capital programs and operating costs of the GOCs have increased sharply and unsustainably in response to prescriptive system design standards, such as the N-1 security standard and the Minimum Service Standards (MSS) imposed by Government.

In the network review undertaken in 2004, both DNSPs made submissions that included their concerns that the adoption of the N-1 security standard was not warranted on the broad basis prescribed and would contribute to increased capital and operating costs. The DNSPs also submitted that customers would be better served in some circumstances by improved quality of supply rather than increased security of supply.

These standards were originally introduced to improve the reliability of the network but have driven excessive costs and resulted in a degree of over-engineering of the networks. The entrenching of the standards within State licences and through Government direction have also limited the ability of the economic regulator, the Australian Energy Regulator (AER), to adequately assess the prudence of these investments. This constrains the application of the NEM economic regulatory regime to the Queensland NSPs.

The Boards and management of the DNSPs amended their capital and operating programs to work towards meeting these standards. The Panel acknowledges the efforts of engineering, field and support staff in responding to the challenges of increased programs of work. At the same time, staff have delivered improved emergency and fault response.

The 2011 Electricity Network Capital Program (ENCAP) Review was, in part, a response to ongoing submissions to Government from the DNSPs for modifications of the strict N-1 requirement.

Another factor contributing to the escalation in capital programs has been the consistent over-estimation of demand by the NSPs. The Panel also notes that the current revenue cap control mechanism places volume risk on customers. Where demand is over-estimated, capital programs will be excess to requirements and network tariffs to customers will increase during the regulatory control period to ensure the NSPs are able to recover the allowable revenue.

Through consultations with stakeholders and discussions with Technical Reference Groups (established by the Panel and comprising representatives from the NSPs), it is further evident that these issues have been compounded by:

- an industry engineering culture biased toward expanding the network infrastructure and enlarging the capital base of the NSPs;
- a deficient commercial model in that there was no rigorous capital rationing by the Government, as shareholder and provider of capital, to guide investment decisions; and
- a regulatory model that limits the ability of the AER to drive the NSPs towards the delivery of efficient capital and operating programs.

One outcome has been expenditure on demand management and emerging technologies, much of which has yet to yield commercially viable solutions as genuine alternatives to network augmentation. The level of expenditure in these areas by the Queensland DNSPs is much higher than in the privately owned DNSPs in other States.

The primary consequence of all these factors has been rapidly rising network tariffs that have unnecessarily burdened households and businesses with electricity price rises well in excess of inflation. This situation is unnecessary and unsustainable for households and businesses in Queensland and recommendations are made to address it.

In addition, the Panel considers that Queensland taxpayers continue to be burdened by significant and increasing costs in the provision of electricity supply in isolated areas and retail services within the Ergon Energy distribution area. Excessive overhead allocations in these two areas have added significantly to the Government's CSO payments to support uniform retail electricity tariffs throughout the State.

The Panel's preference is to move towards an outcomes-based approach, to hold the Boards and senior management of the NSPs accountable for outcomes and costs through:

- delivering services that meet customers' expectations;
- benchmarking network performance against best practice; and
- creating value through the activities they undertake.

This Report summarises the Panel's findings and recommendations for reform.

The recommendations of this Panel, changes in market demand conditions and internal efficiency programs driven by the new Chairs and Boards of the NSPs, will result in large reductions to the expenditure programs of the NSPs.

The Panel estimates that **reductions** in total expenditure across the NSPs of around **$3.6 billion**[1] can be achieved compared with the current 5-year regulatory expenditure

[1] This figure is calculated as the difference between total expenditure (operating plus capital) in the AER determinations and the total expenditure projected by the Panel over the current regulatory periods, in nominal terms. For the DNSPs, the period is 2010/11 to 2014/15. For the TNSP, the period is 2012/13 to 2016/17.

programs approved by the AER. The capital component of these reductions includes efficiencies identified by the Panel and the NSPs as well as program adjustments in response to the ENCAP Review and changes in market demand.

The recommendations of the Panel are estimated to result in savings of a further **$1.4 billion**[2] in indirect costs alone in the DNSPs over the five years from the end of the regulatory periods.

The Panel expects that, as a result of the implementation of its recommendations, the **impact on electricity prices from network operations and capital programs will be greatly reduced.**

In the period to 30 June 2015, the Panel estimates that there will be a lower rate of increase in this component of household electricity prices (Tariff 11) compared with prices that would have prevailed under the original regulatory determinations.

In the next regulatory period commencing 1 July 2015 (for the DNSPs), the Panel expects that this component of electricity prices will fall by between 1.0 and 1.5 cents per kWh and then stabilise in real terms over the remainder of the next regulatory period. For a household consuming an average 7,934[3] kWh of electricity per annum, this translates to a decline of between $79 and $119 for this component of the annual household electricity bill.

The Panel notes that there are other drivers of electricity price increases such as green schemes, carbon imposts, electricity generation costs and regulatory factors which are unrelated to the efficiency of the capital and operating programs of the NSPs. The Panel is unable to comment on the future impact of these other drivers on household electricity prices.

[2] This has been calculated as follows. It includes all savings in indirect costs from business efficiency programs, Panel savings and structural synergies, in nominal terms, from 2015/16 to 2019/20. The baseline for this calculation is the DNSPs' May 2012 draft Statements of Corporate Intent.

[3] ACIL Tasman, *Electricity Bill Benchmarks for residential customers*, Report prepared for the Consumer Information Implementation Committee, December 2011, Table 18.

Key Findings and Recommendations

Four key areas of reform are addressed in this report and most of the recommendations relate to these.

Network Reliability Standards

On the basis of its analysis, including consultation with the NSPs and regulatory bodies, the Panel considers that network security standards:

- are overly prescriptive;
- have resulted in over-engineering of the network and driven excessive capital and operating costs;
- have not sufficiently involved economic analysis of the benefit of network capital expenditure relative to outcomes that are acceptable to customers in terms of both reliability and cost; and
- have driven excessive increases in network tariffs that affect the affordability of electricity supply for households and business.

The Panel has made a number of recommendations to reduce the degree of prescription of network standards, place a greater focus on outcomes rather than inputs, take greater account of customer expectations in terms of reliability of supply and affordability, and require the Boards and management of the NSPs to benchmark performance and outcomes against best practice domestically and internationally.

See Recommendations 1 to 10.

Overhead Expenses – Indirect Costs

The overhead expense (indirect costs) of Ergon Energy and Energex is more than $1 billion annually (Ergon Energy $543 million; Energex $510 million). This expense has grown rapidly in recent years and places the Queensland DNSPs among the least efficient in the NEM.

The three NSPs have all commenced programs to improve the efficiency of their operations and reduce both indirect and direct costs. The Panel acknowledges that these programs will yield results but believes that additional impetus is needed to produce the level of savings required to restore affordability for customers.

See Recommendations 11 to 16, 20, 27 and 28.

Operational Efficiency – Direct Costs

Comparative data indicate that the Queensland DNSPs are less efficient than their interstate peers on a range of operational metrics (see Figures 25 and 26).

The Panel estimates that every 1% gain in labour productivity would deliver annual savings of over $4 million. It has made a number of recommendations focussed on improving operational efficiency.

See Recommendations 21 to 26 and 40 to 42.

Structural Reform

The Panel considered a range of possible structural reforms during the course of its review.

In assessing the efficacy of the options, the Panel considered the following key criteria:

- the need for cultural change as a driver for operational improvement and refocus on cost effective outcomes that meet customer expectations;
- the potential to deliver material synergistic cost savings, particularly in overhead costs;
- the potential to deliver material operational efficiency improvements; and
- implementation risks relative to the potential returns.

The Panel estimates that the existing efficiency programs combined with the recommended structural reform would deliver additional cumulative indirect cost savings of **$1.4 billion**[4] over the period from 2015/16 to 2019/20.

See Recommendation 30.

Other areas of reform considered by the Panel and related recommendations are set out in the body of this report.

The Panel has also recommended that Government give consideration to eventual privatisation of the DNSPs, which will drive significant further efficiencies.

See Recommendation 43.

Some of the recommendations will take time to have an effect and the Panel considers that the Government needs to give high priority to the implementation of these reforms.

See Recommendation 44 and 45.

[4] This has been calculated as follows. It includes all savings in indirect costs from the DNSPs' business efficiency programs, Panel savings and structural synergies, in nominal dollar terms, from 2015/16 to 2019/20. The baseline for this calculation is the DNSPs' May 2012 draft Statements of Corporate Intent.

Recommendations

Planning and Reliability Standards for Transmission		P
Recommendation 1	Remove the N-1 condition in the Transmission Authority for Powerlink and replace this with minimum performance standards to be met on a best endeavours basis. Powerlink would then have the flexibility to adopt the hybrid approach to network planning that it has recommended to the Panel. *Implementation: DEWS*	41
Recommendation 2	The Government notify the AER of this change in Authority conditions. *Implementation: DEWS*	41
Recommendation 3	The Powerlink Board be made responsible for the delivery of best practice supply reliability having regard to the expectations of Queensland electricity users and the minimum performance standards in the Transmission Authority. *Implementation: DEWS*	41

Planning and Reliability Standards for Distribution		P
Recommendation 4	The Government should no longer prescribe input-based security standards for the DNSPs. Responsibility for security standards should reside with the respective Boards and Management. The Government should notify the AER of this change in policy. *Implementation: DEWS*	42
Recommendation 5	Each DNSP should review its security standards and publish its network security policy in its annual report and the Distribution Annual Planning Report. *Implementation: DNSPs*	42
Recommendation 6	Remove the Minimum Service Standards from the Electricity Industry Code and instead include them in the DNSPs' Distribution Authorities, with systemic failures to meet these standards to be considered a breach of Authority conditions. *Implementation: DEWS*	43
Recommendation 7	Set Minimum Service Standards levels for the DNSPs at the levels applying at the commencement of the current regulatory control period (i.e. 1 July 2010). *Implementation: DEWS*	45
Recommendation 8	The Boards of the DNSPs should review reliability performance against comparable national or international networks and report on these comparisons in their annual reports. *Implementation: DNSPs*	46
Recommendation 9	The Boards of the DNSPs should continue to monitor Worst Performing Feeders and report on their performance in their annual reports and the Distribution Annual Planning Reports.	47

	Implementation: DNSPs	
Recommendation 10	Retain Guaranteed Service Level arrangements as currently specified. *Implementation: DEWS*	47
Efficiency of Indirect Cost Activities		P
Recommendation 11	The Boards of the DNSPs continue with the implementation of their efficiency programs. *Implementation: DNSPs*	53
Recommendation 12	Return the role of the Office of the Chief Information Officer to each of the DNSPs and SPARQ Solutions focus on its role as a service provider to the DNSPs. *Implementation: DNSPs*	54
Recommendation 13	Each of the DNSPs reassess its Information Communication and Technology capital expenditure priorities and focus on the prudent capital expenditure required to maintain its core distribution business activities (including regulatory compliance and safety obligations). *Implementation: DNSPs*	54
Recommendation 14	In addition to the cost savings already identified by SPARQ Solutions, further efficiencies should be achieved through actions such as: ▪ Streamlining the testing process through the adoption of an automated testing tool; ▪ Developing a common set of automated financial and management reports for the DNSPs; and ▪ Reviewing existing system contracts to reduce user licence costs in line with future staffing levels within SPARQ Solutions and the DNSPs. *Implementation: DNSPs*	55
Recommendation 15	Alternative service delivery models for Information and Communication Technology services currently delivered by SPARQ Solutions should be tested as follows: ▪ issue market tenders for the delivery of capital projects; and ▪ issue market tenders for the delivery of the relevant operational Information Communication and Technology services. *Implementation: DNSPs*	55
Recommendation 16	Implement an integrated operating model that consolidates the Planning and Partnering positions within DNSPs to minimise the number of touch points between SPARQ Solutions and the DNSPs. *Implementation: DNSPs*	55

Recommendation 17	Progress the ROAMES project in partnership with parties that can assist with the commercialisation process and provide the additional capital required. *Implementation: Ergon Energy*	56
Recommendation 18	Ergon Energy seek expressions of interest from external providers of modular substations and other related workshop services and discontinue the internal provision of these services if this results in lower cost. *Implementation: Ergon Energy*	56
Recommendation 19	Ergon Energy divest its holdings of land for forests and reinvest the sale proceeds in core network assets. *Implementation: Ergon Energy*	56
Recommendation 20	The DNSPs take immediate action to reduce expenditure on consultancies, professional services and non-frontline contractors and achieve reductions commensurate with the revised programs of work. *Implementation: DNSPs*	57
Efficiency of Direct Cost Activities		P
Recommendation 21	The DNSPs pursue as part of current efficiency programs the implementation of an effective scheduling tool to improve the efficiency of scheduling and increase the productivity of the workforce. *Implementation: DNSPs*	60
Recommendation 22	The DNSPs implement a common set of output-based performance measures at the depot level to ensure that labour efficiency is measured and reported. *Implementation: DNSPs*	62
Recommendation 23	In the Ergon Energy service delivery area, consideration be given to the adoption of a Local Service Agent model for depots in the range of 8 to 15 employees where there would be improved services to customers, service delivery would be more cost effective and where there is broad support amongst staff for the adoption of this type of service delivery model. *Implementation: Ergon Energy*	62
Recommendation 24	The NSPs take urgent action to reduce overtime to benchmark levels and review gross pay to base pay ratios for all employees. *Implementation: NSPs*	63

Recommendation 25	Amend existing regulatory instruments/legislation and seek to amend other relevant commercial arrangements to: ▪ reduce constraints on the issue of permits for road access for DNSP works; ▪ allow DNSPs to take responsibility for repositioning telecom equipment when power poles are replaced; ▪ ensure that the asset condition monitoring requirements in the *Electrical Safety Code of Practice 2010* – works take account of pole types; and ▪ ensure that photovoltaic installations are not connected to the network until a new meter has been installed and the inverter maximum voltage settings have been verified as compliant with the connection and installation agreements. *Implementation: DEWS*	64
Recommendation 26	The NSPs remove internal constraints to improved efficiency, as follows: ▪ Apart from categories of work which are contracted as a matter of policy, NSPs should fully utilise internal resources before packaged maintenance and minor works are contracted out. Some projects could also be jointly resourced to increase field workforce utilisation. ▪ The DNSPs improve workforce flexibility to match start/finish times with work requirements. ▪ The NSPs harmonise their Fatigue Management Policies by 1 July 2013. *Implementation: NSPs*	65
Recommendation 27	Ergon Energy should reduce the overhead allocated to isolated generation and networks from the current level of $23 million per annum to no more than $4 million per annum. The reduction in overhead of $19 million should not be re-allocated within the Ergon Energy business and should instead be removed through the efficiency programs from total overhead costs. *Implementation: Ergon Energy*	66
Recommendation 28	Ergon Energy should apply a similar principle to overheads currently allocated to the retail business. *Implementation: Ergon Energy*	67
Recommendation 29	The Government call for expressions of interest from the private sector to operate and maintain the isolated supply assets in Queensland as an independent power producer. *Implementation: DEWS*	67

Structures for the Distribution Businesses		P
Recommendation 30	Establish a new holding company for the two DNSPs to drive efficiencies and other operational improvements, structured as follows: ▪ A common Board providing governance for the holding company and the two DNSP subsidiaries; ▪ A Chief Executive Officer of the holding company who will also be the Chief Executive Officer of the two DNSP subsidiaries; ▪ A Chief Operating Officer for each of the two DNSP subsidiaries reporting to the Chief Executive Officer; ▪ Corporate and strategic leadership located within the holding company, comprising the Chief Financial Officer, Chief Investment Officer and Executive General Managers for Corporate Strategy, Network Stewardship and Strategic Procurement; ▪ Core and support processes remain within the subsidiaries; ▪ SPARQ Solutions to become a subsidiary of the holding company; and ▪ A Major Projects group to provide services to both DNSP subsidiaries, structured as a separate business unit. *Implementation: DEWS*	88
Network Regulation		**P**
Recommendation 31	The Queensland Government advocate greater independence for, and strengthening of, the national energy regulator, by: ▪ separating the AER from the ACCC in order to give it greater capacity to discharge its obligations; and ▪ ensuring the AER has the ability to attract suitably qualified and experienced staff, including the ability to offer commensurate levels of remuneration. *Implementation: DEWS*	90
Recommendation 32	The Queensland Government seek the agreement of the Standing Council on Energy and Resources for a review of the AEMC's role and exercise of its rule making powers, specifically: ▪ governance arrangements aimed at greater transparency in its operations and ensuring the AEMC is more directly accountable to Energy Ministers; and ▪ establishment of a materiality threshold for rule change requests. *Implementation: DEWS*	90

Recommendation 33	The Queensland Government: ▪ seek the support of the Standing Council on Energy and Resources for a comprehensive review of the National Electricity Rules under s.41 of the National Electricity Law, aimed at reducing the current regulatory complexity to ease the compliance burden on the industry; and ▪ support the selection of a Weighted Average Price Cap control mechanism by the AER during the Queensland Framework and Approach process. *Implementation: DEWS*	91
Network Planning		P
Recommendation 34	Retain the Network Management Plan requirement but transition to the Distribution Annual Planning Report as required under the National Electricity Rules. Remove the requirement for the Network Management Plan from the Electricity Industry Code once the Distribution Annual Planning Report rule has commenced. *Implementation: DEWS*	92
Recommendation 35	Remove the requirement for Summer Preparedness Plans from the Electricity Industry Code. *Implementation: DEWS*	92
Recommendation 36	The Government support changes to the connection and service classification arrangements which facilitate connection between major customers or generators and the relevant NSPs. Government should not support the adoption of mandatory regulatory processes which would reduce the flexibility of users to negotiate or limit the ability for extension works to be provided in a timely and responsive manner. *Implementation: DEWS*	93
Recommendation 37	The Government encourage competition and private sector investment in unregulated transmission extensions through changes that streamline easement acquisition processes. *Implementation: DEWS*	94
Recommendation 38	The Government prepare and publish a Regulatory Statement to clearly describe the licensing and approvals required for electricity supply network infrastructure in Queensland. *Implementation: DEWS*	94
Demand Forecasting		P
Recommendation 39	The NSPs retain responsibility for demand forecasting as the basis for network planning at the State and regional level. The Panel does not support nationally centralised demand forecasting for this purpose. *Implementation: DEWS*	96

Managing Peak Demand		P
Recommendation 40	Demand management projects and activities should proceed only where a rigorous commercial assessment has been completed. *Implementation: DNSPs*	101
Recommendation 41	Discontinue demand management projects and activities associated with emerging technologies that will not be commercialised or provide benefits to consumers within the medium term. This excludes projects covered by the AER's Demand Management Incentive Scheme. *Implementation: DNSPs*	101
Recommendation 42	Resources should be adjusted to match changes in activity consequent to Recommendations 40 and 41. *Implementation: DNSPs*	101

Ownership		P
Recommendation 43	The Government give consideration to the privatisation of the NSPs. *Implementation: DEWS*	102

Implementation		P
Recommendation 44	DEWS to develop an implementation plan including a timetable. *Implementation: DEWS*	106
Recommendation 45	The implementation plan developed by DEWS should include a process for reporting to allow Government to monitor progress with implementation. *Implementation: DEWS*	106

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Glossary

Abb.	Term
3D	Three Dimensional
ACCC	Australian Competition and Consumer Commission
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
c/kWh	Cents per kilowatt hour
CAGR	Compound Annual Growth Rate
CBD	Central Business District
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CIO	Chief Information Officer
COAG	Council of Australian Governments
COO	Chief Operating Officer
CSO	Community Service Obligation
DEWS	Department of Energy and Water Supply
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
EDSD	Electricity Distribution and Service Delivery
EEPL	Ergon Energy Pty Ltd
EEQ	Ergon Energy Queensland Pty Ltd
EGM	Executive General Manager
EIC	Electricity Industry Code
ENCAP	Electricity Network Capital Program
ENCAP Review	Electricity Networks Capital Program Review 2011
Energex	Energex Limited
Ergon Energy	Ergon Energy Corporation Limited
ETU	Electrical Trades Union
EUAA	Energy Users Association of Australia
Federal Government	Commonwealth Government of Australia
FTE	Full Time Equivalent
GOC	Government Owned Corporation
GOC Act	Government Owned Corporations Act 1993 (Qld)
GSL	Guaranteed Service Level
GSP	Gross State Product
GWh	Gigawatt hour
HR	Human Resources
ICT	Information and Communication Technology
IDC	Interdepartmental Committee
IPP	Independent Power Producer
IRP or the Panel	Independent Review Panel on Network Costs
IT	Information Technology
ITOMS	International Transmission Operations and Maintenance Study
kV	kiloVolt
kW	kilowatt
kWh	kilowatt hour
LMR	Limited Merits Review
LSA	Local Service Agent

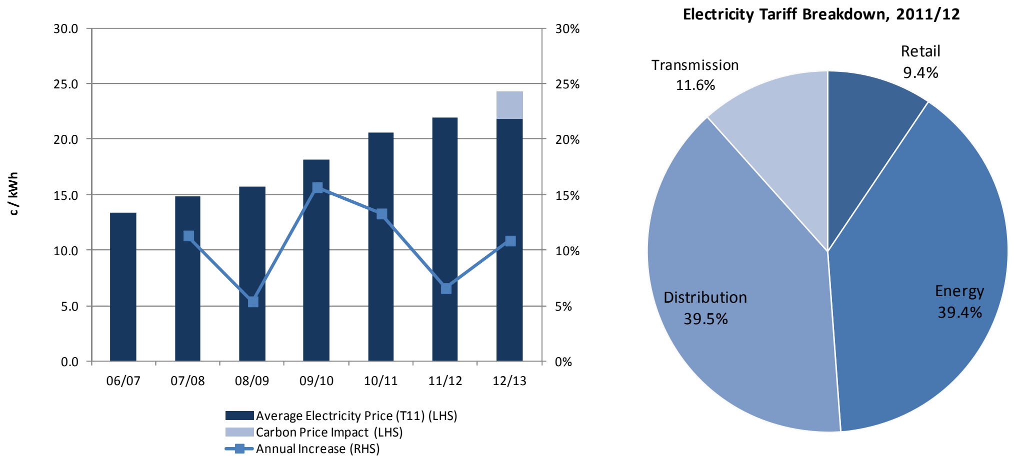
Abb.	Term
MAR	Maximum allowable revenue
MCE	Ministerial Council on Energy
MSS	Minimum Service Standards
MVA	Megavolt amp
MW	Megawatt
MWh	Megawatt hour
N-1	Security of Supply standard, where supply is maintained with one element out of service
NECF	National Electricity Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NMP	Network Management Plan
NPV	Net Present Value
NSP	Network Service Provider or Ergon Energy, Energex and Powerlink collectively
PC	Productivity Commission
PoE	Probability of Exceedance
PoW	Program of Work
PV	Photovoltaic
PwC	PricewaterhouseCoopers
QCA	Queensland Competition Authority
QEIST	Queensland Electricity Industry Structure Taskforce
QSU	Queensland Service Union
QTC	Queensland Treasury Corporation
RAB	Regulatory Asset Base
ROAMES	Remote Observation, Automated Modelling, Economic Simulation
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCER	Standing Council on Energy and Resources
SOPP	Statement of Policy Principles
SPARQ	SPARQ Solutions
STPIS	Service Target Performance Incentive Scheme
TFR	Transmission Frameworks Review
The Rules	National Electricity Rules
The State	The Queensland Government
TNSP	Transmission Network Service Provider
TRG	Technical Reference Group
WACC	Weighted Average Cost of Capital

1. Introduction

1.1. Background

Retail electricity prices in Queensland have risen in nominal terms by 82% since 2006/07[5] in a trend apparent across all Australian jurisdictions in the National Electricity Market (NEM). The primary driver of these increases in retail prices has been network charges, which have risen by 96% over the same period.[6]

Figure 1. Residential Retail Electricity Price (T11), 2006/07 – 2012/13



Source: Queensland Government Gazette Vols 342(42), 345(46), 348(30), 351(41), 354(26), 357(35) and 360(43).

In this context, the Government established the Independent Review Panel on Network Costs (IRP or the Panel) to assess the potential for reform of the government-owned electricity distribution and transmission corporations – Ergon Energy, Energex and Powerlink.[7] This Panel's task is a critical component of the broader investigation by the Government's Interdepartmental Committee (IDC) on Electricity Sector Reform.

1.2. Terms of Reference

Under the Terms of Reference set by the IDC the objective of the Panel was to *"develop options to address the impact of the development of the electricity network in Queensland on electricity prices"*. While the Panel was not limited in the areas which it could investigate, the Terms of Reference directed it to make specific recommendations on:

- The optimal structures of the Government Owned Corporation (GOC) distribution network businesses (Ergon Energy and Energex) having regard to reform processes being progressed elsewhere in Australia;
- The efficiency of current network capital and operational expenditure within the GOC network businesses (Ergon Energy, Energex and Powerlink) and innovative options to:
  - address peak demand increases;
  - improve the efficiency of capital and operating expenditure;
  - plan for (and respond to changes in) economic growth;

[5] Based on gazetted residential Tariff 11 for 2006/07 and 2012/13, and average four-person household consumption of 7,934 kWh per annum (from ACIL Tasman, *Electricity Bill Benchmarks for residential customers, Report Prepared for the Consumer Information Implementation Committee, December 2011*). The real (i.e. inflation adjusted) increase is 52%.

[6] QCA, *Benchmark Retail Cost Index for Electricity: 2006-07 and 2007-08*, Final Decision, June 2007; QCA, *Benchmark Retail Cost index for Electricity: 2011-12*, Final Decision, May 2011.

[7] Minister for Energy and Water Supply, *IRP set for electricity price reform*, Ministerial Media Statements, Queensland Government, 30 May 2012

- deliver savings in corporate and overhead costs including Information Technology (IT);
- reduce the Community Service Obligation (CSO) payment in support of non-contestable customers;
- incorporate the value to customers of network security and reliability in network planning and the setting of performance standards; and
- improve demand forecasting;

- Current and future issues in relation to national regulatory reform for the network businesses, with particular reference to areas that Queensland should influence in order to improve outcomes for network costs; and
- A timeframe for potential reductions in network prices.

The full Terms of Reference are provided in Appendix A.

1.3. Queensland Electricity Network Businesses

The review was focussed on the Government-owned electricity distribution and transmission corporations, which are:

- Ergon Energy (Ergon Energy Corporation Limited), which owns and operates the electricity distribution network in regional Queensland and the north-west Queensland network around Mount Isa, as well as 34 isolated networks (including 33 small-scale generators) in more remote locations across Queensland;
- Energex (Energex Limited), which owns and operates the electricity distribution network in south-east Queensland; and
- Powerlink (Queensland Electricity Transmission Corporation Limited), which owns and operates the high voltage transmission network across Queensland, and the main interconnection to the NEM.

Ergon Energy and Energex are registered distribution network service providers (DNSPs) and Powerlink is a registered transmission network service provider (TNSP) within the NEM under the National Electricity Rules (the Rules). The NSPs are incorporated under the *Corporations Act 2001* (Cth) and are GOCs wholly owned by the Queensland Government under the *Government Owned Corporations Act 1993* (Qld) (GOC Act).

The GOC Act requires GOCs to operate as commercial entities. It also imposes requirements for transparency, accountability, probity in commercial dealings, high standards of ethical behaviour and comprehensive reporting, consistent with their public ownership. Boundaries are set on the extent of Government control and direction, with the Boards and management responsible for implementing specified expectations of the Government as shareholder of the companies. Where Government mandates the provision of specific services that are not commercial, there is a requirement for explicit CSOs to be recognised.

1.4. The Panel's Approach to Meeting the Terms of Reference

The Panel was selected by the Queensland Government to bring a depth of expertise and wide energy-sector experience covering policy, industry and technical perspectives. The Panel comprised:

- Mr Tony Bellas (Chair), with over 25 years in senior public and private sector management, including as Chief Executive Officer (CEO) of Ergon Energy (2004-2007) and CS Energy (2001-2004);

- Mr Matt Rennie (Panel Member), with over 18 years' experience providing strategic and economic advice to boards and management of energy and infrastructure businesses, governments and regulators in the Asia Pacific region; and
- Mr Alec Faulkner (Panel Member), with 30 years' experience as an international adviser to the mining and electricity industries, including as the Chair of the Advisory Board for Powercor Network Services.

In undertaking its task, the Panel applied the following guiding principles:

- ensuring that the NSPs and their Boards understand the need for industry to:
  - deliver services that meet customers' expectations;
  - benchmark network performance against best practice; and
  - create value through the activities they undertake;
- adopting less prescriptive regulation where possible, and providing an environment that encourages innovation and drives efficiency in network service delivery; and
- supporting a streamlined, effective and efficient national regulatory framework.

The primary goal was efficiency improvement in the existing businesses. Efficiency gains from structural reform of the DNSPs were considered in a second stage.

Biographical summaries for the Panel members are provided in Appendix B.

1.5. Interaction with Stakeholders

The Panel acknowledges the support of the NSPs through their timely and considered responses to information requests. The NSPs have provided assistance through:

- responses to requests for specific data;
- written submissions to complement the data requests;
- secondment of specialist staff;
- participation in Technical Reference Groups (TRGs); and
- providing the findings of their own reviews of operational efficiency.

The Panel consulted widely with a range of stakeholders. It thanks those organisations and individuals for their time and, in many cases, for providing supplementary information that assisted in the preparation of this Report.

A list of organisations that met with the Panel is set out in Appendix C.

1.6. Structure of this Report

This report addresses the requirements of the Terms of Reference as follows:

Table 1. Report Structure

Report	Purpose
Chapters 1-4	Set out the background for this review, including the Terms of Reference. Provide an overview of Ergon Energy, Energex and Powerlink, and the regulatory environment in which they operate.
Chapters 5 -7	Examine key drivers of network costs and recommend process and resource changes to deliver greater efficiency. Assess the likely impact of the national regulatory framework on achieving these outcomes.
Chapter 8	Presents the case for structural change for the DNSPs. Assesses three options for their potential to drive further efficiency gains, synergy cost savings and a more commercial, innovative culture. Sets out initial steps for implementing the preferred structure.
Chapter 9	Considers other aspects of regulation, network planning, large customer connections, demand forecasting and demand management.
Chapter 10	Considers the issue of public versus private ownership of regulated, monopoly network businesses.
Chapter 11	Summarises the savings from the Panel's recommendations and current efficiency initiatives.
Chapter 12	Outlines the key recommendations for implementation.

2. Overview of Queensland Electricity Networks

The NSPs are a vital part of the electricity supply chain, delivering electricity to approximately 2.1 million customers[8] in Queensland. This chapter provides an overview of the electricity supply industry in Queensland.

2.1. Overview of the Queensland Electricity Supply Industry

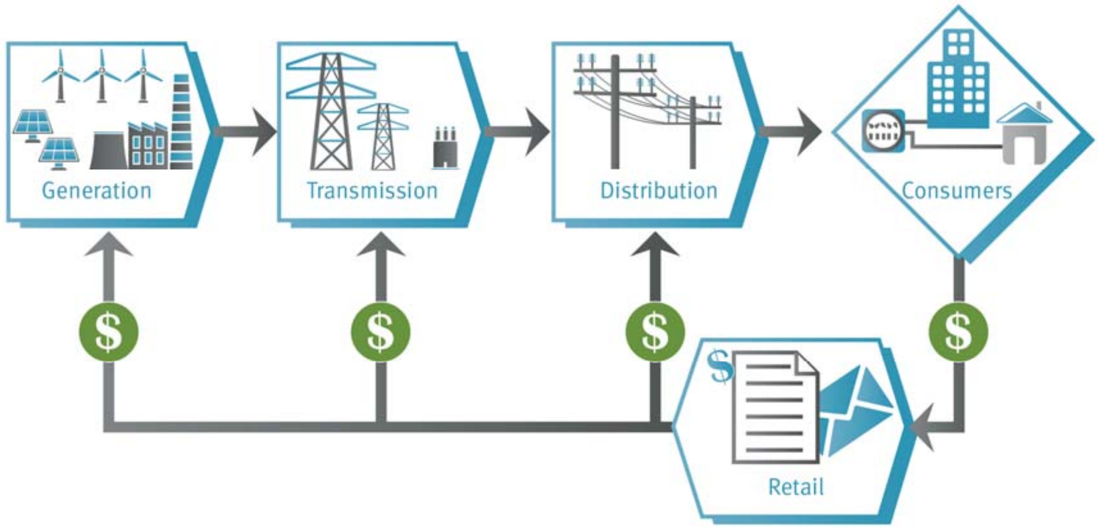
The electricity supply industry comprises:

- generators, which produce and supply electricity to the network. In Queensland, they include the publicly owned companies, such as Stanwell Corporation and CS Energy, and privately owned generators such as Intergen, Alinta and Origin Energy. Around 50% of the generation capacity[9] in the State is held by private sector companies;
- TNSPs, which transport electricity at high voltages from generators either directly to large customers or to connection points with the distribution networks. Powerlink is the only registered and operating TNSP in Queensland. It is owned by the Queensland Government;
- DNSPs, which distribute electricity at lower voltages from the transmission and embedded generation connection points to end-use residential, commercial and industrial customers. In Queensland, the registered and operating DNSPs are Ergon Energy and Energex.[10] Ergon Energy and Energex are owned by the Queensland Government; and
- retailers, which purchase electricity from the market and sell it to end-use consumers. In Queensland, there are 28 licensed retailers.[11] Ergon Energy is the only retailer owned by the Queensland Government.[12]

The electricity supply value chain is summarised in the following diagram.

[8] The number of connections has been used as a proxy for the number of customers.
[9] Based on installed capacity. Queensland Government, *Electricity Generation*, http://www.business.qld.gov.au/industry/energy/electricity-industry/electricity-queensland/electricity-generation.
[10] Essential Energy is a New South Wales distributor which is registered as a DNSP in Queensland as its network in north western New South Wales extends into the area around Goondiwindi.
[11] Department of Energy and Water Supply, *Retail Authorities (Licences) Under the Electricity Act 1994 (Qld)*
[12] CS Energy and Stanwell Corporation also hold retail licences. Neither provides retail services to residential or small commercial customers.

Figure 2. Overview of the Electricity Supply Industry



Source: DEWS

2.2. Electricity Contracts and Tariffs

Retail prices are the aggregate of:

- the cost of electricity purchased from generators;
- the cost of transmission and distribution services (i.e. arranging for the electricity to be delivered to customers); and
- a retail margin (to cover the retailer's own costs plus profit).

Each NSP has a range of network tariffs, reflecting the cost profile, metering facilities and demand profile of customer groups assigned to each tariff class. Generally, network tariffs comprise one or more of the following elements:

- fixed daily charge ($ / day);
- capacity charge ($ / kW / month);
- demand charge ($ / kW / month); and
- volume charge ($ / kWh).

Network tariffs for residential and small commercial customers, with consumption less than 100MWh per annum, generally comprise a fixed daily charge and a volume charge. The structures of tariffs for residential customers are limited by the type of meters installed at customer premises. These are typically accumulation meters that do not record the time of consumption or the maximum demand and are therefore not able to provide the data necessary for time-based or demand tariffs.

Since the introduction of full retail contestability in 2007, residential customers are able to choose their retailer and also whether they are supplied under a:

- Standard Retail Contract, which is based on electricity tariffs set by the Queensland Government; or
- Negotiated Retail Contract, which is based on electricity tariffs determined by the retailer.

The tariffs applicable to the Standard Retail Contracts are the regulated retail tariffs published in the Queensland Government Gazette. For residential customers, these are:

- Tariff 11 – Residential (Lighting, Power and Continuous Hot Water), which is the standard tariff for residential customers. It is a two-part tariff comprising a fixed daily charge and a volume charge;
- Tariff 12 – Residential (Lighting, Power and Continuous Hot Water) Time of Use, which is a two-part tariff with a fixed daily charge and a volume charge that varies depending on the time of day and day of the week the electricity is consumed. Higher charges apply during peak periods and lower charges during shoulder and off-peak periods;[13]
- Tariff 31 – Night Rate (Super Economy), which is a volume charge only tariff for off-peak (usually night time) supply of electricity for hot water systems; and
- Tariff 33 – Controlled Supply (economy), which is a volume charge only tariff for interruptible supply of electricity for appliances such as hot water systems and pool pumps.[14]

2.3. Overview of the NSPs

2.3.1. Ergon Energy

Ergon Energy Corporation Limited (Ergon Energy) was established in 1999, following structural reforms recommended by the Queensland Electricity Industry Structure Taskforce (QEIST). Ergon Energy comprises the distribution network businesses of the six predecessor regional electricity corporations[15].

The retailer jointly owned by the six predecessor corporations, Ergon Energy Pty Ltd (EEPL), became a subsidiary of Ergon Energy. EEPL continued as a subsidiary of Ergon Energy until 2007, when the contestable part of the retail business was sold and the remaining non-competing business, servicing subsidised customers, transferred to a new company, Ergon Energy Queensland Pty Ltd (EEQ). Under section 55G of the *Electricity Act 1994*, EEQ is prohibited from entering into negotiated retail contracts with customers and is effectively limited to providing retail services to customers within Ergon Energy's distribution area under standard retail contracts (i.e. offering the regulated retail tariff).

Key regional centres for Ergon Energy include Cairns, Townsville, Mackay, Rockhampton, Maryborough and Toowoomba, largely reflecting the locations of the original regional distribution bodies. The development of the network and the practicalities of servicing it reflect the decentralised nature of the State, the scale and dispersion of the customer base, and the geographic, climatic and vegetation variations in the Ergon Energy service area. Field service delivery and operational work is managed from regional depots (locations shown in Figure 3).

Ergon Energy also supplies field services to Powerlink for sub-transmission assets in the northern part of its service area.

The head office and some corporate functions of Ergon Energy are based in regional centres. The Brisbane office includes stakeholder relations (e.g. government and large customers), and other specific corporate support activities.

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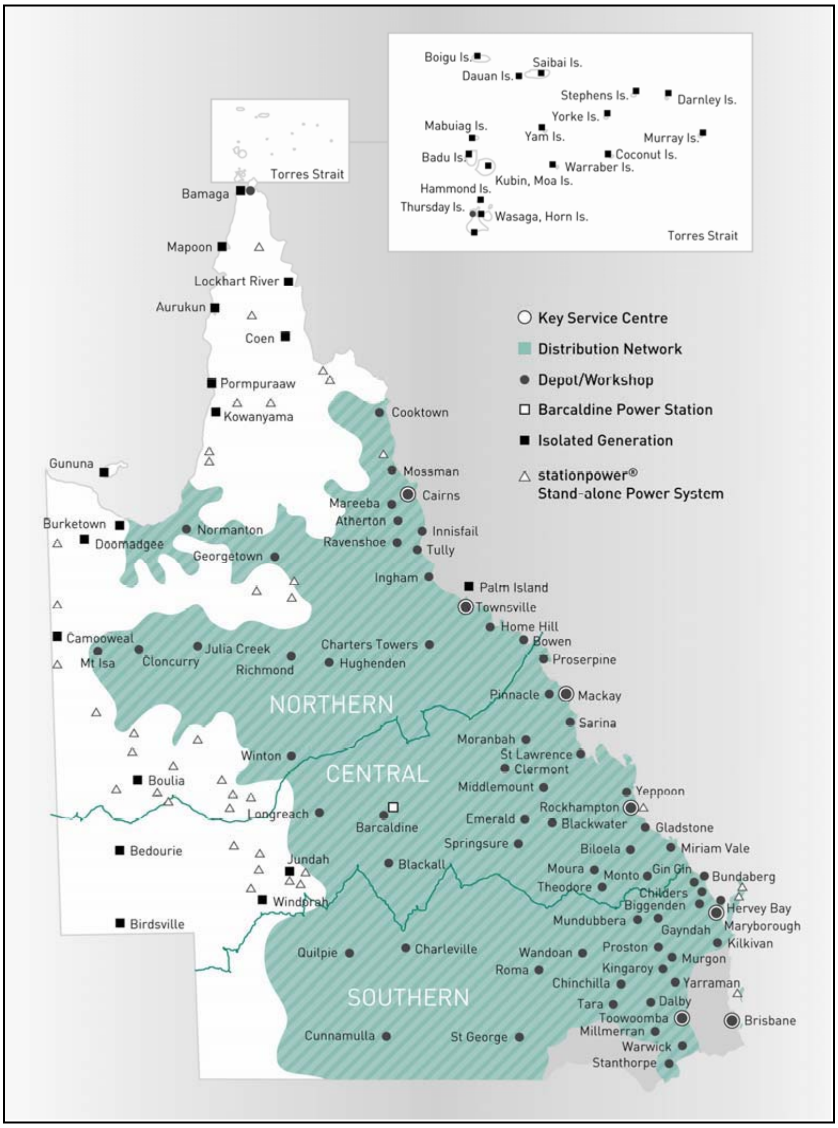
[13] Queensland Government, Queensland Government Gazette, 29 June 2012, 360. The "peak" period is defined as 4pm-8pm on weekdays and the "off-peak" period is defined as 10pm-7am on weekdays and weekends. All other times are defined as "shoulder" periods.

[14] Queensland Government, *Queensland Government Gazette*, 29 June 2012, 360(43).

[15] Far north Queensland Electricity Board, North Queensland Electricity Board, Mackay Electricity Board, Capricornia Electricity Board, Wide Bay-Burnett Electricity board and South West Queensland Electricity Board.

Ergon Energy provides distribution network services to approximately 690,000 customers. Approximately 90% (or 621,000) of Ergon Energy's customers are located in the area east of the Great Dividing Range (the East Zone).[16] Most of the larger industrial loads are also in that area, or in adjacent coalfields.

Figure 3. Ergon Energy's distribution service area, including isolated generation



Source: Ergon Energy

Approximately 70% of Ergon Energy's network by line length is classified as rural, with very low customer density in the West Zone.[17] Ergon Energy also supplies 34 isolated systems, which are too remote to be connected to the national grid. These are in western Queensland, Cape York, the Gulf of Carpentaria, Palm Island, Mornington Island and several Torres Strait Islands.

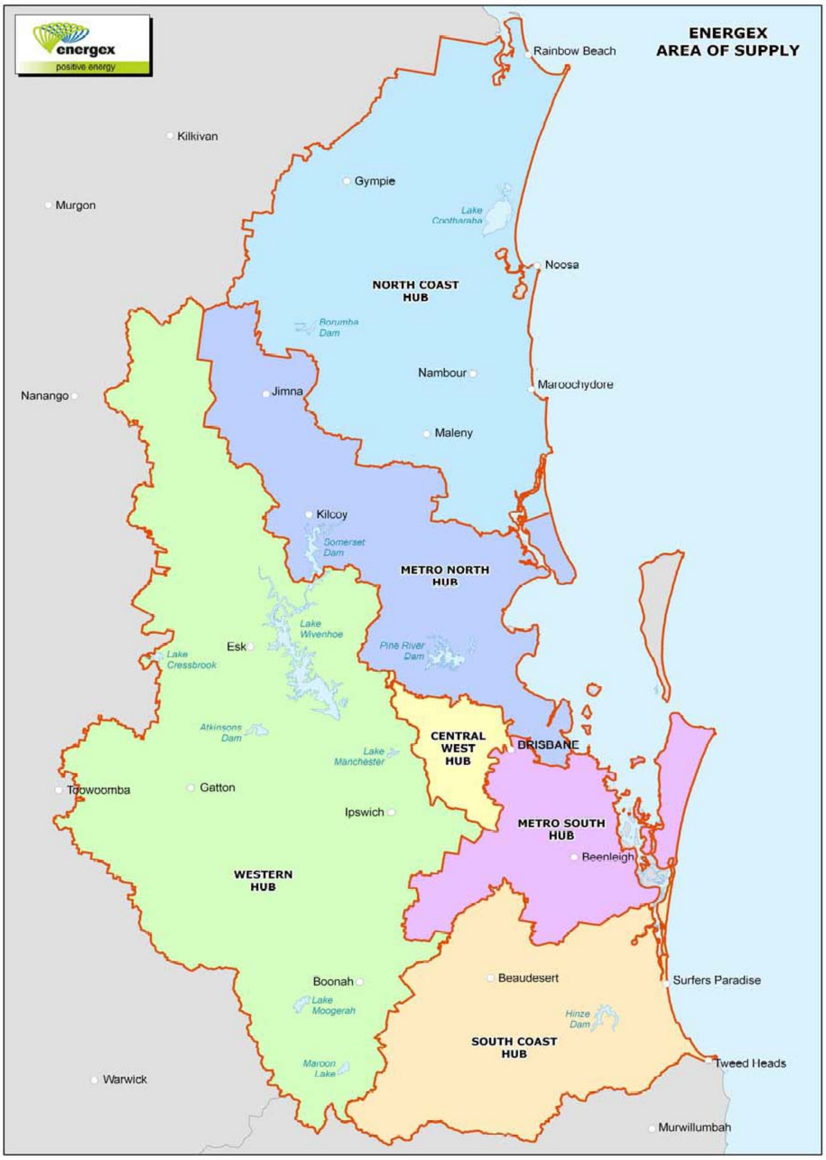
[16] Ergon Energy separates its network into three pricing zones (East, West and Mount Isa). Ergon Energy, *Network Management Plan, Part A: Electricity Supply for Regional Queensland 2012/13 to 2016/17*.

[17] Ergon Energy, *Network Management Plan, Part A: Electricity Supply for Regional Queensland 2012/13 to 2016/17*.

2.3.2. Energex

Energex Limited was established in 1997, following structural reforms recommended by the QEIST. The Energex service area was formerly covered by the South East Queensland Electricity Board. Energex operated both retail and distribution businesses in south east Queensland until divestment of the retail business in 2007, as part of industry reforms to promote full retail competition.

Figure 4. Energex Area of Supply



Source: Energex

Energex provides distribution network services to around 1.3 million customers across its service area. This covers around 25,000 square kilometres, from Coolangatta to Gympie, and west to the Great Dividing Range. Energex also supplies the Central Business District (CBD) areas of Brisbane, the Gold Coast and the Sunshine Coast. Its distribution operation comprises six hubs (Figure 4) - North Coast, Metro North, Central West, Western, Metro South and South Coast. The hubs provide regional asset and resource management and outage response.

2.3.3. Powerlink

Powerlink is the trading name of Queensland Electricity Transmission Corporation Limited, which was established in 1995. It replaced the transmission functions of the former Queensland Electricity Commission.

Powerlink owns, operates, and maintains Queensland's transmission network, transporting electricity from generators to bulk supply points of the distribution networks owned by Energex and Ergon Energy, as well as to some customers connected directly to the transmission network.

The transmission system extends 1,700 kilometres along the east coast of Queensland from the New South Wales border to north of Cairns and west into the central Queensland coalfields and the western Darling Downs as shown in Figure 5 below.

Figure 5. Powerlink's Network Area

Source: Powerlink

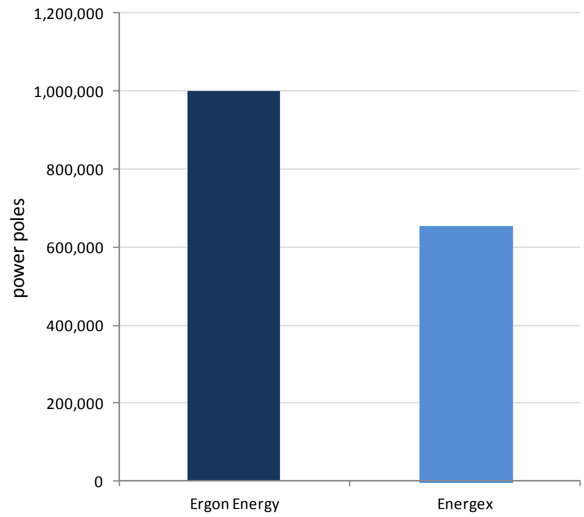
Powerlink, in conjunction with the New South Wales transmission body, TransGrid, transports electricity to and from New South Wales via the Queensland/New South Wales Interconnector. Another privately owned interconnector, Terranora, also connects the Queensland and New South Wales electricity grids.

2.4. Key Metrics

The size of an electricity network business can be defined by the length of overhead lines and underground cables, measured in kilometres. Overhead lines comprise conductors supported by towers or poles.

The following figure compares the number of poles owned by each of the DNSPs. Ergon Energy, with around one million poles, geographically covers 97% of Queensland. Energex has around 655,000 poles located in the South East corner.

Figure 6. Number of Poles, DNSPs



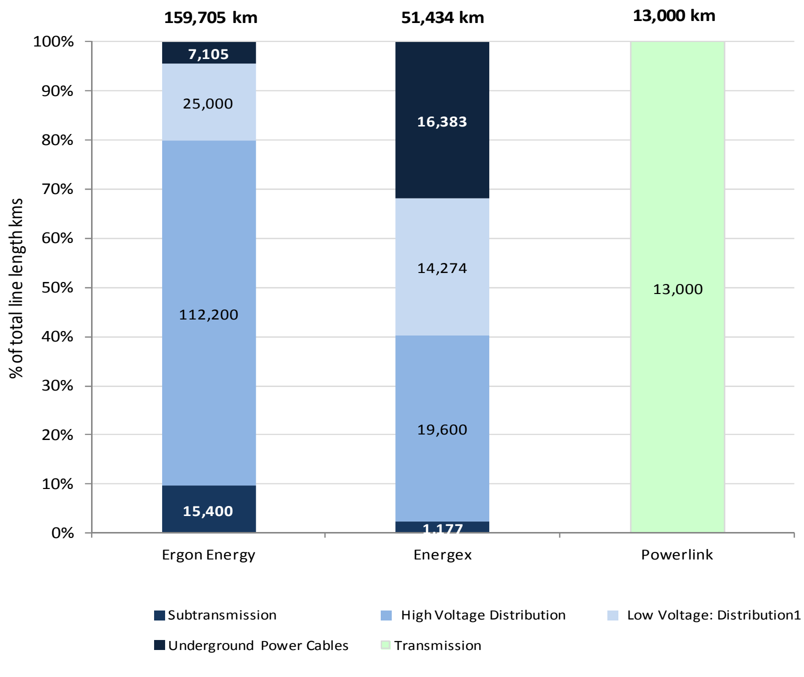
Source: Ergon Energy, Energex

Powerlink has 23,000 transmission towers located along the east coast of the State.[18]

Figure 7 outlines the operating voltages of the lines maintained by the NSPs. Ergon Energy, with around 160,000 kilometres, has a relatively high proportion of sub-transmission and high voltage distribution lines, while Energex has around 51,000 kilometres of lines with a high proportion of low voltage lines and underground cables.

Powerlink has 13,000 kilometres of transmission lines operating in the range of 110 kV to 330 kV.[19]

Figure 7. Composition of NSP power lines by length



Source: Ergon Energy, Energex, Powerlink

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[18] Powerlink, *A New 500kV transmission network*, October 2009.
[19] Powerlink Annual Report 2011/12, Statistical Summary, p60-61.

Table 2 sets out additional information on the DNSPs' operational assets.

Table 2. Ergon Energy and Energex operational assets

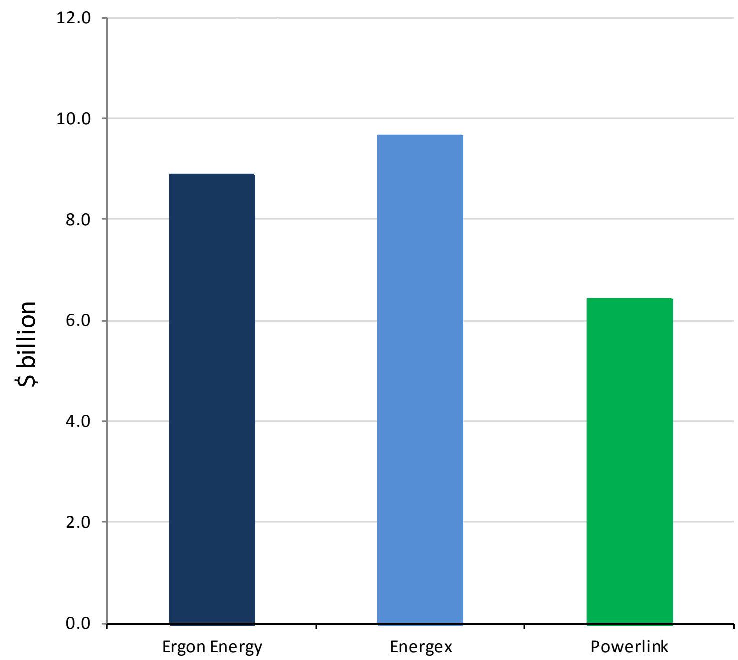
Indicator	Energex	Ergon Energy
Bulk Supply Points	41	24
Zone Substations	235	365
Major Power Transformers (33kV to 132kV)	566.	738
Distribution Transformers	46,792	92,300

Source: Ergon Energy and Energex

Figures 8-10 illustrate the Regulatory Asset Bases (RAB), maximum allowable revenue (MAR) and workforce in Full Time Equivalents (FTEs) for each of the NSPs.

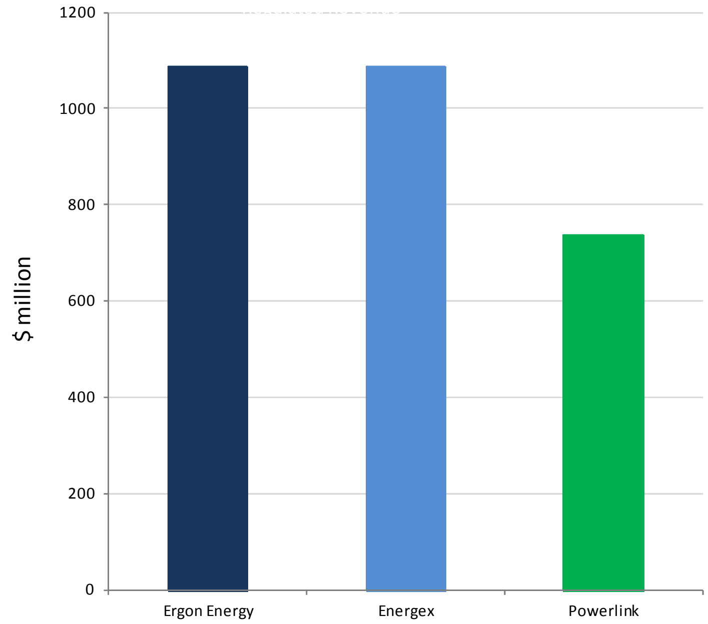
The DNSPs have similar sized asset bases. Ergon Energy had a RAB of $8.9 billion and Energex had a RAB of $9.7 billion as at 1 July 2012. The DNSPs each had regulated revenue of around $1.1 billion in 2011/12. Powerlink had a RAB of $6.4 billion at 1 July 2012 and regulated revenue of $736 million.

Figure 8. Regulated Asset Base, NSPs, 1 July 2012



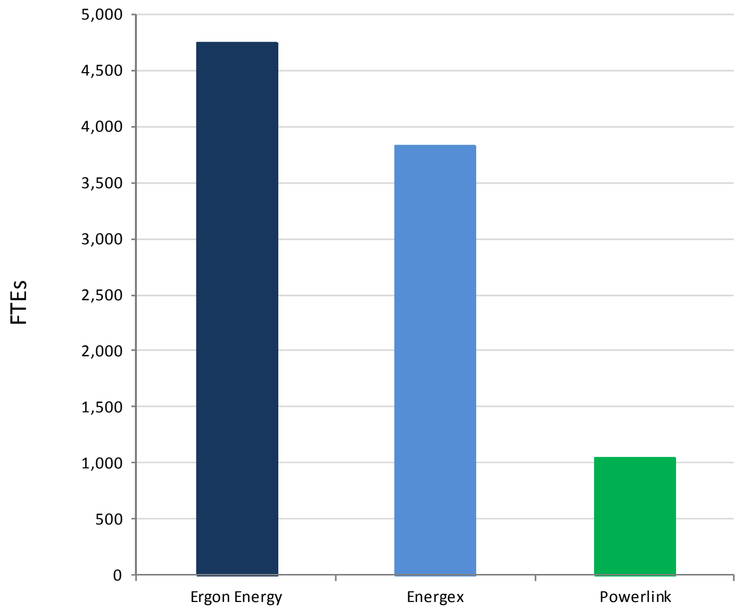
Source: Energex, Ergon Energy, Powerlink

Figure 9. Maximum Allowable Revenue, NSPs, 2011/12



Source: Energex, Ergon Energy, Powerlink

Figure 10. Workforce FTEs, NSPs, 2011/12



Source: Energex, Ergon Energy, Powerlink

3. Electricity Market Regulatory Framework

Ergon Energy, Energex and Powerlink are part of the NEM subject to the requirements of the Rules, and economic regulation by the AER. The NSPs are also required to comply with their respective Authorities held under the *Electricity Act 1994* (Qld).

Complex frameworks define the operating environment for NSPs. This chapter summarises these frameworks and the way in which the NSPs operate.

3.1. National Electricity Market

3.1.1. Establishment of the NEM

The NEM was formed in 1998, following agreement by Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia to introduce competition for electricity generation across state boundaries. The purpose of the NEM was to ensure availability of reliable and competitively priced electricity for end-use customers.

It is now the world's longest interconnected electricity transmission and distribution system, physically connecting Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania[20] and South Australia and delivering 186,000 GWh of electricity to more than eight million end-use customers each year.[21],[22]

3.1.2. Governance Arrangements

The NEM governance and legislative arrangements have undergone almost constant review. The current arrangements reflect the outcomes of the Council of Australian Governments review of the energy market in 2002.

These reforms, which were given effect through the Australian Energy Market Agreement (AEMA)[23], included the creation of a new National Electricity Law (NEL). A single National Electricity Objective (NEO) was included in the NEL to make explicit the principles and objectives of the energy market framework, which is to *"promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to (a) price, quality, safety, reliability, and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system"*.[24]

The governance arrangements set out in the AEMA include the:

- Ministerial Council on Energy (MCE) (superseded in 2011 by the Standing Council on Energy and Resources (SCER)), which is responsible for national oversight and co-ordination of energy policy development;
- Australian Energy Market Commission (AEMC), which is responsible for rule making and market development (as it relates to the Rules). The AEMC is funded by State and Territory Governments;

[20] Tasmania joined the NEM in 2005 and was physically connected with the market in April 2006.
[21] AEMO, *National Electricity Forecasting Report 2012*, 29 June 2012
[22] AEMO, *An introduction to Australia's National Electricity Market*, July 2010
[23] The AEMA is an inter-governmental agreement adopted by the Commonwealth, States and Territories on 30 June 2004.
[24] National Electricity (South Australia) Act 1996 Version: 1.7.2012, Schedule; Part 1 Preliminary; Chapter 7; National Electricity Objective; p36.

- AER, which is the national regulator and has enforcement, market monitoring and economic regulatory functions. The AER is funded by the Commonwealth Government and is part of the Australian Competition and Consumer Commission (ACCC); and
- Australian Energy Market Operator (AEMO), which is the market operator responsible for operating the national electricity (and gas) markets and the associated national power system and providing national transmission planning information and advice.

3.1.3. Queensland's Role in NEM Governance Frameworks

The AEMA governs participation of each jurisdiction in the NEM and adherence to the national legislative framework. The AEMA discourages jurisdictions derogating from the Rules.

The Queensland Government is represented at the Standing Council on Energy and Resources (SCER) and therefore has a key role in national energy policy decision making including any changes to the NEL, although changes to the Rules do not require agreement by SCER.[25]

Under Section 8 of the NEL, Ministers may issue a Statement of Policy Principles (SOPP) on any matters relevant to the exercise of the AEMC's rule-making powers. A SOPP requires agreement by all Ministers, who must be satisfied that the SOPP is consistent with the NEO. The rule change process also includes substantial public consultation by the AEMC and requires the AEMC to be satisfied that any proposed changes meet the NEO.

3.2. Regulatory Compliance Obligations

The NSPs are required to comply with regulatory instruments covering the planning, construction, operation and pricing of network services. These obligations are summarised in the following table.

Table 3. Regulatory and policy compliance obligations

Jurisdiction	Obligation	Ergon Energy & Energex	Powerlink
Queensland	Obligations to plan and operate the network to meet or manage demand within security requirements	✓	✓
	Obligations to connect customers and supply electricity under the Electricity Act	✓	✓
	Regional system / network control responsibilities under the Electricity Act	✓	✓
	Obligations to comply with reliability and service standards, including reporting on performance against Minimum Service Standards (MSS) and Guaranteed Service Levels (GSLs) under the Electricity Industry Code	✓	×
	Compliance with technical obligations under the Electricity Industry Code	✓	×
	Preparation of annual planning documents on network management, summer preparedness and demand management alternatives	✓	×
	Compliance with safety obligations under the *Electrical Safety Act 2002*	✓	✓
NEM	Compliance with network connection and planning obligations under the Rules	✓	✓

[25] Unless it will impose an obligation on the SCER or a Minister of a participating jurisdiction.

Jurisdiction	Obligation	Ergon Energy & Energex	Powerlink
	Approval of annual regulated revenue by the AER under the Rules (including Ergon Energy's Mount Isa – Cloncurry network)	✓	✓
	Approval of network tariffs by the AER under the Rules	✓	✓
	Compliance with power system security and quality of supply obligations under the Rules, including relevant incentive schemes	✓	✓

Source: National Electricity Law, National Electricity Rules, Electricity Act 1994 (Qld), Electricity Regulation 2006 (Qld) and Queensland EIC

3.3. Economic Regulatory Framework

At the formation of the NEM, monopoly NSPs became subject to national economic and access regulation aimed at providing market participants open access to network services at a fair and reasonable price. The Rules set out the regulatory framework that the AER must apply in setting the revenue and prices for distribution (Chapter 6) and transmission (Chapter 6A) networks.

The regulatory framework has been designed to simulate, as far as possible, market conditions and to provide incentives to NSPs to operate efficiently. As the maximum revenue for Queensland NSPs is set by the AER, profitability can be improved only by reducing costs.

3.3.1. Setting the Maximum Allowable Revenue

The MAR is determined by the use of the building block formula, which takes into account efficient operating and maintenance expenditure, depreciation, taxation liabilities and a return on the RAB. The MAR is set in advance for a five year regulatory control period under Chapters 6 and 6A of the Rules.

While the Rules set out how the MAR is to be determined, they also provide the AER with discretion in:

- determining efficient capital and operating expenditure allowances, subject to the factors and criteria in the Rules;
- setting the rate of return on capital or Weighted Average Cost of Capital (WACC), subject to the publication of the Rate of Return Guidelines; and
- approving the NSPs' Cost Allocation Methodologies and Pricing Principles Statements/Pricing Methodologies in accordance with the Rules and with the AER's Pricing Methodology Guideline.

Prior to making a determination, the AER undertakes an ex-ante assessment of each NSP's proposed expenditure in accordance with the Rules and must only approve forecast expenditure if it is satisfied this expenditure reflects among other things[26]:

- the efficient costs of satisfying the capital and operating expenditure objectives in the Rules;
- the costs that a prudent operator in the circumstances[27] of the business would achieve; and
- a realistic expectation of the demand forecast and cost inputs.

[26] Refer 6.5.6 and 6.5.7 of Chapter 6 and Chapter 6A.5.6 of the Rules for the full list of the matters that the AER must have regard to.

[27] The recently -made Economic Regulation Rule change removes the specific reference to the circumstances of the business, to remove doubt about the AER's ability to apply top-down techniques including benchmarking.

In addition to regulation of the NSPs' revenue, the AER also has responsibilities under Chapter 5 of the Rules in relation to augmentations and expansions.

In the event of a major planned augmentation or expansion of the network, the Rules require NSPs to conduct a regulatory investment test. This is a cost/benefit test to analyse and assess the various investment options (including non-network alternatives) to address a projected network constraint. The test is designed to ensure that major projects are delivered at the highest net benefit to the electricity market, or the lowest long run cost to consumers. Importantly, completion of a regulatory test is required to ensure that the cost of the new investment can be included in the determination of the NSP's allowed revenue in the future.

3.3.2. Adjustments to MAR

There is limited scope for adjustments to the MAR within the regulatory control period. NSPs and other parties may challenge regulatory determinations through the Limited Merits Review regime set out in the NEL. The Rules also allow for revenue determinations to be re-opened in limited circumstances, such as adjusting for the costs of a pre-nominated contingent project[28] or for the impacts of certain types of exogenous events (i.e. pass-through events).

3.3.3. Outcomes under AER Determinations

Powerlink has been subject to economic regulation by the ACCC/AER since 1 January 2002, while Ergon Energy and Energex have been regulated by the AER since 1 July 2010. The DNSPs were previously regulated by the Queensland Competition Authority (QCA).

The following tables set out the most recent revenue determinations[29] by the AER for each of the NSPs.

Table 4. Ergon Energy Determination 2010/11 – 2014/15

Building Block	2010/11 ($m)	2011/12 ($m)	2012/13 ($m)	2013/14 ($m)	2014/15 ($m)	Total ($m)
Return on Assets	694.7	783.6	870.9	963.6	1,062.3	4,375.1
Regulatory Depreciation	145.0	147.0	150.4	164.3	144.8	751.5
Operating Expenditure Allowance	362.2	389.3	398.0	404.4	401.0	1,954.9
Net Tax Allowance	23.8	68.3	73.8	85.9	83.6	335.4
Capital Contributions[1]	(111.8)	(115.8)	(120.4)	(130.7)	(141.5)	(620.2)
Revenue from Shared Assets	(3.2)	(3.3)	(3.4)	(3.4)	(3.5)	(16.8)
Accelerated Depreciation	10.5	-	-	-	-	10.5
Total MAR (unsmoothed)	**1,121.0**	**1,269.2**	**1,369.2**	**1,484.0**	**1,546.6**	**6,790.0**
Total MAR (smoothed)	**1,123.1**	**1,237.8**	**1,364.1**	**1,503.4**	**1,570.1**	**6,798.5**

1. Assets obtained through capital contributions are included in the regulated asset base. The value of these assets is then deducted from the allowable revenue so that Ergon Energy does not earn revenue on gifted assets. Note: Totals may not sum due to rounding. Source: Australian Competition Tribunal, *RE: Application under s.71B of the National Electricity Law for a Review of a Distribution Determination Made by the Australian Energy Regulator in Relation to Ergon Energy Corporation Limited pursuant to Clause 6.11.1 of the National Electricity Rules*, Determination, 19 May 2011.

[28] Currently only applies to TNSPs, but the Economic Rule change extends this to DNSPs.
[29] Including adjustments resulting from appeals to the Australian Competition Tribunal by both Ergon Energy and Energex.

The total MAR for Ergon Energy including adjustments made following an appeal to the Australian Competition Tribunal is $6.8 billion, for the regulatory control period 1 July 2010 to 30 June 2015. Return on Assets accounts for 64% of the MAR, followed by operating expenditure which accounts for 29% of MAR. The smoothed revenue for Ergon Energy provides for a 10% increase in revenue each year from 2011/12 to 2013/14, with a 4% increase for the final year.

Table 5. Energex Determination, 2010/11 – 2014/15

Building Block	2010/11 ($m)	2011/12 ($m)	2012/13 ($m)	2013/14 ($m)	2014/15 ($m)	Total ($m)
Return on Assets	764.5	873.6	987.3	1,101.2	1,213.9	4,940.5
Regulatory Depreciation	78.5	87.2	98.1	110.3	111.6	485.7
Operating Expenditure Allowance	326.6	336.7	354.7	372.5	377.5	1,768.0
Net Tax Allowance	80.6	87.4	96.0	105.9	113.5	483.4
Capital Contributions[1]	(65.1)	(69.1)	(71.5)	(74.2)	(76.4)	(356.3)
Revenue from Shared Assets	(4.0)	(4.7)	(5.5)	(6.1)	(5.7)	(26.0)
Total MAR (unsmoothed)	**1,181.1**	**1,311.1**	**1,459.2**	**1,609.6**	**1,734.4**	**7,295.4**
Total MAR (smoothed)	**1,135.1**	**1,292.1**	**1.470.9**	**1,674.4**	**1,741.0**	**7,313.5**

1. Assets obtained through capital contributions are included in the regulated asset base. The value of these assets is then deducted from the allowable revenue so that Energex does not earn revenue on gifted assets. Note: Totals may not sum due to rounding. Source: Australian Competition Tribunal, RE: Application under s.71B of the National Electricity Law for a Review of a Distribution Determination Made by the Australian Energy Regulator in Relation to Energex Limited pursuant to Clause 6.11.1 of the National Electricity Rules, Determination, 19 May 2011.

The total MAR for Energex, including adjustments made following an appeal to the Australian Competition Tribunal, for the regulatory control period 1 July 2010 to 30 June 2015 is $7.3 billion. Return on Assets accounts for 68% of the MAR, followed by operating expenditure which accounts for 24% of the MAR. The smoothed revenue for Energex provides for a 14% increase in revenue each year from 2011/12 to 2013/14, with a 4% increase for the final year.

Table 6. Powerlink Determination, 2012/13 – 2016/17

Building Block	2012/13 ($m)	2013/14 ($m)	2014/15 ($m)	2015/16 ($m)	2016/17 ($m)	Total ($m)
Return on Assets	553.3	610.8	657.7	688.8	723.6	3,234.1
Regulatory Depreciation	41.0	53.6	77.3	95.2	104.7	371.8
Operating Expenditure Allowance	181.8	193.7	203.7	216.9	229.0	1,025.1
Net Tax Allowance	11.5	12.5	13.4	15.4	17.0	69.7
EBSS Carryover Amounts	(2.7)	(0.7)	(3.0)	2.3	-	(4.0)
Total MAR (unsmoothed)	**784.9**	**869.8**	**949.2**	**1,018.6**	**1,074.2**	**4,696.7**
Total MAR (smoothed)	**835.0**	**882.6**	**933.0**	**986.2**	**1,042.4**	**4,679.1**

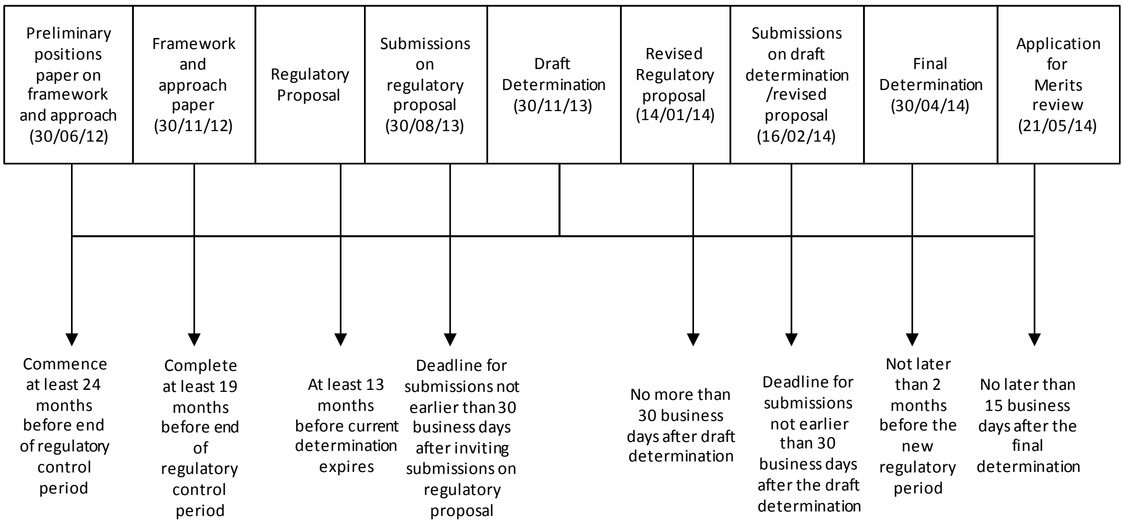
Note: Totals may not sum due to rounding.
Source: AER, Powerlink Transmission Determination 2012-13 to 2016-17, Final Decision, April 2012.

The total revenue allowance for Powerlink under its current determination is $4.7 billion over the five years to 2016/17. Return on Assets accounts for 69% of the MAR, followed by operating expenditure which accounts for 22% of MAR. The smoothed revenue for Powerlink provides for a 6% increase in revenue each year from 2012/13 to 2016/17.

3.3.4. AER Determination Process

The regulatory determination process for a DNSP under Chapter 6 of the Rules is illustrated in Figure 11. The transmission determination process is very similar, with the key differences being that Chapter 6A excludes the framework and approach stage and requires a predetermination conference. It should be noted that this process has been amended by the Final Rule Change Decision[30].

Figure 11. Distribution Regulatory process time line (with sample dates)



Source: AEMC, *Directions Paper – Economic Regulation of Network Service Providers Rule change*, 2 March, 2012.

There are significant costs associated with compliance under the national regulatory arrangements. The aggregate cost to the NSPs for regulatory reset compliance was $45 million over the period 2006/07 to 2010/11. The following costs were incurred:

- Ergon Energy's regulatory compliance costs have increased from $3.5 million in 2006/07 to $9.8 million in 2011/12. Ergon Energy submitted that its costs for regulatory reporting and revenue proposal preparation increased from 2007/08 onwards due to the change in regulator from the QCA to the AER. Another key contributor to Ergon Energy's cost has been compliance and preparation for the National Energy Customer Framework (NECF), which has contributed $6.4 million to Ergon Energy's regulatory costs since its inception.[31]
- Regulatory reset compliance costs for Energex have increased from $6.1 million in 2006/07 to $13.9 million in 2011/2012. Included in this are compliance costs resulting from preparation for NECF that contributed $10 million in regulatory capital and operating expenditure to date for Energex.[32]

[30] AEMC; Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers), 29 November 2012.
2012
[31] Independent Review Panel on Network Costs, Ref No: IRP.EE.68; IRP.EE.03b; IRP.EE.03a
[32] Submission to the Independent Review Panel on Network Costs 17 October 2012, p8; Table 2 p9

- Powerlink's regulatory reset compliance costs were relatively stable from 2007/08 to 2011/12, at an average of $5.0 million per annum.[33]

3.4. Emerging Policy Environment

In the past year, several national market review processes have been initiated to examine the regulatory arrangements applying to electricity networks. The key reviews are:

- Economic Regulation Rule Change;
- Expert Panel Review of the LMR Regime;
- AEMC Power of Choice review; and
- Productivity Commission Inquiry into Electricity Network Regulation.

The following sections summarise the objectives of these reviews.

3.4.1. Economic Regulation Rule Change

The AEMC's Economic Regulation Rule Change process which concluded on 29 November 2012, responds to two Rule Change Proposals, by the AER and the Major Energy Users Group. These were combined into one rule change process by the AEMC. The rule change alters parts of Chapter 6 and Chapter 6A relating to the assessment of operating and capital expenditure proposals, to allow the AER greater discretion in some elements of decision making.

The changes to the Rules:

- clarify the AER's powers to question and substitute electricity NSPs' capital and operating expenditure proposals and to apply efficiency benchmarking; and include new capital expenditure incentive powers including regular ex-post prudency reviews of past capital expenditure;
- reform the rate of return framework for NSPs to provide for a single, more flexible framework that is aimed at delivering a higher quality estimate by enabling adaptation to changing market conditions and differing NSP characteristics; and
- amend the determination process by extending the timeframe and steps to give the AER more time to make decisions and to enhance consumer engagement.

3.4.2. Merits Review (Expert Panel)

An independent Expert Panel was appointed by SCER in March 2012 to assess the effectiveness of the Limited Merits Review (LMR) regime under the NEL and to advise on what, if any, amendments or restructuring of the LMR framework are required.

The Expert Panel recommended major reforms to the regime in its Final 'Stage Two' Report, released in late September 2012. Proposed changes were:

- replacing the Australian Competition Tribunal, for this purpose, with a new independent administrative and investigative body attached to the AEMC;
- creating a ground for appeal only if there is reason to believe a materially preferable decision exists;
- ensuring that the review body is able to, and should, assess the merits of the AER's overall decision;

[33] Powerlink, Request for Data by 26 September 2012, Appendix A, Table A.1 Revenue Reset Costs.

- introducing measures to limit review activity such as materiality thresholds, time limits, and a requirement to adopt the AER's record of decision as a starting point, so the review body's decision process is incremental to the AER's, rather than starting from the beginning; and
- placing a stronger focus on the long term benefits for consumers.

3.4.3. Power of Choice (Demand Side Participation)

The MCE-initiated Power of Choice – Demand Side Participation Stage 3 review by the AEMC examined the relationship between peak demand and electricity prices, and the impact of the Rules on efficient demand side participation.

The AEMC's Final Report, released on 30 November 2012[34], recommended improving incentives for NSPs to consider demand side participation options rather than investment in capital projects where efficient to do so. A key finding was that the economic framework requires reform to ensure there are sufficient profit incentives for NSPs to pursue demand side participation.

3.4.4. Inquiry into Electricity Network Regulation

While not scheduled for completion until April 2013, the Productivity Commission Inquiry is examining issues material to economic regulation, including the potential for greater use of benchmarking to drive efficiency in NSP expenditure, and the appropriateness of the rate of return earned by NSPs. Outcomes of the Productivity Commission Inquiry would be implemented through the national governance arrangements of SCER and/or the AEMC.

3.4.5. Other Relevant Reviews

These are:

- **Transmission Frameworks Review (TFR)** – Initiated by the MCE, this AEMC review is considering the efficiency and effectiveness of the arrangements for the provision and utilisation of transmission services in the NEM. It has implications for the way in which new transmission connections and extensions are treated in the Rules.

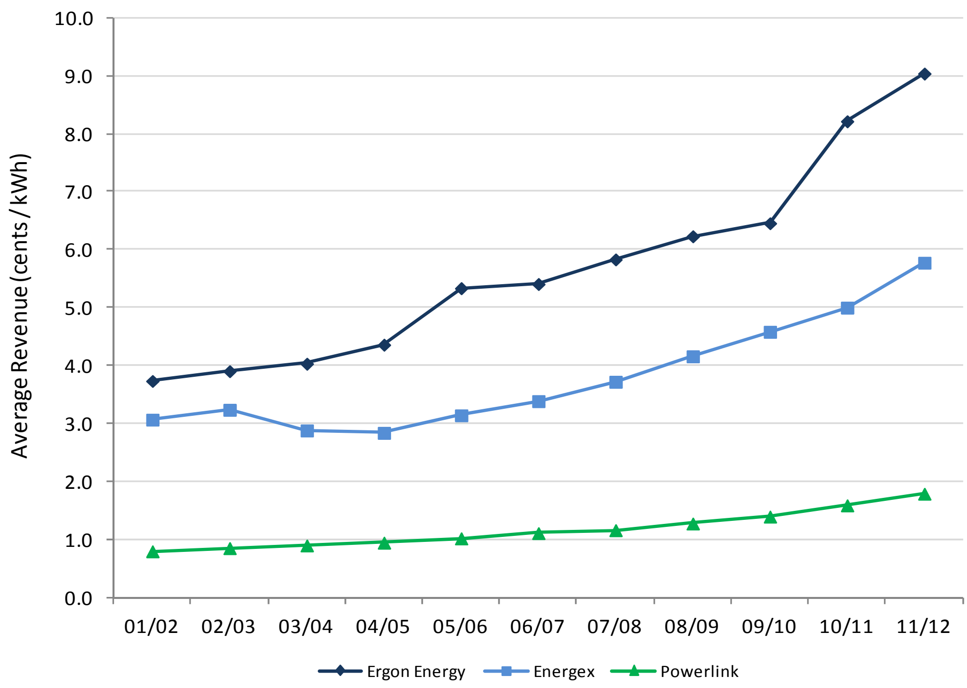
  Proposed changes to the electricity frameworks, in the AEMC's Second Interim Report, released in August 2012, cover generator access, planning and connections.
- **Distribution Network Planning and Expansion Rule Change** – This change, to commence on 1 January 2013, shifts the rules governing planning and expansion of distribution networks from largely state-based requirements to the national framework. The new framework largely replaces state-based mechanisms (such as Queensland's Network Management Plans). It includes a new annual planning review and reporting process, a Demand Side Engagement Strategy, and a new regulatory test to replace the test currently applying to distributors under the Rules.
- **Review of Distribution Reliability Outcomes and Standards** –This MCE-directed review by the AEMC will advise on the merits of developing a nationally consistent framework for setting distribution reliability standards across the NEM, which could be voluntarily adopted by jurisdictions or used as a reference point. While the intent is that jurisdictions will retain the power to set their own reliability standards (based on the national frameworks), both these reviews are looking at developing benchmarks to promote national consistency.

[34] Final Report: Power of choice review – giving consumers options in the way they use electricity; AEMC; 30 November 2012.

4. Past Capital and Operating Expenditure by the NSPs

Network charges in Queensland have risen significantly since 2004/05, driven by large increases in capital and operating expenditure by the NSPs.

Figure 12. Average Network Charge, 2001/02 -2011/12



Source: Ergon Energy, Energex, Powerlink (includes FIT)

Figure 12 above shows that the increases in overall network tariffs are driven primarily by changes in distribution network tariffs. While the average annual growth in the transmission tariff has been similar to that of the DNSPs, it represents a smaller proportion of the total average network tariff.

Average network revenue for Ergon Energy increased from 3.7 cents per kWh in 2001/02 to 8.7 cents per kWh in 2011/12 in nominal terms, representing an average annual increase[35] of 8.9%. Average network revenue for Energex increased on average by 6.5% per annum, from 3.1 cents per kWh in 2001/02 to 5.8 cents per kWh in 2010/11 in nominal terms.

Similarly, average distribution network tariffs for the New South Wales Government-owned DNSPs have increased by 8.7% per annum (Endeavour Energy) and by 9.7% per annum (Essential Energy) from 2005/06 to 2011/12.[36] In contrast, the average distribution tariffs for the privately-owned DNSPs in Victoria have increased by only 1.2% per annum (CitiPower) and by 4.6% per annum (Powercor) from 2005/06 to 2011/12.[37]

Increases in the average network charges are primarily the result of record increases in capital and operating expenditures by the NSPs. Network charges have also been impacted by increases in the cost of capital during the global financial crisis.

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[35] Measured by the compound annual growth rate (CAGR).

[36] NSW Distribution Determination Final Decision 2009-14, IPART Regulatory determination 04-08.

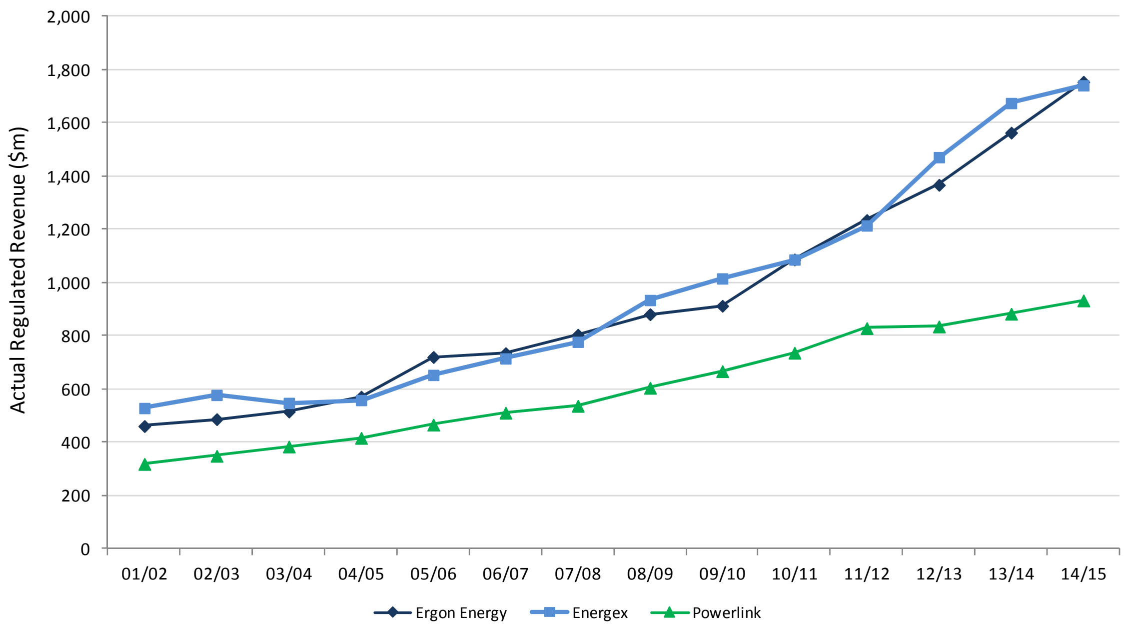
[37] 2011-15: Power Core Final Revenue Determination 2011 -15 p 20 Average Revenue Requirements; United Energy Final Revenue Determination 2011-2015 p 19; Jemena Electricity Networks Final Determination 2011-2015 p19; CityPower Distribution Determination 2011-2015 p17.

4.1. Network Revenue

Increases in average network prices reflect the record increases in the MAR of the Queensland NSPs.

Regulated revenue[38] for Ergon Energy increased from $461 million in 2001/02 to $1,195 million in 2011/12, representing a Compound Annual Growth Rate (CAGR) of 10.0%. Energex's regulated revenue has increased by 8.7% per annum, from $528 million in 2001/02 to $1,214 million in 2011/12. Powerlink's regulated revenue has increased by 10% per annum, from $319 million in 2001/02 to $829 million in 2011/12.

Figure 13. Regulated Network Revenue, 2001/02 -2014/15



Source: Ergon Energy, Energex, Powerlink

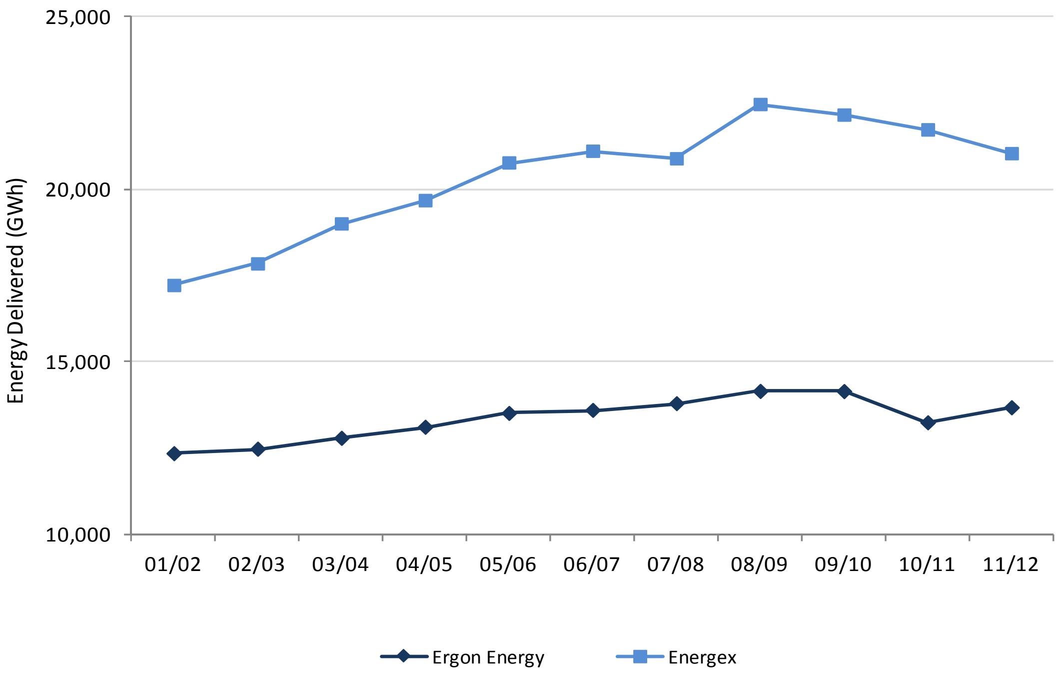
4.2. Energy Delivered

Ergon Energy delivered 13,664 GWh of electricity to its customers in 2011/12, which is 3.3% greater than 2010/11, but less than the volume of electricity delivered in each of the three years prior to that. Similarly, Energex delivered 21,025 GWh of electricity in 2011/12, which was a decrease of 3.2% on the prior year. The reduction in energy delivery, for a given asset base and allowable revenue, results in increases in network tariffs, compounding the effects of cost increases.

The following charts illustrate the trend in energy delivered by the NSPs since 2001/02.

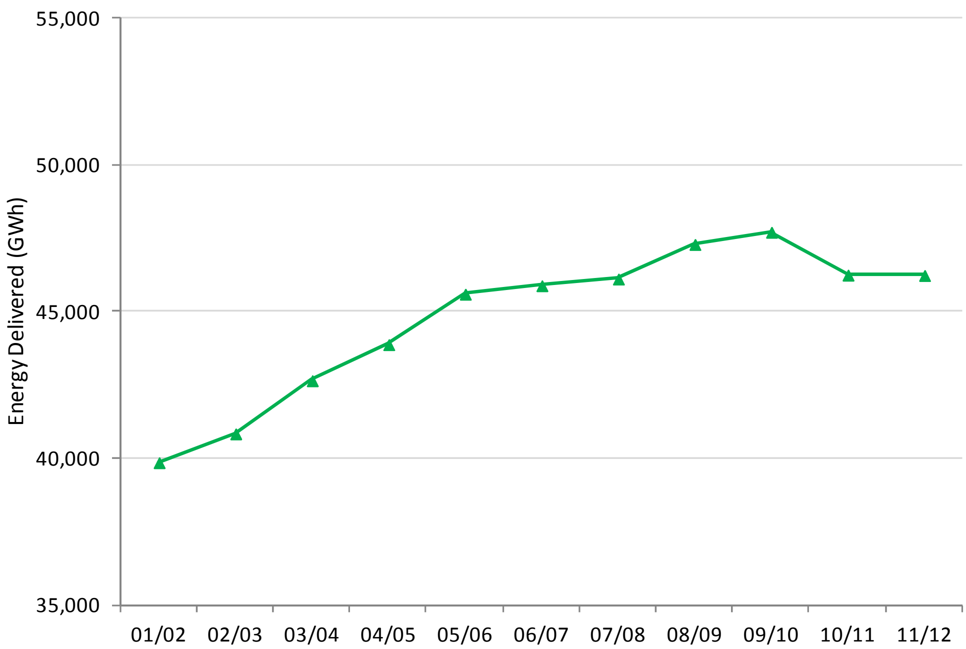
[38] This refers to actual revenue received for the delivery of standard control services. This does not include revenue received from the delivery of alternative control services. The difference between this revenue and the MAR reflects that the MAR is an approved forecast amount, whereas this measure reflects the actual received for the same services.

Figure 14. Ergon Energy and Energex - Energy Delivered, 2001/02 -2011/12



Source: Ergon Energy, Energex

Figure 15. Powerlink - Energy Delivered, 2001/02 -2011/12



Note: The difference between the energy delivered by Powerlink and the total energy delivered by Ergon Energy and Energex reflects directly connected customers and line losses.
Source: Powerlink

The energy delivered by the NSPs exhibited a general upward trend until 2008/09. However, energy delivered has since begun trending down. The DNSPs attributed this to:

- natural events, such as the wide-spread flooding in January 2011 and Tropical Cyclone Yasi (Yasi) in 2011, which limited the ability of customers to access electricity;
- milder summers, which have reduced the use of air conditioners;

- greater energy conservation consciousness of consumers and the replacement of low energy efficiency appliances with higher energy efficiency appliances;
- the impacts on the broader economy of the Global Financial Crisis;
- increasing penetration of residential photovoltaic (PV) generation, which reduces the load delivered by the network;
- lower than predicted population growth in south east Queensland, particularly in terms of interstate and international migration;
- a subdued housing market in south east Queensland, with a significant reduction in the number of new housing lots being developed; and
- for Ergon Energy, the transfer of some large industrial customers directly to the Powerlink network.

4.3. Network Maximum Demand

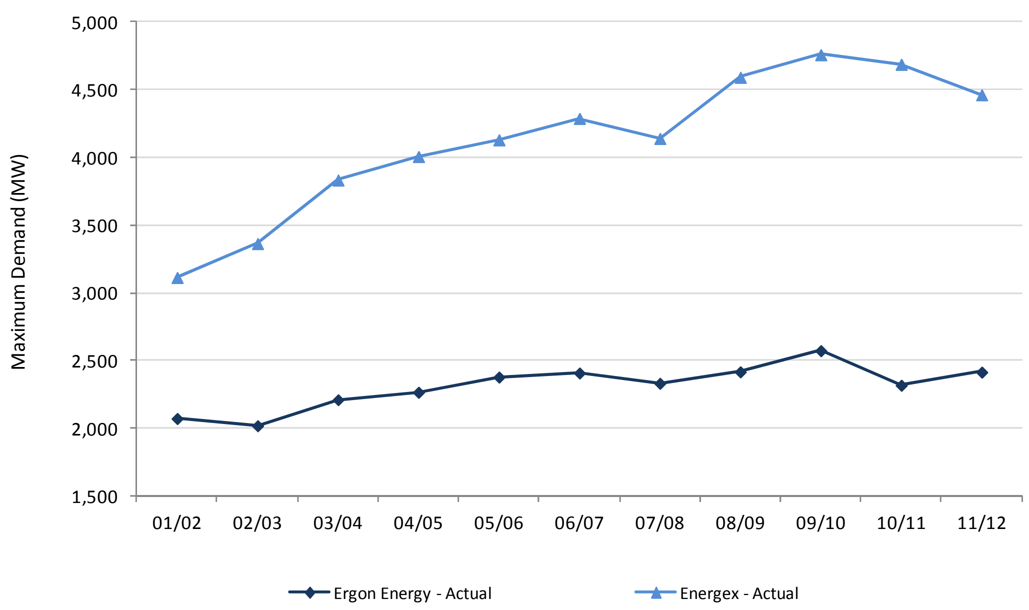
Although energy delivered is used for billing purposes, particularly for smaller customers, it is not a key driver of network costs. Maximum demand determines the capacity of the network required to maintain the security and reliability of the network.

Network demand is a measure of the load on the system at any one time. Maximum demand is the load during the half hour period in the year when network demand peaks. The Energex network experienced strong growth in maximum demand from 2001/02 to 2006/07, representing an average annual growth rate of 6.6%. This is largely attributable to strong economic growth and the increasing penetration of air conditioning load. Ergon Energy's maximum demand also grew over this period, but at a slower rate of 3.1% per annum (CAGR).

The growth in maximum demand has since fallen sharply, with a CAGR of just 0.1% for Ergon Energy and 0.8% for Energex from 2006/07 to 2011/12.

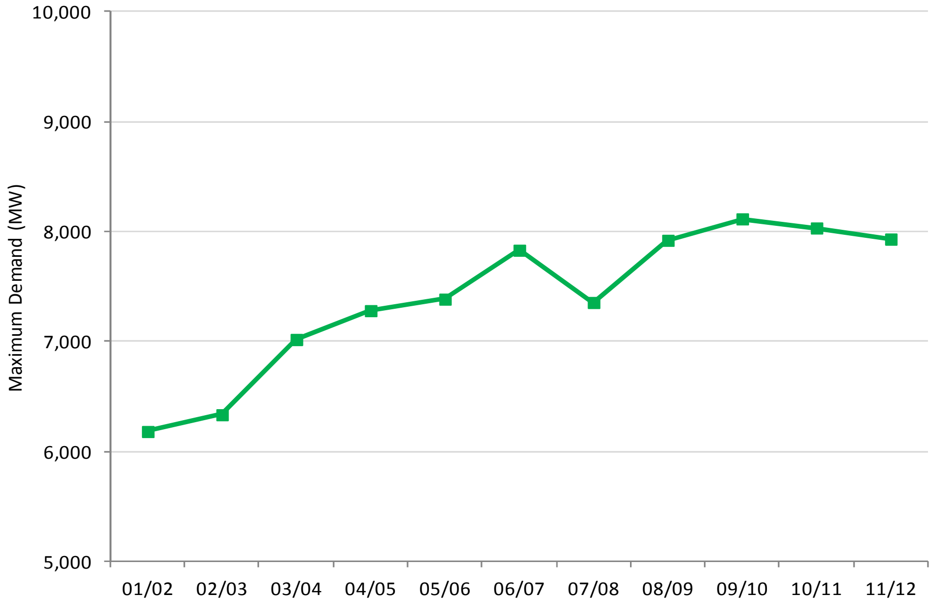
Powerlink's maximum demand followed a similar trend.

Figure 16. Maximum Network Demand – DNSPs' 2001/02 -2011/12



Source: Ergon Energy, Energex

Figure 17. Maximum Network Demand - Powerlink, 2001/02 -2011/12



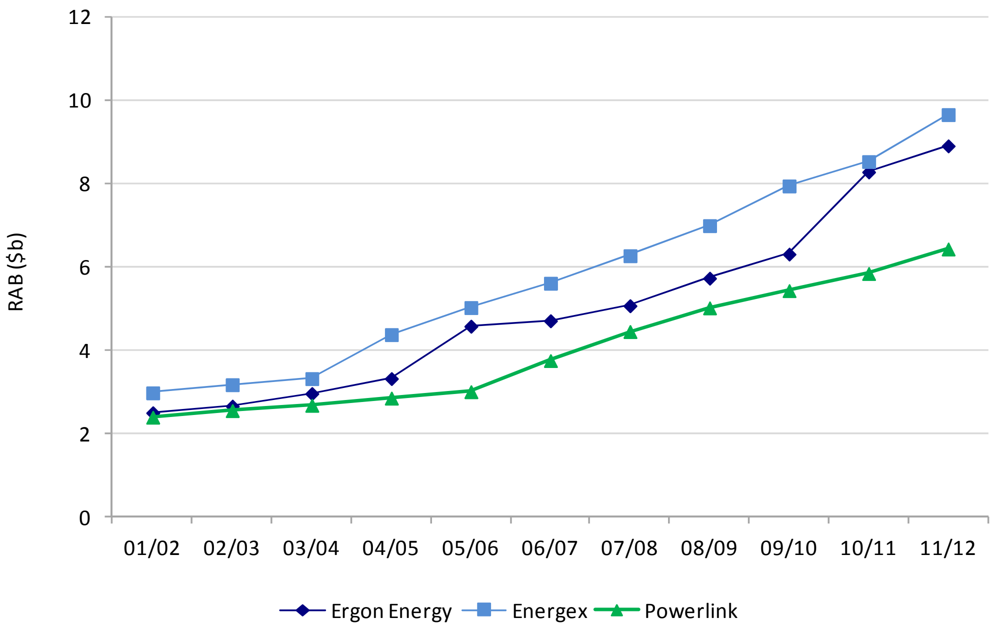
Source: Powerlink

The causes of reduction in energy consumption have also driven reductions in maximum demand. In addition, the DNSPs noted that maximum demand has also been affected by lower domestic peak load influenced by demand reduction promotions.

4.4. Regulated Asset Base

Between 2001/02 and 2011/12, the RAB for each of the NSPs increased as follows: Ergon Energy \$2.5 billion to \$8.9 billion; Energex \$3.0 billion to \$9.7 billion; and Powerlink \$2.4 billion to \$6.4 billion. See Figure 18 below.

Figure 18. Regulated Asset Base, 2001/02 -2011/12



Source: Ergon Energy, Energex, Powerlink

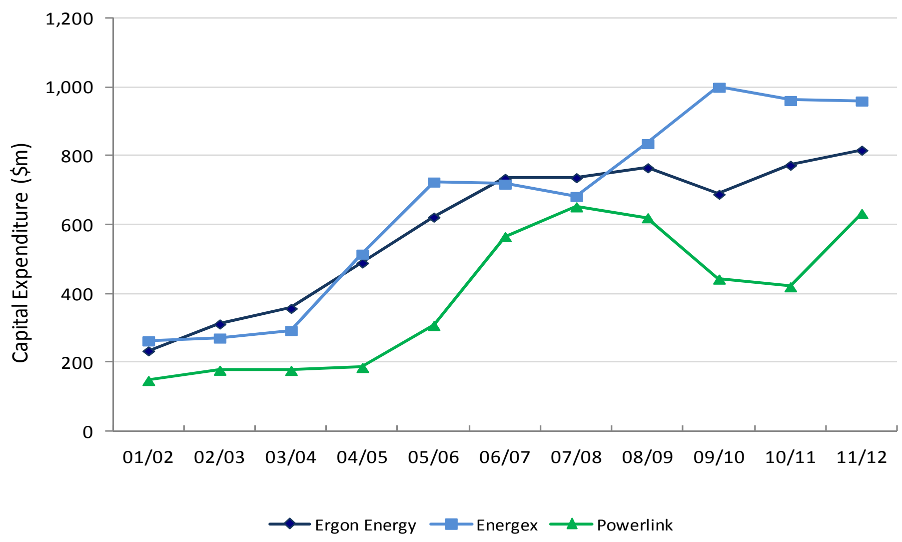
4.5. Expenditure

4.5.1. The NSPs' Historic Capital Expenditure

The annual capital expenditure across the three NSPs has increased sharply since 2004/05 as shown in Figure 19 below.

Ergon Energy's regulated capital expenditure increased at an average annual compound rate of 13.3%, from $235 million to $817 million over the ten years from 2001/02 to 2011/12. Over the same period, Energex's regulated capital expenditure increased at an annual average compound rate of 13.8% from $264 million to $960 million and Powerlink's regulated capital expenditure increased by 15.6% per annum, from $149 million to $633 million.

Figure 19. Regulated Capital Expenditure, 2001/02 -2011/12



Source: Ergon Energy, Energex, Powerlink

Increases in the annual direct capital expenditure from 2004/05 reflect, in part, the outcomes of the Electricity Distribution and Service Delivery (EDSD) Review, which was undertaken in 2004 in response to a series of severe storms. Among the recommendations of the EDSD Review were:

- the imposition of a deterministic N-1 planning standard; and
- the introduction of Minimum Service Standards (MSS).

These recommendations were adopted by the Queensland Government and were subsequently implemented by the DNSPs.[39] The sharp increase in system capital expenditure from 2004 was driven by the deterministic N-1 planning standard and by load growth.

The ENCAP Review assessed the capital expenditure programs of the NSPs since the EDSD Review. It recommended that the N-1 planning standard could be modified to reduce capital expenditure without impacting materially on reliability.

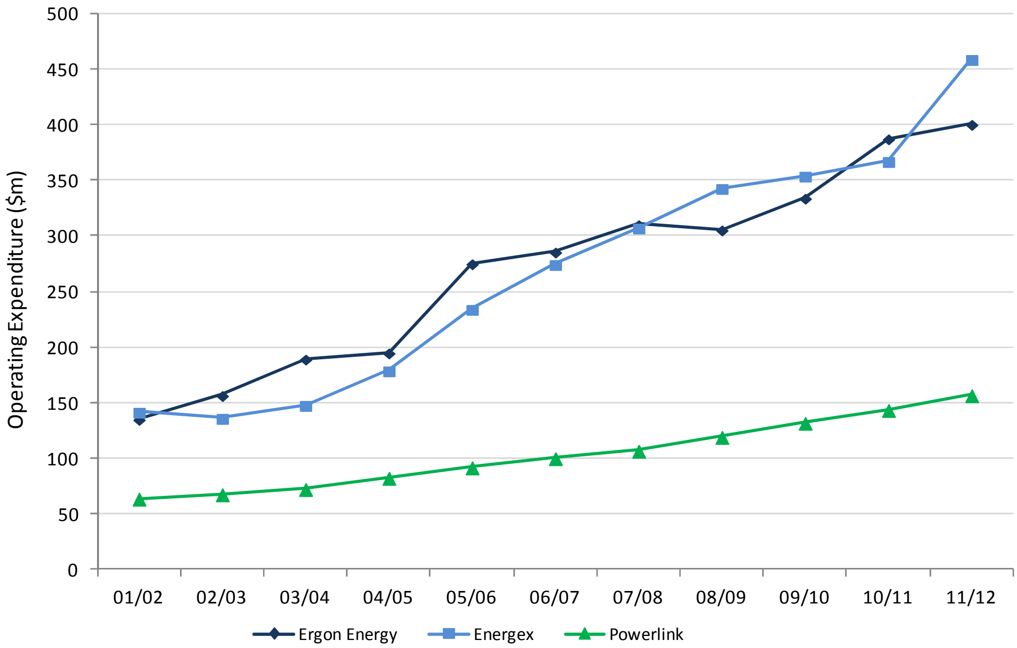
As a result, the DNSPs revised their capital expenditure programs for the remainder of the current regulatory control period.

[39] Electricity Network Capital Program Review 2011, Detailed Report of the Independent Panel.

4.5.2. The NSPs' Historic Operating Expenditure

The regulated operating expenditure of all three NSPs has also increased sharply as shown in Figure 20 below. Operating expenditure has risen on average by 11.5% per annum for Ergon Energy, 12.5% per annum for Energex and 9.4% per annum for Powerlink, over the period from 2001/02 to 2011/12.

Figure 20. Regulated Operating Expenditure, 2001/02 -2011/12



Source: Ergon Energy, Energex, Powerlink (included FIT)

The DNSPs attribute the increases in operating expenditure to:

- growth in the size of the network;
- enhanced inspection, vegetation management and maintenance programs; and
- increased penetration of domestic PV installations, resulting in higher feed-in tariff payments to customers by the DNSPs.

4.5.3. Historic Overhead Expenses (Indirect costs)

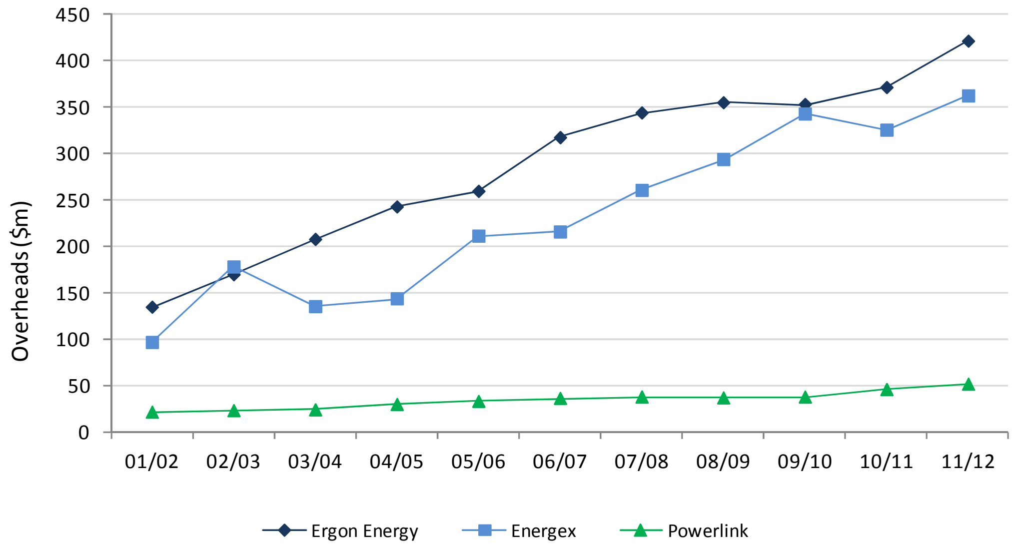
Indirect costs are overheads that are not directly attributable to network services, and are therefore attributed to capital and operating expenditure programs based on a cost allocation methodology. For the NSPs, these overheads include:

- senior management and Board activities;
- business support functions such as finance, legal, human resources, governance and information technology; and
- costs of direct labour not charged to productive activities.

Annual overhead costs have risen by $582 million over the past ten years as shown in Figure 21 below. Cost allocation methodologies vary slightly across the NSPs.

Overhead costs allocated to capital expenditure will flow through to network charges more gradually over a longer period as the assets are amortised. Overhead costs allocated to operating expenditure have a more immediate flow through to network charges.

Figure 21. Regulated Overheads, 2001/02 -2011/12



Source: Ergon Energy, Energex, Powerlink

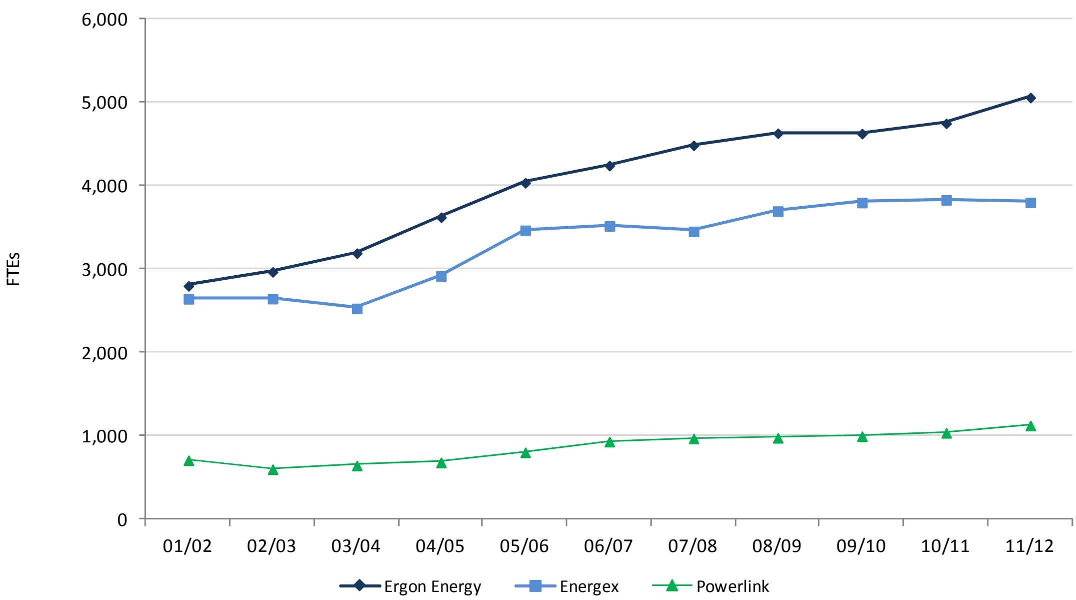
The Panel has made a number of recommendations to reduce overhead costs and to ensure that the relativities between operating expenditure and capital expenditure avoid the potential for a greater proportion of overheads being allocated to operating expenditure.

4.6. Workforce Trends

The workforce for the NSPs comprises both employees and contractors.

For the NSPs, the total workforce including contractors in 2011/12 was as follows: Ergon Energy 5,062 FTEs; Energex 3,805 FTEs; and Powerlink 1,133 FTEs.

Figure 22. Total Workforce, 2001/02 – 2011/12



Source: Ergon Energy, Energex, Powerlink

Over the ten years to 2011/12, the NSP workforce has increased as follows: Ergon Energy from 2,806 to 5,062 (80%); Energex from 2,650 to 3,805 (44%); and Powerlink from 717 to 1,133 (58%).

4.7. System Performance

Minimum Service Standards (MSS)[40] were introduced for Ergon Energy and Energex in 2004/05 following the EDSD Review. They are assessed against:

- System Average Interruption Duration Index (SAIDI), which is the sum of the duration in minutes of each interruption divided by the total number of customers averaged over the financial year for each distributor; and
- System Average Interruption Frequency Index (SAIFI), which is the total number of interruptions, divided by the total number of customers averaged over the financial year for each distributor.

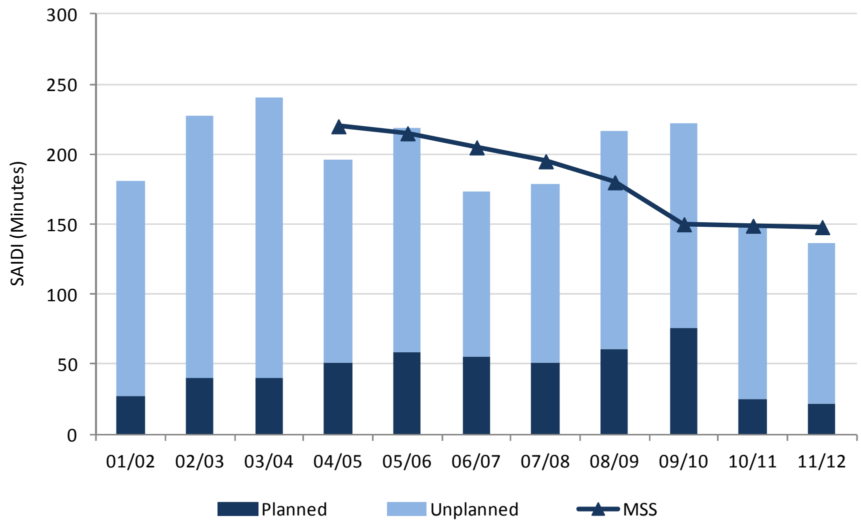
In Queensland, SAIDI and SAIFI calculations for the MSS include planned and unplanned outages.[41] The impact of extreme events (e.g. severe storms and flooding) and momentary interruptions (i.e. of less than 1 minute duration) are excluded from the calculations.

Ergon Energy and Energex are required to report quarterly to the QCA on their performance against the MSS for the following feeder types:

- CBD (Energex only);
- Urban;
- Short Rural; and
- Long Rural (Ergon Energy only).

The following charts summarise the performance of Ergon Energy and Energex against the MSS for urban feeders, which account for the majority of residential customers.

Figure 23. SAIDI for Urban Feeders - Ergon Energy 2001/02 - 2011/12

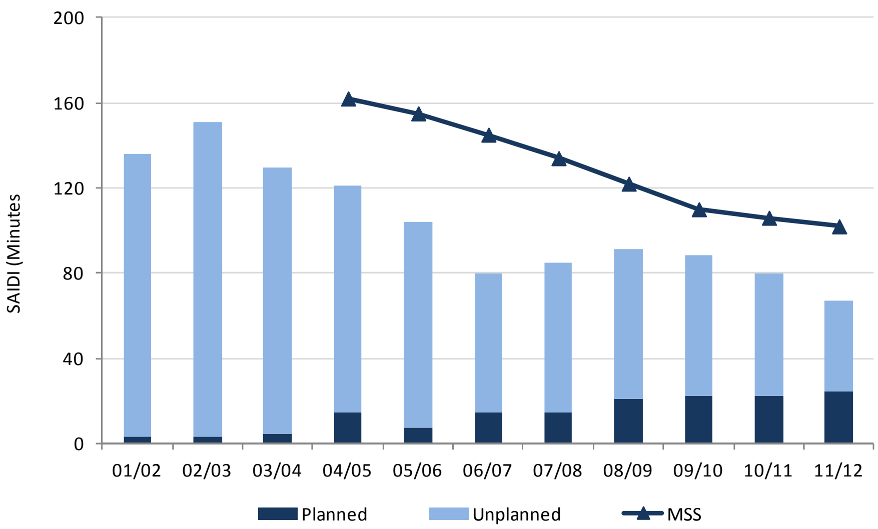


Source: Ergon Energy

[40] The MSS for each business is set out in the EIC made under the *Electricity Act 2004*, twelfth edition, 1 July 2012, p 16, 17

[41] Planned outages are those outages scheduled by the DNSP to, for example, undertake maintenance on the network. **Unplanned** outages are those that occur because of events outside of the control of the DNSP, such as flooding, storms and accidents.

Figure 24. SAIDI for Urban Feeders –Energex 2001/02 - 2011/12



Source: Energex

The differences in the urban feeder SAIDI MSS for Energex and Ergon Energy take account of differences in:

- network configurations (mesh v radial);
- topography and line length; and
- environmental conditions.

Further discussion of the performance against the MSS is provided in Chapter 5.

4.8. Performance against Industry Peers

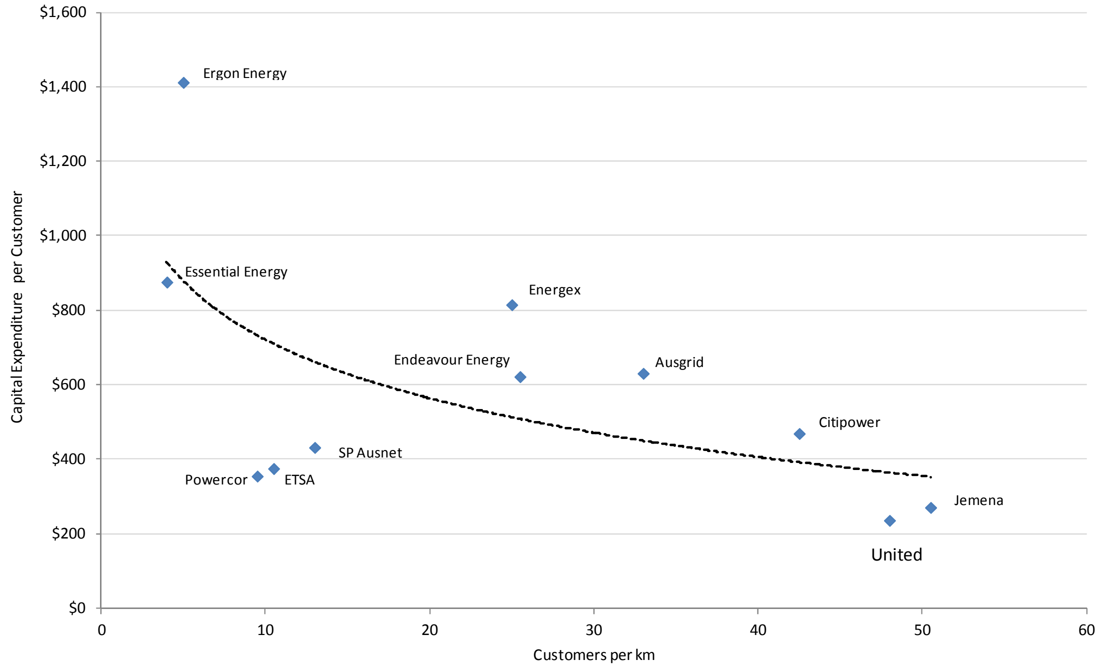
The Panel undertook a comparative assessment of the efficiency of the NSPs relative to their peers domestically and, in the case of Powerlink, internationally. This benchmarking approach is referred to as a “top down” assessment. It covered direct capital expenditure, operating expenditure and indirect costs. Direct expenditure relates to operations and activities involved in the design, construction, maintenance and operation of the network. Indirect expenditure arises from the overhead costs of a business.

The Panel commissioned a report which benchmarked the performance of Ergon Energy and Energex against DNSPs in New South Wales, Victoria and South Australia, using data from the most recent regulatory determinations and other publicly available information.

Taking into account issues such as scale and dispersion, and geographic and climatic variability, Ergon Energy is a higher cost provider in terms of both capital expenditure and operating expenditure relative to its network peers with broadly comparable customer densities.

The results also show Energex as being a higher cost DNSP compared to other DNSPs with similar customer densities. Energex ranked mid-range in relation to capital expenditure as a proportion of its RAB, but was generally at the higher end of the range for capital expenditure per customer and capital expenditure per MW of demand.

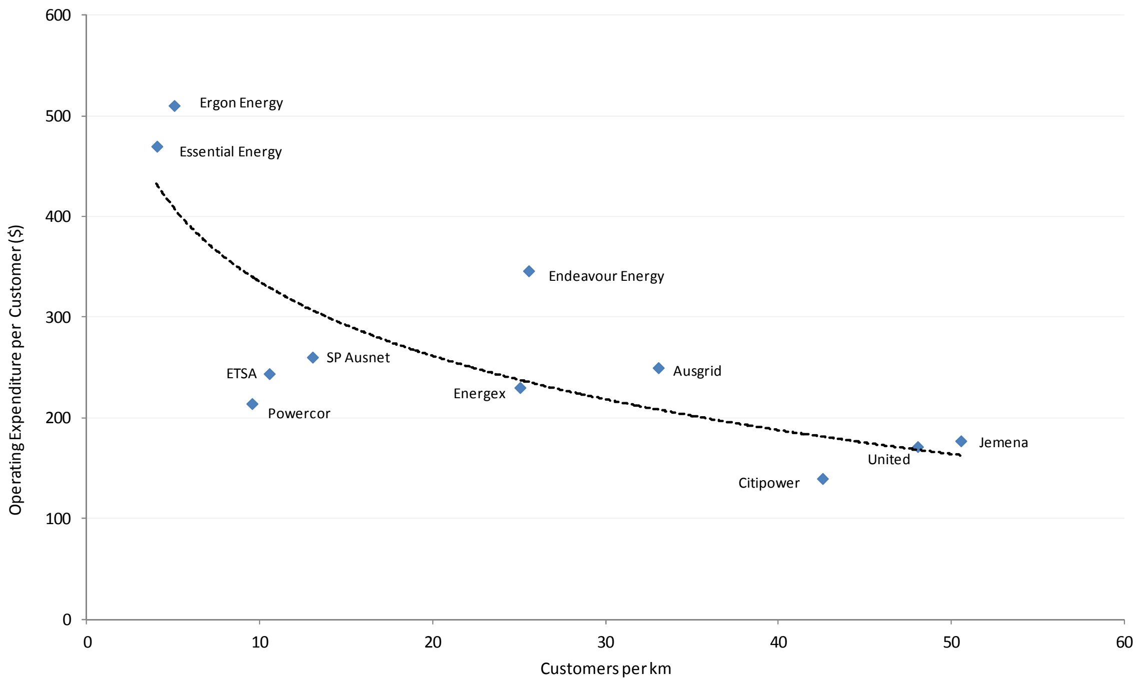
Figure 25. Comparison of capital expenditure per customer versus customers per km of line



Source: IRP

In relation to per customer operating expenditure relative to customer density, the government-owned DNSPs in Queensland and New South Wales (with the exception of Energex) were higher cost providers than the privately owned DNSPs in Victoria and South Australia (see Figure 26 below).

Figure 26. Comparison of operating expenditure per customer versus customers per km of line



Source: IRP

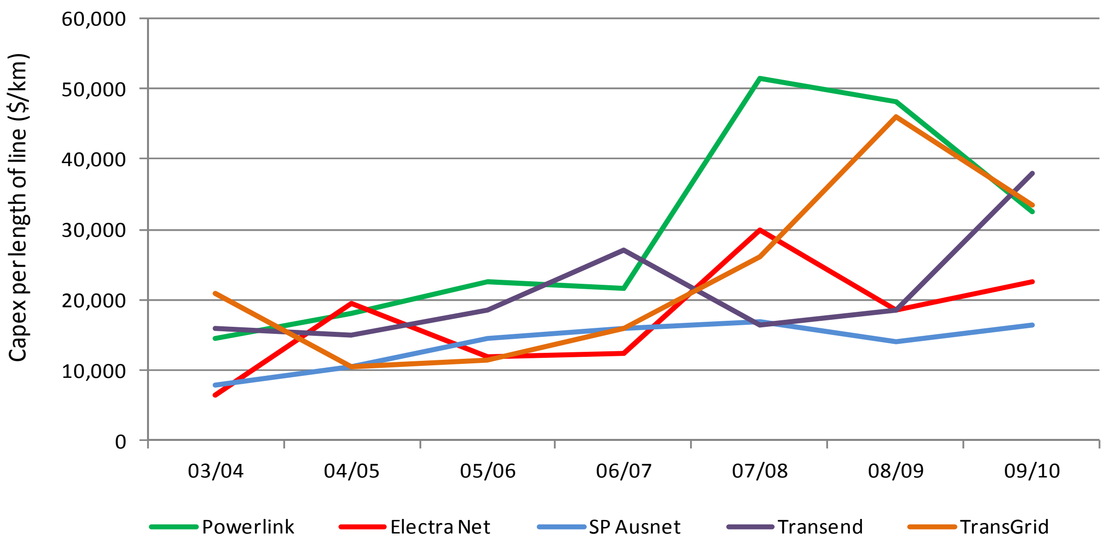
The Panel also reviewed the DNSPs' overhead costs relative to their peers. The results for both DNSPs showed that their corporate overhead and support costs were among the least efficient. This is consistent with the findings of the "bottom up" analysis commissioned by the Panel.

In contrast, the Panel's analysis showed that Powerlink performed well against other Australian and international TNSPs in respect of operating expenditure, and had lower overhead expenditure when compared to other Australian TNSPs.

In January 2012, the AER released a comparative performance report for Australia's TNSPs. There is no customer density measure used for the transmission sector. The AER used a measure of capital expenditure per kilometre of line.

In the period from 2003/04 to 2009/10, Powerlink was at the upper end of the cost range on this measure compared with its peers. Powerlink's capital expenditure per kilometre of line more than doubled from 2005/06 to 2006/07, driven in part by the N-1 security planning standard in its Transmission Authority and amplified by load growth.

Figure 27. Comparison of capital expenditure per km of line for TNSPs

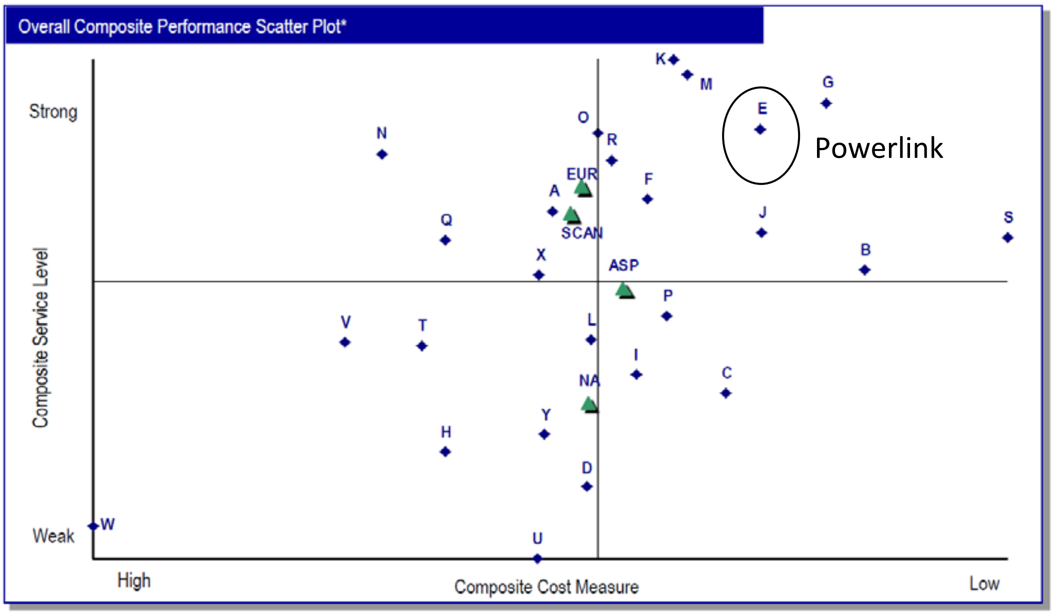


Source: AER

Powerlink participates in the International Transmission Operations and Maintenance Study (ITOMS) used by transmission companies to compare performance and practices. ITOMS includes data from 25 transmission network businesses globally and is updated on a two-yearly basis (most recently in 2011).

The study shows that Powerlink is among the lowest cost performers on a composite measure (comprising measures of line and substation maintenance) and ranks well against its peers in overall service provision and network maintenance measures.

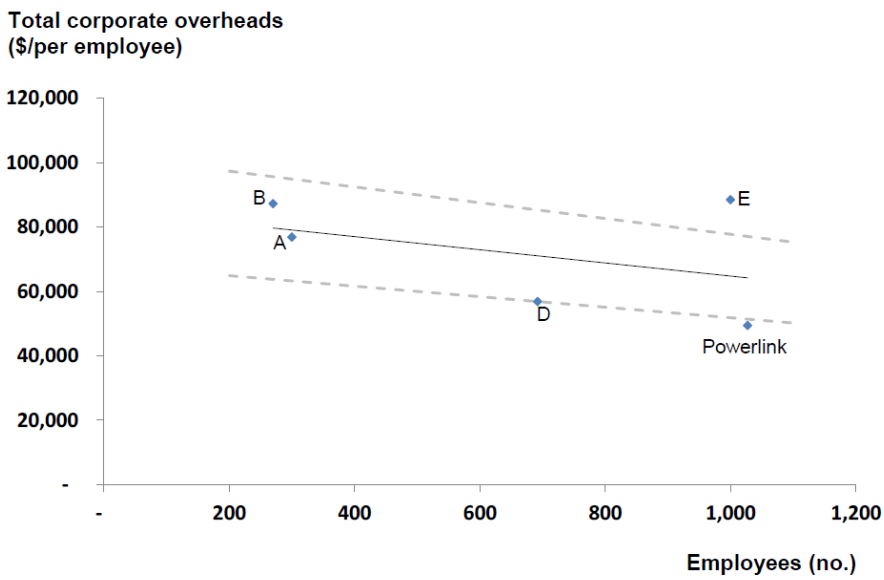
Figure 28. Powerlink overall performance in ITOMS



Source: ITOMS report (supplied by Powerlink)

As part of the corporate overhead benchmarking undertaken by the Panel, Powerlink was compared with other Australian TNSPs on a range of measures. In general, it was found that the corporate costs of Powerlink are lower than other Australian TNSPs across all indicators.

Figure 29. Total corporate costs per employee compared with employee numbers for TNSPs



Source: Consultants report for the IRP

5. Network Security and Reliability

Capital expenditure is driven, in part, by the network security and reliability standards it is required to meet. Powerlink's planning standard[42] is mandated in its Transmission Authority while its performance standards are largely determined at the national level. Planning standards for the DNSPs are determined by the Queensland Government. Performance standards are also determined by the Queensland Government on the basis of recommendations from the QCA.

This chapter summarises the current framework for security and reliability standards and recommends a number of changes.

5.1. Planning and Reliability Standards for Transmission

Outages on the transmission network have the potential to impact a large number of customers. An outage on Powerlink's network also has the potential to affect customers in other states because of interconnectivity with the NEM. Governance of the operations of the transmission network is embedded in national and State law and regulations, Powerlink's Transmission Authority and customer connection agreements.

As discussed in Chapter 3, the Rules require the AER to make a transmission determination taking into consideration Powerlink's obligations to maintain quality, reliability and security of its prescribed transmission services.

At the state level, the *Electricity Act 1994* (Qld) requires Powerlink to:

- operate, maintain (including repair or replace) and protect its transmission grid to ensure the adequate, economic, reliable and safe transmission of electricity;
- operate the grid in coordination with transmission grids to which it is connected directly or indirectly; and
- ensure, as far as technically and economically practicable, that the transmission grid is operated with enough capacity to provide network services to persons authorised to connect to the grid or take electricity from the grid.

Powerlink's Transmission Authority issued under the *Electricity Act 1994,* also requires it "to plan and develop its transmission grid in accordance with good electricity industry practice such that:

- if the power quality standards specify different obligations during normal and other operating conditions — the power quality standards will be met by the transmission entity;
- if the power quality standards do not specify different obligations during normal and other operating conditions — the power quality standards will also be met by the transmission entity even during the most critical single network element outage; and
- the power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage.

These obligations apply unless otherwise varied by a connection or other agreement made by the transmission entity with a person (customer) who receives transmission services."

The Transmission Authority thus requires Powerlink to plan and operate its network to a deterministic N-1 standard.[43] This means that the transmission system is planned on the basis

[42] "Planning standards" for transmission are sometimes referred to as "security standards" for distribution.

[43] The level of security in the system is described by how many key network elements can be lost without an interruption to supply. That is, if a system comprises "N" elements, a design of N-1 would maintain supply with one element out of service.

that no loss of supply will occur as a result of an outage of a single piece of plant, such as a transmission circuit or a transformer. Essentially this means additional equipment is constructed but remains idle or partially used as a back-up to other equipment.

This planning standard requires ongoing high levels of capital investment.

The majority of NEM connected States (Queensland, New South Wales and South Australia) plan their transmission networks to the N-1 standard or higher (e.g. N-2), depending on the criticality of the load being served. These standards are set by Government policy or a State based regulator.

In the case of Victoria, AEMO plans the network using a probabilistic approach that assesses the risk of loss of supply and the cost benefit implications from deferring capital expenditure in making augmentation decisions.

The following table summarises the TNSPs' planning standards in the NEM.

Table 7. Summary of Transmission Planning Standards, by NEM Jurisdiction

Jurisdiction	Planning Standard	Required by
Queensland	N-1	Transmission Authority under the *Electricity Act 1994*
New South Wales	Mix of N-1 and N-2 Sydney CBD area/inner Metropolitan (subject to load categories)	Transmission Network Design and Reliability Standard for New South Wales (Government Policy)
Victoria	Probabilistic approach	Economic Planning Criteria – Victoria (AEMO document required under the Rules)
South Australia	Mix of N-1 and N-2 (subject to load categories)	Electricity Transmission Code ET/06 (ESCOSA document required under the *Essential Services Commission Act 2002* (SA))

The inclusion of N-1 in Powerlink's Transmission Authority results in rigidity and does not allow consideration of alternative approaches that may reduce capital expenditure requirements at little risk to supply reliability.

This view is supported by the recent *Victoria over-capacity review* report prepared for AEMO, which compared transmission transformer and line utilisation rates across New South Wales, Victoria and Queensland (after adjustments were made for weather and line ratings).[44] This report confirmed that, in 2011, Queensland had the lowest utilisation rates for its network assets.

The Panel also considers that the prescription of the N-1 standard limits the ability of the AER to make an assessment of whether capital expenditure associated with meeting the standard is prudent.

In a presentation to the Panel, Powerlink outlined an alternative to the prescriptive N-1 standard. This involved the adoption of a hybrid approach to network planning that combines a deterministic standard with a probabilistic approach.

Powerlink's proposed approach would involve first assessing the likely impacts on consumers of adoption of alternative standards and then adopting the standards which balanced the incremental costs with the benefits of the investment. For example, Powerlink advised that a given level of load (up to 8MVA) could be placed at risk of load shedding if a credible

[44] Nuttall Consulting, *Victoria over-capacity review*, July 2012.

contingency occurred on the network for a short duration. This approach has the potential to defer capital expenditure, thereby reducing upward pressure on network tariffs.

Rather than the Queensland Government specifying an input standard to which Powerlink plans, the Panel sees merit in a framework which focuses on the value electricity consumers place on the transmission services delivered by Powerlink. The TNSP would operate to deliver that value using best transmission engineering practice.

Under this model, Powerlink would assess the benefits and costs of network and non-network investments to meet the expectations of consumers with regard to electricity transmission services and meet or exceed minimum performance standards.

Powerlink should be responsible for the development and justification to the AER of a prudent and efficient program of works to adequately meet and manage system demand to meet the expectations of customers, while meeting or exceeding the minimum performance standards.

The Panel would support a national approach to setting transmission reliability standards and notes that Council of Australian Governments (COAG) agreed in principle to such an approach at its meeting on 7 December 2012. The Panel also notes that the Federal Government's *Energy White Paper 2012* supports output-based standards.[45]

Recommendation 1

Remove the N-1 condition in the Transmission Authority for Powerlink and replace this with minimum performance standards to be met on a best endeavours basis. Powerlink would then have the flexibility to adopt the hybrid approach to network planning that it has recommended to the Panel.

Implementation: DEWS

Recommendation 2

The Government notify the AER of this change in Authority conditions.

Implementation: DEWS

Recommendation 3

The Powerlink Board be made responsible for the delivery of best practice supply reliability having regard to the expectations of Queensland electricity users and the minimum performance standards in the Transmission Authority.

Implementation DEWS

5.2. Planning and Reliability Standards for Distribution

The introduction of the deterministic N-1 security standard for the DNSPs' bulk supply and zone substations and sub-transmission lines, following the EDSD review, led to much higher levels of redundancy in the distribution networks. Although neither DNSP has achieved full N-1 compliance, the introduction of the N-1 standard has resulted in higher levels of reliability for the distribution networks, as well as significantly higher costs that are now reflected in electricity prices.

The DNSPs have, at various times since 2004, suggested that:

- it is not necessary to adopt a uniform N-1 approach in the "upstream" parts of their networks to achieve levels of reliability that meet consumers' requirements; and

[45] Department of Resources, Energy and Tourism, *Energy White Paper 2012*.

- the requirement may be leading to excessive capital expenditure.

The ENCAP Review found that more cost effective alternatives exist to achieve acceptable reliability levels than the duplication of major assets (i.e. N-1). This more outcome-focussed approach, which still included some specified levels of redundancy, was adopted, resulting in identified capital expenditure savings of approximately $505 million[46] over the remainder of the 2010-15 regulatory period. The Panel notes that the DNSPs have not yet achieved full compliance with the amended standards.

The Panel considers that the security policy adopted in 2004 resulted in excessive capital expenditure.

While the ENCAP Review had the effect of reducing the rate of growth of capital programs, the Panel considers that the current explicit input-based security policy requirements should be removed. The focus should be placed instead on reliability outcomes that meet customer expectations, reflect engineering best practice and represent benchmark performance. Consistent with this alternative approach, responsibility for determining the security standards necessary to deliver reliable supply should be returned to the Boards of the DNSPs.

The DNSPs should develop network security policies based on customers' expectations, the trade-offs between reliability and cost, delivery of reliability outcomes at least cost, and industry best practice.

This should allow for a more transparent and efficient approach to capital investment in the distribution networks, with the DNSPs required to justify the need for capital investment to both the AER and their customers.

Consistent with the AEMC Rule change on network regulation, this approach will also enhance, and be supported by, consultation with consumers in the early stages of regulatory determination processes.

Recommendation 4

The Government should no longer prescribe input-based security standards for the DNSPs. Responsibility for security standards should reside with the respective Boards and Management. The Government should notify the AER of this change in policy.

Implementation: DEWS

The Panel considers that a total review of security policies within each DNSP, incorporating the expectations and willingness of customers to pay for reliability, and the AER's requirements of prudency, would achieve a more efficient approach to long-term network planning and associated capital expenditure.

The DNSPs should ensure that their security standards are clearly identified to their customers and the Panel considers that their respective Annual Reports are the most appropriate place for reporting.

Recommendation 5

Each DNSP should review its security standards and publish its network security policy in its annual report and the Distribution Annual Planning Reports.

Implementation: DNSPs

The DNSPs' network reliability outcomes are reported against MSS set out in the Electrcity Industry Code (EIC or the Code). These are "best endeavours" reliability targets.

[46] Somerville et al, *Electricity Network Capital Program Review 2011*, p.73

The MSS are whole-of-system targets specified for each distributor by feeder category (i.e. CBD, urban, short rural, long rural). They are incorporated in the Code, and are reviewed and monitored by the QCA. The QCA may propose changes to the MSS, but the Minister for Energy and Water Supply is responsible under the *Electricity Act 1994* for approval of any such changes.

The DNSPs do not face any direct sanctions if they fail to meet the MSS, notwithstanding that there is a Distribution Authority condition requiring compliance with the Code. The only incentive/penalty arrangements in respect of reliability are the AER's Service Target Performance Incentive Scheme (STPIS) and a requirement under the EIC for reliability GSL payments to be made to small customers where they experience specified excessive levels of supply interruption frequency or duration. The STPIS provides an incentive to ensure supply reliability is not impacted by savings incentives under the revenue cap regulation model.

The MSS should be a minimum level of acceptable reliability performance for the DNSPs. They should be set as conditions of Distribution Authorities (licences) so that systemic failure to achieve the MSS carries a higher penalty.

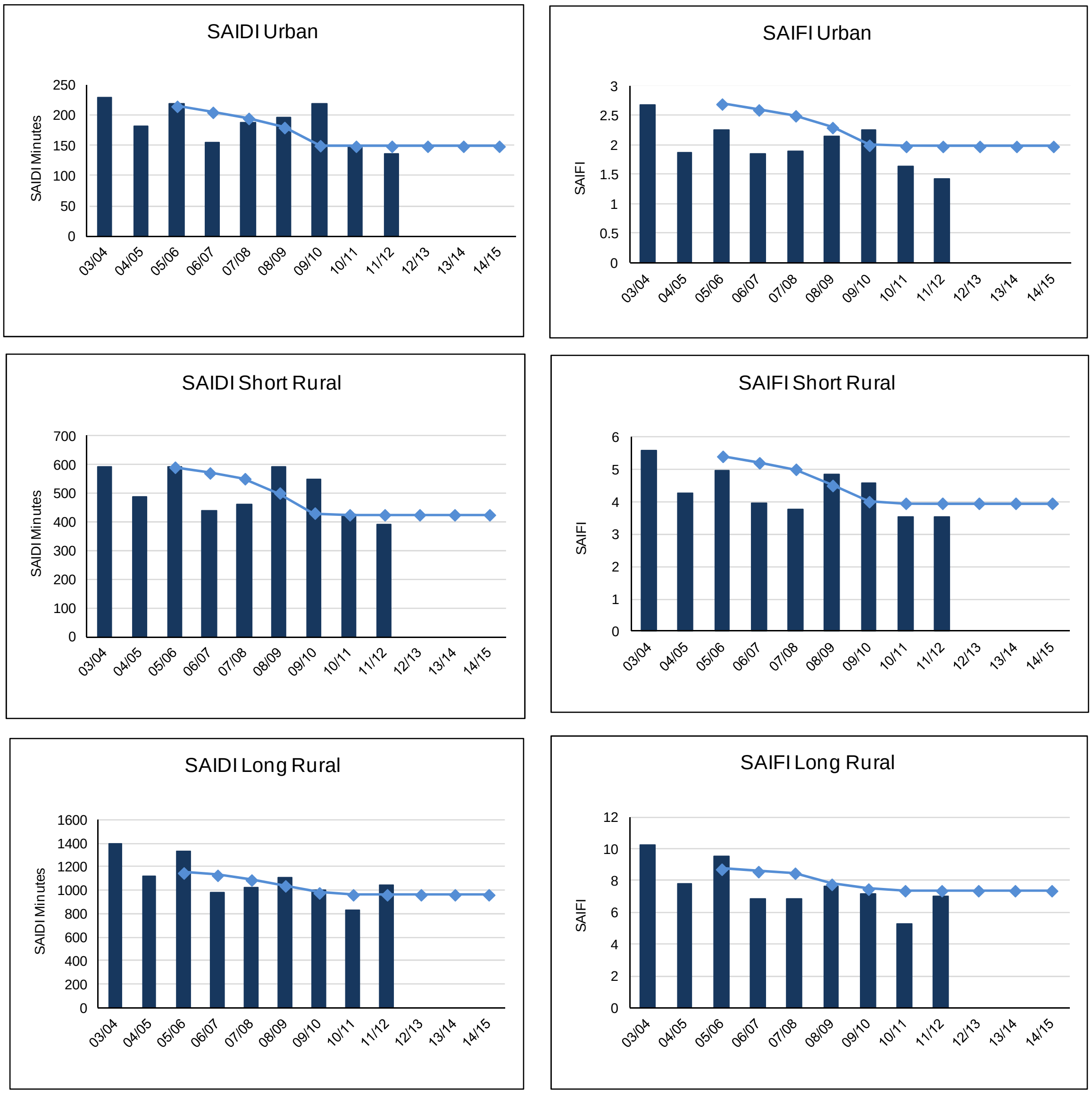
Recommendation 6

Remove the Minimum Service Standards from the Electricity Industry Code and instead include them in the DNSPs' Distribution Authorities, with systemic failures to meet these standards to be considered a breach of Authority conditions.

Implementation: DEWS

Ergon Energy's reliability performance has been inconsistent since 2003/04. Factors that have affected Ergon Energy's reliability performance include major events such as the floods of 2011, cyclones Larry and Yasi, bushfires, and limitations on the use of live line operations to address specific safety issues. Major event day exclusions often do not apply because the number of customers affected is below the threshold.

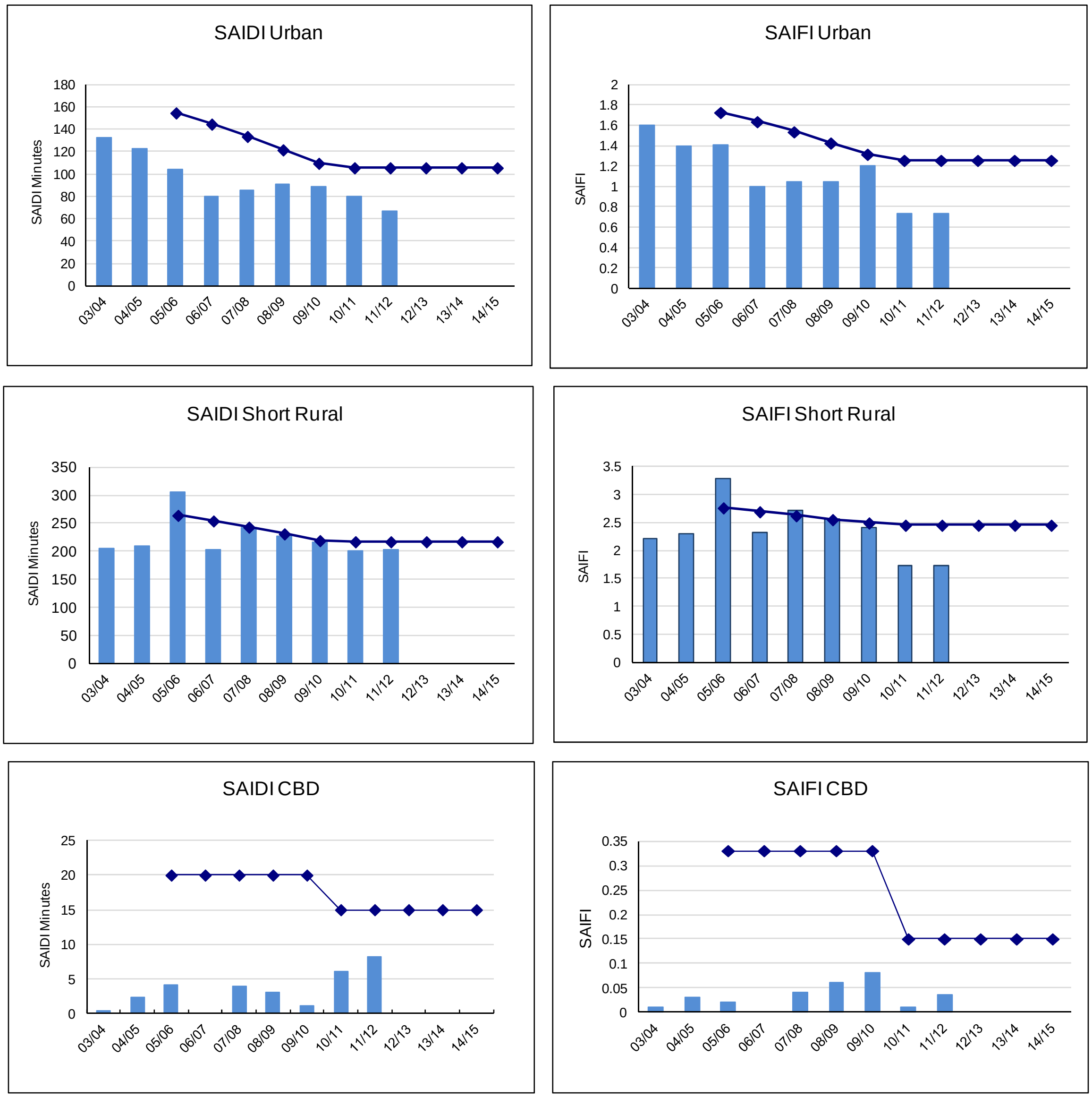
Figure 30. Ergon Energy MSS Reliability Performance



Source: Ergon Energy

Energex has consistently met its MSS since 2003/04, even when external events impacted its network. For example, the 2011 Brisbane flood which, while treated as a Major Event Day exclusion, resulted in associated reliability issues outside the exclusion definition (e.g. the failure of a pole as a result of flood damage several weeks after the flood subsided and the major event day exclusion was lifted).

Figure 31. Energex Reliability Performance - Urban and Short Rural



Source: Energex

Stakeholder views expressed during the Panel's consultation program indicate that the level of reliability being delivered under the current MSS exceeds the level for which some customers are willing to pay. Therefore, the Panel considers that the MSS for the DNSPs should be set at the levels applying at the start of the current regulatory period. This should reduce the upward pressure on network costs and thus network prices.

Recommendation 7

Set Minimum Service Standards levels for the DNSPs at the levels applying at the commencement of the current regulatory control period (i.e. 1 July 2010).

Implementation: DEWS

The MSS are a minimum standard and it is expected that the DNSPs will target service levels above these minimums. Subject to the Distribution Authority conditions specifying the MSS, the Boards and management of the DNSPs will be accountable for:

- determining the appropriate reliability standards for their networks based on customers' expectations and willingness to pay for reliability;

- justifying their reliability targets and the capital expenditure required to support them to the AER; and
- publicly reporting their comparative performance.

Recommendation 8

The Boards of the DNSPs should review reliability performance against comparable national or international networks and report on these comparisons in their annual reports.

Implementation: DNSPs

The MSS are specified and calculated on the basis of system-wide averages for each feeder class within each DNSP. Even where the standards are met, there will always be feeders where reliability is below average, and may be unacceptably poor. This will not be evident when reported reliability results are system averages.

Historically, both DNSPs have been required to report on worst performing feeders and actions planned to address them. This approach is consistent with what has occurred across the NEM in respect of "worst served customer provisions". Interstate arrangements are set out in the following table.

Table 8. Worst served feeder / customer programs, by jurisdiction

Jurisdiction	Worst Served Customer Provisions
Queensland	Network Management Plans (NMPs) are required to report on how worst performing feeders are defined, an analysis of the performance in the previous financial year and an analysis of worst performing feeders identified in the preceding NMP
Australian Capital Territory	Set separate reliability targets where groups of customers are expected to receive substantially different levels of service
South Australia	Required to report annually on the nature of any discrete areas of poor performance; the reasons for that performance; and the remedial actions taken or proposed to improve performance
Tasmania	Required to report on areas which are underperforming and how the DNSP proposes to improve performance. Poor performing communities are identified on the basis of exceeding the Tasmanian Electricity Code limits for frequency or duration of outages
Victoria	DNSPs are required to report where feeder performance falls below targets set by the Essential Services Commission Victoria, based on the worst served five per cent of customers
New South Wales	Standards set out minimum performance requirements for individual feeders. DNSPs are required to report and take steps to improve performance of feeders if those standards are not met

Source: AEMC, *Review of Distribution Reliability Outcomes and Standards*, Issues Paper, 28 June 2012.

To meet these obligations, both DNSPs introduced Worst Performing Feeder Programs across all feeder categories. These programs target specific reliability issues by carrying out preventative-corrective measures aimed at delivering significant reliability improvements.

The Panel supports the continuation of the Worst Performing Feeder programs, particularly as customer expectations will play a greater role in determining reliability standards in the future.

The Distribution Annual Planning Reports (DAPRs)[47] that will replace the current NMPs do not include a requirement to report on worst performing feeders. The Boards and management of the DNSPs should continue the programs and report publicly on their performance.

Recommendation 9

The Boards of the DNSPs should continue to monitor Worst Performing Feeders and report on their performance in their annual reports and the Distribution Annual Planning Reports.

Implementation: DNSPs

Guaranteed Service Levels (GSLs) were incorporated into the EIC following the EDSD Review in 2004.

While the majority of the GSLs relate to customer service, two GSLs are applicable to supply reliability. A customer receives a GSL payment (currently $104[48]) credited to their electricity account when they experience an interruption which exceeds a specified duration, or when they experience a number of interruptions in a financial year greater than the number specified in the Code. These standards are not the (average) MSS but higher frequencies and durations that might be interpreted as unacceptable performance on an individual customer basis.

Originally, GSLs were paid to customers upon application, with Energex paying one or two reliability GSLs each year. However, GSL payments have increased substantially in the past two years, after both DNSPs moved to an automatic payment of GSLs where service was below the minimum level. In 2011/12, the GSL payments for failing to meet reliability standards amounted to $42,640 for Energex and $305,916 for Ergon Energy.

These overall payments are not a material contributor to overall increases in network tariffs, and they provide customers with some recognition of poor service and impose a reputational discipline on the DNSPs. The Panel therefore supports maintaining the GSLs.

Recommendation 10

Retain Guaranteed Service Level arrangements as currently specified.

Implementation: DEWS

[47] DAPRs are addressed in more detail in Chapter 9.

[48] Electricity Industry Code made under the Electricity Act 1994, Clause 2.5.10 Amount of GSL Payments p23.

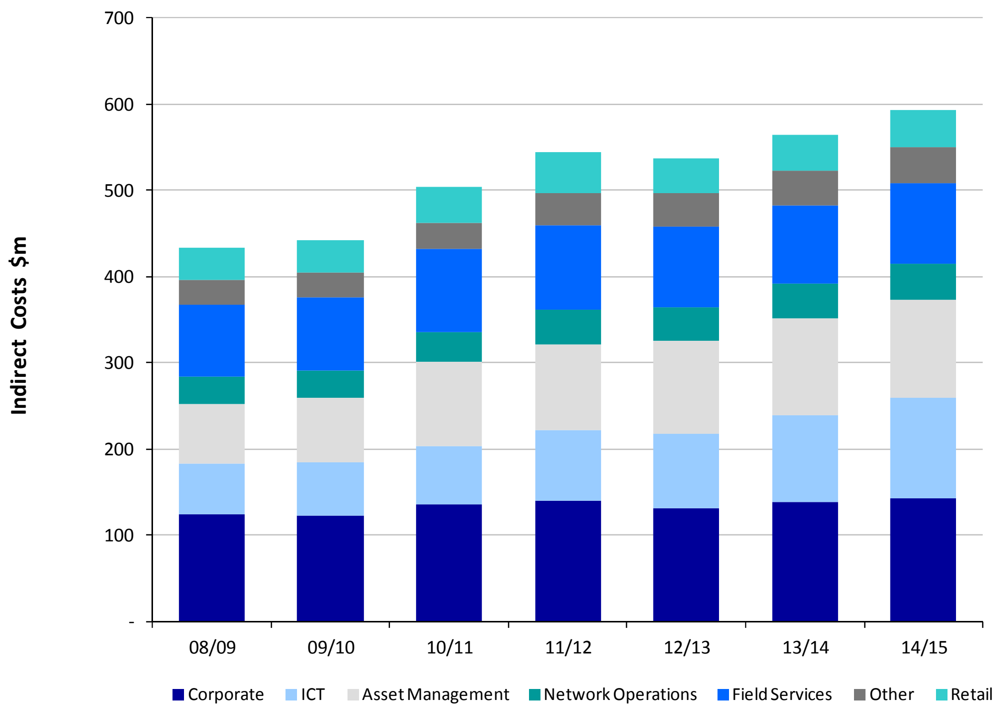
6. Efficiency of Overhead expenses - Indirect Costs

6.1. Overhead Expenses - Indirect Costs

Overhead costs are largely associated with engineering, asset management, resourcing, administration and governance activities. The DNSPs also allocate costs of field work time to the indirect pool where these cannot be charged to direct capital or operating activities.

Information provided by Ergon Energy shows a trend of increasing indirect costs, from $434 million in 2008/09 to a forecast $594 million in 2014/15. The Panel notes that these figures include around $40 million annually attributable to Ergon Energy's retail function (which are outside of the scope of this investigation). Nevertheless, indirect costs excluding retail were expected to increase by 39% over the period.

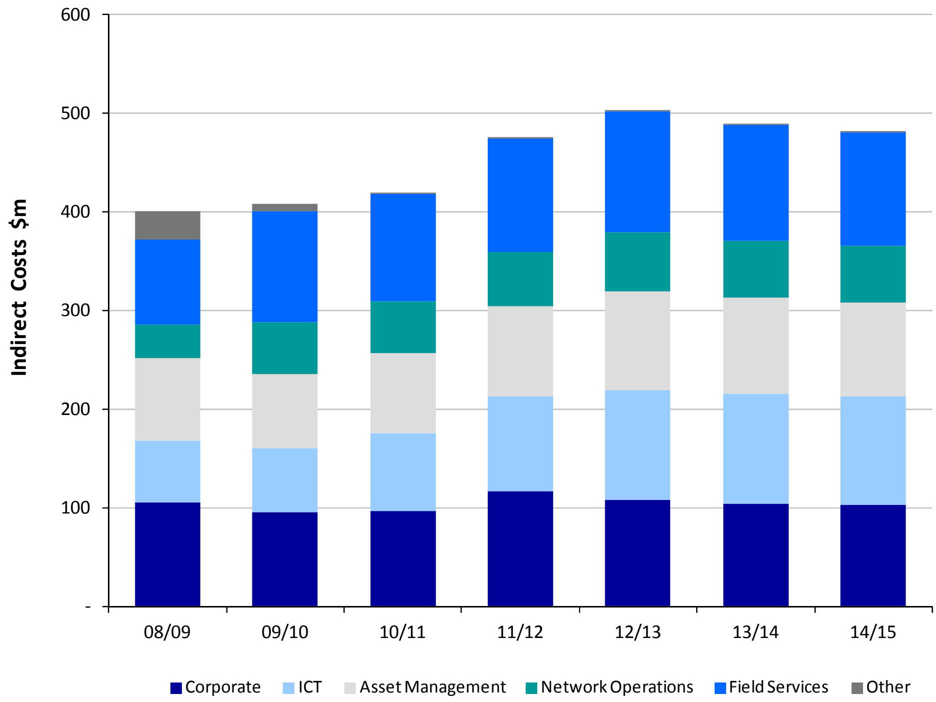
Figure 32. Ergon Energy Indirect Costs 2008/09 to 2014/15



Source: Ergon Energy, IRP analysis

Information provided by Energex also shows a general trend of growth in indirect costs, rising from $400 million in 2008/09, peaking at $503 million in 2012/13 before a slight decline to $482 million in 2014/15. This represents 20% growth over the period.

Figure33. Energex Indirect Costs by Category, 2008/09 to 2014/15



Source: Energex, IRP analysis

Powerlink's indirect costs have increased from $36 million in 2008/09 to $55 million in 2012/13 and are expected to increase to $59 million by 2014/15. Given its relative performance against other Australian TNSPs and low indirect costs compared with the DNSPs, the Panel considered that further assessment of Powerlink's indirect costs was not required.

6.2. DNSP Efficiency Improvement Programs

Individual functional areas were reviewed to determine the efficiency of indirect costs. This assessment incorporated the results of work already being undertaken by the DNSPs as follows:

- Ergon Energy's Efficiency and Effectiveness Program, which commenced in November 2011 and is now being implemented; and
- Energex's Business Efficiency Program, which commenced in August 2012.

These programs cover both indirect and direct expenditure and have identified major expenditure reduction opportunities. The scopes of work within each DNSP are similar and focus on areas offering the greatest cost reduction opportunity. These include corporate support functions, technical and engineering functions and management functions in both DNSPs.

The Panel examined the outcomes of these programs to assess the likely benefits and to evaluate whether further improvements were possible.

In this regard, the Panel reviewed the reports and assessments prepared by the DNSPs, and met with the consultants that assisted the DNSPs in this process. These reviews varied in coverage and some areas within each business were not subject to full scrutiny. The Panel has therefore concluded that these efficiency programs can be expanded to identify and capture a broader range of possible cost savings.

6.2.1. Ergon Energy Efficiency and Effectiveness Program

Ergon Energy engaged PricewaterhouseCoopers (PwC) in October 2011 to undertake a two stage process for delivering its Efficiency and Effectiveness Program. The two stages were:

- Diagnostic Phase – October 2011 to January 2011; and
- Detailed Design Phase – January 2012 to date.

Table 9 describes key elements of this program.

Table 9. Ergon Energy Efficiency and Effectiveness Program

Function	Diagnostic Description
Finance	A process and structural review identified potential synergies between different functions, process and system improvement opportunities and a narrow span of control that can be addressed to bring the function more in line with benchmark levels.
Human Resources (HR)	Ergon Energy is modernising, reducing and refocusing the services provided by the HR function. More accountability is being provided to frontline managers to undertake human resource management functions, supported by improved processes and systems.
Health, Safety and Environment	Accountability for key health, safety and environment management activities is being assigned to appropriate frontline management roles in line with contemporary business models. This will be supported by addressing span of control issues in the remaining central support team and simplifying administration and reporting functions.
Communications/Stakeholder Engagement	These functions are being redesigned to remove non-critical roles.
Information and Communication Technology (ICT)	Ergon Energy's ICT provider, SPARQ, has committed to a number of targeted initiatives to reduce headcount and associated costs with a particular emphasis on Ergon Energy more directly managing demand for ICT programs. *See Section 6.3 below.*
Contractors and Labour Hire	Across many corporate functions, a large number of contractors and labour hire resources were engaged to fill temporary positions (e.g. maternity leave) as well as specialist roles. Work is under way to reduce the overall headcount in this area.
Program and Project Management	Ergon Energy has traditionally utilised a large program and project management team to support non-frontline projects. The corporate program has been rationalised over recent months to focus on core reform projects. As well, a realignment of the Program Delivery Group has further reduced the number of permanent roles.
Procurement and Logistics	The adoption of a strategic procurement model is expected to reduce procurement expenditure.

Function	Diagnostic Description
Property and Fleet	Opportunities for property and fleet savings include increasing fleet and property utilisation levels, improving control of capital expenditure and more efficient and strategic management of fleet and property assets. One-off benefits may also be realised through the sale of surplus and non-core property and other assets.
Asset management	Savings can be achieved in the short to medium term through an increased span of control, removal of middle management roles/functions, and consolidation of like functions to reduce hand-offs or duplication of activity (e.g. planning, data management). Further efficiencies will be pursued which will simplify and standardise systems and processes.
Labour Optimisation	Initiatives include staggered starts for staff, shiftwork and overtime limits on weekends supported by more detailed monitoring of overtime statistics.

Source: PwC

Table 10 below summarises the staff reductions and cost savings arising from Ergon Energy's Efficiency and Effectiveness Program.

Table 10. Ergon Energy Efficiency and Effectiveness Program target reductions –Indirect and Direct Costs

Opportunity Area	**FTE reductions**[49]		**Annual expenditure reductions ($m)**[50]		**One-off benefits ($m)**[51]	
	Low	High	Low	High	Low	High
Corporate Support	90	227	29	55	-	-
Other Support Functions	44	52	54	86	45	50
Labour Resource Optimisation	115	264	40	92	-	-
Adjustment for Overlapping FTE/Cost Savings[52]	-	-	-	-	-	-
Implementation Costs	-	-	-	-	-	-
Total	**249**	**543**	**123**	**233**	**45**	**50**

Source: Ergon Energy, IRP

[49] FTE savings at peak full year.
[50] Annual undiscounted expenditure reduction at peak full year.
[51] One-off benefits from property rationalisation
52 Adjustment for cost savings overlap is included in the FTE/annual expenditure reduction amounts.

6.2.2. Energex Business Efficiency Program

Energex commenced the Business Efficiency Program in July 2012 with a scope similar to that undertaken by Ergon Energy. PwC was engaged by Energex to assist in the analysis and the design of solutions. The work to date at Energex has largely been to quantify the savings potential from major initiatives. The key areas of cost saving opportunity are:

- Reducing overheads as the Program of Work (PoW) reduces;
- Increasing management span of control to industry benchmark levels;
- Rationalising corporate support functions;
- Reducing the use of contractors and consultants;
- Reducing overtime;
- Streamlining PoW management; and
- Addressing restrictive regulations and work practices.

Table 11. Energex's Efficiency and Effectiveness Program

Function	Diagnostic Description
Finance	Major areas of focus are in improving the delivery model for finance services and the underpinning systems and processes as well as improving management spans of control.
Human Resources (HR)	Reducing the number of staff involved in HR management through better alignment with benchmark levels. This will be done through rationalisation of services and improved efficiency of delivery.
Auditing	Rationalising audit and compliance programs and eliminating duplication.
Communications and Marketing	Rationalising the communications function and reducing the level of marketing expenditure.
Works Management and Network Control	Reduce the works management and PoW management functions by approximately 20%, in line with reduced capital and operating programs.
Engineering Design and Capital Program Support	Reduce technical, engineering, design and related activities in line with the reduced PoW. Reduce the size of the engineering design team in line with similar sized network utilities.
Health, Safety and Environment	Consolidate staff and managers undertaking these activities into a single team.
Property and Fleet	Energex holds surplus property which could be sold. Reduce the size of the vehicle fleet in line with other utilities. Rationalise the fleet and property management function.
Labour Optimisation	Increase spans of management control. Reduce overtime in line with industry benchmarks. Improve procurement practices.

Source: PwC

Table 12 outlines the proposed expenditure reductions identified in the Energex Business Efficiency Program.

Table 12. Energex Business Efficiency Program

Opportunity Area	FTE reductions[53]		Annual expenditure reductions ($m)[54]		One-off benefits ($m)[55]	
	Low	High	Low	High	Low	High
Corporate Support	79	105	16	32	-	-
Other Support Functions	25	39	12	20	13	25
Labour Resource Optimisation	514	856	132	229	-	-
Adjustment for Overlapping FTE/Cost Savings[56]	-122	-155	-25	-31	-	-
Implementation Costs	-	-	-	-		
Total	**496**	**845**	**135**	**251**	**13**	**25**

Note: Totals may not sum due to rounding
Source: Energex, IRP

The Panel supports the DNSPs' initiatives and the continuation of the efficiency improvement programs currently under way.

Recommendation 11

The Boards of the DNSP's continue with the implementation of their efficiency programs.

Implementation: DNSPs

6.3. Information and Communication Technology

ICT services for Ergon Energy and Energex are provided by SPARQ Solutions (SPARQ), a jointly owned company formed in 2004. Its purpose was to deliver capital and operating cost savings, estimated to be between $80 million and $100 million in the first five years, through process and system alignment between the DNSPs.

SPARQ provided reports prepared by KPMG on its comparative performance. These showed that SPARQ compares favourably with its peers in terms of operating and capital costs. SPARQ's management also advised that it routinely conducts rigorous assessments of staff costs, including the use of consultants and contractors relative to full time internal staff.

An assessment was undertaken in 2009 which found that, whilst SPARQ had achieved the operational cost savings targeted for its first five years of operation, the anticipated capital expenditure efficiencies had not been realised, due predominantly to unforeseen changes in the industry, such as the introduction of full retail competition.

[53] FTE savings at peak full year
[54] Annual undiscounted expenditure reduction and implementation costs at peak full year. Implementation costs will phase out after the initial costs of achieving the expenditure reduction are incurred.
[55] One-off benefits from inventory reduction
[56] Adjustment for cost savings overlap is included in the FTE/annual expenditure reduction amounts.

The Panel undertook its own assessment of SPARQ's operations and found that:

- SPARQ is delivering ICT operational services such as the helpdesk function, desktop support, and network support efficiently compared with organisations against which it was benchmarked;
- The scale of SPARQ's ICT project delivery function is larger than benchmark due to the size of the current and forecast ICT works programs of the DNSPs; and
- Energex's ICT depreciation and capital expenditure were significantly higher than the benchmark median.

The Panel also concluded that, even if Energex were to reduce its capital expenditure for 2012/13 and future years, it would take several years for the benefit of this to flow through the Asset Service Fee due to the size of the existing asset base and the life over which ICT assets are depreciated. Further, capital expenditure would have to be permanently reduced, not simply deferred to later years.

Despite one of SPARQ's foundation objectives being capital expenditure savings from the joint delivery of projects to Energex and Ergon Energy, the Panel is concerned that there has been very limited delivery of joint projects to date.

Incongruent ICT strategic planning between Ergon Energy and Energex has resulted in key strategic ICT decisions being taken separately by each business, in part because they are at differing points in their asset life cycles with different capital expenditure profiles and priorities. The Panel has found few instances where the DNSPs have chosen to work together to minimise ICT capital costs.

The Panel considers that the services currently provided by SPARQ may be delivered more efficiently by external service providers. To this end, it has recommended that the DNSPs (or, subject to Recommendation 30, the Holding Company) test the provision of these services by competitive tender. Through this market testing, the most cost effective use of in-house and third party ICT service provision should be employed, while maintaining appropriate service levels. This would assist the DNSPs in their regulatory submissions to the AER.

The Panel also considers that changes to governance would achieve a greater degree of alignment of the DNSP's ICT programs. This issue is addressed later in this Report.

The following recommendations on ICT provision should be read subject to the Government's decision on Recommendation 30 for structural change.

Recommendation 12

Return the role of the Office of the Chief Information Officer to each of the DNSPs and SPARQ focus on its role as a service provider to the DNSPs.

Implementation: DNSPs

Recommendation 13

Each of the DNSPs reassess its Information Communication and Technology capital expenditure priorities and focus on the prudent capital expenditure required to maintain its core distribution business activities (including regulatory compliance and safety obligations).

Implementation: DNSPs

Recommendation 14

In addition to the cost savings already identified by SPARQ Solutions, further efficiencies should be achieved through actions such as:

- *Streamlining the testing process through the adoption of an automated testing tool;*
- *Developing a common set of automated financial and management reports for the DNSPs; and*
- *Reviewing existing system contracts to reduce user licence costs in line with future staffing levels within SPARQ Solutions and the DNSPs.*

Implementation: DNSPs

Recommendation 15

Alternative service delivery models for Information and Communication Technology services currently delivered by SPARQ Solutions should be tested as follows:

- *issue market tenders for the delivery of capital projects; and*
- *issue market tenders for the delivery of the relevant operational Information Communication and Technology services.*

Implementation: DNSPs

Recommendation 16

Implement an integrated operating model that consolidates the Planning and Partnering positions within DNSPs to minimise the number of touch points between SPARQ and the DNSPs.

Implementation: DNSPs

6.4. Non-core Business Activities

The Panel identified activities that complement front-line service delivery, but could not be regarded as core DNSP functions. These could be commercialised to capture their value or outsourced to reduce costs.

The Ergon Energy Remote Observation, Automated Modelling, Economic Simulation (ROAMES) Project is the most significant of these. This project has involved significant investment (estimated at $18 million to date) in the development of technology and assets to allow the capture of precise three dimensional (3D) models and high resolution imagery of built infrastructure and environment. The program was initially funded with the expectation of delivery of economic benefits solely to Ergon Energy, particularly in the area of vegetation management.

As the ROAMES project has evolved, additional benefits have been identified through the accurate location, condition assessment and environment monitoring of Ergon Energy's distribution assets and other infrastructure, helping to reduce the cost of network operations by leveraging spatial information for decision making. Positioning infrastructure can also be used to provide precise 3D models and high resolution imagery in real time. This has opened up a wider range of additional benefits to in-field applications of the ROAMES services both internally within Ergon Energy and externally to other commercial customers.

The ROAMES project is currently costing around $100,000 per month and its commercialisation will require additional investment capital. The Panel considers the project to be worthwhile, but is aware that commercialising these types of products and services (taking them from proven concept to commercialised, revenue generating products) requires specialist entrepreneurial, financial and technological skills and experience. The ROAMES project should be progressed in partnership with parties that can assist with the commercialisation process and provide the additional capital required.

Recommendation 17

Progress the ROAMES project in partnership with parties that can assist with the commercialisation process and provide the additional capital required.

Implementation: Ergon Energy

Ergon Energy has a separate business division based in Brisbane, which builds modular substations and associated infrastructure for Energex and Ergon Energy.

The Panel is aware that, at the time the business division was established, the preference of both DNSPs was to outsource these services to the private sector as they were not a core function. There was limited private sector interest at that time. This situation has changed, and there is now the opportunity to source these services from private sector providers at potentially lower cost. The Panel recommends that Ergon Energy review the ongoing in-house provision of these services against private sector alternatives.

Recommendation 18

Ergon Energy seek expressions of interest from external providers of modular substations and other related workshop services and discontinue the internal provision of these services if this results in lower cost.

Implementation: Ergon Energy

Ergon Energy has interests in land and forests, which it has been acquiring since 2006 to guarantee future access to hardwood for power poles. The capitalised value of these land and forestry holdings is around $20 million. The divestment of these assets on the basis of secure off-take agreements would allow the recovery of this capital for future investment in core network assets.

Recommendation 19

Ergon Energy divest its holdings of land for forests and reinvest the sale proceeds in core network assets.

Implementation: Ergon Energy

6.5. External Contractors, Consultants and Professional Services

In 2011/12, the NSPs spent, in aggregate, almost $1.5 million per week on external contractors, consultants and professional services. This comprised $32 million in Ergon Energy, $30 million in Energex and $7 million in Powerlink. It should be noted that this excludes front-line and engineering consultants and contractors engaged in field work.

While the Panel acknowledges that all businesses will, at times, appropriately make use of external professional services to manage peak workloads and to deliver highly specialised services, the extent of such use in the Queensland DNSPs in particular appears excessive. The Panel's view is that this is symptomatic of a systemic disregard for cost and a culture of over-reliance on external services.

This pattern and level of use of external resources has continued in 2012/13, despite the current focus on the impacts of rising electricity prices on the cost of living and the clear signals from Government that costs need to be more carefully managed.

Table 13. NSP Contractor Numbers and Costs (2011/12 and 2012/13 YTD)

Business	2011/12 Frontline	2011/12 Non -frontline	2012/13 (as at Aug '12) Frontline	2012/13 (as at Aug '12) Non-frontline
Energex	30	127	8	137
Ergon Energy	174	117	172	125
Powerlink	100	3	53	5
Totals	**304**	**247**	**233**	**267**

Source: Energex, Ergon Energy, Powerlink

Recommendation 20

The DNSPs take immediate action to reduce expenditure on consultancies, professional services and non-frontline contractors and achieve reductions commensurate with the revised programs of work.

Implementation: DNSPs

7. Efficiency of Direct Cost Activities

The Panel reviewed work management activities within the NSPs to enable an assessment of the efficiency of operations. Through this process, opportunities were identified in the DNSPs for substantial improvements in labour utilisation and efficiency from more effective scheduling, output measurement, performance monitoring and management reporting.

Direct costs are driven by the volume of work in the capital and operating expenditure programs and the efficiency and effectiveness of how that work is identified, scoped, planned, resourced and executed. Direct costs are primarily related to:

- developing and augmenting the power, protection and communications networks to meet customer electricity demands and approved standards for security of supply;
- operating the network;
- maintaining and repairing network components and responding to faults to restore supply; and
- clearing vegetation beneath and adjacent to lines.

7.1. Program of Works Scheduling

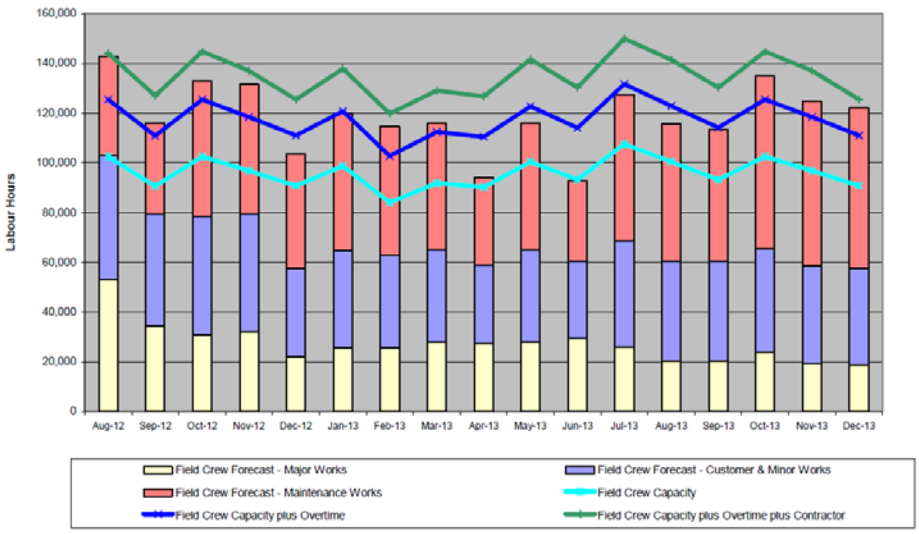
The work management process begins by assembling a 5 to 10-year picture of the forecast future workload in preparation for a regulatory determination every five years. This long-term forecast is updated annually.

This plan is converted into a resource-balanced PoW for the following 18 to 24 months in the project management system. PoW projects arise from:

- demand growth;
- reliability improvement;
- asset replacement; and
- repairs.

The PoW is updated quarterly. The chart below shows a typical PoW including estimated resource availabilities.

Figure 34. Example of a Resourced 18 month PoW



Source: Energex

From the PoW, resources are adjusted to balance the workload, costs, internal labour and contract labour requirements. This information is loaded into the Ellipse Enterprise Resource Planning system to access standard engineering designs and material requirements. Work orders are then raised in the Ellipse system to enable work to be scheduled for field activities.

The outcome of this work management process is a data bank of approved and funded projects and work packages from which schedules are developed for allocating work to project teams and work crews in the field.

The Panel utilised a reliability improvement project as a work management case study. The steps in the work management process are illustrated below.

Table 14 Case Study

CASE STUDY: Morningside Substation Reliability Improvement Program

A strategic review of feeder performance at the Morningside Substation identified 10 projects to reduce SAIDI for consumers. These included:

- 8 automatic circuit reclosers;
- 12 sets of line fault indicators;
- 1 set of master drop-out fuses; and
- 2 sets of wildlife proofing.

One of the projects to install an automatic circuit recloser in the Monmouth Street feeder was selected for the Case Study.

The work involved standing a new pole to replace an adjacent pole and installing a pole mounted recloser in a narrow suburban street. A live line crew was required to ensure that supply was not interrupted to the consumers fed from the feeder. The replacement pole was to be installed in a concrete footpath.

Preparatory activities for the project included:

- Work site scoping for issues such as vegetation, business premises and access for householders;
- Obtaining traffic permits;
- Identifying customer requirements and notifying residents of parking restrictions;
- Arranging supply of material, pole delivery, pole hand sink and traffic control; and
- Preparing the work schedule and allocating crews and vehicles.

Risk considered included:

- Crew fatigue management;
- Equipment failure;
- Public access;
- Weather conditions; and
- Possible emergency response required.

Relocation of broadband and Telstra equipment attached to the old pole could not be included in the project scope because of the absence of agreed arrangements with the telecommunications companies.

Project completion included the recovery of the old pole once the communication assets were relocated by the telecommunications companies' contractors.

Source: IRP

Scheduling of these types of projects must contend with uncertainties of weather and the complexities of coordinating materials supplies, site preparation, customer requirements and traffic control. Project scheduling therefore requires the support of sophisticated systems which can take account of constraints and provide the flexibility for re-scheduling when conditions change.

The effectiveness of short term scheduling is a major determinant of labour productivity for the field workforce within the NSPs. Schedules should be developed to maximise the time spent on productive work by limiting the amount of travel and reducing the likelihood of delays. Powerlink uses proprietary software to schedule the activities of its commissioning crews which achieves an acceptable level of labour utilisation.

Both DNSPs have historically attempted to use Ellipse as a scheduling tool, but work-arounds are still being pursued in both organisations. In Ergon Energy, monthly work schedules are, in most cases, based on Microsoft Excel spreadsheets, with wide variations in practice between depots. In Energex, weekly work schedules are prepared using Microsoft Outlook to diarise tasks. The lack of a single well-structured system for scheduling depot activities is contributing to under-utilisation of labour within the DNSPs.

While it is not within the Panel's scope to recommend the most appropriate IT system or package for scheduling support, the scheduling issue should be addressed as a matter of priority. The Panel estimates that every 1% gain in labour productivity would deliver annual savings of over $4 million across the DNSPs.

The Panel therefore recommends that the efficiency programs within the DNSPs focus on establishing a low cost sustainable solution for the current limitations of Ellipse as a scheduling tool. This could include extending the use of existing work programming applications within the DNSPs.

Recommendation 21

The DNSPs pursue as part of current efficiency programs the implementation of an effective scheduling tool to improve the efficiency of scheduling and increase the productivity of the workforce.

Implementation: DNSPs

7.2. Measuring Labour Efficiency

The work management control loop should be closed by reporting on the results of the work against the schedule elements. The integrity of a works management system depends on disciplines being in place to ensure that:

- paid time is booked accurately to account codes to reflect where and how time is spent;
- project estimates reflect the work content and account for inevitable variations in field work projects; and
- work completed is accurately logged and the value of output is captured.

The measurement of labour utilisation and schedule achievement should be balanced by monitoring and measuring labour efficiency as the third factor which affects productivity. In this regard, output must be measured consistently across all work types. The Panel found that output is not being measured in a way that generates information for monitoring and reporting productivity at the crew, depot or regional levels.

In Ergon Energy, labour utilisation is measured and reported and is a key performance indicator for supervisors through to senior management. Consequently, there is an incentive for field staff to book time against productive work orders, rather than delays and other unproductive activities, to drive up the utilisation result for management.

In Energex, the emphasis is on monitoring and reporting schedule achievement but measurement of labour utilisation could be improved.

There are three fundamental performance measures which should be used to manage work at the depot level. These are:

- schedule achievement – how much of the work in the initial schedule is completed;
- labour utilisation – the proportion of time spent on productive work; and
- labour efficiency – the ratio of the work output to the time spent.

As a guide, the Panel has prepared a template to illustrate how a monthly work schedule for a depot crew should be constructed so that the data required for these measures can be collected without imposing an excessive administration burden on field supervisors. Ultimately the implementation of contemporary field computing capability (Field Force Automation) has the potential to streamline administration activities.

Table 15. Monthly Work Schedule and Report Template

Depot Work Management Monthly Control Report							
Labour Availability Man Hours	Activities	Units Schedules	Unit Value (Std Hours)	Schedule Value (Std Hrs)	Units completed	Output (Std Hrs)	Labour Input (man Hrs)
1106	**Scheduled Work**						
	Install remote control closer	1	100	100	1	100	90
	Inspect regulators	12	10	120	12	120	80
	Repair isolators	24	6	144	16	96	50
	Install customer services	15	3	45	10	30	30
	Upgraded pole mounted transformer	2	112	224	2	224	190
	Build 3-Pole 11kv extension	1	210	210	0.6	126	100
	Rebuild Pole tops	4	24	96	4	96	80
	Replace open wire services	20	3	60	8	24	16
	Replace ABS	2	12	24	2	24	20
	Replace earths	16	6	96	10	60	60
	Total Work Loaded			**1119**			
	Scheduled Work Completed					900	716
	Scheduled Work Completed					100	100
	Total Productive Work					**1000**	**816**
	Delays						
	Equipment failure						34
	Waiting for network access						84
	Waiting for Work						58
	Rework						16
	Training						40
	Waiting for Materials						58
	Total Delays						290
	Total Time Booked						1106
	Control Measures						
	Schedule achievement				80%		
	Labour Utilisation				74%		
	Labour Efficiency				123%		

Source: IRP

The Panel considers that increasing the utilisation of the internal workforce will reduce the need for contractors and overtime.

Recommendation 22

The DNSPs implement a common set of output-based performance measures at the depot level to ensure that labour efficiency is measured and reported.

Implementation: DNSPs

7.3. Operation of Smaller, Regional Depots

The Panel has considered the extent to which greater private sector participation in Ergon Energy's smaller depots could improve efficiency and innovation and increase the autonomy of staff in those depots. A Local Service Agent (LSA) arrangement is considered by the Panel to be capable of delivering these outcomes. This model was implemented in a Victorian distribution company over ten years ago and has proved to be a successful alternative service delivery model. The Victorian experience is that LSAs have, in most cases, been set up by employees of the network company.

The LSA can be an effective model for reducing costs in smaller regional depots of around 8 to 15 employees, as it mitigates the impact on the DNSP of fluctuating works programs commonly experienced in these types of depots.

The LSA would continue to provide services such as outage response, customer service work such as reconnections and disconnections and routine maintenance and minor capital works. LSAs also have the opportunity to develop a business providing other services in the surrounding area and therefore provide opportunities for the employees and owners of these businesses that are not available under the current structure.

Ergon Energy advised the Panel that it is considering the implementation of LSAs for selected depots and the Panel supports this initiative.

Recommendation 23

In the Ergon Energy service delivery area, consideration be given to the adoption of a Local Service Agent model for depots in the range of 8 to 15 employees where there would be improved services to customers, service delivery would be more cost effective and where there is broad support amongst staff for the adoption of this type of service delivery model.

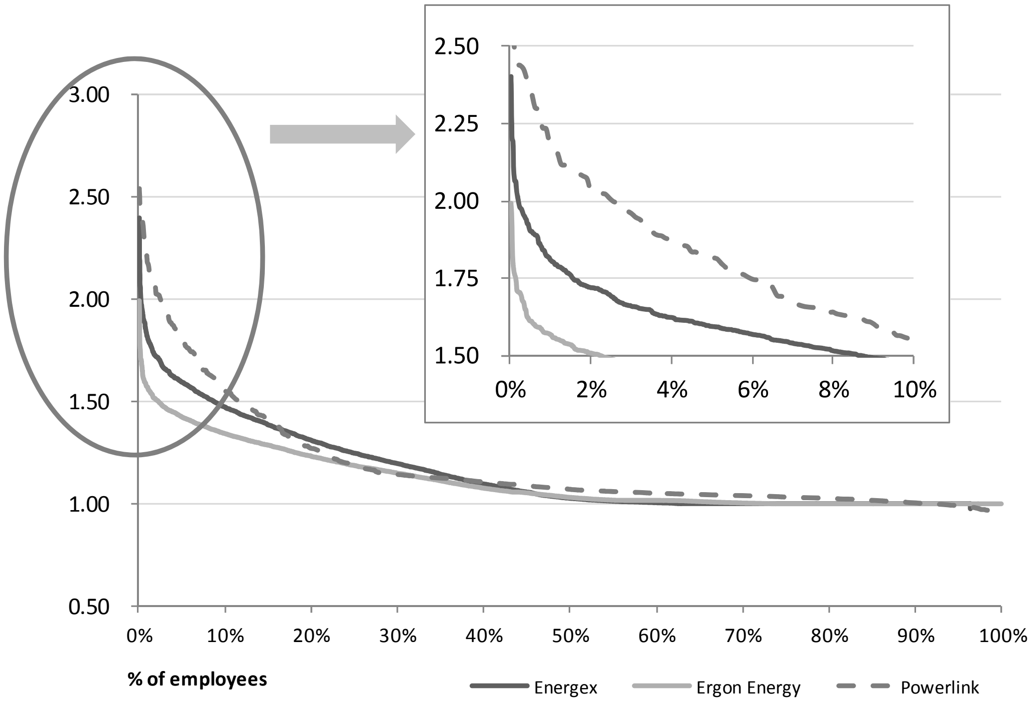
Implementation: Ergon Energy

7.4. Total to Base Pay Ratios (Overtime)

The Panel analysed data provided by the NSPs on overtime costs and identified that, across the three companies, 647 employees earned in excess of 1.5 times their base pay, as shown below. At the extreme, 27 employees earned twice their base pay in 2011/12. The Panel considers that such high ratios are likely to result in lower levels of productivity.[57]

[57] This ratio is based on overtime and base pay rates only but excludes allowances such as Living Away From Home Allowance .

Figure 35. Total to Base Pay Ratios for the NSPs, 2011/12



Source: Ergon Energy, Energex, Powerlink

The efficiency programs under way in the DNSPs have identified overtime cost reduction opportunities which are being assessed at present and cost reduction targets are included within the existing programs. Similarly, Powerlink is implementing a range of initiatives to better manage overtime.

Recommendation 24

The NSPs take urgent action to reduce overtime to benchmark levels and review gross pay to base pay ratios for all employees.

Implementation: NSPs

7.5. External Factors

A number of external factors impose inefficient work practices on the NSPs. For example, all three NSPs have raised concerns about the costs and inflexibility associated with obtaining permits necessary to undertake works on electricity assets located or planned adjacent to road and rail infrastructure.

The current access permitting process increases project costs through:

- the application processes, including consultants fees, police approval fees and Council application fees;
- permit conditions, such as requirements for works to be undertaken at night or on weekends, contributing to overtime expenses; and
- the requirement to re-permit when works have to be rescheduled because of external events such as adverse weather.

Energex estimates that potential savings annually of $4.5 million would be achievable if permitting processes were simplified and streamlined.

Another issue relates to the increased incidence of third party telecommunications cables attached to power poles. Where poles are required to be replaced, costly delays can be incurred where there is a lack of coordination with the telecommunications companies regarding the relocation of their telecommunication cables.

The DNSPs raised the issue that the *Electrical Safety Code of Practice 2010 – Works* incorporates pole condition monitoring (particularly below ground condition) requirements that do not account for the type of pole (i.e. steel, concrete or timber). These requirements create unnecessary costs for steel and concrete poles.

The Panel is also concerned that quality of supply complaints associated with overvoltage are increasing in some regions, driven by solar PV equipment particularly where clusters occur. Solar PV installation agreements between the customer and installer specify that the inverter voltage limit should be set at 255 volts. However, some installers are not complying with this specification. The requirement to investigate the cause of overvoltage reduces skilled staff availability and disrupts work schedules.

Recommendation 25

Amend existing regulatory instruments/legislation and seek to amend other relevant commercial arrangements to:

- *reduce constraints on the issue of permits for road access for DNSP works;*
- *allow DNSPs to take responsibility for repositioning telecom equipment when power poles are replaced;*
- *ensure that the asset condition monitoring requirements in the Electrical Safety Code of Practice 2010 – Works take account of pole types; and*
- *ensure that PV installations are not connected to the network until a new meter has been installed and the inverter maximum voltage settings have been verified as compliant with the connection and installation agreements.*

Implementation: DEWS

7.6. Workforce Utilisation

The Panel is concerned that the DNSPs currently engage a large number of external resources to provide services that could be more efficiently provided internally. Other recommendations in this report deal specifically with non-front line, non-engineering external resources.

Consultation with line personnel within the DNSPs indicated that over-use of external resources may be occurring in front line engineering areas, including in the field.

The Panel acknowledges that it is accepted practice in the electricity industry to employ contractors for major projects, which pose highly variable demands in any one region, and to carry out high volume routine activities, such as line inspection and vegetation control.

During consultation, employees and unions expressed three common views on the use of external resources outside these areas of activity:

- contract resources are used inefficiently;
- internal resources are being under-utilised; and
- external service providers generally require more management time and are more costly to supervise than internal resources.

It is beyond the Panel's scope to investigate the DNSPs' current mix of contractors and internal personnel. However, it notes that the feedback received from staff and unions during the consultation phase is consistent and considers that the Boards and management should give these issues due consideration.

The DNSPs' Union Collective Agreements provide for flexible working hours. In practice, however, the start times of work crews are often not matched to the requirements of particular projects. The Panel has been advised that live line crews in Energex, for example, start work at 6.30am due to established practice. When they are required to work in a team with other line crews that are scheduled to start at 7.30am, a rigid adherence to these start times means that there is a mismatch, leading to reduced productivity and possibly longer outage durations. The Panel encourages the Boards and management of the DNSPs, where possible, to work with staff and unions to harmonise start and finish times, to increase productivity and ensure secure and reliable supply to customers.

Each of the three network businesses has autonomous fatigue management policies with different rules governing the timing and duration of rest periods. During consultation, the Panel was advised that, when crews from one network business are called on to assist another (e.g. following a natural disaster), the differences in fatigue management policies complicate crew scheduling and joint workforce management leading to response delays, inefficiencies and potential safety issues. The Panel therefore considers that the NSPs should work collectively to harmonise these policies.

Recommendation 26

The NSPs remove internal constraints to improved efficiency, as follows:

- *Apart from categories of work which are contracted as a matter of policy, NSPs should fully utilise internal resources before packaged maintenance and minor works are contracted out. Some projects could also be jointly resourced to increase field workforce utilisation.*
- *The DNSPs improve workforce flexibility to match start/finish times with work requirements.*
- *The NSPs harmonise their Fatigue Management Policies by 1 July 2013.*

Implementation: NSPs

7.7. Services to Isolated and Remote Communities

The Queensland Government made CSO payments of $418 million to Ergon Energy's retail subsidiary, EEQ, in 2011/12 to fund it for the losses incurred in supplying energy to regional and remote communities at the regulated retail tariff. This CSO requirement has been forecast to grow to $620 million in 2012/13.

The Panel's terms of reference did not extend to reviewing the efficiency of EEQ. It is noted, however, that the major causes of the CSO requirement are the:

- significantly higher network prices in the Ergon Energy area compared with those in the Energex area (the uniform tariffs being largely based on Energex network prices); and
- very high costs of supply in the isolated areas served by Ergon Energy.

Ergon Energy provides electricity supply and network services to 39 remote communities through 34 isolated systems. This involves the operation and maintenance of small scale generators and the maintenance of local electricity networks.

The power stations range from 165 kW to 9.55 MW installed capacity, with the smaller power stations being remotely controlled and, therefore, unattended except for maintenance and breakdown response. There is generally a local part-time attendant to undertake minor maintenance/operations duties.

The Panel was concerned by the high cost of supply in the isolated areas and the resultant impact on the CSO. The reported total cost to EEQ of the service in 2011/12, at around $122 million, greatly exceeded the revenue charged to customers, at around $22 million, leading to a CSO cost to the State budget of $100 million. The CSO accounted for more than 80 percent of the cost of supplying the isolated and remote communities and represented a subsidy of over $15,000 each for approximately 6,600 customers.

Of the total cost of $122 million, an amount of $117 million was paid to Ergon Energy for the operation and maintenance of the isolated generation and associated local networks. The balance of $5 million related to EEQ's retail cost to serve and a retail margin.

The amount of $117 million was Ergon Energy's net cost of provision of the service, after allowing for receipt of a diesel fuel rebate from the Commonwealth Government, and is inclusive of a regulated rate of return[58] on the assets owned by Ergon Energy. EEQ purchases energy and network services for the isolated communities from its parent Ergon Energy on a full cost recovery basis which is ultimately borne by Government in the CSO. Ergon Energy's charges to EEQ are not subject to regulation or contractual constraints. Further, the CSO arrangements place no incentives on either Ergon Energy or EEQ to minimise these costs.

Action should be taken to reduce the cost of providing these services and ease the burden of the subsidy on the State budget. A major contributing factor to the cost of these services provided by Ergon Energy is the allocation of overhead expense in accordance with Ergon Energy's Cost Allocation Methodology. In 2011/12, the allocation of overheads to operating costs for the isolated systems was $23.3 million. This expense includes an overhead allocation in 2011/12 of $16.5 million attached to the cost of diesel fuel ($42.7 million excluding overhead). Therefore, this component of overhead added almost 40% to the cost of fuel.

This excessive overhead cost allocation could be avoided if the Ergon Energy retailer took responsibility for the supply of fuel. An equivalent overhead cost reduction should be made within the DNSP so that this cost is not merely redistributed to the regulated network.

Ergon Energy has recently undertaken a review of the costs of the isolated supply and has also identified the issue with the overhead allocation.

Ergon Energy has advised Government that it has revised downwards its projected annual capital and operating expenditures on the isolated systems by around $5 million and $22 million respectively, commencing in 2012/13.

In order to assess the efficiency of the cost of the isolated supply, the Panel reviewed the various components of costs and found that the benchmark corporate overhead costs for an Independent Power Producer (IPP) would be in the order of $4 million, compared with $23 million that Ergon Energy allocated to overheads for this function in 2011/12.

Recommendation 27

Ergon Energy should reduce the overhead allocated to isolated generation and networks from the current level of $23 million per annum to no more than $4 million per annum. The reduction in overhead of $19 million should not be re-allocated within the Ergon Energy business and should instead be removed through the efficiency programs from total overhead costs.

Implementation: Ergon Energy

[58] Although the isolated systems are not regulated, Ergon Energy applies the regulated rate of return that applies to its regulated network (i.e. 9.72%) to the calculation of the costs to serve for the isolated systems.

Recommendation 28

Ergon Energy should apply a similar principle to overheads currently allocated to the retail business.

Implementation: Ergon Energy

Further savings could be possible if the operation and maintenance of these remote facilities were contracted to existing employees as service agents or to a specialist service provider. The Panel considers that the efficiency of the whole of the isolated supply business should be tested by inviting expressions of interest from the private sector to operate and maintain the assets. Existing employees should be encouraged to respond by forming Local Service Agencies to operate and maintain the assets in one or more of the regions in which they are located.

Finally, the Panel considers that, whatever delivery mechanism eventuates, there should be an explicit and transparent contractual or regulatory arrangement put in place to ensure that the isolated systems are built, maintained and operated efficiently and cost effectively, to specified standards agreed by the Government as the provider of the CSO.

Recommendation 29

The Government call for expressions of interest from the private sector to operate and maintain the isolated supply assets in Queensland as an IPP.

Implementation: DEWS

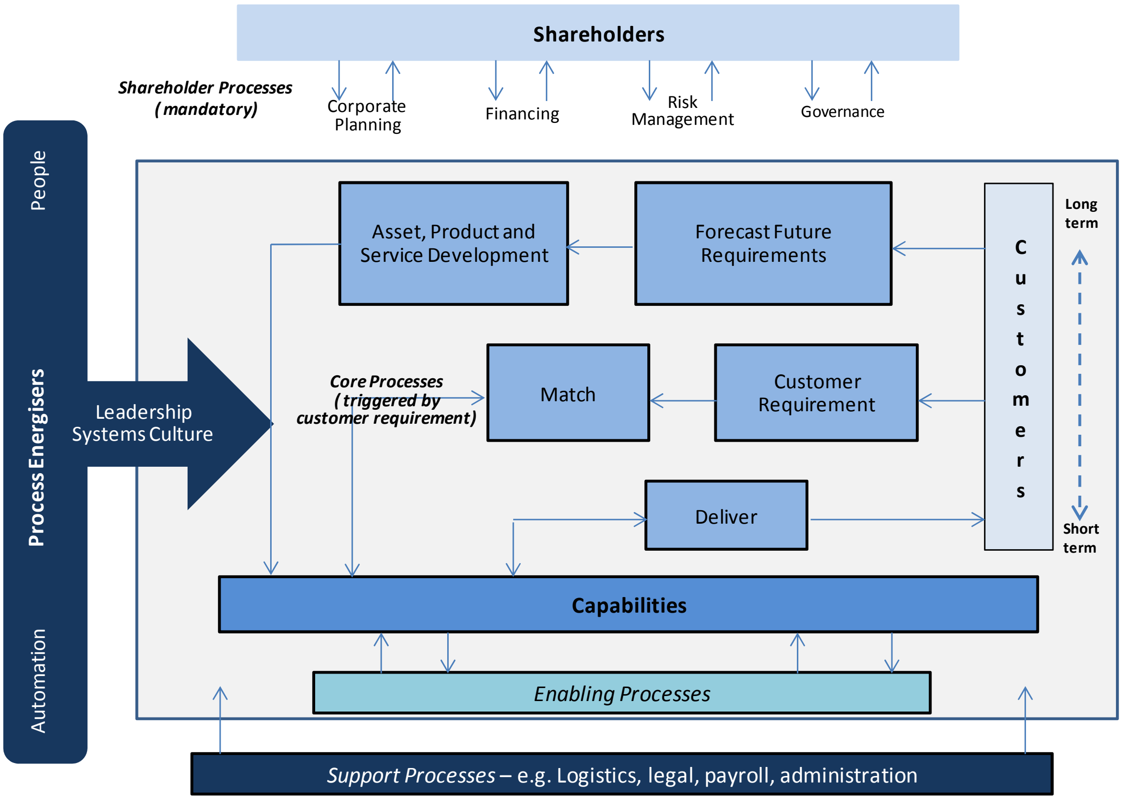
8. Structural Reform

The Panel's Terms of Reference require it to make specific recommendations on the optimal structures of Ergon Energy and Energex. The Panel focused on whether potential structural options would:

- enhance the likelihood that the efficiency savings identified in this report are delivered;
- provide additional synergy benefits (where particular functions in the two DNSPs are combined); and
- sustainably deliver long term capital and operating efficiencies.

Practical structural options were developed from a business process model which maps the functionality of a DNSP as a set of processes. This model is shown in Figure 36 and illustrates how a DNSP operates to deliver current and future customer demand outcomes.

Figure 36 . Network Business Process Model



Source: IRP

The model comprises:

- *Core Processes* which are triggered by customer requirements and deliver outcomes to satisfy those requirements;
- *Shareholder Processes* which provide for strategic planning, governance, financing and risk management;
- *Enabling Processes* which sustain the corporate 'stay in business' capabilities, and
- *Support Processes* which deliver common services.

Using the model the Panel considered whether the functional groups within the DNSPs responsible for activating the core processes of each DNSP have the ability and the incentives to make the right decisions regarding development and maintenance of the network. Ideally, the

DNSPs would also ensure that the groups providing enabling, support and shareholder processes are accountable for delivering cost-effective outcomes.

While the process structures of DNSPs are largely driven by customer demands, statutory requirements and competitive imperatives, functional structures (i.e. organisation design) are determined by management preferences. In this way, the structure of an organisation reflects management's view on the optimal way to deploy resources and achieve objectives. In the event that there are more effective ways of achieving objectives, alternative organisational structures may need to be considered. Alternative structures will also influence the effectiveness of processes to deliver required outcomes and the efficiency of resource use.

Any change to the structures of the DNSPs will involve implementation costs and a period of disruption during transition to the new structure. The Panel has considered whether the benefits of structural change, in terms of immediate and long-term cost savings, outweigh the associated risks and costs associated of implementation.

The Panel also considered whether structural change would disrupt or delay the current efficiency improvement programs, and whether management and staff could successfully implement both efficiency and structural savings concurrently. At the same time, the Panel considers that disruption triggered by structural change can provide an opportunity to overcome cultural or organisational barriers to efficiency improvement and create a new culture which values efficiency equally with safety and reliability.

The Panel has considered the findings of previous structural reviews. These identified potential efficiencies, costs and risks which have informed the Panel's financial modelling and analysis. The Panel also considered the findings of the ICT Blueprint process undertaken by the DNSPs and SPARQ.

Based on the analysis of the existing structures and the previous attempts at structural reform, the Panel concluded that:

- **The first option should be the current structures, given the size of the DNSPs and hence the implementation costs and risks that would be involved in changing to a new structure.** The Panel approached the assessment of options with a strong preference for retaining the status quo, unless substantial benefits, net of implementation costs, could be achieved by changing to a different structure. Synergy benefits from combining business functions will require a major investment in aligning business processes.
- **While the DNSPs are organised on the basis of two sets of corporate structures, two separate network operations and two regulated networks, there is no reason why this arrangement should be maintained.** The optimal structure for the regulated networks could involve changing the number of corporations, the number of businesses and the number of regulated networks, or some combination. Citipower/Powercor in Victoria is an example of a single business that operates two separate regulated networks.
- **As an electricity distribution network is a regulated monopoly, there is no prima facie need for the Queensland Government to own the distribution network through a number of competing businesses.** While the State's electricity generation assets are currently held in two organisations, to ensure adequate competition in the wholesale electricity market, the monopoly networks are subject to economic regulation.
- **The number of separate regulated networks needs to consider the effects on economic regulation.** Amalgamating the two regulated networks may make the AER's task more difficult and incur transitional costs and risks. Accordingly, the Panel has a preference to retain the current two networks.

- **As achieving alignment in business processes is critical to realising cost savings, the businesses may need to be 'stapled' together at some point in the governance chain.** Currently, the DNSPs are combined in terms of having a common shareholder and in a collaborative sense through their involvement in joint workings and SPARQ. However, while joint workings or joint ventures could deliver efficiencies without structural change, the anticipated benefits have not been fully delivered in the past. Ultimately, a single point of accountability is the best means of ensuring alignment.

The Panel has concluded that there are three viable options for the future structure of the Queensland electricity distribution industry:

- retaining the current structures with both DNSPs pursuing individual efficiency programs;
- creating a holding company to oversee both operating companies; or
- merging the two businesses.

The Panel also considered further joint ventures, (i.e. expansion of existing joint workings), the creation of multiple new DNSPs, and the separation of Ergon Energy into coastal and western areas. These options were dismissed on the basis that the cost, complexity, regulatory issues and timeframes for implementation would constrain the delivery of net benefits to consumers.

The two alternative structure options involve a single board and executive management, to extract additional efficiency savings through a cost conscious culture and achieve synergy benefits by aligning processes across the networks:

- The Holding Company structure (Option 2) creates a new holding company for Ergon Energy and Energex, to provide single point accountability and drive cultural change.
- The Merger (Option 3) would create a series of profit-driven network service businesses to deliver the business process outcomes under the leadership of a single network holding company. Under this model, the operations of Ergon Energy and Energex would be converted into a number of profit-driven network service entities.

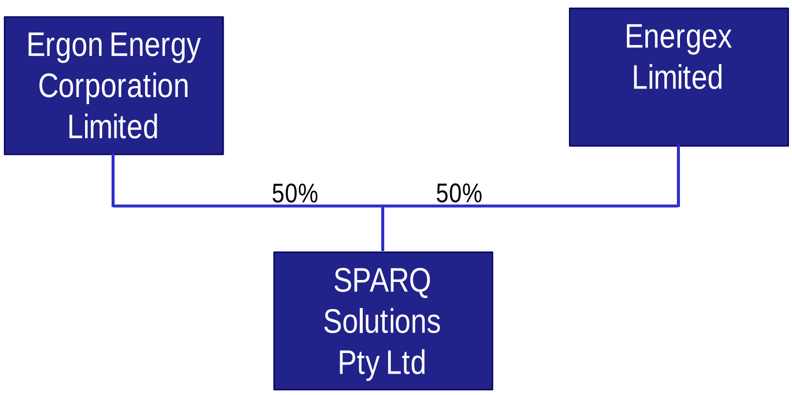
The structural diagrams in this chapter include only those functions which relate to the operations of the distribution networks. Business functions such as electricity retailing, telecommunications and spatial analysis (e.g. ROAMES) are excluded.

8.1. Option 1 – Current Business Structures

8.1.1. <u>Description</u>

Figure 37 below shows the current business structures of the DNSPs.

Figure 37: **Current business structure**



Note: there are other corporate subsidiaries of Ergon Energy and Energex which are not shown in this chart
Source: IRP

This option retains the existing business structures for Ergon Energy and Energex with each business continuing to focus on its own efficiency programs.

The current Joint Workings program would be continued to contribute efficiencies in both businesses. New joint working initiatives would be matters for the Boards. For example, alignment of ICT would no longer be expected; however, the DNSPs could decide to cooperate on individual platforms or projects.

8.1.2. *Advantages*

- This model clearly communicates the expectation that efficiencies are to be driven within each business, rather than through joint workings or structural change. It eliminates any ongoing uncertainty within the DNSPs regarding the shareholder's long-term expectations, and reflects a conscious decision to place accountability for outcomes at the management and Board level within each organisation.
- Existing efficiency programs can be continued without any delays or distraction associated with pending structural changes.
- Costs and disruption associated with transitioning to a new structure are avoided.
- The current baselines (i.e. actual expenditure) against which efficiencies can be identified and measured are maintained.

8.1.3. Disadvantages

- There is a risk that efficiency opportunities that have a positive NPV when combined across the DNSPs will not be identified or pursued.
- Both DNSPs would continue to invest in more costly independent ICT platforms.
- There are no cost savings from combining duplicated functions, such as corporate head office and shared services.
- There is no trigger for cultural change.

The Panel considers that, under this option, the base case efficiency targets identified by the DNSPs would be the limit of efficiencies that could be achieved.

8.1.4. Financial Impacts

Ergon Energy's Efficiency & Effectiveness program has identified indirect cost savings of approximately $82 million per annum[59], with a Net Present Value (NPV) of $290 million (after implementation costs).

Energex's Business Efficiency Program has identified indirect cost savings of $57 million per annum, with a total NPV of $177 million after implementation costs.[60] The NPV of savings from Energex is lower compared with Ergon Energy because Energex's May 2012 draft Statement of Corporate Intent, which was used as the base case, already incorporated anticipated savings of approximately $18 million per annum.

Table 16 summarises the potential NPV benefits from efficiency savings within the current structure.

[59] This is the 'steady state' benefit, which is expected to be fully achieved by 2015/16.

[60] The 'steady state' benefit of $56.5 million is expected to be fully achieved by 2015/16. This benefit and the total NPV of savings is calculated against the May 2012 draft Statement of Corporate Intent baseline, which already included an estimated $17.5 million of anticipated savings from the efficiency program. The total steady state benefit is $74.0 million.

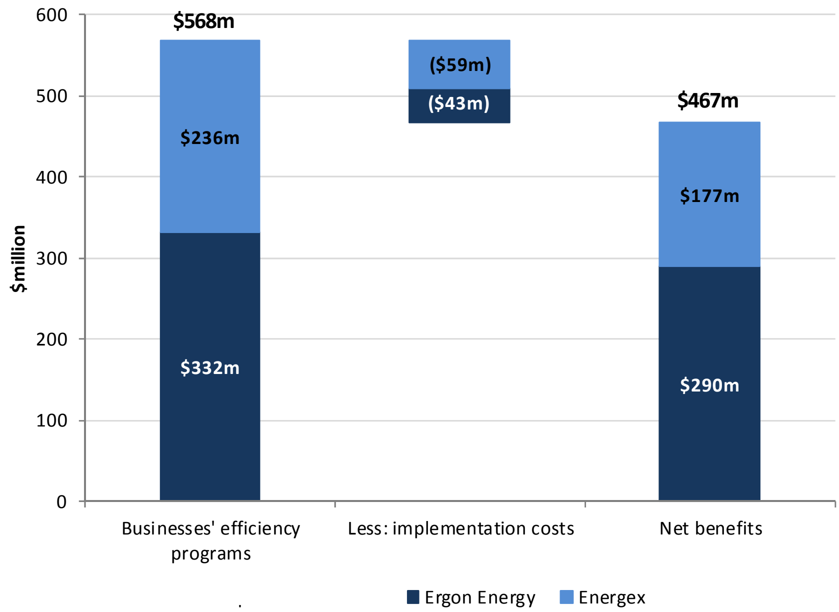
Table 16. NPV of efficiency programs - Option 1

	Businesses' efficiency programs ($m)	Implementation costs ($m)	Net benefits ($m)
Ergon Energy	332	(43)	290
Energex	236	(59)	177
Total	**568**	**(101)**	**467**

Note: Totals may not sum due to rounding.
Source: IRP

Figure 38 shows the NPV of business efficiency savings and implementation costs for Ergon Energy and Energex.

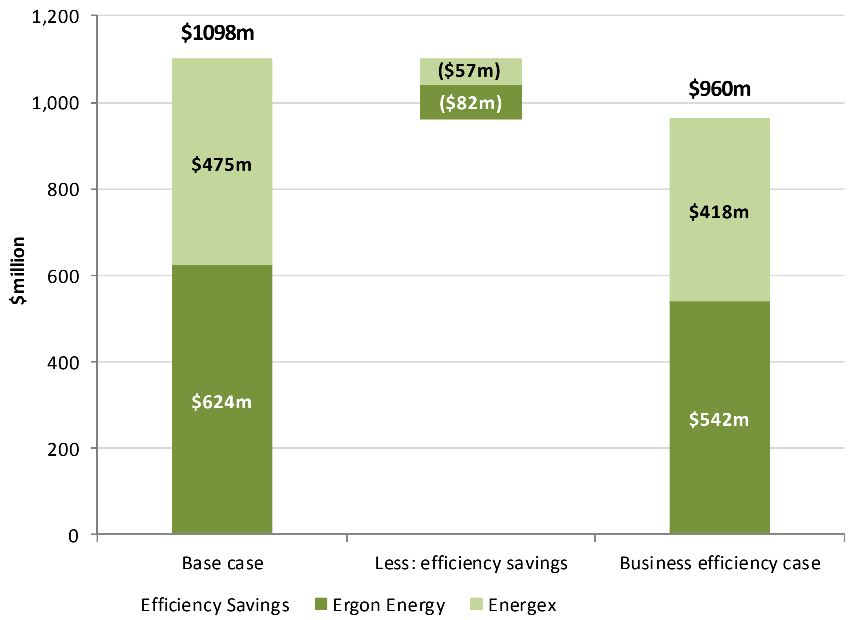
Figure 38. NPV of Option 1 – Business Efficiency Programs



Note: Totals may not sum due to rounding.
Source: IRP

Figure 39 shows the impact of the business efficiency programs on total indirect costs in 2015/16, compared to the base case forecasts.

Figure 39. Total indirect costs 2015/16 – base case and business efficiency case

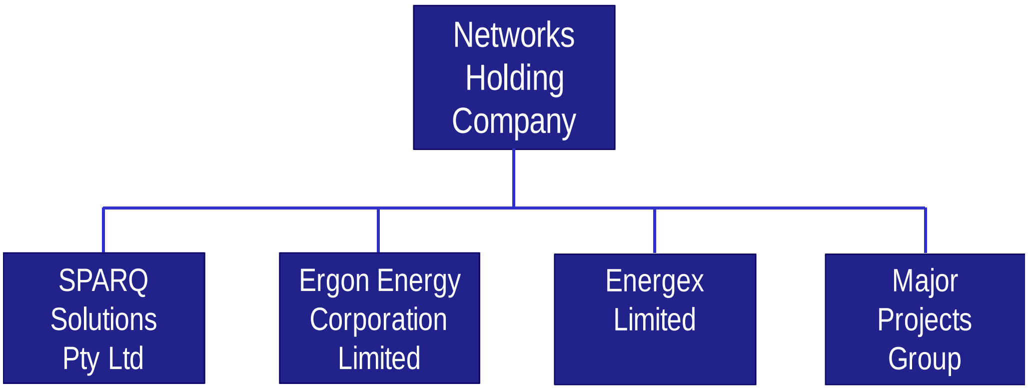


Note: Totals may not sum due to rounding.
Source: IRP

8.2. Option 2 – Holding Company

Figure 40 below shows the proposed structure for the Holding Company option.

Figure 40 Holding Company structure



Note: There are other corporate subsidiaries of Ergon Energy and Energex which are not shown in this chart.
Source: IRP

8.2.1. Description

Under this option, a Holding Company would be created to hold the shares in Ergon Energy and Energex. A single Board would be appointed to the Holding Company and these board members would replace the Boards of Ergon Energy and Energex. The Holding Company would appoint a CEO, CFO, CIO, and Executive General Managers (EGMs) for Corporate Strategy, Asset Strategy and Corporate Governance.

The Holding Company would be responsible for delivering the *Shareholder Processes*, including corporate strategy, corporate governance, financing, risk management and performance monitoring.

The Holding Company would also assume responsibility for the *Enabling Processes* of the business, including the network strategy processes. This would drive a common, best-practice approach to the performance of core asset management processes within its subsidiaries, Ergon Energy and Energex.

Delivery of the *Core Processes* would remain within the operating companies, however delivery of the asset management processes would follow the strategies, standards and policies set by the Holding Company.

Delivery of the *Support Processes* would, at least initially, remain within the operating companies, with the exception of procurement and inventory management where there are synergies available from joint operation.

The *Automation Process Energisers* would continue to be delivered by SPARQ, which would be owned directly by the Holding Company. A single CIO at the Holding Company level would have the power to achieve greater alignment in IT systems and achieve reductions by aligning IT investments and combining capital expenditure.

People Process Energisers would be delivered by Energex and Ergon Energy. The Holding Company would also develop a small HR function to deliver its own people requirements. It would be a decision for management to determine the extent to which the Holding Company assumed a strategic HR role for the subsidiaries, although this is a foreseeable outcome.

With the exception of those processes assumed by the Holding Company, the operating companies would remain responsible for delivery of most of the *Core Processes* and *Support Processes* of the network. This includes asset management, program of work management, network operations and delivery of network services. However, the creation of the Holding Company may provide greater potential to align the two programs of work and share resources between network services groups in Ergon Energy and Energex. This would be a decision for the Holding Company executive.

While there is some alignment in standards and work practices already (as a result of Joint Workings), the operating companies still have different approaches to performing the network business processes. Under this model, it would be a decision for the Holding Company as to whether to pursue greater alignment between the operating companies in the performance of particular functions. This could occur on a case-by-case basis.

This model is likely to drive greater alignment because the benefits and costs are captured within the corporate structure rather than being shared (sometimes in unequal proportions) between the operating companies. Financial and management reporting must be provided in a common format to the Holding Company. Alignment may also be required in order to ensure that network strategy is consistently translated into asset management plans.

Under this model, separate Ergon Energy and Energex networks are retained with two regulatory determinations. The Holding Company would ensure a common regulatory approach and strategy is taken to the next regulatory determinations, and there would be cost savings through combining consultancies and other common tasks.

Holding company – potential future state options

Formation of the Holding Company could allow other functions to be combined in the future, depending on shareholder priorities, if the management elected to pursue joint ventures or functional mergers in shared services, customer engagement (i.e. contact centres), network operations (i.e. control centres), works program management and operational asset management.

8.2.2. Implementation

To implement this option, Government would establish:

- A common Board providing governance for the holding company and the two DNSP subsidiaries;
- A CEO of the holding company who will also be the CEO of the two DNSP subsidiaries;
- A Chief Operating Officer (COO) for each of the two DNSP subsidiaries reporting to the CEO;
- Corporate and strategic leadership located within the holding company, comprising the CFO, CIO and Executive General Managers (EGMs) for Corporate Strategy, Network Stewardship and Strategic Procurement;
- Core and support processes remain within the subsidiaries;
- SPARQ to become a subsidiary of the holding company; and
- A Major Projects group to provide services to both DNSP subsidiaries, structured as a separate business unit.

To achieve the efficiency benefits under this option, it is important that the holding company management positions are filled quickly, and that the new management group develops a plan to transition from the existing efficiency plans at Ergon Energy and Energex into a single cost reduction strategy.

Employees would be recruited into the Holding Company to fill positions in the following areas:

Reporting to the Chief Financial Officer:

- Financial reporting
- Management reporting
- Treasury
- Taxation

Reporting to the EGM Corporate Strategy:

- Corporate strategy
- Regulatory strategy
- Efficiency programs
- Corporate governance
- General counsel
- Internal audit
- Human resources (to service the Holding Company)

Reporting to the EGM Network Stewardship:

- Asset strategy
- Standards

Reporting to the EGM Strategic Procurement

- Procurement strategy
- Logistics strategy

The Holding Company is expected to employ a relatively small proportion of the workforce, with around 116 FTEs including 16 executives.

A number of the shareholder and enabling functions within Ergon Energy and Energex would no longer be required. While some of the employees from these groups would be transferred to the Holding Company, remaining staff would need to be re-deployed or exit the business.

8.2.3. Advantages

- While creation of the Holding Company is relatively straightforward, the creation of the legal structure and appointment of directors, management and employees would involve a process of several months. The ability to implement the new structure quickly reduces uncertainty and lost productivity associated with structural change.
- The holding company would capture all of the benefits and costs of alignment, even where there was uneven sharing of benefits and costs within its operating companies. This removes a barrier to current benefits realisation. In areas where management has decided to pursue alignment, oversight would be provided by the holding company to resolve differences between the operating companies and ensure that agreed standards, policies and processes are followed.
- The holding company could elect to continue with existing efficiency programs within each of the operating companies, or to make changes and rationalise the programs into one.
- The continued operation of the Ergon Energy and Energex networks would allow the existing regulated networks to remain in their current form. There would be changes to the way in which corporate costs from the Holding Company are allocated to the respective operating companies.

8.2.4. Disadvantages

- The Holding Company approach involves the merger of a limited range of functions, and therefore the immediate cost savings through FTE reductions are modest compared to a full functional merger. However, industrial relations constraints are likely to restrict the ability to achieve immediate headcount reductions in any case.
- There are implementation costs associated with the restructure, including the need to align accounting policies and charts of accounts to achieve common financial reporting processes and systems.
- There may be taxation issues associated with the merger of Ergon Energy and Energex into the tax consolidated group headed by the Holding Company. This could affect the availability of tax losses and tax cost bases of assets. Expert advice will need to be sought to manage the tax implications of the restructure.
- The success of this model depends on appointing a board and management team which is focussed on efficiency savings and has the capacity to introduce cultural change.

8.2.5. Financial Impacts

The financial benefits under the Holding Company structure are predominantly driven by additional efficiency savings through the implementation of new management structures, driving a culture of operational and financial efficiency across both businesses. As the Holding Company itself is relatively small, the structural savings component is not the main contributor to overall savings. However, the Panel is of the view that the new Holding Company structure would allow the realisation of the additional efficiency savings identified by the Panel.

Formation of the Holding Company would provide a catalyst for cultural change in the two existing organisations, which is expected to result in the realisation of additional efficiency savings with a NPV of $353 million within the Ergon Energy and Energex operating companies. These are additional efficiency benefits identified by the Panel. Synergy benefits are estimated to be $98 million. Total implementation costs for the new structure are $168 million, in addition to expected costs of $101 million for the existing efficiency programs. The net savings in this case are $750 million, or an additional $283 million compared to the status quo.

Table 17 shows the NPV of savings under the Holding Company structure compared to the Current Structure.

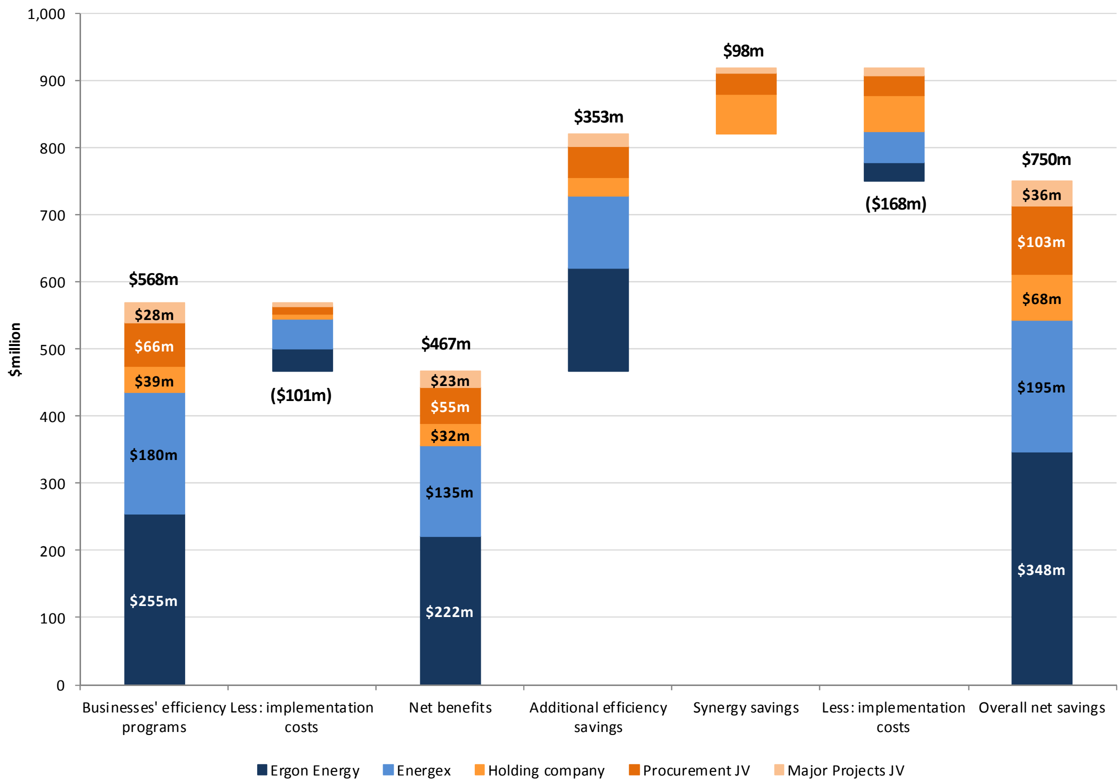
Table 17. Holding Company – NPV of savings

	Efficiency savings ($m)	Synergy savings ($m)	Total ($m)
Ergon Energy	409	-	409
Energex	286	-	286
Holding Company	67	60	127
Shared procurement	112	31	143
Major Projects Group	46	7	53
Total savings	**920**	**98**	**1,018**
Less: implementation costs			(269)
Net savings			**750**

Note: Totals may not sum due to rounding.
Source: IRP

Figure 41 shows the savings from business efficiency programs (net benefits of $467 million), and the incremental benefit from additional efficiency savings ($353 million) and synergy benefits ($98 million), including implementation costs.

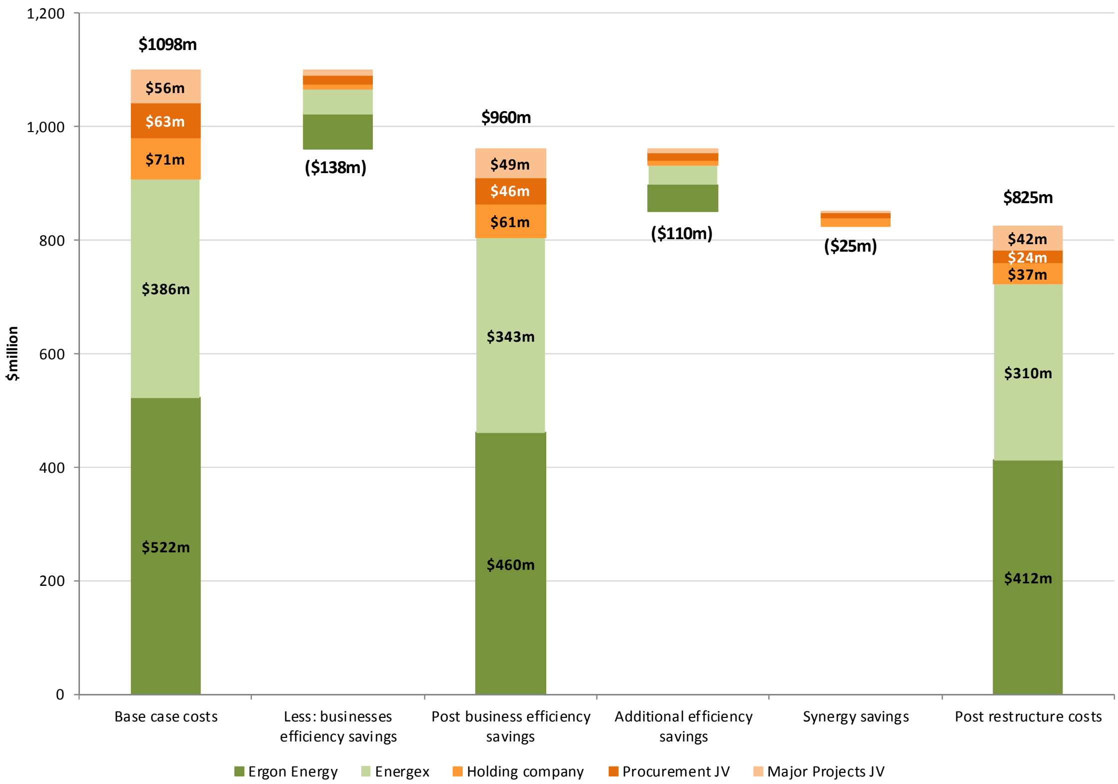
Figure 41. NPV of savings – Option 2



Note: Totals may not sum due to rounding.
Source: IRP

Figure 42 below shows the total reduction in indirect costs in 2015/16 as a result of the implementation of the Holding Company compared to the Current Structure. The Base Case indirect cost forecasts in 2015/16 for both DNSPs is $1,098 million, which would be reduced under Current Structure to $960 million. Implementation of the Holding Company structure should result in indirect costs being reduced to $825 million, around $273 million lower than the Base Case.

Figure 42: Total indirect costs 2015/16 under Option 2



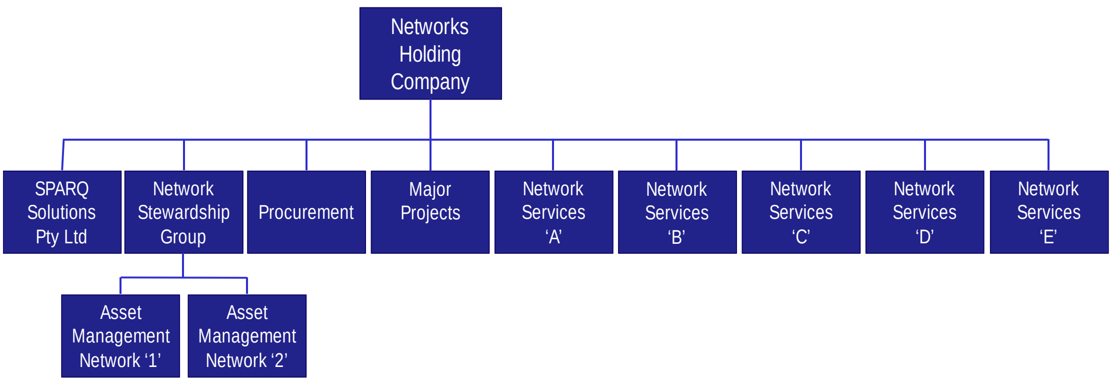
Note: Totals may not sum due to rounding
Source: IRP

8.3. Option 3 – Full Merger

8.3.1. Description

Figure 43 below shows the proposed structure for the Full Merger option.

Figure 43. Full Merger structure



Note: There are other corporate subsidiaries of Ergon Energy and Energex which are not shown in this chart.
Source*:* IRP.

This option involves a restructure of both organisations to create a series of profit-driven businesses under the control of a Networks Holding Company. Figure 43 above shows the organisation structure of the group, and Figure 44 shows the legal structure.

The Networks Holding Company would have the following functions:

- Board
- Chief Executive Officer;
- finance, treasury, taxation;
- corporate strategy;
- corporate governance and legal;
- regulatory;
- HR and industrial relations; and
- shared services.

The Network Stewardship Group would have responsibility for:

- load forecasts;
- performance standards;
- network plans; and
- development standards.

The Asset Management Network ‘1’ and Asset Management Network ‘2’ groups would be responsible for operational asset management, in accordance with the strategic asset direction set by the Network Stewardship Group. These operational asset management groups would be responsible for:

- operational asset strategies (i.e. at the individual asset level);
- network operations;
- development plans;
- project scopes;
- conceptual designs; and
- estimates and standard prices.

The Major Projects Group would be responsible for large customer connections, augmentations or other major network projects across the State, including:

- detailed design;
- estimating;
- tendering;
- contract formation;
- project management;
- contract administration; and
- commissioning.

The Network Services groups would be responsible for all field work, excluding major projects, in defined geographical areas. In some cases, the work would be contracted by the Network

Services groups to external providers, where this was cost effective. The Network Services groups would perform the following functions:

- detailed design;
- estimating;
- resourcing;
- planning and scheduling;
- augmentation;
- extension;
- replacement;
- fault response;
- fault repair;
- maintenance; and
- metering.

The Procurement Group would be responsible for procurement, inventory management and logistics for the Major Projects group and each of the Network Services groups.

Profit-driven model

All of the businesses outside of the Networks Holding Company would be established as profit-driven entities.

This model would be implemented by creating arm's length internal prices for particular services, determined by reference to efficient costs of providing particular services.

Pricing would need to ensure that the businesses can recover costs over which they do not have control, for example the cost of shared services and ICT, which are determined by the strategic direction of the Networks Holding Company.

8.3.2. Implementation

Implementation of the Full Merger would involve major changes to combine both organisations and create new businesses:

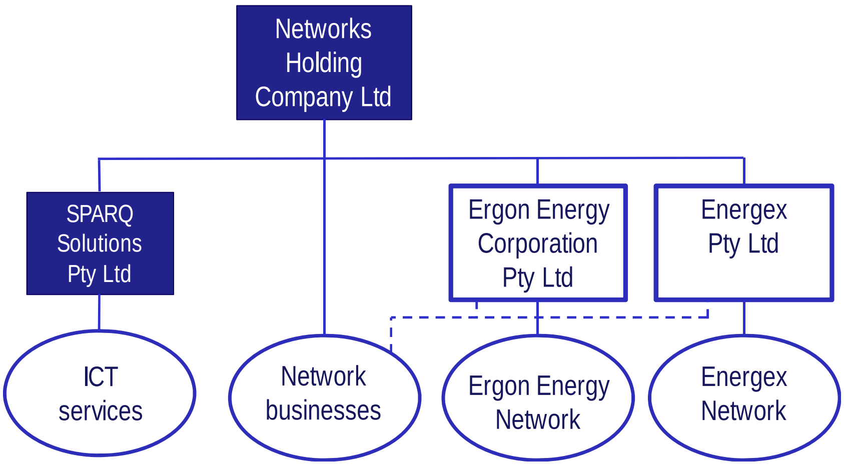
- the first step would involve the formation of a Networks Holding Company to acquire the shares in Ergon Energy and Energex. Those existing groups within Ergon Energy and Energex that perform Corporate Processes, Support Processes and Core Processes would be transferred to the Networks Holding Company.
- Ergon Energy's Asset Management division and Energex's Network Performance division would be combined and restructured to create the Network Stewardship Group and two Asset Management groups. The network operations functions in Ergon Energy's Energy Network Services and Energex's Network Operations Group would be incorporated into the respective Asset Management groups in the new structure. These groups would also include the contact centres for both networks.
- Ergon Energy's Fleet Procurement & Logistics group and Energex's Procurement & Supply group would be merged to create the Procurement Group in the new structure.
- the five Network Services businesses would be based on the existing three Service Delivery groups (Northern, Southern and Central) in Ergon Energy and the two Field Services groups (North and South) in Energex. The Network Services businesses would incorporate a share of employees and assets from the support groups in Ergon Energy (such as Works

Enablement, parts of Energy Network Services and Engineering Group within Service Delivery Transmission & Projects) and Energex (such as Business Operations and the Design Group).

The business processes of legacy Ergon Energy and Energex functions would need to be aligned to the processes designed by the Networks Holding Company.

The legal structure of each group and the means of transferring employees and assets into the new groups would involve a period of transition until the final legal structure is created. The Networks Holding Company would be established as a company to acquire shares in Ergon Energy and Energex (which would convert from 'Limited' companies to 'Pty Ltd' subsidiary companies). It is likely that the Networks Holding Company would acquire the shares in SPARQ, rather than these being held through Ergon Energy and Energex. The network service businesses would be established within the existing companies, depending on where the majority of the employees for each business are currently located (to minimise employee transfers). The initial legal structure is shown in Figure 44 below:

Figure 44. Full Merger Structure – legal entities



Note: 'Network businesses' includes all businesses shown in Figure 43, excluding ICT (under SPARQ).
Source: IRP

Ergon Energy Corporation Pty Ltd[61] and Energex Pty Ltd would continue to own the regulated assets and earn revenue from the provision of network services to fund the capital expenditure, operating expenditure and indirect costs of the group.

8.3.3. Advantages

- The Full Merger represents a fundamental change from the existing Ergon Energy and Energex businesses, which provides the catalyst for cultural change within the entire organisation.
- The profit-driven model would create incentives for efficiency in each of the Network Services businesses and other businesses in the new structure. Accountability for financial performance within those businesses would encourage innovation in asset management and work practices, and create ongoing incentives to continue delivering further efficiency.
- The Network Stewardship group would be focused on developing risk-based standards and policies to reduce network investment and operating costs to an efficient level and maximise asset and resource utilisation.

[61] Ergon Energy Corporation Limited would become Ergon Energy Corporation Pty Ltd once it becomes a subsidiary of the holding company. Similarly, Energex Limited would become Energex Pty Ltd..

- Centralising corporate and support processes in the Networks Holding Company would eliminate the duplication that exists in the current structure and the Option 2 model. Creating single shared services and back office functions would also allow greater efficiency in ICT capital expenditure.

8.3.4. Disadvantages

- The implementation cost associated with this model is significantly higher than other options.
- The implementation risk is higher than other models, because this change affects all aspects of the DNSPs.
- The decision to adopt the new structure would disrupt existing efficiency programs, which are likely to be put on hold. Although the new businesses are likely, ultimately, to reach a higher degree of efficiency than other options, the effort required to implement the new structure would temporarily overwhelm efficiency initiatives.

8.3.5. Financial Implications

The Full Merger is expected to provide the impetus to realise additional efficiency savings identified by the Panel, with a NPV of $353 million. In addition, the structure is expected to produce synergy savings of $305 million in the Networks Holding Company, Network Stewardship Group and Procurement Group, each of which combine two existing functions into a single function. In other businesses, such as the five Network Services groups, there are no expected synergy benefits.

The implementation cost for this model is expected to be substantial, given it involves a complete redesign of the existing organisation structures in most areas outside of field services. There are expected to be large costs associated with aligning business processes across the organisation so groups can interact efficiently with other group members (i.e. rather than have different processes in legacy Ergon Energy and Energex groups). For this structure, implementation costs are estimated at $307 million, in addition to the implementation costs of $101 million associated with the current efficiency programs.

Table 18. New Business Structure – NPV of savings

	Efficiency savings ($m)	Synergy savings ($m)	Total savings ($m)
Networks Holding Company	348	189	538
Network stewardship group	115	81	195
Asset management 1	53		53
Asset management 2	33		33
Procurement	112	35	147
Major projects	46		46
Network services A	40		40
Network services B	22		22
Network services C	26		26

	Efficiency savings ($m)	Synergy savings ($m)	Total savings ($m)
Network services D	62		62
Network services E	62		62
Total savings	**920**	**305**	**1,226**
Less: implementation costs			(408)
Net savings			**817**

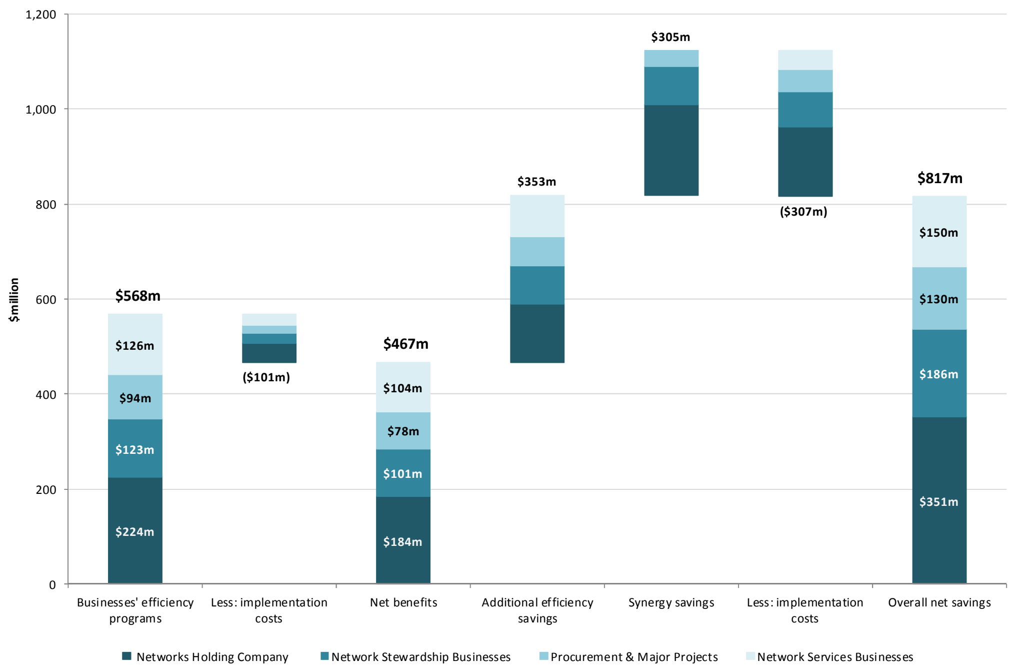
Note: Totals may not sum due to rounding.
Source: IRP

The Panel's estimate of implementation costs of $408 million is higher than the previous estimates of restructuring costs by Ergon Energy and Energex.

The estimated savings assume that the current efficiency targets and Panel efficiency targets can be met, notwithstanding the period of structural change that is expected to last two to three years.

Figure 45 shows the NPV of Option 3 compared to the Current Structure. The benefit of efficiency programs currently underway within the businesses is $467 million, and the additional efficiency savings and synergy benefits achieved because of the new structure are $353 million and $305 million respectively, with additional implementation costs of $307 million:

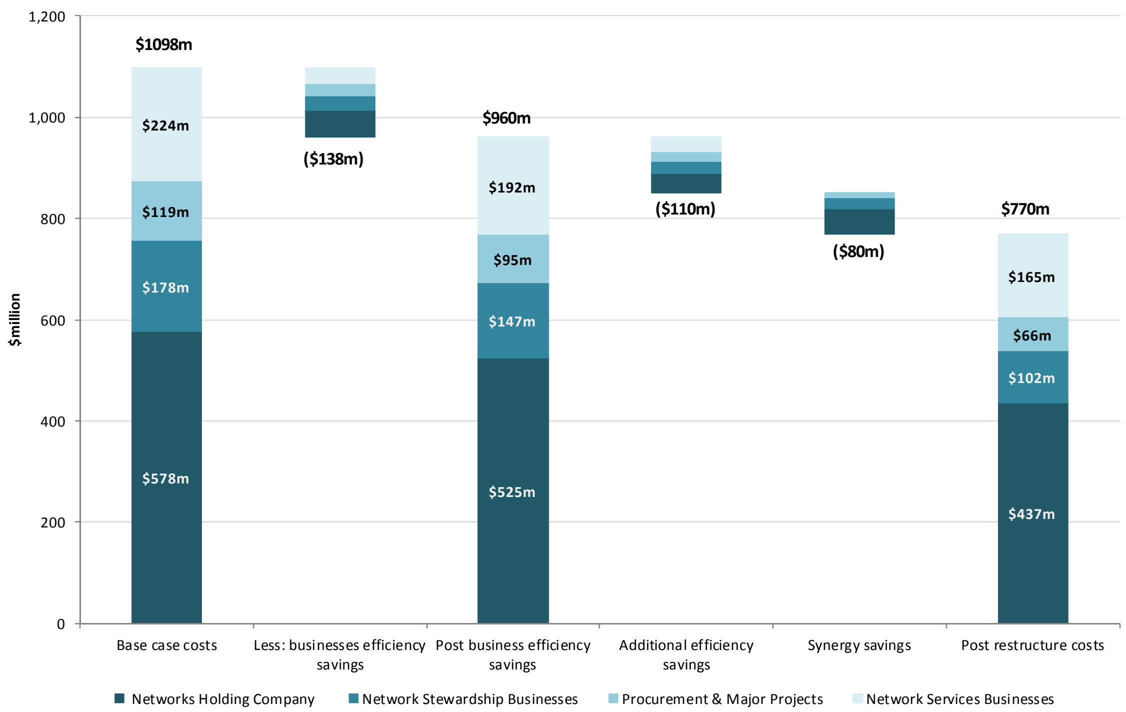
Figure 45. NPV of benefits – Option 3



Note: Network Stewardship and the two Asset Management businesses are combined in 'Network Stewardship Businesses', Procurement and Major Projects joint ventures are shown on a combined basis, and Network Services Business includes the five businesses. Totals may not sum due to rounding.
Source: IRP

Option 3 is also expected to result in significant savings in total indirect costs by 2015/16, as shown in Figure 46. Base Case total indirect costs are expected to be reduced from $1,098 million in 2015/16 to $770 million under the Full Merger, compared to $960 million in the Current Structure.

Figure 46: Total indirect costs 2015/16 – Option 3



Note: Network Stewardship and the two Asset Management businesses are combined in 'Network Stewardship Businesses', Procurement and Major Projects joint ventures are shown on a combined basis, and Network Services Business includes the five businesses. Totals may not sum due to rounding.
Source: IRP.

Provided the implementation issues can be managed successfully, the NPV of the Full Merger is higher than the other structural options. In addition, the potential for further efficiency gains in direct costs through innovation within the Network Services Businesses is higher than for the other business structures, given the profit-driven model that would be established. It is the Panel's view that the Full Merger is likely to provide the lowest cost option for delivering efficient distribution network services in the long term, however the implementation challenges and costs are expected to be high in the short to medium term.

8.4. Ranking the Structural Options

The Panel has ranked the options using the following criteria (not in any particular order):

- *Cultural*: whether the existing or new structure is more likely to contribute to a culture of efficiency within the DNSPs;
- *Risk/complexity*: the level of risk involved in implementing the structure, and the risk of delays or loss of focus on efficiency programs;
- *Synergy benefits*: the ability to achieve cost savings by rationalising duplicated functions across the DNSPs;
- *Cost reduction*: realisation of immediate cost savings (efficiency or synergy benefits), so that most efficiencies have been achieved within a four year period;
- *Policy flexibility*: whether the structure limits the ability to sell the assets to investors, in the event that Government changes its existing policy on ownership;

- *Government expectation*: whether the structural option meets the needs of Government to deliver cost savings and lower electricity prices;
- *Regulatory issues*: whether transition to the new structure is likely to create regulatory risk (such as impacts on cost bases or future expenditure allowances);
- *Regional*: whether the structure supports regional jobs;
- *Industrial relations*: whether the structure creates risks that industrial relations constraints may impact on cost efficiency; and
- *Implementation Cost*: the costs incurred in implementation of each option.

The following table summarises the ranking of the three options against each of the criteria, with further comments on the following pages.

Table 19. Ranking structural options

Criteria	Current structure	Option 2 Holding company	Option 3 Full Merger
Cultural	X	✓	✓
Risk/complexity	✓	✓	X
Synergy benefits	X	✓	✓
Cost reduction	½	✓	✓
Policy flexibility	✓	✓	X
Government expectation	½	✓	✓
Regulatory	✓	✓	X
Regional	✓	✓	½
Industrial relations	✓	✓	X
Implementation cost	✓	½	X

Source: IRP

The Panel's key findings on each of the structures are summarised in the following table.

Table 20. Structural options summary

Criteria	Current structure	Option 2 Holding company	Option 3 Full Merger
Cultural	Would be challenging to change culture within current organisations	New structure facilitates cultural change for both businesses	Completely new businesses facilitates establishment of a new culture
Risk/complexity	Retains current structure – low risk Some risk of reduced focus on delivering efficiencies once current reviews end	Implementation risk is relatively low (as it has been done before), but appointing the right management team will be critical	Greater complexity and multiple businesses increases implementation challenge
Synergy benefits	Nil – focus on efficiency rather than joint workings	Some immediate benefits from establishing holding company, with significant future potential	Synergies achieved by combining elements of existing businesses into a series of new efficient businesses
Cost reduction	Some cost reduction delivered through existing efficiency programs	Immediate cost savings for holding company functions and senior management	Large potential cost reductions but would take longer to implement as new businesses are built
Policy flexibility	No change	Preserves ability to sell at asset level	More difficult to sell assets with integrated business, but more options to sell different businesses once established
Government expectation	Relies on efficiency programs delivering on targets	Immediate synergy benefits plus greater likelihood of realising efficiencies	Large synergy benefits available over long term
Regulatory	No change	Limited regulatory risk as current regulated networks retained	Moderate risk of adverse cost outcomes given lack of history with new businesses
Regional	No change	Holding company employs 116 people so most staff unaffected	Preserves regional network services businesses which enhances regional presence
Industrial relations	No change	No change	Some complexity around harmonisation of industrial conditions
Implementation cost	No structural change costs Would incur costs to implement efficiency programs	Moderate implementation costs plus efficiency program costs	Major implementation costs and efficiency program costs

Source: IRP

The Full Merger offers the greatest potential for cost savings over the long term. In the short term, however, there are likely to be significant implementation costs and a sustained period of major change would precede the establishment of the new businesses. There is a risk that the focus on current efficiency programs would be lost during the transition to the new structure.

The Holding Company structure could be implemented relatively quickly, and provides immediate synergy benefits with increased focus on driving efficiencies within the two existing business structures. While the Holding Company employs a small number of senior managers and technical experts, it would exert a great influence on the culture of both organisations. Cultural change is an important part of efficiency programs, being the difference between a perception that the organisation is in control of its own future compared to the lack of commitment to efficiency where this is being imposed from outside.

Retaining the current structure avoids implementation costs and risks, as well as potential delays to efficiency programs while there is uncertainty around a possible new structure.

8.5. Summary of Structural Options

8.5.1. Preferred Structural Option

The Panel's preferred option is to establish a Holding Company, with a single CEO, senior management group and Board to oversee the current businesses of Energex and Ergon Energy.

The Panel has had extensive discussions with management and employees of both DNSPs, and has analysed the businesses' cost structures and the results of efficiency reviews undertaken by external consultants.

There are potentially significant efficiency savings that can be realised from both DNSPs through reducing the size of the organisations in line with lower expected programs of work, matching industry benchmarks and eliminating waste.

However, based on past performance, the current organisational structures may not be able to achieve the full extent of the identified efficiency savings. A contributing factor is that the prevailing culture in both organisations is not conducive to reducing the current levels of expenditure or reliance on external resources.

Under the Holding Company option, a new leadership structure would be put in place. While this is not as complete a solution as a merger of the businesses, the Panel considers it would facilitate a degree of cultural change across both organisations, towards a focus on efficiency, accountability and innovation to reduce costs, without incurring the scale of implementation complexity and cost associated with a merger. Under this option, the current indirect costs of over $1 billion per annum are estimated to be $273 million less per annum within 4 years.

In the Panel's view, the holding company could be formed and senior management positions appointed before ownership of the businesses is transferred to the new structure on 1 July 2013.

Financial analysis of the structural options was conducted with the assistance of Queensland Treasury Corporation. The results of this analysis are shown in the table below.

Table 21. Cumulative Value of Benefits from 2015/16 to 2019/20, Indirect (Overhead) Costs

	Current Structure ($m)	Holding Company ($m)	Full Merger ($m)
Net Benefit	**Up to 731**	**1,401**	**1,694**
Benefit vs Status Quo	-	670	963

Source: IRP analysis

The cumulative saving under the Panel's preferred option is $1.4 billion over the period from 2015/16 to 2019/20, when compared to the DNSPs' original forecasts of costs submitted in their May 2012 draft Statements of Corporate Intent. This is a saving of at least $700 million more than the Panel's expectations of savings from the DNSPs' current efficiency programs.

While the full merger option may achieve greater synergy savings, the Panel is concerned about the additional implementation risk and cost associated with this option.

It is important to note that the financial modelling is based on indirect cost savings only, which are around one-third of the total capital and operating expenditure of the two DNSPs. This means that the financial modelling has excluded any additional direct capital and operating expenditure savings that would be expected to be derived through the preferred option over time.

8.5.2. Implementation

Some of the recommendations will take time to have an effect and the Panel considers that the Government needs to give high priority to the implementation of these reforms. In this regard, the following steps should be taken:

1. Immediately appoint a new Chairman and Board which will be common to Energex and Ergon Energy.
2. Commence recruitment of the CEO for the restructured DNSPs. Until the formation of the new Holding Company, this CEO will be the CEO for both DNSPs.
3. Establish the new Holding Company and subsidiary structures for the DNSPs.
4. In the interim, task the new Board and existing management to continue with the existing efficiency initiatives of the two DNSPs and with implementation of the recommendations.
5. Board and CEO to define corporate functions and select corporate leadership team by 31 May 2013.

Recommendation 30

Establish a new holding company for the two DNSPs to drive efficiencies and other operational improvements, structured as follows:

- *A common Board providing governance for the holding company and the two DNSP subsidiaries;*
- *A CEO of the holding company who will also be the CEO of the two DNSP subsidiaries;*
- *A COO for each of the two DNSP subsidiaries reporting to the CEO;*
- *Corporate and strategic leadership located within the holding company, comprising the CFO, CIO and EGMs for Corporate Strategy, Network Stewardship and Strategic Procurement;*
- *Core and support processes remain within the subsidiaries;*
- *SPARQ to become a subsidiary of the holding company; and*
- *A Major Projects group to provide services to both DNSP subsidiaries, structured as a separate business unit.*

Implementation DEWS

9. Network Regulation and Planning

9.1. Network Regulatory Arrangements

The regulatory regime applying to NSPs is the subject of a series of national and state reviews. These include the recent report by the Senate Select Committee on Electricity Prices released on 1 November 2012, the Productivity Commission Draft Report released on 18 October 2012, the AEMC Transmission Frameworks Review due in March 2013, and Rule change proposals lodged by the AER and the EUAA in November 2011, on which a Final AEMC Rule determination was made on 29 November 2012.

These Reports have highlighted the incentives within the Rules for NSPs to over-invest, concerns about the capacity and ability of the AER to fulfil its obligations under the Rules to limit this expenditure, and the differences between the expenditure patterns and rates of return exhibited by private versus publicly owned NSPs.

The Panel has considered these Reports and consulted over the course of the review period with the Queensland NSPs, the AER, and the AEMC to better understand the various perspectives of the industry, the regulator and the Rule maker. While there are clear differences in the perspectives of these parties with respect to operational regulatory matters, they all support the continuation of a national framework. The Panel endorses this view.

There are, however, several matters relating to the national regime which are of concern, and which are worthy of policy action by the Queensland Government.

The Panel is concerned about the increasingly input-based approach being taken by the AER to the determination of revenues for NSPs. This includes an increased focus on benchmarking and the receipt and analysis of data requests such as the Regulatory Information Notices, and the development by the AER of “one size fits all” models for determining the efficiency of capital and operating expenditure. The Panel considers that such approaches reflect a capability shortfall within the AER. This view was also expressed by other parties during the consultation process.

The Panel agrees with the widely held view that the use of the building block formula provides incentives for NSPs to overstate their capital and operating cost requirements. It also acknowledges that the information asymmetry faced by the AER poses significant challenges in determining whether the levels of expenditure requested by NSPs are prudent and efficient. However, the Panel considers that the approach being taken by the AER to address this situation requires review. This is particularly important in an environment where the AER is seeking greater discretion, most notably through its 2011 Rule change proposals.

The establishment of the AER as part of the Australian Competition and Consumer Commission (ACCC) is a contributing factor to this issue. In particular, the Panel understands that the AER does not have the flexibility to attract and retain suitably qualified regulatory staff and management, particularly in terms of salaries and employment packages. This places the AER at a distinct disadvantage in dealing with industry.

Recommendation 31

The Queensland Government advocate greater independence for, and strengthening of, the national energy regulator, by:

- *separating the AER from the ACCC in order to give it greater capacity to discharge its obligations; and*
- *ensuring the AER has the ability to attract suitably qualified and experienced staff, including the ability to offer commensurate levels of remuneration.*

The Panel is also concerned about the ongoing excessive review and amendment of the Rules. Over the past 5 years, there have been over 100 Rule changes.

While all legislation requires ongoing maintenance and review, the rate of Rule change has forced excessive compliance costs on industry participants and governments. There is a need to ensure that Rule changes are made only when there is a clear and demonstrable, material benefit to the operation of the NEM and the interest of electricity consumers, consistent with the NEO.[62]

Recommendation 32

The Queensland Government seek the agreement of the Standing Council on Energy and Resources for a review of the AEMC's role and exercise of its rule making powers, specifically:

- *governance arrangements aimed at greater transparency in its operations and ensuring the AEMC is more directly accountable to Energy Ministers; and*
- *establishment of a materiality threshold for rule change requests.*

Implementation: DEWS

The Panel is concerned that the size and complexity of the Rules is causing excessive costs to industry participants. The Rules have increased from 909 pages when brought into effect in 2005 to 1,373 pages today. This compares with around 600 pages when the National Electricity Code was promulgated in 1998.

The Panel considers that simplifying the regulatory environment and clarifying regulatory responsibilities should be a priority and therefore the Rules should be streamlined.

The Panel has also considered the influence of control mechanisms and the incentives provided by these as a determinant of end use customer prices. The control mechanism is currently set out by the AER prior to each regulatory determination in a Framework and Approach Paper and is binding on the DNSPs.

The rules allow for the AER to select a control mechanism from a range of possible mechanisms set out in clause 6.2.5(a) of the Rules. Generally, this has been either a revenue cap or a weighted average price cap (WAPC), with revenue caps currently in place in Tasmania and Queensland, and WAPCs in New South Wales, Victoria and South Australia.

While the Panel acknowledges that all control mechanisms are essentially neutral in the case where actual demand/consumption is equal to forecast demand/consumption, a WAPC provides for revenue to exceed MAR where actual demand/consumption exceeds forecasts. This can create an incentive for DNSPs to under-forecast demand.

The Panel supports DNSPs being responsible for forecasting demand based on their expectations of the market and revenue being linked to these forecasts. The current revenue cap control

[62] *National Electricity (South Australia) Act 1996*, Part 1, preliminary, Section 7, National Electricity Objective, p36.

mechanism transfers volume risk to customers. The adoption of a WAPC control mechanism would pass this risk back to the DNSP subject to approval of the forecasts by the AER.

This would provide an outcome where the risk of overstating demand would lie with the Board and management of the DNSPs. Where demand is lower than forecast, as has been the case in Queensland in recent years, the DNSPs revenue would fall, subject to any rebalancing of tariffs permitted under that mechanism. At the same time, consumers receive the benefit of relative stability in average tariffs.

The role of the AER would be critical in ensuring that the DNSPs did not shift from their current practice of overstating demand to a new practice of understating demand in order to over recover their maximum allowable revenue.

The Panel has therefore recommended that the Queensland Government support the selection of a WAPC control mechanism by the AER during the Queensland Framework and Approach process.

Recommendation 33

The Queensland Government:

- *seek the support of the Standing Council on Energy and Resources for a comprehensive review of the National Electricity Rules under s.41 of the National Electricity Law, aimed at reducing the current regulatory complexity to ease the compliance burden on the industry; and*
- *support the selection of a WAPC control mechanism by the AER during the Queensland Framework and Approach process.*

Implementation: DEWS

9.2. Network Management Plans

Forecasts of electricity consumption and peak demand are key drivers of network expenditure.

The electricity network is planned to meet forecast demand growth, the connection of new customers and maintenance of reliability standards. Planning of the distribution networks in Queensland is the responsibility of the DNSPs, while planning of the transmission network is the responsibility of Powerlink. This is consistent with planning arrangements in other NEM jurisdictions, with the exception of Victoria where transmission planning is undertaken by AEMO.

The NSPs are required to prepare a set of public planning documents detailing how they intend to manage the networks. For the DNSPs, these include the following annual plans:

- Network Management Plan (NMP);
- Summer Preparedness Plan; and
- Demand Management Plan.

In planning the transmission network, Powerlink is required to prepare an Annual Planning Report, which sets out an assessment of the forecast electricity demand and network augmentation, non-network solutions or asset replacement required to meet that demand.

The AEMC issued a Final Rule Determination on 11 October 2012 that introduces requirements in the Rules for DNSPs to undertake an annual planning review with a forward planning period of at least five years and prepare a Distribution Annual Planning Report (DAPR) *"by the date* *specified by the relevant jurisdictional government"*.[63] The requirements of the DAPR are similar to those in the NMP. Once the DAPR requirement is in place, the Queensland NMPs will not be required. The practical impact is expected to be relatively minor as Queensland's DNSPs already produce the most comprehensive annual planning reports in the NEM.[64]

The Panel considers that a prudent DNSP would undertake all the activities required to prepare NMPs as part of its asset management strategy. Given the introduction of the DAPR will make NMPs redundant, the Panel considers that the EIC should be amended to remove this requirement.

Recommendation 34

Retain the Network Management Plan requirement but transition to the Distribution Annual Planning Report as required under the National Electricity Rules. Remove the requirement for the Network Management Plan from the Electricity Industry Code once the Distribution Annual Planning Report rule has commenced.

Implementation: DEWS

The DAPRs do not include a requirement to prepare a Summer Preparedness Plan. This is consistent with the Panel's view that a prudent and efficient DNSP would ensure that its network and systems were prepared for the summer storm months, irrespective of an explicit requirement to prepare such a plan.

Furthermore, the DNSPs have demonstrated their summer preparedness planning capabilities through their responses to Cyclone Larry in 2006, Cyclone Yasi in 2011 and the 2011 Floods. Therefore, the Panel considers the obligation to develop Summer Preparedness Plans on request[65] is no longer necessary. The preparation of adequate plans for managing the summer storm season should be a matter for the Boards and management of the DNSPs.

Recommendation 35

Remove the requirement for Summer Preparedness Plans from the Electricity Industry Code.

Implementation: DEWS

9.3. Transmission Customer Connection Processes

The Panel was required to investigate options to plan for and respond to changes in economic growth. With the rapid growth in the mining and gas industries in Queensland, the strong contributions to employment and Gross State Product from these and related industries, and the importance of timely and least cost connection of new developments to the NEM, the Panel sought to review whether these connection arrangements were deficient in any way and whether any improvements were possible.

Connection arrangements for large customer connections are presently the subject of a review, the Transmission Frameworks Review, by the AEMC. This review has noted industry concerns regarding instances of high cost and delays in delivering large customer connection works.[66] Further, the AEMC is considering changes to the current classifications of these works as unregulated or negotiated services.

[63] The AEMC expects that the majority of DNSPs will publish a DAPR in 2013. Source: AEMC, *Distribution Network Planning and Expansion Framework*, Rule Determination, 11 October 2011.
[64] Pers. comm. AEMC staff progressing the Distribution Network Planning and Expansion Rule Change (Claire Rozyn), via teleconference on September 6.
[65] Under section 2.2 of the EIC, the QCA may request a DNSP to prepare and submit a summer preparedness plan. Although it may recommend changes to the DNSP's summer Preparedness Plan, the QCA does not approve the plan.
[66] AEMC, *Transmission Frameworks Review*, First Interim Report, 17 November 2011.

Large customers and proponents of major projects value flexibility. Engaging in non-regulated negotiations with NSPs provides a useful framework to achieve this.

Recommendation 36

The Government support changes to the connection and service classification arrangements which facilitate connection between major customers or generators and the TNSP. Government should not support the adoption of mandatory regulatory processes which would reduce the flexibility of users to negotiate or limit the ability for extension works to be provided in a timely and responsive manner.

Implementation: DEWS

The existing arrangements for large customer connections are well known by project proponents, some of whom may be at advanced and critical stages of negotiations with the NSPs. Any changes to the arrangements for large customer connections need to take account of potential implications for current major projects.

The Queensland NSPs effectively fill two different roles in providing network services: owner and manager of the shared network; and provider of network services for connection assets (those assets used by only one, or a small group of network users). This second role includes the provision of construction services to large users and the negotiation of a price and costs for these services.

In typical large infrastructure or construction projects, information regarding the key cost-of-production components is shared between the buyer and the seller, and negotiation is undertaken specifically on risk and return.

This is not always the case for negotiations with NSPs, where there is limited transparency for the network user. In ordinary markets, competition in the provision of the services would correct this, with new entrants offering to provide greater transparency and price competition. This does not appear to have been the case in Queensland, where the Panel understands there is limited competition for the construction of connection assets, extensions and associated infrastructure.

Further, there does not appear to be a central base of information to better inform users about connection options and better inform entities wishing to enter the market to construct these connections about their rights and obligations. Effective and efficient information systems are key to ensuring information can be provided in a timely manner to connection applicants. Under current regulatory arrangements, major users receive all information from Powerlink, which is the entity with whom they are negotiating.

The Panel acknowledges the need to balance the interests of:

- Powerlink, as an entity which has invested in good faith in developing its unregulated network business operations;
- major users who are part way through negotiations; and
- future major users who may desire a choice of possible parties to develop, fund and operate network connections.

The Panel notes the AEMC's findings in its second interim report and has identified two areas where change could benefit economic development.

The first relates to land access and easements. The Panel understands that Powerlink has a right to acquire easements along the route of proposed new transmission lines.[67] These rights do not accrue to other parties and may constitute a barrier to entry for other providers. NSPs also have the advantage of being able to use existing easements for providing extension works for large customer connections.

The Panel considers that Government should ensure that appropriate access to land is available to private sector power line proponents and notes that there are provisions in the *State Development and Public Works Organisation Act 1971* and the *Electricity Act 1994* which are relevant to this issue.

An electricity entity (as defined in the *Electricity Act 1994*) may be authorised by the Minister, by Gazette notice, to enter land to consider its suitability for (electricity) works and to compulsorily acquire land for such works. This means that there is no legislative barrier to a party other than one of the existing NSPs obtaining compulsory acquisition rights. Land may also be compulsorily acquired by the Coordinator-General for third parties for development in a State Development Area or for an Infrastructure Facility of Significance (as approved by the Governor in Council). However, such action is ultimately a decision for the Coordinator-General.

The Panel is not aware of either of these processes being applied for the provision of third party electricity infrastructure, although the proposed CopperString transmission project was declared an Infrastructure Facility of Significance in 2011.

The second relates to information provision. The Panel considers that Government should establish a method of informing users about their rights and obligations under the Rules and when connecting through entities such as Powerlink. The Rules are a complex, large and prescriptive document which is constantly being amended, and it is unreasonable to assume that even large users will be able to negotiate with the TNSP on a fully informed basis.

Recommendation 37

The Government encourage competition and private sector investment in unregulated transmission extensions through changes that streamline easement acquisition processes.

Implementation: DEWS

Recommendation 38

The Government should prepare and publish a Regulatory Statement to clearly describe the licensing and approvals required for electricity supply network infrastructure in Queensland.

Implementation: DEWS

9.4. Demand Forecasting

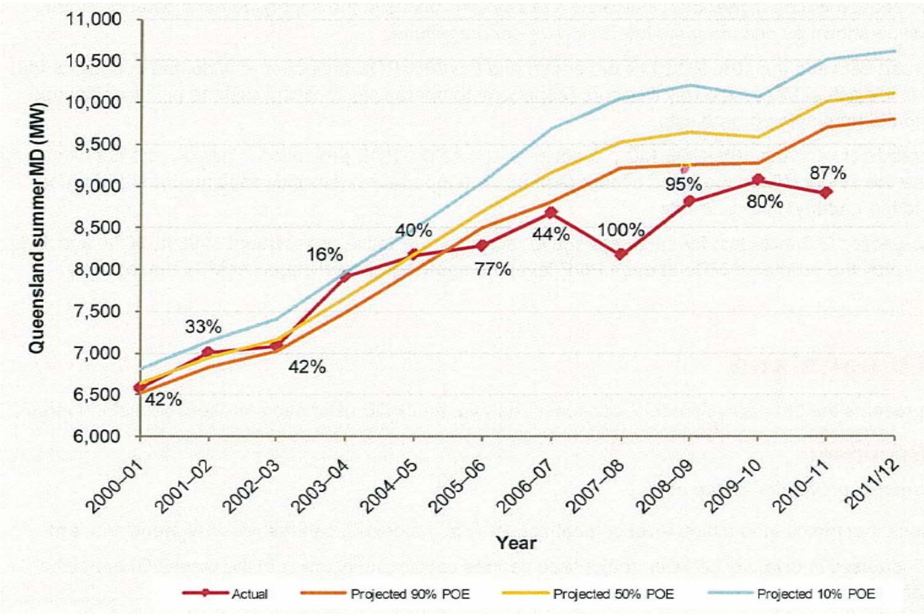
Projections of electricity demand in Australia have been the focus of continued attention from market participants. In Queensland, this is largely due to the NSPs' relatively poor performance in demand forecasting over the past five years.

In this regard, the AER rejected Powerlink's demand forecasts in the most recent revenue determination on the basis that it was not a realistic expectation of demand and the AER adopted its own demand forecasts. Similarly, the AER used its own demand forecasts for the most recent determination for the DNSPs.

[67] The *Acquisition of Land Act 1967* provides both voluntary and compulsory avenues for acquiring land (which includes taking of easements). NSPs have certain rights to acquire easements along the route of proposed new power lines by virtue of the fact that they are recognised as constructing authorities under the *Acquisition of Land Act 1967*.

The Panel found that Powerlink's 'one-year-out business as usual' projection of demand has exceeded actual demand for the past six years. Furthermore, actual demand has been below Powerlink's lower bound (90% probability of exceedence (PoE)) one-year-out forecast since 2005/06. The figure below highlights Powerlink's recent forecasting performance by comparing forecast demand one year out with actual demand.

Figure 47. Powerlink Summer One-Year-Out Forecasts and Actual Maximum Demand



Note: The percentage next to each demand data point represents the estimated PoE of the peak demand for that year.
Source: AEMO 2011 Electricity Statement of Opportunities Appendix B

The DNSPs have demonstrated similar inaccuracies in demand forecasting. The Panel is aware, however, that the vast majority of demand forecasts over the past five years by all participants in the NEM have been inaccurate. This is a result of changes to energy market conditions and the impact of the Global Financial Crisis on general economic conditions.

The Panel considered the option of transferring responsibility for transmission demand forecasting to another party. It compared the NSPs' performance against that of the AEMO, the body responsible for demand forecasting for South Australia and Victoria. The Panel found that AEMO's demand forecasting for these jurisdictions was no more accurate than the Queensland NSPs in recent years, indicating that AEMO's forecasts were similarly affected by uncertainty surrounding economic growth.

If AEMO was made responsible for system demand forecasts, the NSPs would still be responsible for 'bottom up', localised demand forecasting in their role as investment decision maker. Demand forecasts would then be duplicated and AEMO's fees would increase total network costs. The Panel considers that transferring the responsibility for demand forecasting to AEMO would not result in measurably better outcomes for Queensland consumers.

It noted, however, that AEMO, in its role as National Transmission Planner, has undertaken to develop system peak demand and consumption forecasts for each of the NEM regions. The Panel welcomes the development of this additional input to system demand forecasting and considers that the NSP and AEMO processes, working together, will result in more accurate forecasts across the NEM.

> ***Recommendation 39***
>
> *The TNSP and the DNSPs retain responsibility for demand forecasting as the basis for network planning at the State and regional level. The Panel does not support nationally centralised demand forecasting for this purpose.*
>
> *Implementation: DEWS*

9.5. Managing Peak Demand

There is a clear relationship between maximum demand at critical points in the network, and capital expenditure, which has been documented in reports prepared by NSPs nationally and internationally, and endorsed by reports completed by the AEMC and the AER. Therefore, the Panel supports efficient investment in activities aimed at reducing the incidence of peak demand to lower both short term and long-term expenditure requirements.

9.5.1. The Peak Demand Problem

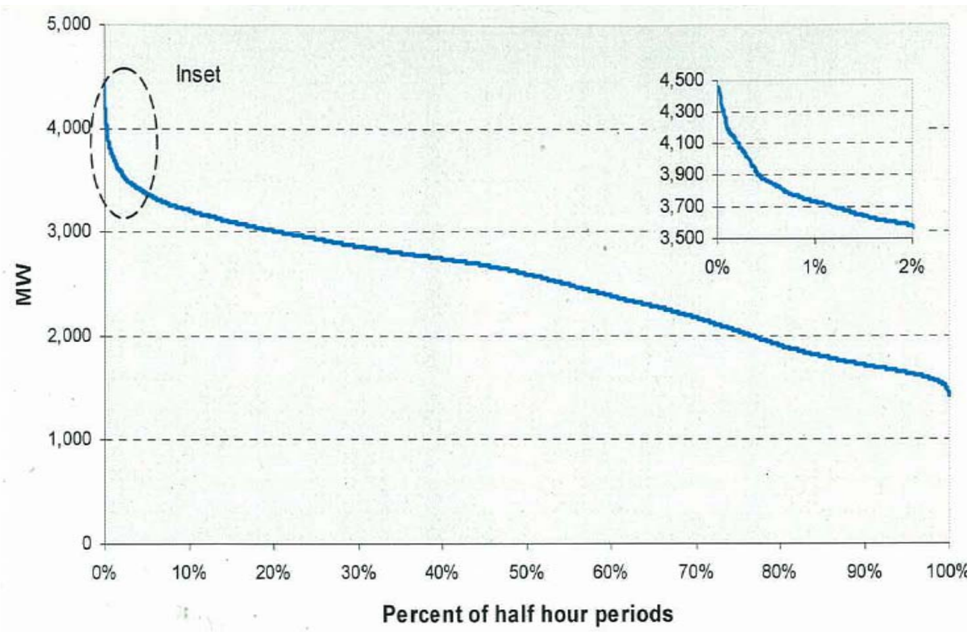
Peak electricity demand refers to the times of the day when electricity is being drawn from the network at the greatest rate. It is a critical driver of network investment and therefore consumer costs. Growth in peak demand has been driven primarily by the increased penetration and use by households of energy intensive appliances, especially air conditioners.

NSPs base their network investment plans on forecasts of peak demand to ensure reliable and secure supply and to minimise the number of consumers that experience supply interruptions.

Peak demands occur over relatively short periods of time during the year. The full capacity of the network is therefore underutilised. Energex estimates that approximately 16% of its network has been built to satisfy electricity demand that occurs less than 1% of the time (i.e. fewer than 88 hours in the year), usually for a few hours on the hottest days.

This is illustrated in the load duration curve in Figure 48 below.

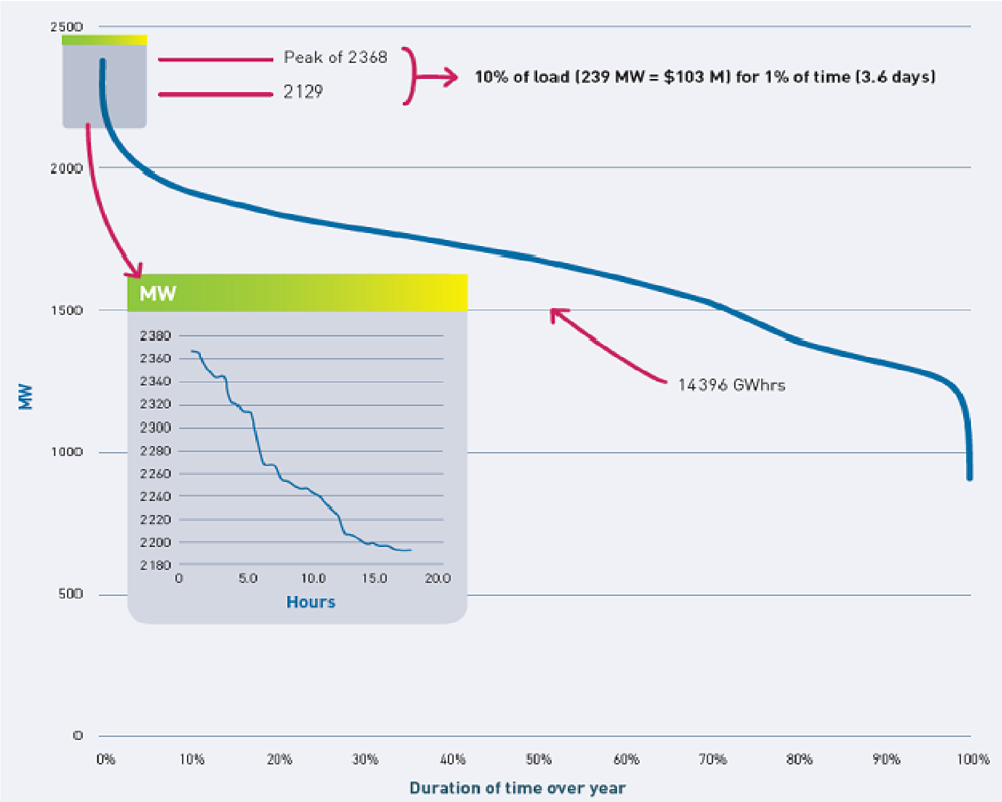
Figure 48. Energex 2011/12 Load Duration Curve



Source: Energex

A similar situation is shown in the load duration curve for Ergon Energy, in the figure below.

Figure 49. Ergon Energy system total Load Duration Curve 2010/11

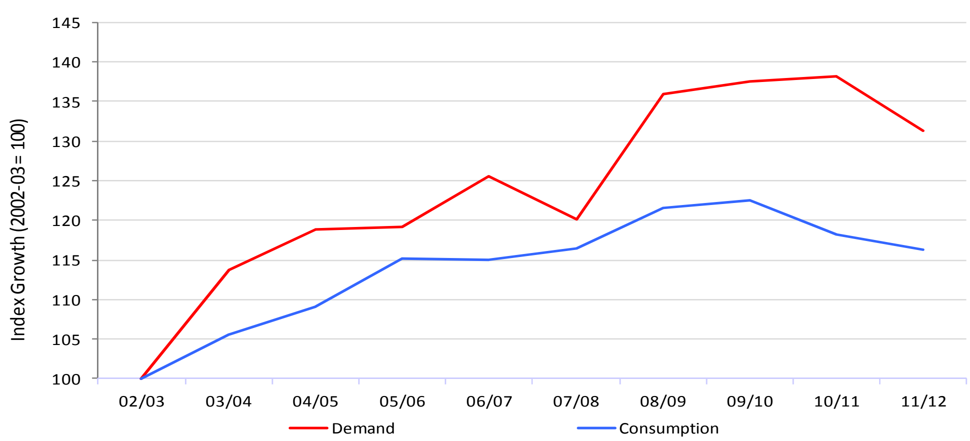


Source: Ergon Energy

Network utilisation (or load factor) provides a measure of how efficiently network assets are employed. In part, it is driven by the gap between peak and average demand. It is also influenced by the extra capacity required for reliability standards, the need to build for future growth, and the difference between expected and actual demand. These factors can result in networks being built to a capacity significantly above that needed to accommodate actual peak demand which in turn drives down capital productivity.

Figure 50 compares growth in consumption (energy supplied) with growth in maximum demand in the Ergon Energy network between 2002/02 and 2011/12. The gap between the two curves reflects the extent of network under-utilisation. It demonstrates that growth in peak demand has consistently exceeded growth in consumption since 2002/03, which has served to widen this gap.

Figure 50. Queensland Peak Demand and Consumption Growth Index



Source: Powerlink

As discussed in the previous chapter, the NSPs have consistently over-estimated future demand over recent years. At the same time, energy consumption has declined. This exacerbates the under-utilisation of the Queensland networks.

In addition to driving additional expenditure on network capacity that flows to electricity price, the lower network utilisation characteristic of peak demand increases the price of electricity to the consumer. Network revenue is essentially fixed on an annual basis and is primarily recovered on a per-unit basis. Where peak demand increases at a greater rate than average demand, there is an increase in the per-unit costs charged to customers.

9.5.2. Demand Management Programs

Demand management activities aim to reduce electricity demand and particularly peak demand, typically at the customer level, in order to defer or eliminate the need to augment the network. Demand management activities include energy conservation measures that reduce the electricity consumption of appliances or equipment overall, and load control measures that shift demand away from peak times.

The DNSPs have developed demand management programs to address the network underutilisation arising from the load profiles shown above. Over the last four years, they have invested heavily in broad-based programs designed to build capability and establish linkages to private sector providers of alternative energy solutions.

The DNSPs' current demand management programs include the following activities:

- Residential:
  - Broad-based initiatives including load control for air–conditioning, pool pumps and hot water systems; and
  - Trials of Reward Based Tariffs to determine the most effective cost reflective tariff options and delivery mechanisms to encourage voluntary energy conservation or load shifting.
- Commercial and Industrial:
  - Permanent load reductions through facilitating power factor correction, energy efficiency and co-generation activities; and
  - Demand response initiatives that contract businesses to run standby generation or shift load to reduce the impact of demand at peak times.

The following table summarises Peak Demand Programs.

Table 22 Peak Demand Programs

Program	Description
Demand management for Commercial and Industrial Customers (Energex)	High energy consuming businesses are incentivised with network support payments to adopt energy efficiency solutions such as Heating Ventilation and Air Conditioning upgrades, lighting, and building management systems or demand management measures such as load curtailment or embedded generation. These achieve energy consumption and demand reductions at net benefit for customer and distributor respectively. The original funding package (to which the Queensland Government contributed \$9.2m) commenced January 2009 is due to complete in December 2012 and to date has delivered a 53.7MVA demand reduction at a cost of \$10.6m.[68]

[68] As at 30 Sept 2012. From Energex Energy Conservation & Demand Management Quarterly Report 12.

Program	Description
Toowoomba Power Factor Correction (Ergon Energy)	A sub-project of Ergon Energy's larger C&I program, this pilot proved the business case and technical viability of power factor correction. C&I customers in the Toowoomba, Dalby, Warwick and Oakey areas were offered financial contributions towards the cost of installing dynamically switched power factor correction units on their switchboards. The program has delivered a 4.14 MVA reduction at a cost of $1.47m and informed the approach for Ergon Energy's broader C&I work.[69]
Pool Pump Programs (Energex and Ergon Energy)	Broad-based residential programs that offer cash incentives to householders who purchase a minimum 5 star energy efficient pump or switch their existing pump to off-peak Tariff 33. The program has catalysed a transformation in the pool pump market where 8 star pumps are now the norm and this has allowed distributors to begin to phase out their incentive payments. Collectively this program has delivered 9.5 MVA of demand reduction at a cost of $8m.[70]
Air conditioning Programs (Energex and Ergon Energy)	The DNSPs work with air-conditioning began with limited scale trials that offered rebates for the installation of retrofited load control technology. In Energex's "Energy Conservation Communities" this approach has secured a 5.26 MVA load reduction at a cost of $11.7m[71] and proven the technology and consumer acceptance. The DNSPs are transitioning now to a whole-of-Queensland program that aims, with the support of Government, to encourage customers to install air-conditioning units with built-in "PeakSmart" load control technology through attractive tariff offerings. This is expected in the long term to be vastly more cost effective than the retrofit model and current rebate offers. This strategy is providing the impetus for the market to adopt the "PeakSmart" (AS4755) technology, which is now offered by five major manufacturers across 50% of all available models. Energex have also developed a cost effective model deployment for holiday apartments that involves working with apartment managers and unit owners to undertake mass retrofits of load control technology at apartment complexes.

Source: Ergon Energy, IRP analysis

These activities have been funded through revenues from network tariffs and by the Queensland Government through targeted funding.

Ergon Energy employs 72 staff (FTE) in Energy Conservation and Demand Management and Alternative Energy activities. Energex employs 37 staff (FTE) in demand management activities. These staff costs are included in overhead expenditure.

[69] To end June 2012. From Ergon Energy Demand Management Outcomes Report 2011/12 p17

[70] To end June 2012. From Energex and Ergon Energy Demand Management Outcomes Reports 2011/12 and advice to government.

[71] MVA reduction reported by Energex for Cycleit installs is 78% of the total MVA reduction achieved for the program as a whole. $11.7m is 78% of the total program spend.

From 2009 to 2011 the Queensland Government's Energy Conservation and Demand Management Initiative Package contributed $18 million to Ergon Energy and $27 million to Energex.[72] This Package comprised four major initiatives:

- Commercial and Industrial Customer Initiative
- Residential Targeted Initiative
- Energy Conservation Communities
- Rewards Based Tariff Trials and Policy Development Initiative

The current AER revenue determinations include allowances for demand management projects of $63 million for Ergon Energy and $195 million for Energex over five years for a range of ECDM activities including $125 million for demand management as well as funding for smart metres and grid support payments. Also included in the allowance was $5 million each through the Demand Management Incentive Scheme (DMIS).[73,74] The DMIS provides for the DNSPs to investigate and implement efficient non-network approaches to match supply and demand and improve demand management capabilities in the longer term. It is not intended to be the primary source of funding for demand management activity but provides an avenue for businesses to respond to unexpected and untested demand management opportunities. The balance of the allowance was approved by the AER as regulated capital and operating expenditure, as part of the distribution determinations.

Over the five years to 2015, a total of $240 million could be spent by the DNSPs on demand management activities. Given this level of expenditure, the Panel consulted with the DNSPs in order to understand the relationship between the historic costs of demand side management and the benefits to date. Both businesses provided information about specific examples of network augmentations that had been deferred.

However, in undertaking the analysis of the DNSPs' demand management programs, it became apparent that there were issues with the transparency, consistency and rigour applied in delivering and evaluating the benefit of demand management solutions as an alternative to network augmentation.

The Panel has greater confidence in the non-network solutions that have been developed as part of the normal network investment process. In keeping with other sections of this report, the Panel is of the view that the DNSPs should be responsible for delivering the network in the most cost-effective manner and should have processes in place to determine whether network or non-network solutions are the most appropriate in individual cases.

Both DNSPs have stated that they are transitioning from broad-based projects to more targeted roll-outs of specific demand management activities. Direct controlled air-conditioning and off-peak pool pumps are two areas of current focus, and both DNSPs are working with the Queensland Government to assist in the development of new types of network tariffs designed to reward customers for reducing demand. In addition, Ergon Energy is engaging with commercial and industrial customers on demand management initiatives in constrained areas of the network.

Both DNSPs have advised that they are expecting demand management expenditures and resourcing to reduce over the next two to three years as these types of programs become "business as usual".

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[72] Queensland Government, *Electricity Demand Management Initiative Package Funding – Deed of Variation No. 2*, 23 January 2012.

[73] Energex, *Energex_Response_to_Request_for_Information_by_IRP_No6_14 August 2012 FINAL.pdf*, Submission to the IRP, August 2012, p.5

[74] Ergon Energy regulatory proposal 2010-15 p313, (adjusted in AER final determination p181). Rounded from $58.64m.

Recommendation 40

Demand management projects and activities should proceed only where a rigorous commercial assessment has been completed.

Implementation: DNSPs

Recommendation 41

Discontinue demand management projects and activities associated with emerging technologies that will not be commercialised or provide benefits to consumers within the medium term. This excludes projects covered by the AER's Demand Management Incentive Scheme.

Implementation: DNSPs

Recommendation 42

Resources should be adjusted to match changes in activity consequent to Recommendations 40 and 41.

Implementation: DNSPs

10. Ownership

The cost savings and the structure recommended in Chapter 8 assume that the DNSPs remain in Government ownership.

The Panel's analysis, supported by similar data from the AER and findings of the Energy Users Association of Australia, indicates that the privately owned DNSPs in Victoria and South Australia have been consistently more efficient than the Government owned DNSPs in Queensland and New South Wales.

Importantly, the performance of the privately owned DNSPs in terms of reliability and service standards is either superior to, or comparable with, their government owned counterparts.

The Panel also notes that the national regulatory regime is moving towards greater use of incentives to drive improved performance. It considers that Government owned entities are much less responsive to regulatory incentives due to less constrained access to capital and because the strict commercial charter that should apply under corporatisation is often compromised by the collateral social and economic objectives of Government.

In contrast, in jurisdictions where these services are provided by the private sector, the DNSPs exhibit a high degree of responsiveness to economic signalling, driven by capital rationing and a focus on increasing efficiency to lower costs.

The experience of private ownership and operation of NSPs in Victoria and South Australia is that this essential service can be safely, reliably and cost-effectively provided under the national regulatory regime that applies to all NSPs regardless of ownership.

In this context, there is a compelling case for privatisation of the DNSPs in Queensland that can unlock further cost savings to ultimately benefit consumers.

Accordingly, the Panel considers that, in the interests of all stakeholders, Government should give consideration to the privatisation of the DNSPs.

Recommendation 43

The Government give consideration to the privatisation of the DNSPs.

Implementation: DEWS

11. Summary of Cost Savings

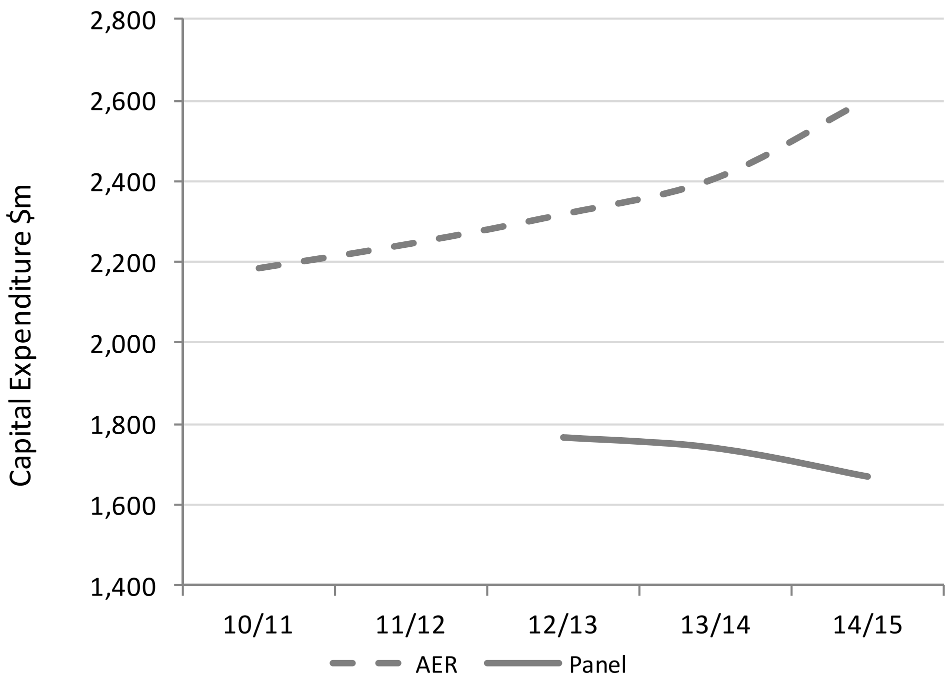
11.1. Cost Savings

The recommendations of this Panel, changes in market demand conditions and internal efficiency programs driven by the new Chairs and Boards of the NSPs, will result in large reductions in their expenditure programs.

The Panel estimates that cumulative **reductions** in total expenditure across the NSPs of around **$3.6 billion**[75] can be achieved compared with the current 5-year regulatory expenditure programs approved by the AER. This includes the savings from the ENCAP Review, efficiency initiatives undertaken by the NSPs in 2012 and the Panel's recommendations.

The following charts compare the AER-approved capital expenditure and operating expenditure for the DNSPs and TNSP with forecast expenditure consequent to the recommendations. Equivalent individual charts for each of the DNSPs are attached as Appendix D.

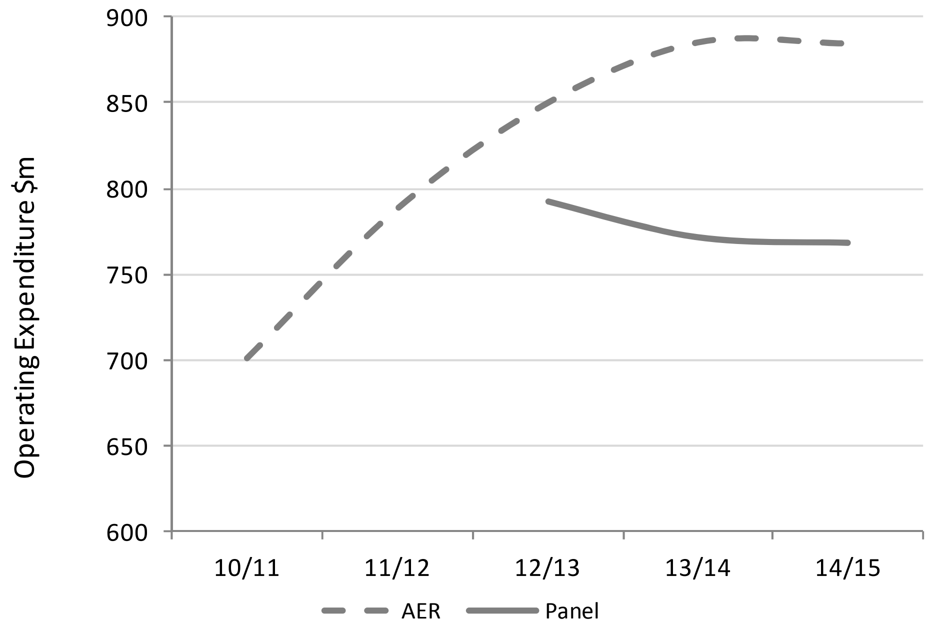
Figure 51. DNSPs Capital Expenditure, 2010/11 – 2014/15



Source: IRP

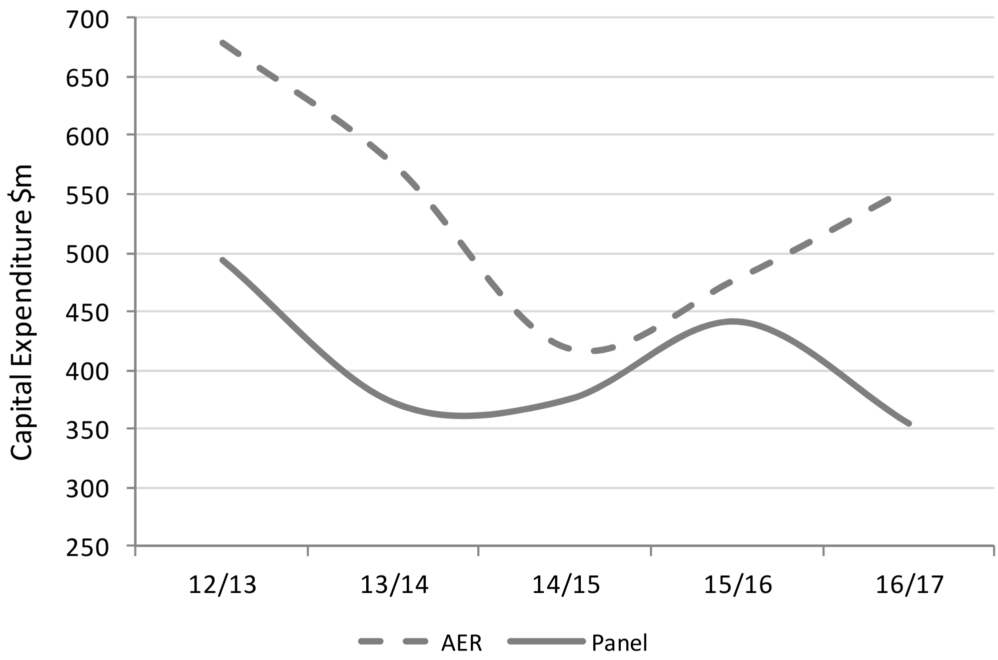
[75] This figure is calculated as the difference between total expenditure (operating plus capital) in the AER determination and the total expenditure projected by the Panel over the current regulatory period, in nominal terms. For the DNSPs, the period is 2010/11 to 2014/15. For the TNSP, the period is 2012/13 to 2016/17.

Figure 52. DNSPs Operating Expenditure, 2010/11 – 2014/15



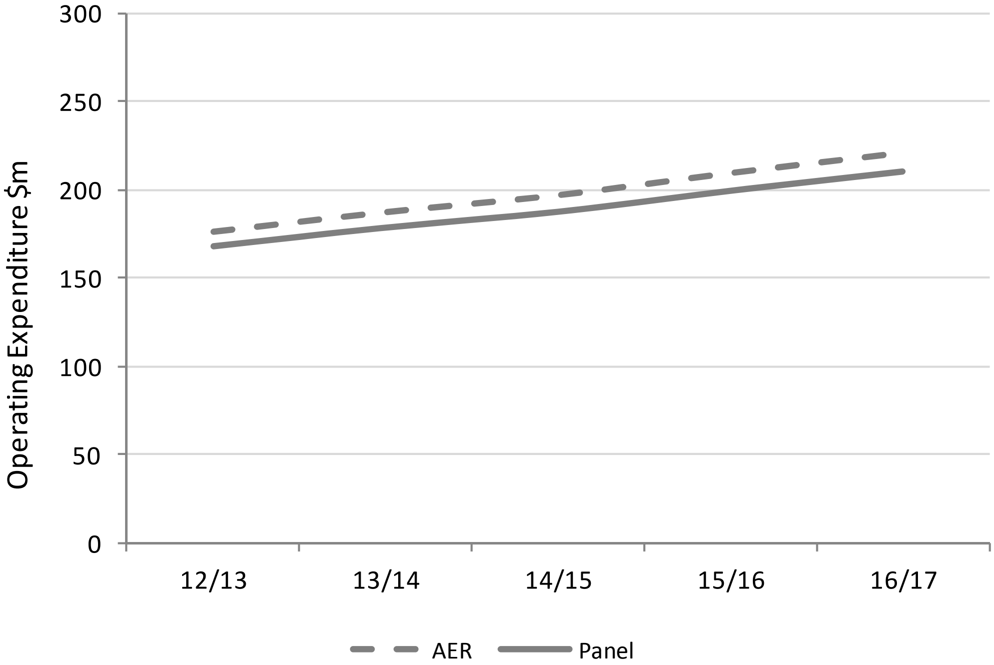
Source: IRP

Figure 53. Powerlink Capital Expenditure, 2012/13 – 2016/17



Source: IRP

Figure 54. Powerlink Operating Expenditure, 2012/13 – 2016/17



Source: IRP

The Panel's recommendations are estimated to result in savings of a further **$1.4 billion**[76] in indirect costs alone in the DNSPs over the five years from the end of their current regulatory periods.

In summary, the Panel has estimated that there will be savings of at least **$5.0 billion** in the period to 2019/20. This includes: operating efficiencies identified by the Panel and the companies, and reductions in capital due to program of works efficiencies identified by the Panel and the NSPs, as well as the ENCAP Review and changes in market demand.

The Panel expects that, as a result of the implementation of its recommendations and other initiatives currently under way, the **impact on electricity prices from network operations and capital programs will be greatly reduced.**

In the period to 30 June 2015, the Panel expects these reductions will permit a lower rate of increase in this component of household electricity prices (Tariff 11) compared with prices that would have prevailed under the original regulatory determinations.

In the DNSPs' next regulatory period commencing 1 July 2015, the Panel expects that this component of electricity prices will fall by between 1.0 and 1.5 cents per kWh and then stabilise in real terms over the remainder of the next regulatory period. For a household consuming an average 7,934[77] kWh of electricity per annum, this translates to a decline of between $79 and $119 for this component of the annual household electricity bill.

The Panel notes that there are other drivers of electricity price increases such as green schemes, carbon imposts, electricity generation costs and regulatory factors which are unrelated to the capital and operating programs of the NSPs. The Panel is unable to comment on the future impact of these other drivers on household electricity prices.

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[76] This has been calculated as follows. It includes all savings in indirect costs from business efficiency programs, Panel savings and structural synergies, in nominal terms, from 2015/16 to 2019/20. The baseline for this calculation is the DNSPs' May 2012 draft Statements of Corporate Intent.

[77] ACIL Tasman; Electricity Bill Benchmarks for residential customers, Report prepared for the Consumer Information Implementation Committee, December 2011,Table 18.

12. Implementation

The savings and other initiatives identified by the Panel are predicated on an expeditious implementation program. The Panel has identified accountability for implementation of its recommendations either by the NSPs or DEWS.

Subject to the consideration of this report and its recommendations by the IDC and, ultimately, by Government, DEWS should have an over-arching role in developing an implementation plan. This should include an implementation timetable for all recommendations and a comprehensive and transparent reporting process to allow Government to monitor progress with implementation.

Recommendation 44

DEWS develop an implementation plan including a timetable.

Implementation: DEWS

Recommendation 45

The implementation plan developed by DEWS should include a process for reporting to allow Government to monitor progress with implementation.

Implementation: DEWS

Appendix A – Terms of Reference (Panel)

Objective

The objective of the Independent Review Panel on Network Costs is to develop options to address the impact of the development of the electricity network in Queensland on electricity prices.

Context

Consistent with other jurisdictions in the National Electricity Market (NEM), retail electricity prices in Queensland have risen dramatically over recent years. Network costs currently make up around 50 per cent of the price of electricity to residential consumers and have been the main driver of recent price increases.

To address the impact of this on the cost of living, the Queensland Government has put a freeze on the standard domestic electricity tariff (Tariff 11) for 2012-13. Such action can only be a short term measure and other options to address projected future price rises need to be investigated.

Scope

The IRP will be required to provide recommendations on issues relevant to the delivery of Queensland's electricity network. Within this boundary, the IRP will not be limited in scope but must make recommendations on:

- The optimal structures of the Government-Owned Corporation (GOC) distribution network businesses (Energex and Ergon Energy) having regard to reform processes being progressed elsewhere in Australia;
- The efficiency of current network capital and operational expenditure within the GOC network businesses (Powerlink, Energex and Ergon Energy) and innovative options to:
  - address peak demand increases;
  - improve efficiency of capital and operating expenditure;
  - plan for (and respond to changes in) economic growth;
  - co-ordinate electricity network and land-use planning;
  - deliver savings in corporate and overhead costs including IT;
  - reduce the Community Service Obligation payment in support of non-contestable customers;
  - incorporate the value to customers of network security and reliability in network planning and the setting of performance standards; and
  - improve demand forecasting.
- Current and future issues in relation to national regulatory reform for the network businesses, with particular reference to areas that Queensland should influence in order to improve outcomes for network costs.
- A timeframe for potential reductions in network prices.

Operation

The Interdepartmental Committee (IDC) on Electricity Sector Reform (within the Queensland Government) is responsible for setting the Terms of Reference.

The IRP will work independently to provide recommendations to the IDC on issues relevant to the IRP Terms of Reference. The IRP has the authority to undertake consultation on all matters within scope and may undertake periods of public consultation where appropriate.

The IRP is requested to deliver early recommendations on any issues within the scope if this is necessary. All recommendations should be contained in the Final Report.

The IDC may also seek advice from the IRP on issues outside of the scope of the IRP.

The IDC has provided the authority for the IRP to engage expert advice. An initial budget of $1,500,000 has been allocated to the IRP. The procurement aspects of engaging the expert advice will be managed by the Secretariat.

Stakeholder engagement

The IRP will be required to engage directly with a range of industry stakeholders. The following broad stakeholders groups have been identified:

- Government-owned network businesses;
- Trade Unions;
- Industry Peak Bodies; and
- Consumers and Consumer Advocates.

Specific stakeholders within these groups will be identified and contacted by the IDC directly at the time of the public announcement of the IDC and IRP. They will be advised that they may be contacted by the IRP as part of its investigations

It is expected that the IRP will directly engage with these groups and relevant contacts within the groups will be provided to the IRP to facilitate their stakeholder engagement.

Deliverables

1. The IRP will be required to deliver a final report to the IDC on its recommendations and findings by 14 December 2012. An interim report is required by 2 November 2012.
2. The IRP will be required to present its findings and recommendations to the IDC, following delivery of the Final Report.
3. The IRP will undertake public consultation on selected issues within scope.
4. Where relevant the IRP will be responsible for the delivery of work by external consultants.
5. The IRP will provide monthly updates to the IDC.

Membership

The IRP will be comprised of the following members:

- Mr Tony Bellas;
- Mr Alec Faulkner; and
- Mr Matt Rennie.

Governance

The Chair of the IDC will be Mr Tony Bellas.

Secretariat will be provided by the Energy Group of DEWS, with support from Queensland Treasury and Trade.

Timeframes

The IRP will deliver its final report to the Queensland Government by 14 December 2012.

Appendix B – Panel Biographical Information

Tony Bellas (Chair)

Tony Bellas has over 25 years experience in senior management roles in the public and private sectors, including previously being the Chief Executive of Ergon Energy (January 2004 to October 2007) and CS Energy Limited (December 2001 to January 2004) Tony is currently a director of a number of public and private companies including ERM Power Limited and CTM Travel Limited.

Prior to this, Tony held senior positions in Queensland Treasury including the position of Deputy Under Treasurer. In that role, Tony had oversight of a number of related Treasury operations including Fiscal Strategy, Office of Government Owned Corporations and Office of State Revenue. As an Assistant Under Treasurer, Tony was responsible for the Industry and Energy Division and was heavily involved in the formulation of the State Government's Energy Strategy released in May 2000.

Matt Rennie

Matt Rennie is an economist and strategic advisor to the energy and infrastructure sectors across the Asia-Pacific region.

Commencing his career as an economist with Northern Territory Treasury in 1994, Matt entered the electricity industry in 1997 as an investment analyst and pricing manager. Matt advised industry, government and regulatory clients around Australia in private practice until early 2011 when he merged his advisory company into Ernst & Young.

Matt is currently the Oceania Leader of Ernst & Young's Power and Utilities business responsible for strategy, business development and sector performance of the service lines of Advisory, Transactions, Tax and Assurance. He speaks regularly at industry conferences and in panel discussions on energy and regulatory issues.

Alec Faulkner

Alec Faulkner has over 30 years' business consulting experience, spanning asset strategy development, implementation of asset management systems, industrial relations strategy development, productivity improvement projects and business performance reporting and monitoring. Alec is a past chairman of a major international management consulting firm and Chairman of an electricity network Advisory Board in Victoria.

Alec has experience in the electricity generation, transmission and distribution; minerals exploration; mining and minerals processing; steel manufacturing; railways, ports and forestry sectors. He has operated across these sectors in Australia, New Zealand, USA, Italy, UK, PNG, Malaysia and Hong Kong.

Appendix C – IRP Consultation

The Panel would like to thank the following:

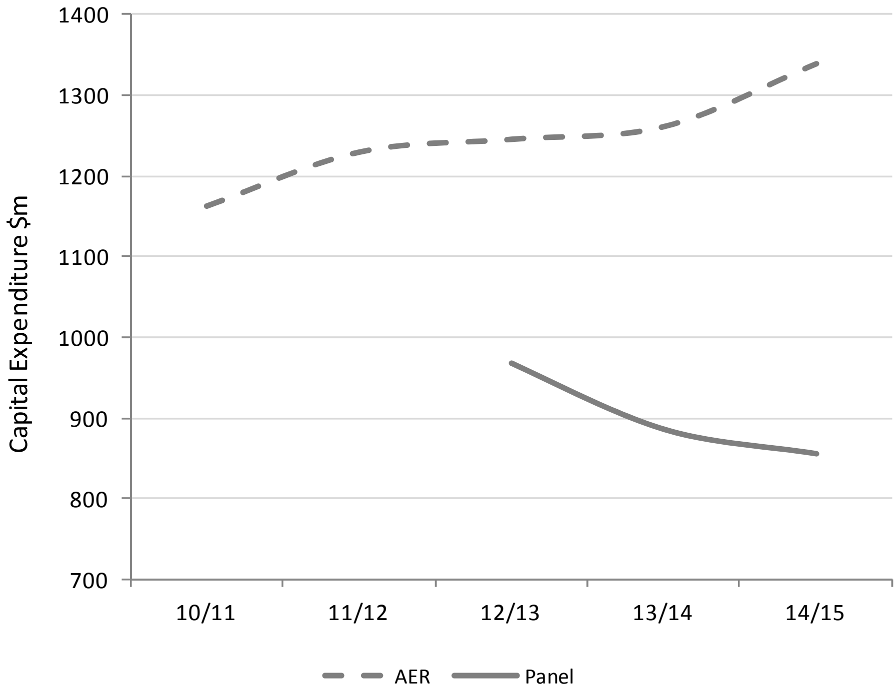
- Energy & Water Ombudsman Queensland
- Queensland Council of Social Service
- St Vincent de Paul
- APA Group
- Australian Energy Market Commission
- Australian Energy Market Operator
- Australian Energy Regulator
- Energy Supply Association of Australia
- Energy Users Association of Australia
- Energy Networks Association
- Grid Australia
- Energy Efficiency Council
- Energy Retailers Association Australia
- SmartGrid Australia
- Urban Land Development Authority
- Chamber of Commerce & Industry Queensland
- Local Government Association Queensland
- Queensland Resources Council
- Electrical Trades Union
- The Services Union
- Townsville Enterprise
- Townsville Chamber of Commerce
- Townsville City Council
- SunMetals
- Hill Michael
- Queensland Nickel
- James Cook University
- Port of Townsville
- Guildford Coal
- Windlab
- Productivity Commission
- Energex
- Ergon Energy
- Powerlink

Technical Reference Groups

- Energex
- Ergon Energy
- Powerlink
- Electrical Trade Union
- The Services Union (QSU)

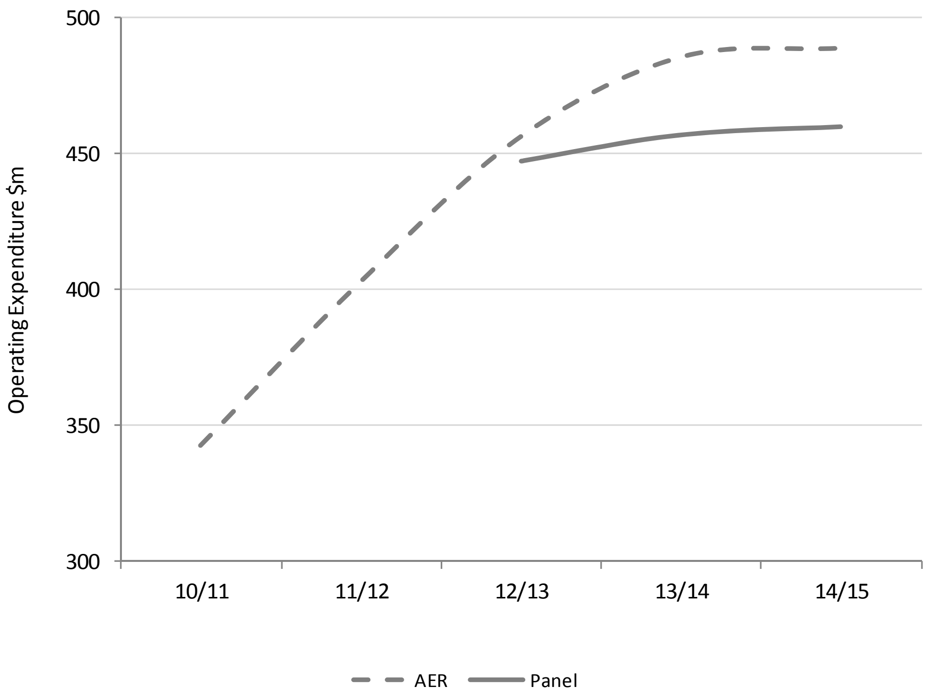
Appendix D – Expenditure Trends of Energex and Ergon Energy

Figure 55. Energex Capital Expenditure, 2010/11 - 2014/15



Source: IRP

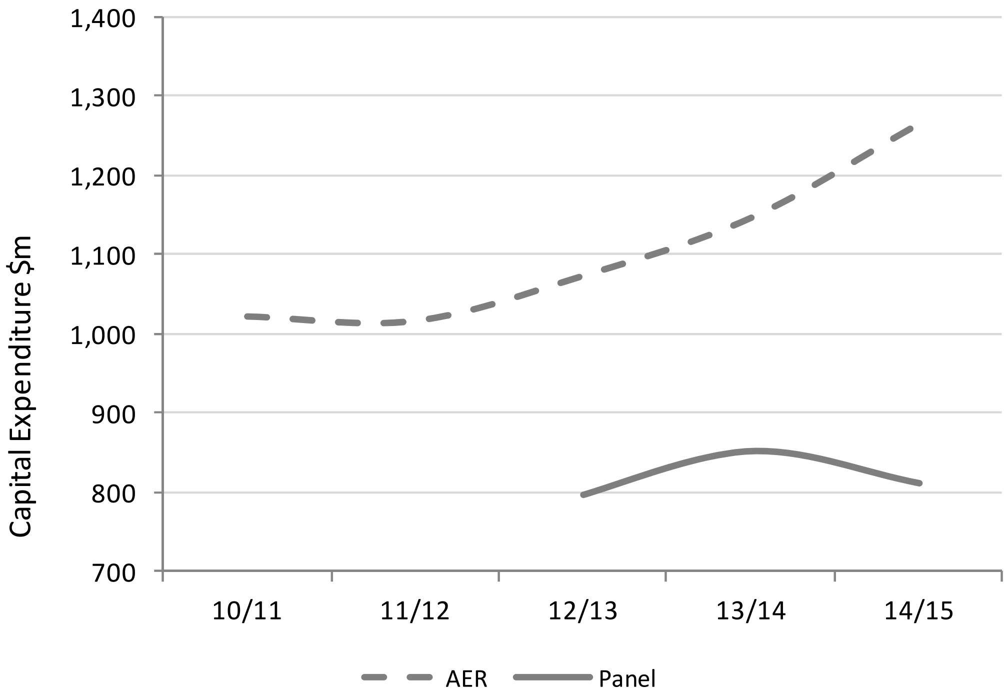
Figure 56. Energex Operating Expenditure, 2010/11 - 2014/15[78]



Source: IRP

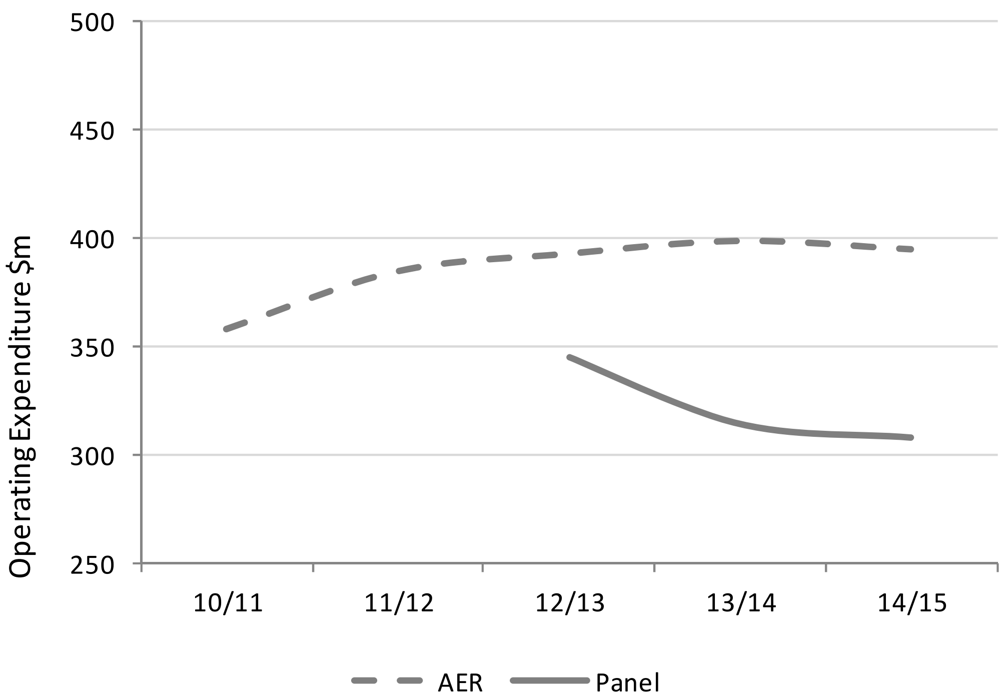
[78]The AER determination has been adjusted for the higher cost of Feed in Tariff (FIT) which had been under estimated at the time of the determination.

Figure 57. Ergon Energy Capital Expenditure, 2010/11 - 2014/15



Source: IRP

Figure 58. Ergon Energy Operating Expenditure, 2010/11 - 2014/15



Source: IRP

Appendix E – Terms of Reference – Technical Reference Group

Purpose and Objective

The purpose of the Technical Reference Group (TRG) is to provide the Independent Review Panel on Network Costs (IRP) with technical expertise and personal experience on:

- Planning, designing, building, operating and maintaining network infrastructure; and
- Resourcing and work practices.

The objective is to achieve coordinated technical input into the Review in a timely and cost-effective manner so that:

- material technical issues are identified and dealt with as the IRP sees fit; and
- the practicality and workability of the recommendations in the final IRP report is enhanced.

Context

Technical working groups have provided invaluable input and support for previous reviews of Queensland's electricity networks. The IRP has asked that the Department of Energy and Water Supply (DEWS) convene a TRG to support its work.

Scope

It is expected that TRG members will provide comment on the practical ("on the ground") issues specifically relating to the IRP's Terms of Reference, and the workability of any suggestions/proposals of the Panel. The Panel will ensure that any advice sought is relevant to the role and function of individual TRG members. Specifically, comments relating to health and safety issues will not be sought as the Panel feels that such matters should be dealt with through the existing Transmission and Distribution Industry Health and Safety Committee. Should such issues arise during the TRG discussions, the Panel may refer them to that committee for consideration.

Governance

Mr Alec Faulkner, a member of the IRP, will act as the Chair of the TRG.

Secretariat will be provided by the DEWS staff supporting the IRP.

Membership

The IRP will establish two TRGs for each distribution business, responding to two separate pieces of IRP work. One TRG comprising both work streams is to be established for Powerlink.

Each TRG will comprise:

- members of the IRP as required;
- 3 representatives from the relevant network business;
- 1 representative from Electrical Trades Union (ETU);
- 1 representative from the Queensland Services Union (QSU); and
- 1 representative from the Association of Professional Engineers, Scientists and Managers Australia (APESMA).

Only nominated representatives will attend meetings of the TRG (or a proxy in the case of unavailability). Invited guests may also attend meetings of the TRG as required by the IRP.

Meeting Schedule

It is expected the TRG will meet during August and September. Further meetings may be held at the discretion of the IRP. The IRP may elect to meet separately with TRG representatives, as considered appropriate to address specific elements of the IRP's and the TRG's Terms of Reference.

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