TRANSEND

Our mission is transmission

Transend Networks Pty Ltd

Transitional Revenue Proposal

Regulatory control period
1 July 2014 – 30 June 2015

Company Information

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Corporate Strategy and Compliance Group,
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Version 1.1 (Amended Appendix 1 – Network
capability incentive action plan incorporated
following receipt of updated AEMO advice)

TRANSEND

Our mission is transmission

Executive summary

Executive summary

Highlights

This proposal supports lower electricity prices for consumers.

In the current regulatory period:

- Our network delivered record amounts of energy.
- We worked hard to find more efficient ways to deliver our services.
- Peak demand forecasts did not eventuate and we responded to the changed circumstances.
- We reduced capital expenditure and reduced our operating expenditure.
- We charged our customers less than the allowed revenue and maintained service levels.

Looking ahead to the next regulatory period:

- Consumers will continue to benefit from the savings made in the current period.
- Capital expenditure is forecast to be nearly 50 per cent less than the current period.
- We will work hard to deliver savings from the merger and make further reductions to operating costs.
- Consumers will benefit immediately—in the first year our revenue will drop.

Transend Networks Pty Ltd owns and operates the electricity transmission network in Tasmania. Our core business is providing safe, reliable and efficient electricity transmission and telecommunication services in a national market.

From 1 July 2014, we will merge with the distribution business of Aurora Energy, creating Tasmanian Networks Pty Ltd (TasNetworks). Consequently, TasNetworks will become the Tasmanian transmission network service provider from 1 July 2014.

While preparing for the merger, we continue to implement our strategy of:

- looking after customers;
- driving down costs; and
- positively influencing the changing industry framework.

In considering our business strategy we regularly engage with our customers and other end-use consumers to understand their needs and issues and to discuss and explain future transmission requirements.

A clear message from our engagement with customers is concern about electricity prices.

In 2012 we made a pragmatic decision not to fully recover our maximum allowed revenue. Under that decision, we will not recover $11 million of allowed revenue in 2012–13 and $26 million in 2013–14. Customers have indicated that they appreciate the efforts we have made to curtail increases in transmission prices, and want us to do more.

In 2014 we must submit two transmission revenue proposals to the Australian Energy Regulator (AER): a transitional Revenue Proposal in January 2014 and a full Revenue Proposal in May 2014.

This document is our transitional Revenue Proposal. It sets out our indicative revenue requirements for a transitional period (from 1 July 2014 to 30 June 2015) and the following four years.

A changed market

We lodged our last revenue proposal in a 'pre-GFC' world: Asian markets were flourishing; commodity prices were booming; the exchange rate supported domestic exports. Electricity networks throughout Australia were embarking on large investment programs to renew aging networks and meet security and reliability standards in an environment of continually rising demand. Peak demand was rising for Tasmanian industrial, business and domestic customers. There was high demand for skilled labour, and plant and equipment prices were rising at rates well in excess of the consumer price index (CPI).

There was uncertainty of policy response regarding managing carbon pollution, and a flourishing renewable energy industry, supported by renewable energy targets. Tasmania had been in drought, with imports from Victoria across the Basslink interconnector supporting Tasmanian energy needs.

In the intervening years, there has been a marked increase in delivered energy prices throughout Australia. Customers have responded with increased energy efficiency measures and a move to distributed generation, with uptake of solar photo-voltaic equipment contributing to a fall in energy delivered through the transmission and distribution networks.

A price on carbon was introduced. A new gas-fired generator and better rainfall in Tasmania contributed to increased Tasmanian water storages, and record levels of energy flows to the Victorian region of the national electricity market as Hydro Tasmania exported carbon-free energy to the rest of the national electricity market.

Across Australia, there has been structural reform to the economy—many traditional industries have closed or moved offshore. In Tasmania, paper mills at Burnie and Wesley Vale closed in 2010. Another of our large customers, TEMCO closed for three months in 2012 before resuming operations. Aurora Energy, the dominant retailer in Tasmania, has seen a continued decline in energy sales compared to forecasts.

Despite that, peak demand on our network has continued to grow in some areas of the state. However, state-wide peak demand for Tasmanian customers has fallen. Transend and Australian Energy Market Operator (AEMO)—the national market operator and national transmission planner—have revised demand forecasts downwards, as have all network businesses in the national electricity market.

We have worked with customers to review investment needs and deferred a number of projects. Projects required to strengthen both reliability and security of supply were efficiently delivered, notably the Waddamana-Lindisfarne 220 kV transmission line into Hobart's eastern shore, and connection of the new St Leonards Substation and connecting transmission corridor in Launceston.

We continued our decade-long renewal program to clear a backlog of critical system assets at the end of their service lives. Investment in optical fibre ground wire along the 220 kV backbone network strengthened the resilience of the network to lightning events, improved communications capability and brought us in line with practice in the rest of the national electricity market.

In addition to critically reviewing capital investment needs, we have worked hard to reduce our operating costs, achieving real cost reductions of 15 per cent since 2007–08. We have been innovative about managing risks to drive expenditure down. Savings have been challenging to achieve and have required a number of difficult decisions, including reductions in the number of staff.

During the current regulatory period our concerted efforts have resulted in actual capital and controllable operating expenditures below the regulatory allowances: compared to the allowance we reduced capital expenditure by about 15 per cent, or $100 million, and operating expenditure by about 13 per cent, or $40 million. We returned some of this benefit to our customers during the period, by not recovering our full revenue entitlement. Customers have therefore funded only the capital expenditure incurred, not the higher allowance. In the next period customers continue to benefit as these savings lead to a lower opening asset base and a lower operating cost base.

Our focus on responding to our market and finding ways to deliver our services at lower cost continues. Our indicative capital expenditure forecast for 2014–19 is $304 million ($ 2013–14) which is a fall of nearly 50 per cent in real terms. Controllable operating expenditures also fall over the next regulatory period—6 per cent ($13 million) in real terms. The expenditure forecasts in this proposal commit us to working hard to find more ways to reduce our costs. We have put forward this very challenging proposal to support a lower delivered cost of energy. Our continued efficiency drive will assist our Tasmanian customers and the broader national electricity market.

Revenue proposal

This document sets out our indicative revenue requirements for a transitional period from 1 July 2014 to 30 June 2015 and the following four years. The transitional regulatory period acts as a placeholder in advance of our full revenue proposal, due in May 2014. The full proposal will address our revenue requirements for the five-year period from 1 July 2014 to 30 June 2019 and will provide detailed supporting information.

Our indicative building block revenue requirements are set out in Table E.1.

Table E.1 Components of the annual building block revenue requirement, 2014–15 to 2018–19 ($m nominal)

Component	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Return on capital	119.4	122.2	126.6	130.6	133.5	**632.4**
Return of capital (regulatory depreciation)	21.8	29.3	33.5	34.5	35.3	**154.5**
Total operating expenditure	47.8	48.3	49.8	51.2	51.9	**249.0**
Efficiency carryover	11.7	9.9	6.4	5.9	0.0	**33.9**
Net tax allowance	9.3	9.9	10.7	10.9	11.6	**52.4**
Annual building block revenue requirement—unsmoothed	**210.0**	**219.7**	**227.0**	**233.1**	**232.4**	**1,122.2**
Annual building block revenue requirement—smoothed	**215.5**	**219.7**	**224.1**	**228.6**	**233.1**	**1,121.0**
X factor	**15.22%**	**0.50%**	**0.50%**	**0.50%**	**0.50%**	

Table E.2 shows the total unsmoothed and smoothed revenue in real 2013–14 terms.

Table E.2 Unsmoothed and smoothed revenue, 2014–15 to 2018–19 ($m 2013–14)

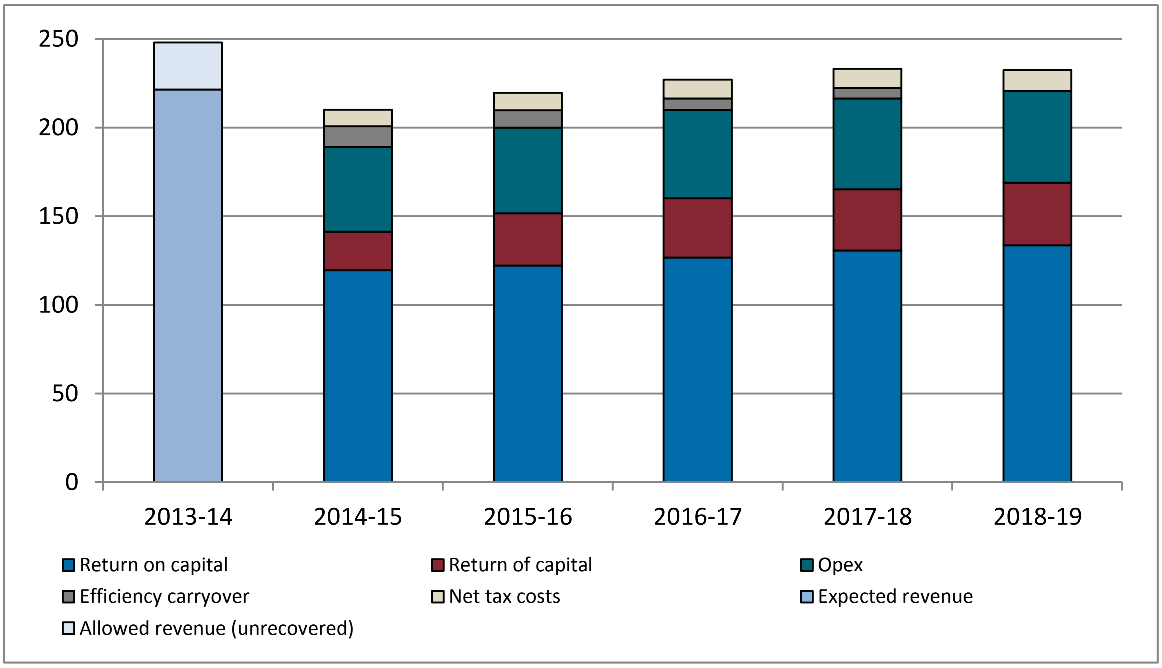
	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Annual building block revenue requirement—unsmoothed	204.9	209.1	210.8	211.2	205.4	1,041.4
Annual building block revenue requirement—smoothed	210.2	209.2	208.1	207.1	206.0	1,040.6
X factor	15.22%	0.50%	0.50%	0.50%	0.50%	

The indicative smoothed revenue requirement for the transitional year (2014–15) represents a reduction of 15.22 per cent in real terms from allowed revenue of $247.9 million in 2013–14. Further reductions in revenue of 0.5 per cent in real terms are forecast for each subsequent year of the next regulatory period.

As noted previously we decided to recover $26 million less than our allowed revenue in 2013–14. Therefore, the indicative smoothed revenue in 2014–15 is 5.1 per cent lower in real terms than the expected revenue[1] to be recovered in 2013–14.

Figure E.1 provides a further presentation of the annual building block revenue requirements.

Figure E.1 Annual building block revenue requirements ($m nominal)



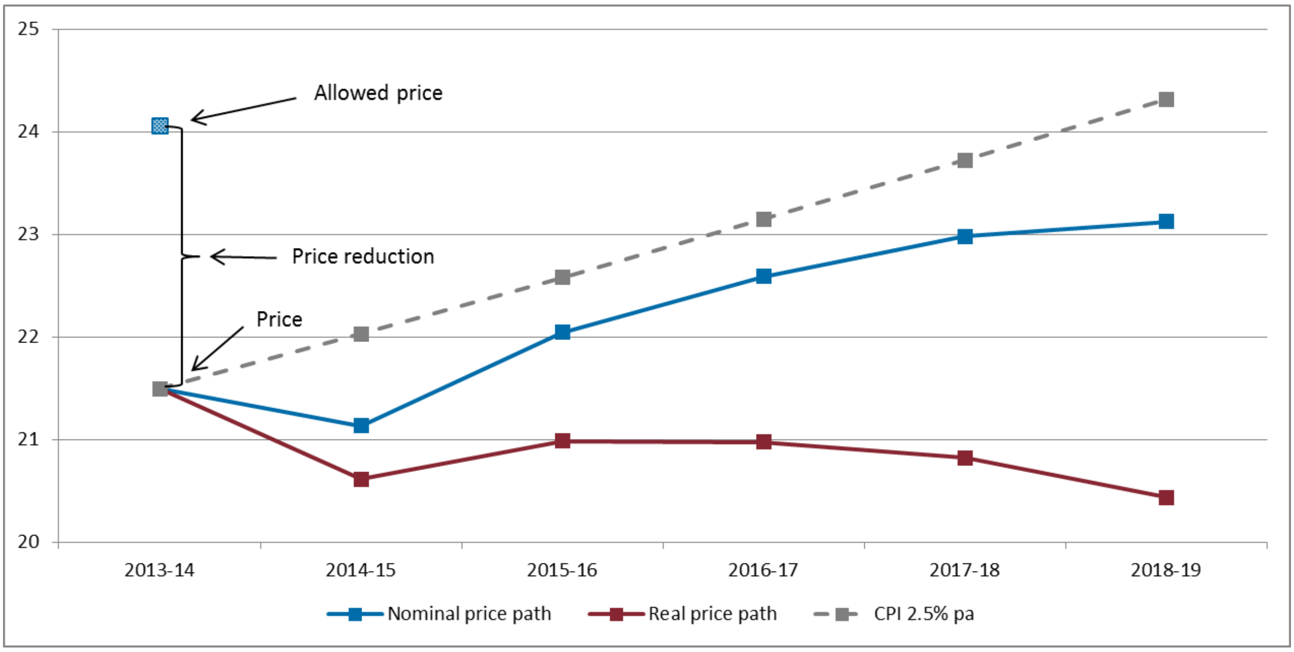
Prices for customers depend on total revenues and future energy and demand. Table E.3 and Figure E.2 show the proposed average price path per megawatt hour (MWh) of energy delivered in Tasmania over the next five years. This is compared with our revenue entitlement and expected revenue for the 2013–14 year.

Table E.3 Average price impact of revenue proposal

		2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Nominal revenue ($m)	2013–14 Allowed revenue	247.9	215.5	219.7	224.1	228.6	233.1
	2013–14 Expected revenue	221.5					
Real revenue ($m) ($2013–14)	2013–14 Allowed revenue	247.9	210.2	209.2	208.1	207.1	206.0
	2013–14 Expected revenue	221.5					
Load forecast[2]	MWh ('000)	10,305	10,196	9,967	9,922	9,946	10,081
Nominal price ($/MWh)	2013–14 Allowed revenue	24.06	21.13	22.05	22.59	22.98	23.12
	2013–14 Expected revenue	21.49					
Real price ($/MWh) ($2013–14)	2013–14 Allowed revenue	24.06	20.62	20.98	20.97	20.82	20.44
	2013–14 Expected revenue	21.49					

[1] Expected revenue is prescribed revenue used to set prices for 2013–14.
[2] The load forecast is based on AEMO's medium forecast contained in its 2013 National Electricity Forecasting Report, less estimated average annual transmission system losses of 2.54 per cent per annum.

Figure E.2 Average price impact of revenue proposal ($/MWh)



Noting that, in constant dollars, our asset base is reducing and our operating and capital costs are falling, the biggest uncertainty in future revenue requirements is the cost of capital. It depends on financial markets and benchmark rates of return. Also, the AER will update the cost of debt component of the weighted average cost of capital, and consequently the maximum allowed revenue, annually throughout the next regulatory period.

In section 8.1 we provide a range of possible maximum allowed revenue outcomes, based on different cost of capital scenarios. The revenue projections are based on our best present estimate of the cost of capital that falls within this upper and lower range.

Conclusions

This proposal demonstrates that Transend is responding to customer and consumer feedback by balancing the need for reliable and secure provision of essential infrastructure with a continued focus on cost control.

In the current regulatory period we have:

- improved operating practices and implemented effective cost controls;
- prudently allocated capital to fund required investments;
- been innovative about managing risk to reduce expenditure;
- delivered record levels of energy; and
- delivered required services for less than the operating and capital expenditure allowances.

We have acted in the interests of our customers by under-recovering maximum allowed revenue. We continue to act in the long-term interests of our customers. In the next regulatory period we will maintain service levels while delivering:

- a significantly lower capital investment program;
- further reductions in real operating costs;
- capital and operating cost savings that require us to drive our business even harder; and
- real decreases in revenues.

Achieving the proposed cost savings will be difficult—even allowing for savings arising from the merger of Transend and Aurora Energy's distribution business. We have put forward challenging expenditure targets because we understand that Tasmanian customers are also facing a number of economic challenges: our business sustainability is linked to the sustainability of our customer base.

Our proposal puts further downward pressure on prices for all electricity consumers. Reducing expenditure levels any further would allocate too much risk to our customers, in particular risk to service levels. Reductions would also compromise our ability to provide appropriate returns to the people of Tasmania, the ultimate owners of our business. We are confident the proposal strikes the right balance for Tasmania's future.

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Our mission is transmission

1 Introduction

1 Introduction

Under the National Electricity Law (NEL) and National Electricity Rules (the Rules), the Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission services provided by transmission network service providers (TNSPs) in the national electricity market (NEM).

Recent changes to Chapter 6A of the Rules mean that we are required to submit a transitional Revenue Proposal to the AER by 31 January 2014 as a 'placeholder' to cover the one-year period commencing on 1 July 2014. As a placeholder, the scope of the transitional proposal and the AER's review is much more limited than would ordinarily be the case.

This submission is our transitional Revenue Proposal.

In considering this proposal, the Rules require that the AER must have regard (amongst other things) to the fact that:

- the revenue requirement for the transitional regulatory control period is an estimate based on indicative inputs; and
- the determination for the subsequent regulatory control period will provide for a true-up.

From 1 July 2014 Transend will merge with the distribution business of Aurora Energy Pty Ltd creating Tasmanian Networks Pty Ltd (TasNetworks). For the purpose of this transitional Revenue Proposal, any reference to Transend should be taken to be TasNetworks' transmission business from that date.

1.1 Customer and consumer engagement

In recent years we have made a concerted effort to strengthen our relationship with customers and to better take account of their business drivers in our decision making. We have designated account managers for each of our connected customers, including the Tasmanian electricity distributor (Aurora Energy). We have an ongoing dialogue with these customers about operational matters such as planned outages and strategic issues, including this revenue proposal.

In preparing for the transitional revenue proposal, we met with each of our connected load, network, and generation customers to explain the revenue regulation process; outline our indicative expenditure forecasts and resulting revenue for the 2014–19 period; and discuss customer specific issues and potential solutions.

We have consulted with directly impacted customers for each of the transmission network issues potentially requiring network development project solutions. In some cases, network investment has been deferred or avoided because customers have accepted the present level of service. In other cases, affected customers have actively supported strengthening the network to improve their level of service.

Our customer engagement efforts are paying off not only in objective measures such as reliability and availability, but also in subjective matters such as customer satisfaction. In the most recent survey, our customers noted improvements in the way we communicate with them and in understanding their needs. Of course, they also provided feedback about the areas where we could improve further.

We are building on our customer engagement experience to develop a similar program for end-use consumers not directly connected to the transmission network. In preparing this transitional proposal, we consulted not only with customers but with other consumers and their representatives. Developing a dialogue with consumers is helping us to better understand their priorities and gives them opportunities to influence our strategic direction. The objective is to ensure transmission services align with consumers' long-term interests.

A clear message from our customer and consumer engagement is concern about electricity prices. Customers have indicated that they appreciate the efforts we have made to curtail increases in transmission prices, and want us to do more. This proposal responds to this feedback by balancing the need for reliable and secure provision of essential infrastructure with a continued focus on cost control. The result is a proposal with no real increase in costs or revenues. This will be very challenging to achieve—even with efficiencies from a network merger—however it helps to put downward pressure on prices for all electricity consumers.

1.2 Structure of this proposal

This proposal is structured as follows:

- Chapter 2 outlines our business and operating environment. It highlights a number of the important industry and regulatory developments that will affect our future operations and expenditure requirements.
- Chapters 3 and 4 present our indicative capital and operating expenditure proposals, respectively.
- Chapter 5 presents the indicative regulated asset base for the forthcoming regulatory period.
- Chapter 6 presents our indicative range for the weighted average cost of capital and regulatory tax allowance.
- Chapter 7 presents our indicative depreciation allowance.
- Chapter 8 presents our indicative total revenue requirement for the transitional regulatory period and the resulting average price path.
- Chapter 9 outlines the proposed cost pass through arrangements to apply during the transitional regulatory period.
- Chapter 10 presents details of the operation of incentive schemes.

All operating expenditure and capital expenditure amounts in this proposal relate to expenditure for provision of prescribed transmission services. 'Actual' operating and capital expenditure amounts include our estimate for 2013–14. The operating and capital expenditure forecasts include only operating and capital expenditure that has been properly allocated to prescribed transmission services in accordance with the principles and policies set out in our cost allocation methodology as approved by the AER.

All monetary values presented in this proposal exclude GST, and numbers and tables throughout the proposal may not add up due to rounding.

We do not claim confidentiality in relation to any part of this transitional Revenue Proposal.

TRANSEND

Our mission is transmission

2 Business and operating environment

2 Business and operating environment

2.1 About Transend Networks

Transend Networks (Transend) is the transmission network service provider (TNSP) in the Tasmanian region of the national electricity market (NEM). We own, operate, maintain and manage Tasmania's high-voltage 220 kilovolt (kV) and 110 kV transmission network and lower-voltage 44, 33, 22, 11 and 6.6 kV connection assets that together form the transmission system. Our transmission system enables safe and reliable transfer of electrical power from generation sources to load connection points and the Basslink undersea transmission network interconnector.

Electrical energy is supplied by power stations connected to our transmission network, embedded generators connected to Aurora Energy's distribution network and generation imports from other NEM states across Basslink. Our transmission network delivers energy to Aurora Energy's distribution network and to directly-connected industrial customers. Basslink is also a load point on the Tasmanian transmission system when exporting energy to Victoria.

Transend Networks Pty Ltd is a private company incorporated and operated in Australia. Transend is owned by two shareholder ministers who hold shares on behalf of the State of Tasmania. Transend is governed by a board of non-executive directors and managed by an executive management team.

As noted in Chapter 1, from 1 July 2014 Transend will merge with the distribution business of Aurora Energy, creating TasNetworks.

2.1.1 Vision, mission and values

Our vision is to be a leader in developing and maintaining sustainable networks. Our mission is transmission: safe, reliable and efficient electricity and telecommunications services.

We have firmly established values and behaviours that underpin the way we do business. Our values of integrity, professionalism, excellence, teamwork and support help us to provide a constructive work environment; provide valued services to our customers and consumers; and deliver appropriate returns to our shareholders.

2.1.2 Business strategy

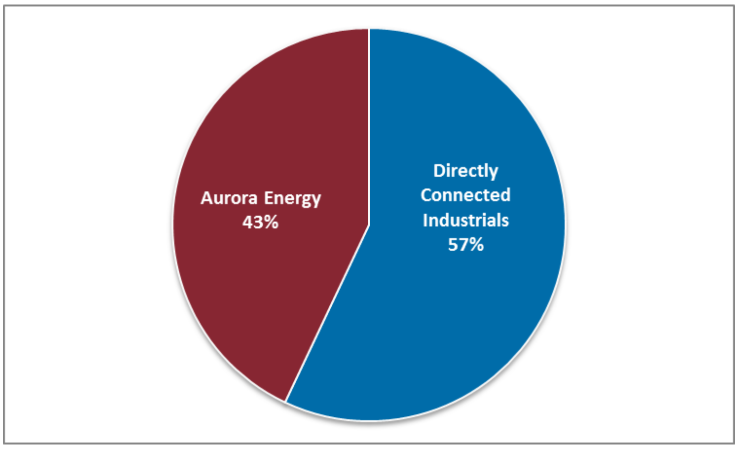
We have a clear focus on customer service, transmission system performance, and efficient delivery of our capital and operating works programs. To ensure that we continue to provide valued services to customers and appropriate returns to shareholders our strategy is to:

- look after our customers;
- drive down costs;
- prepare for network merger; and
- positively influence the changing industry framework.

2.1.3 Customers

We have a relatively small number of customers. Industrial customers directly-connected to the Tasmanian transmission network consume a greater proportion of load than those in other Australian states. Around 57 per cent of electricity transmitted is delivered to these customers, with the majority of that being delivered to the four largest energy users, as shown in Figure 2.1

Figure 2.1 Electricity delivered to Tasmanian load by customer class 2012–13



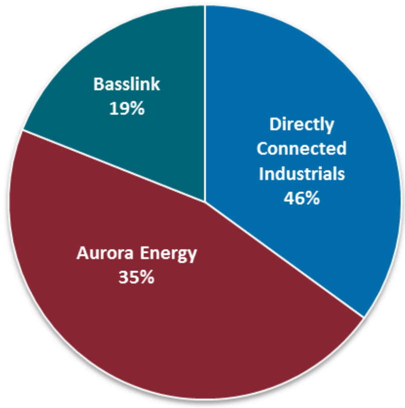
Our customers operate across a range of business sectors. They have a diverse range of operational requirements that affect their demands on the transmission system and how we interact with them in terms of managing outages and emergency response. Our current customers are identified in Table 2.1. Some of these customers have connections to our network at a number of locations.

Table 2.1 Transend's customers

Customer	Description
Directly connected customers	
Bell Bay Aluminium (under a connection agreement with retailer, Aurora Energy)	aluminium smelter
Copper Mines of Tasmania	underground mine and primary ore processing plant
Forestry Tasmania	connection to a timber processing and veneer plant
Grange Resources Tasmania	open cut mine at Savage River and iron ore pelletizing plant at Port Latta
Gunns (liquidator appointed)	woodchip mill
Hellyer Mill Operations (owned by Ivy Resources)	underground mine and primary ore processing plant
Norske Skog	pulp and newsprint mill
Nyrstar	zinc smelter
MM Group Rosebery	underground mine and primary ore processing plant
TEMCO	smelting furnaces and sinter plant producing high-carbon ferromanganese and silicomanganese for steelmaking
Timberlink	timber sawmill and processing plant
Generation connection customers	
Hydro Tasmania	renewable energy generator – total installed capacity of 2,270 MW provided by 29 hydro power stations, of which 2,255 MW is provided by 25 power stations connected to Transend's network
Musselroe Wind Farm	total installed capacity of 168 MW
Tamar Valley Power Station	total installed capacity of 383 MW provided by 178 MW open cycle gas turbine peaking plant and a base load plant of one 205 MW closed cycle gas turbine
Woolnorth Bluff Point Wind Farm	total installed capacity of 65 MW
Woolnorth Studland Bay Wind Farm	total installed capacity of 75 MW
Network connection customers	
Aurora Energy	Tasmanian electricity distributor
Basslink	Market network service provider with converter stations in Victoria and Tasmania and 400 kV undersea direct current (DC) cable

Figure 2.2 shows the breakdown of electricity delivered via the Tasmanian transmission system to customers in Tasmania and the rest of the NEM via Basslink.

Figure 2.2 Electricity delivered to load by customer class 2012–13



From July 2015, Victorian electricity consumers will also pay for use of the Tasmanian transmission network as a result of the new inter-regional transmission charging regime[3]. This will increase the volatility of Tasmanian transmission prices and is discussed further in section 2.5.4.

2.1.4 Electricity consumers

Apart from our directly connected load customers, most of Tasmania's electricity consumers are supplied via Aurora Energy's distribution network. Table 2.2 provides a breakdown of distribution customers.

Table 2.2 Aurora Energy distribution customers (installations)

Type	Number	Percentage
Business – large (>150 MWh pa)	2,532	0.9%
Business – medium (50 to 150 MWh pa)	4,133	1.5%
Business – small (<50 MWh pa)	36,339	13.1%
Residential	234,498	84.5%
Total	**277,502**	**100.0%**

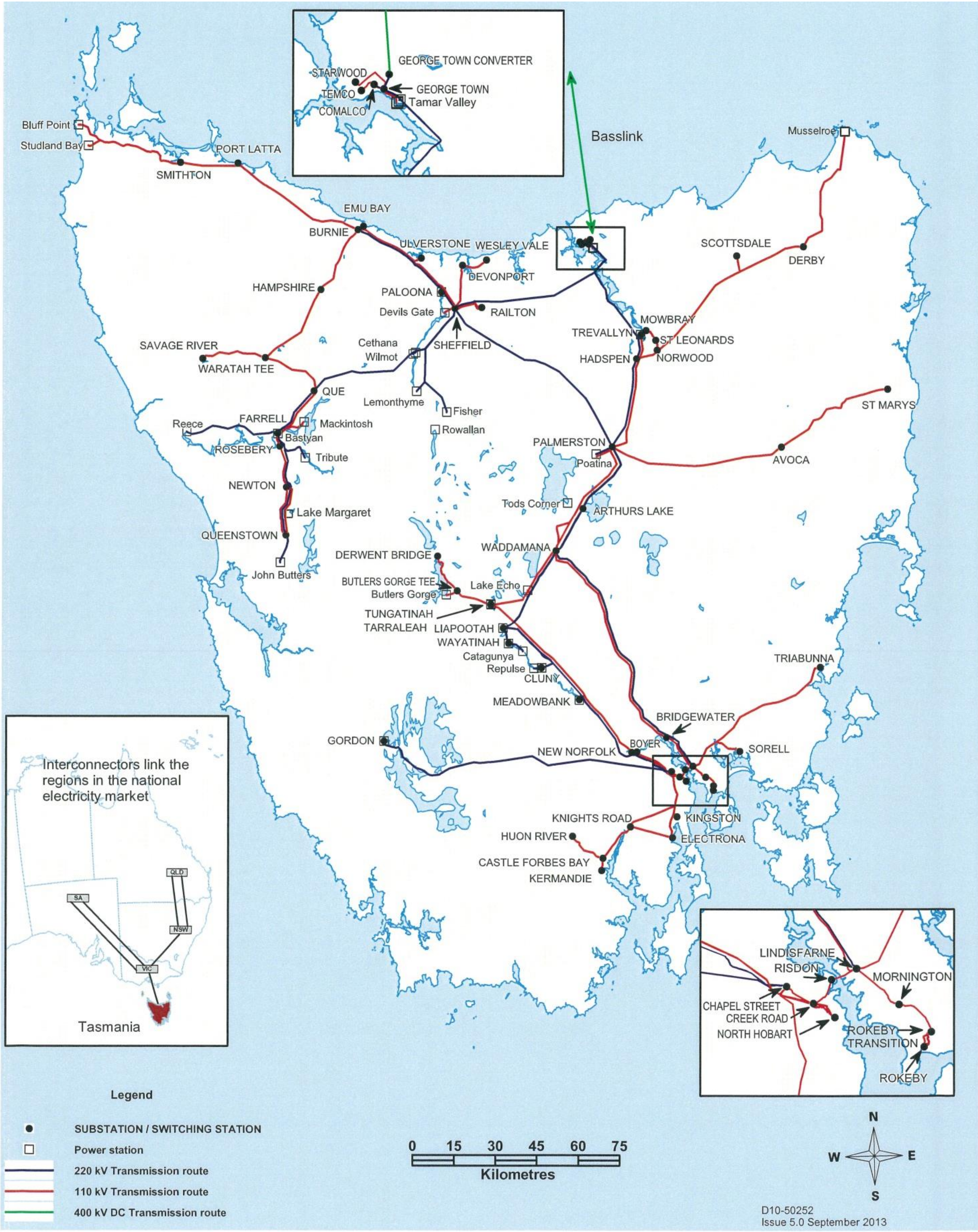
2.2 Tasmanian transmission system

The Tasmanian electricity transmission system is characterised by a backbone network predominantly operating at 220 kV that links the main generators to major load centres, including major industrial customers. A transmission network predominantly operating at 110 kV connects other generators and regional load centres.

Load is concentrated in the north and south-east of the state. Main load centres are connected to the 220 kV transmission network at Burnie, Chapel Street (Hobart), George Town, Hadspen (Launceston and north-east) and Sheffield. Other load centres are connected via the 110 kV peripheral transmission network. Figure 2.3 presents a map of the 2013 Tasmanian electricity transmission system.

[3] Tasmanian consumers will also pay for use of the Victorian transmission network.

Figure 2.3 Tasmanian transmission system 2013



Tasmania's transmission system was predominantly developed to connect remotely located hydro based generators to a range of dispersed load centres. The economics of providing transmission infrastructure between relatively small, geographically dispersed generators and relatively small load centres, has meant that large parts of the north-west, north-east, south-east and southern central (New Norfolk), areas of Tasmania are not strongly linked to the backbone transmission network.

Unlike most other Australian transmission businesses, our transmission system includes a large proportion of connection assets operating at voltages of 44, 33, 22, 11 and 6.6 kV. Substations operating at these sub-transmission voltages connect the transmission system to the distribution system and directly connected load and generation. In total, there are 566 circuit breaker bays that are owned and operated by Transend at these lower voltage levels. Such lower voltage assets are typically characterised by higher operating costs relative to their asset value.

Our prescribed transmission system is also characterised by a high proportion of substations and lines connecting directly-connected industrial customers and radially-connected generators. These assets also attract higher operating costs relative to their asset value, compared to shared network assets. Such assets would normally be funded outside the revenue cap as negotiated or unregulated services, but are presently 'grandfathered' as prescribed services under the Rules.

Many of our assets are in remote, mountainous terrain which contributes to increased construction, maintenance and operational response costs. Construction costs in Tasmania are also affected by the cost of transporting equipment to Tasmania, a smaller market for design, construction and maintenance services, and some reliance on Australian mainland companies to undertake specialised services.

Table 2.3 lists the main components of our transmission system.

Table 2.3 Transend's transmission system

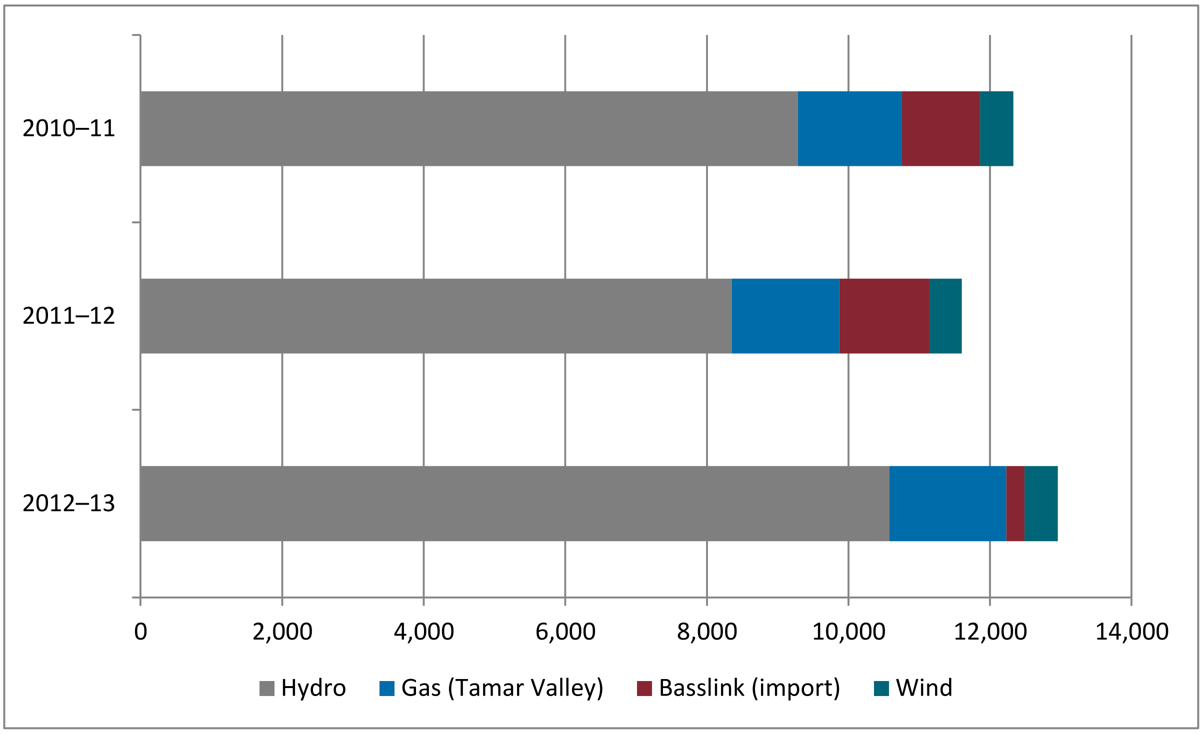
Assets	Quantity
Number of substations	49
Number of switching stations	7
Number of transition stations	2
Number of transmission line support structures	7,852
Circuit kilometres of transmission lines	3,516
Route kilometres of transmission lines	2,344
Easement area (hectares)	11,176
Communications repeater sites	37

As noted, our transmission system has been shaped by the nature of Tasmania's generation system. The supply of electrical energy in Tasmania is dominated by Hydro Tasmania's hydro-electric generators. These generators are usually constrained by energy availability rather than generating plant capacity: their ability to meet energy needs is predominantly a function of water availability.

There is, however, increased diversity on the supply side as other sources of generation are able to make significant contributions to meeting the total demand, in particular imports via Basslink and output from gas-fired and wind generation.

Figure 2.4 shows gigawatt hours (GWh) of energy transmitted by generation source for the last three years.

Figure 2.4 Energy transmitted by generation source - 2010–11 to 2012–13 (GWh)



In June 2013, ownership of the Tamar Valley power station was transferred to Hydro Tasmania. Since then, Hydro Tasmania has changed the station's operating regime, and it is not presently operating as a base load power station.

2.3 Recent market conditions

Transend lodged its last revenue proposal in a 'pre-GFC' world: Asian markets were flourishing; commodity prices were booming; and the exchange rate supported domestic exports. Electricity networks throughout Australia were embarking on very large investment programs to renew aging networks and meet security and reliability standards in an environment of continually rising demand. Peak demand was rising for Tasmanian industrial, business and domestic customers. There was high demand for skilled labour, and plant and equipment prices were rising at rates well in excess of the consumer price index (CPI).

There was uncertainty of policy response regarding managing carbon pollution, and a flourishing renewable energy industry, supported by renewable energy targets. Tasmania had been in drought, with imports from Victoria across the Basslink interconnector supporting Tasmanian energy needs.

In the intervening years, there has been a marked increase in delivered energy prices throughout Australia. Customers have responded with increased energy efficiency measures and a move to distributed generation, with uptake of solar photo-voltaic (PV) equipment contributing to a fall in energy delivered through the transmission and distribution networks.

A price on carbon was introduced. A new gas-fired generator and better rainfall in Tasmania contributed to increased Tasmanian water storages, and record levels of energy flows to the Victorian region of the NEM as Hydro Tasmania exported carbon-free energy to the rest of the national electricity market.

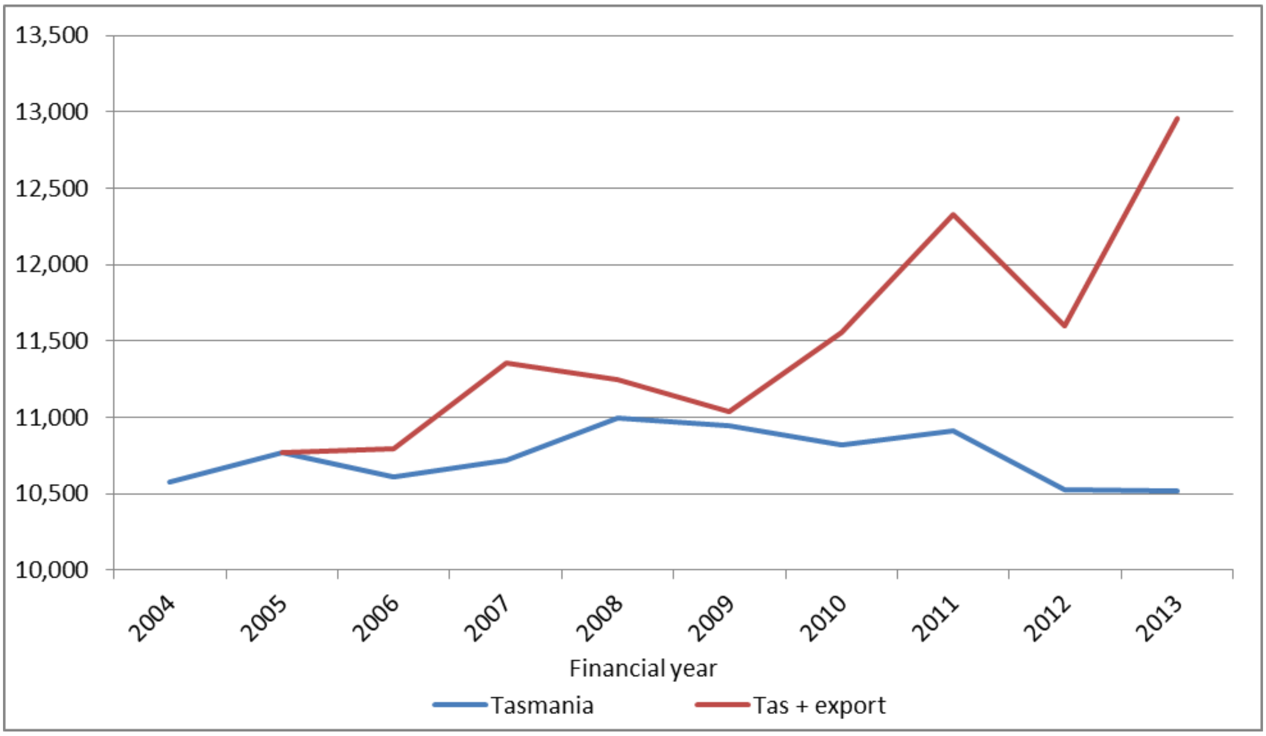
Across Australia there has been structural reform to the economy—many traditional industries have closed or moved offshore. In Tasmania, paper mills at Burnie and Wesley Vale closed in 2010. Another of our large customers, TEMCO closed for three months in 2012 before resuming operations. Aurora Energy, the dominant retailer in Tasmania has seen a continued decline in energy sales compared to forecasts.

Despite that, peak demand on our network has continued to grow in some areas of the state. However, state-wide peak demand for Tasmanian customers has fallen. Transend and AEMO—the national market operator and national transmission planner—have revised demand forecasts downwards, as have all network businesses in the national electricity market.

Many of our customers continue to face challenging market conditions and the outlook for the electricity supply industry has changed. In the past, electricity suppliers could confidently predict steady increases in consumption as consumers added more appliances and industries demanded more energy. For various reasons, including the uptake of solar PV generation, higher prices and increased energy efficiency, electricity consumption in Tasmania and elsewhere in the NEM is also lower than previously forecast.

Figure 2.5 presents annual data on total energy transmitted in Tasmania over the past 10 years. Sales peaked in 2008 at almost 11,000 GWh and have been trending down since then. Despite the fall in local sales, the total amount of energy transmitted by us has increased, reflecting the network's role in exporting electricity to the rest of the NEM.

Figure 2.5 Energy transmitted (GWh)



As well as looking at projections of energy consumption, we consider growth in peak demand around the state. This reflects that our network provides capacity to move energy between various generation and load sources, with transmission networks generally sized to meet peak demand.

Transmission assets are expensive and subject to economies of scale: often for a relatively small incremental cost, larger capacity can be delivered. For assets with average lives exceeding 45 years, when making investments it may be cost-effective to build extra capacity to meet forecast demand. We therefore look at peak demand for each area of the state and each connection point to help us identify whether our network has sufficient capacity to meet demand into the future and securely supply our customers. Looking at future demand also helps us consider whether there are investments that will deliver net market benefits[4].

To produce forecasts for electricity consumption and demand in Tasmania, we are working with AEMO, which is increasing its load forecasting capability across the NEM. We also engage National Institute of Economic and Industry Research and seek information on electricity demand from Aurora Energy and our customers to prepare demand forecasts for each area of the state.

[4] In accordance with the regulatory investment test set out in the Rules.

We have considered the impact that different demand forecasts have on future investment needs. Our sensitivity analysis shows that there is very little difference in augmentation needs between our 2013 medium and low forecasts[5]. Our high load forecast, however, requires a material increase in investment.

Given the uncertain economic outlook in Tasmania, and our continuing work with AEMO, our transitional Revenue Proposal is based on the low demand forecast scenario. Our development program considers the low maximum demand forecast in each area of the state, together with local connection information.

Between our transitional Revenue Proposal and full Revenue Proposal we will continue to work with existing and prospective customers and AEMO to consider the latest state and connection point demand forecasts. As required, we will adjust the indicative capital forecast contained in this proposal to reflect new information.

2.4 Compliance obligations

Compliance with regulatory obligations is an important driver of our expenditure requirements. In particular, we are subject to a wide range of general legislation and regulations, as well as industry-specific instruments that affect expenditure requirements. For example:

- general obligations arise from Corporations Law and other corporate governance obligations including the *Work Health and Safety Act 2012* and Workcover obligations;
- specific obligations arise from the National Electricity Law, the Rules, related regulations, and guidelines issued by the AER and AEMO;
- specific jurisdictional obligations arise from the *Electricity Supply Industry Act 1995* (ESI Act) and other Tasmanian electricity industry specific acts and regulations including the *Electricity Companies Act 1997*, the *Energy Ombudsman Act 1998*, the *Electricity Wayleaves and Easements Act 2000*, the *Electricity Industry Safety and Administration Act 1997* and the Tasmanian Electricity Code (TEC);
- obligations arise under the System Operator Deed with AEMO, which requires us to undertake certain of AEMO's functions and recover the cost from prescribed customers; and
- specific obligations arise from our transmission licence, which is issued by the Tasmanian Economic Regulator.

The Tasmanian Economic Regulator licences Transend, under section 19 of the ESI Act, to operate as a TNSP in Tasmania[6]. The transmission licence requires Transend to fulfil a number of obligations including:

- preparing plans for asset management (including reliability and performance of the transmission system), vegetation management and emergency management;
- planning, proposing and procuring augmentations required to meet Transend's service obligations, including obligations imposed by network planning requirements;
- publishing the Tasmanian Annual Planning Statement (in addition to the Rules requirement for an annual planning report); and
- retaining the capability to manage power system security for the entire Tasmanian power system[7].

2.5 Industry and regulatory development

Transend and our customers face some important industry and regulatory changes over the forthcoming regulatory period. While a number of these developments will not directly affect our revenue in the transitional regulatory period, they may have longer term operational and pricing implications. In this section, we highlight the following developments:

- Transend's merger with Aurora Energy's distribution business;

[5] As outlined in our 2013 Annual Planning Report.

[6] A copy of Transend's transmission licence can be obtained from the website of the Office of the Tasmanian Economic Regulator, at http://www.economicregulator.tas.gov.au/.

[7] This licence condition is established under the ESI Act.

- 'Better Regulation' Rule changes which have introduced new provisions and obligations;
- The Australian Energy Market Commission's (AEMC) Transmission Frameworks Review;
- Inter-regional transmission charges; and
- Tasmanian reliability standards.

Each of these important developments is discussed in turn below.

2.5.1 Merger with Aurora Energy's distribution business

In 2010, the Tasmanian Parliament established an independent Expert Panel to undertake a detailed review of the electricity industry in Tasmania and make recommendations to guide and inform a Tasmanian Energy Strategy. As part of the government response to the Panel's review, Transend will merge with Aurora Energy's distribution business (including the distribution and telecommunications functions) from 1 July 2014.

The government intends the merger to promote the achievement of the following industry objectives:

- lowest sustainable electricity bills (when linked through the regulatory allowance);
- long-term safe, secure and reliable supplies of electricity; and
- financially viable state-owned electricity businesses that run efficiently and effectively and maximise the overall economic benefit to Tasmania.

The government notes that benefits from merging the two businesses could arise through:

- improved operational efficiencies and reductions in overlapping corporate functions;
- dynamic efficiency gains through improved decision making and planning; and
- stronger strategic and cultural alignment.

Transend and Aurora Energy have already been collaborating in various areas of operations, which has provided opportunities to reduce duplication between the two businesses. Full network integration is the next step to capture the remaining benefits of merging the two networks.

A key aim is to create a single business that operates a single network in terms of planning, capital investment, operations and maintenance, while recognising the distinct transmission and distribution responsibilities under the Rules.

Our future revenue requirements recognise the scope for efficiency improvements as a result of the merger.

2.5.2 'Better Regulation' Rule changes and AER guidelines

New Rules require the AER to identify how it proposes to exercise its discretion through a series of guidelines, covering the following matters:

- determining the allowed rate of return on capital;
- how expenditure forecasts contained in revenue proposals will be assessed;
- the development and application of expenditure incentives;
- the treatment of shared assets (those providing partly-regulated and partly-unregulated services);
- assessment of confidentiality claims by the network businesses;
- how network businesses demonstrate effective consumer engagement; and
- implementation of the AEMC's Power of Choice final report recommendations including changes to existing incentive schemes, possible changes to pricing principles and the potential for introducing pricing guidelines.

The new guideline requirements, regulatory information notices and regulatory information orders have significantly increased the obligations on us to compile and provide detailed audited data and information well in excess of business operational needs, for both ongoing reporting and as part of a revenue proposal. This will apply to the information required for the full Revenue Proposal to be submitted in May 2014.

In relation to consumer engagement, as previously noted, we are already consulting with our customers and other consumers, and responding to the commercial pressures they face. As part of TasNetworks, we will continue to work with electricity consumers and improve engagement.

2.5.3 Transmission frameworks review

The AEMC's transmission frameworks review may affect our future operating environment. The focus of the review has been on the interface between transmission and generation including how generators access the wholesale market; the way network congestion is managed; transmission charging arrangements for generators; and how the network is planned.

The AEMC is recommending both short-term reforms to facilitate more efficient connections between generators and transmission networks, and further development of a longer-term optional firm access model for generators.

As the nature and detail of changes are not yet known, no impacts from the AEMC's transmission frameworks review are factored in to this transitional Revenue Proposal.

2.5.4 Inter-regional transmission charging

The AEMC has made a Rule change to introduce inter-regional transmission charging from 1 July 2015.

The new arrangements will better reflect the benefits provided by transmission networks in supporting energy flows between regions. The introduction of an inter-regional charge will not affect the total revenues earned by each transmission network service provider, only how those revenues are recovered from customers. If, in the future, the Tasmanian region is a net exporter of energy then it is expected that some transmission charges would be recovered from the Victorian region.

Although this change will not affect our revenue allowance, it has the potential to affect charges to our customers depending on whether the Tasmanian region is a net importer or exporter of energy. While Tasmania is expected to be a net beneficiary, inter-regional charging will increase volatility in transmission prices for Tasmanian customers.

2.5.5 Reliability standards

We supported a recent review of the regulations that define network planning requirements in Tasmania, the Electricity Supply Industry (Network Planning Requirements) Regulations 2007. The new regulations preserve existing network planning reliability standards and give opportunities for customers to explicitly accept lower standards where all affected customers agree. This transitional Revenue Proposal is based on application of the new Tasmanian regulations.

The transmission reliability standards that apply in Tasmania may be affected by the AEMC's review of the national framework for transmission reliability standards.

Transmission networks are designed to meet a range of network security requirements to keep the bulk-power system stable with sufficient power transfer capability, and free from overloads, high and low voltages, cascading outages and system separations. In its review of reliability standards, the AEMC has presumed such factors related to the integrity of the operation of the electricity system will continue to be managed in accordance with schedule 5 of the Rules. Schedule 5 sets out a range of requirements we must meet relating to frequency, system stability, power transfer capability, voltage, credible contingency events, load shedding, protection systems and fault clearance times. In preparing this transitional Revenue Proposal we also assume these obligations remain.

However the AEMC's recommended framework sets out a new approach to regulating reliability at connection points, with the following key features:

- an economic assessment process to inform the setting of transmission reliability standards. This will involve assessing the expected costs of investments against expected reliability outcomes;
- the expression of transmission reliability standards in terms of network redundancy and requirements relating to when supply would need to be restored following an outage;
- the flexibility for the standard setter to include additional reliability measures to make reliability standards more consistent with customer preferences;
- jurisdictional responsibility for determining the appropriate level of reliability standards with the option to delegate responsibility for applying the framework to the AER or another body which is independent of the transmission business;
- the ability for jurisdictional ministers to specify additional reliability requirements for areas of economic or social importance;
- greater opportunities to consult with customers and consider community preferences;
- obligations under the Rules for transmission businesses to comply with their transmission reliability standards each year; and
- national reporting and auditing of transmission reliability performance and planning.

As the nature and detail of changes are not yet finalised, no impacts from the AEMC's review of national transmission reliability standards are factored into this transitional Revenue Proposal.

3

Indicative capital expenditure forecasts

3 Indicative capital expenditure forecasts

3.1 Introduction

This chapter outlines our indicative capital expenditure requirements. It explains our forecasting methodology and our forecast capital expenditure, and includes a comparison with the current regulatory period.

During the current regulatory period, we have responded to the lower than forecast demand by deferring or cancelling planned development projects. At the same time, we have continued to efficiently deliver our planned renewal/enhancement capital expenditure as assets reach the end of their useful lives. Over the past decade we have cleared a backlog of investment required to renew old equipment that was in poor condition. Since 1998 around $600 million has been invested to renew ageing assets in poor condition whilst also improving the security of the transmission system.

Our investments have delivered a renewed, more reliable and secure transmission system to serve Tasmanian customers and the NEM for years to come. Delivering this outcome over the present period at a lower-than-forecast cost translates into a lower regulated asset base. A lower asset base directly contributes to our objective of containing transmission revenues and prices to our customers.

Our capital expenditure requirements will be much lower over the next five years. This reflects the changed market environment as described in chapter 2. It also reflects the conclusion of a significant renewal phase in the Tasmanian transmission system and a return to a more typical renewal program. The remainder of this chapter is structured as follows:

- Section 3.2 explains the capital expenditure categories.
- Section 3.3 provides an overview of our capital expenditure forecasting methodology.
- Section 3.4 outlines the key variables and assumptions underpinning the capital expenditure forecasts.
- Section 3.5 discusses the interaction between capital and operating expenditure.
- Section 3.6 provides an overview of actual and forecast capital expenditure requirements, and compares the allowance with actual capital expenditure in the current regulatory period.
- Section 3.7 provides details of our annual capital expenditure requirements, and compares that with the actual capital expenditure in the current regulatory period.
- Section 3.8 provides details of forecast average annual expenditure amounts over the 2014–19 regulatory period in the relevant categories.

3.2 Categorisation of capital expenditure

Our indicative capital expenditure forecasts comprise three investment categories: Development, Renewal/enhancement and Non-network (support the business). These investment categories are divided into sub-categories as shown in Figure 3.1.

Figure 3.1 Transend's capital expenditure categories

Total Capital Expenditure								
Network							Non-network	
Development			Renewal/enhancement				Support the business	
Augmentation	Connection	Land and easements	Asset renewal/ enhancement	Physical security/ compliance	Inventory/ spares	Operational support systems	Information technology	Business support

3.3 Forecasting approach for capital expenditure

We manage the Tasmanian transmission system[8] to deliver efficient outcomes for our customers. In addition to meeting our customers' requirements, we must also satisfy our compliance obligations, including those relating to reliability, physical security, safety, and the environment. Our asset management plans and strategies recognise that a range of factors affect our capital expenditure requirements, including:

- load and generation changes, including changes in generation patterns;
- reliability planning standards specified in the Rules or mandated by the Tasmanian jurisdiction;
- opportunities to deliver market benefits to network users;
- unacceptable condition or reliability of assets, including network and business support system assets;
- changes in physical security, technical, safety, environmental or other compliance obligations; and
- efficiency improvement opportunities.

In addressing each of these factors, we are focused on achieving the national electricity objective, which is concerned with promoting efficient investment for the long term interests of consumers with respect to:

- price, quality, safety, reliability, and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.

In November 2013 we provided detailed information to the AER on our capital and operating expenditure forecasting methodologies. To recap, our capital expenditure forecasting methodology comprises several activities[9]:

- identify potential network issues where a capital investment solution may address the identified issue (referred to as 'needs analysis');
- develop a range of conceptual solutions;
- analyse technical and economic impacts and benefits;
- discuss potential solutions and impacts with affected customers, including the Tasmanian distribution business, and seek more cost effective non-network solutions or preferences;
- develop potential solutions and the timing of implementation, produce project cost estimates and select preferred solutions on the basis of the most positive net present value;
- confirm preferred solutions as projects or programs of work, or contingent projects, with further customer consultation where applicable, and included in the capital works program;
- consider all of the projects in the capital works program and operating and maintenance work plan to optimise cost (combining projects into programs of work), and timing (customer constraints, network availability, delivery priority); and
- prepare project cost estimates supported by well-documented project scopes and mature estimating practices that reflect efficient costs.

We work with our customers to provide opportunities for their needs and priorities to be reflected in our expenditure plans. We value the feedback we receive and regard customer engagement as an iterative component of our forecasting methodology.

[8] The transmission system comprises the transmission network, prescribed connection and supporting business assets.

[9] Note that not all steps are applicable to all three capital expenditure investment types noted in section 3.2 and the specific detail of the methodology differs across the investment types.

3.4 Key variables and assumptions

There are a number of key variables and assumptions that underpin our indicative capital expenditure forecasts. In particular, we have taken the following matters into account in preparing our forecasts:

- We have assessed the State and connection point peak demand forecasts, together with existing and forecast generation to identify emerging issues in the transmission system.
- Our asset management plans and strategies inform the forecast scope of efficient renewal/enhancement expenditure. We will manage the transmission system and supporting business assets to deliver operational and capital efficiency outcomes.
- We will meet our compliance obligations, including those relating to reliability requirements, physical security, safety, environment and other matters. The impact of known regulatory changes, such as changes to the Tasmanian Electricity Supply Industry (Network Planning Requirements) Regulations 2007, on our future capital expenditure requirements will be reflected in the expenditure forecasts.
- Our project cost estimates are supported by well-documented project scopes and mature estimating practices that reflect efficient costs and therefore provide a reasonable basis for projecting future capital expenditure costs.
- We have applied an estimate of forecast labour and non-labour escalation rates and inflation for the forthcoming regulatory period.
- We have provided a forecast productivity improvement factor and cost savings (including capital expenditure synergies expected from the merger of Transend and Aurora Energy's distribution business) which assume that our operating environment, including external factors beyond our control, will be conducive to achieving the anticipated improvements.

3.5 Interaction between capital and operating expenditure

While this chapter is concerned with capital expenditure, it is important to note the interaction with operating expenditure. In broad terms, we seek to optimise capital and operating expenditure by:

- Undertaking economic analysis to determine the mix of maintenance, operational and capital solutions that minimises the total whole-of-life costs of providing services to customers.
- Recognising that new technology delivered through the capital works program—for instance, protection relays and other ancillary equipment that have self-diagnostic and remote monitoring capabilities—has a positive impact on operating expenditure in terms of reducing the frequency of removing assets from service for the purpose of undertaking planned maintenance.
- Adjusting the timing and sequencing of asset renewal projects and operational works, to align such work with augmentation or connection projects.
- Ensuring that the capital works program is delivered in a timely manner to minimise the need for additional operating expenditure that would otherwise be required to sustain assets beyond their economic lives.

In addition to the above measures to optimise capital and operating expenditure, we also recognise other interactions. For example, growth in our asset base has an impact on recurrent operating expenditure as new capital additions must be maintained. We recognise the impact of economies of scale and scope when forecasting the additional recurrent operating expenditure requirements.

The interactions between capital and operating expenditure have been taken into account in developing the expenditure forecasts presented in this transitional Revenue Proposal.

With the introduction of the new network capability incentive, discussed further in section 10.1.3, we have carefully considered allocation of capital and operating expenditure between the allowances funded by the maximum allowable revenue, and network capability expenditure funded by the service target performance incentive scheme. Transend has a proud history of increasing the capacity of the transmission system through use of innovative technologies such as dynamic ratings and sophisticated control schemes. Capital and operating expenditure to sustain this network capability, together with expenditure endorsed by AEMO to support increased network capability, is now included in our network capability expenditure forecast, and not funded through the revenue building blocks.

3.6 Overview of actual and forecast capital expenditure

Figure 3.2 shows our forecast capital expenditure compared to the AER's allowance and our actual capital expenditure for the current regulatory period.

Figure 3.2 Capital expenditure ($m 2013–14)

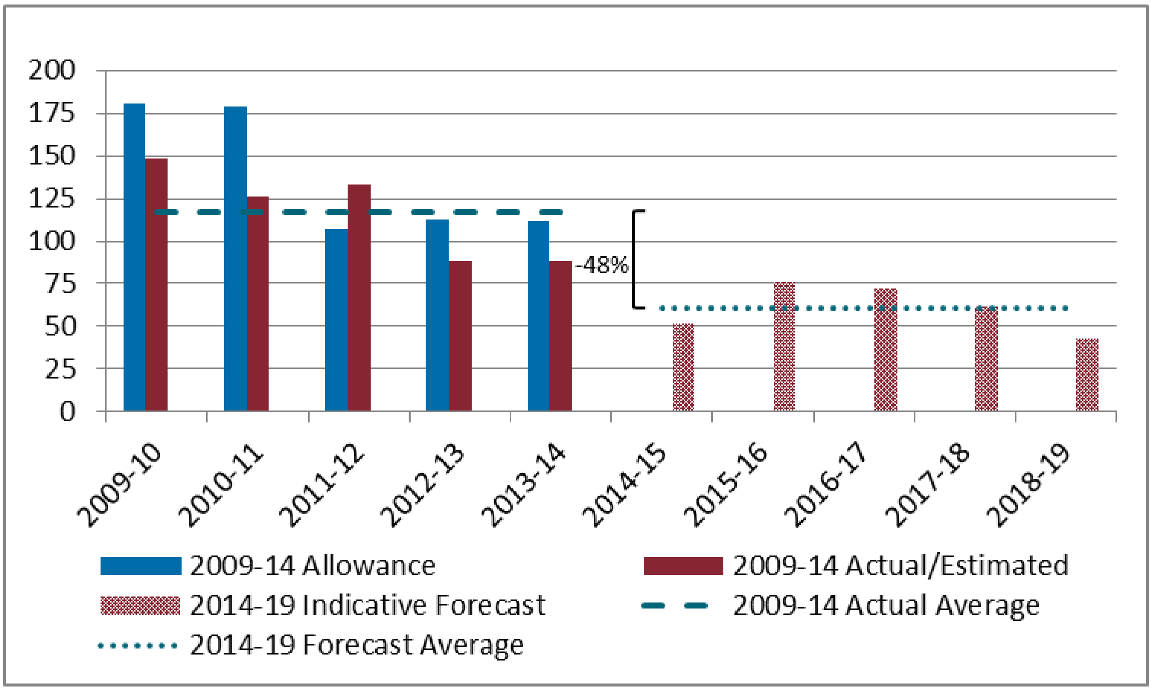


Table 3.1 provides a more detailed breakdown of the above information by expenditure category.

Table 3.1 Actual and forecast capital expenditure by category ($m 2013–14)

Category	2009–14 Allowance	Actual expenditure 2009–14	Forecast expenditure 2014–19
Augmentation	241.5	190.8	50.5
Connection	125.7	68.6	37.0
Land and easements	24.1	1.0	0.0
Development capex	**391.3**	**260.4**	**87.5**
Asset renewal/enhancement	203.2	250.1	140.2
Physical security/compliance	22.0	14.6	14.4
Inventory/spares	12.1	9.9	15.1
Operational support systems	23.8	17.8	33.5
Renewal/enhancement capex	**261.1**	**292.4**	**203.2**
Information technology	19.1	6.7	8.5
Business support	19.5	25.1	5.0
Support the business capex	**38.5**	**31.8**	**13.5**
Total	**690.9**	**584.6**	**304.2**

The key points to note from the above table are that our expenditure in the current period is forecast to be $584.6 million compared to the AER's allowance of $690.9 million; in the next period, our forecast expenditure reduces further, to $304.2 million.

3.7 Actual and forecast capital expenditure by category

3.7.1 Development expenditure

Development capital expenditure in the current period is forecast to be approximately $131 million lower than the AER's allowance for the period. A number of required development projects were efficiently delivered, notably the Waddamana-Lindisfarne 220 kV transmission line into Hobart's eastern shore, and connection of the new St Leonards Substation and transmission corridor, to strengthen reliability and security of supply for the Hobart and Launceston areas respectively. Other large projects included the upgrade to security at George Town 220 kV Substation; new connections for distribution customers at Mornington, Sorell, and Kingston; and augmented capacity at Rosebery Substation.

However, our total development capital expenditure was substantially lower than the AER's allowance as lower than forecast growth during the current period led to deferral of augmentation and connection projects and we delivered required projects at lower cost. In particular, investments at Emu Bay and Wesley Vale substations were deferred, along with planned substation connections to the distribution network at Penguin, Wynyard and Bridgewater. We also concluded that the planned strategic easement acquisition to facilitate a major 220 kV upgrade to the north-west should be deferred. Our largest project, the Waddamana-Lindisfarne 220 kV transmission line project was efficiently delivered at lower than forecast cost.

Table 3.2 Annual development capital expenditure forecast by category ($m 2013–14)

Category	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Augmentation	89.0	37.1	49.5	10.1	5.0	1.1	14.3	23.6	9.5	2.0
Connection	11.8	27.2	27.2	2.4	0.1	2.8	11.0	2.1	7.7	13.5
Land and easements	0.0	0.0	0.1	0.2	0.7	0.0	0.0	0.0	0.0	0.0

In the next regulatory period, development capital expenditure is forecast to be substantially lower than historic levels. Given subdued demand projections and uncertainty of future peak demand growth, we have adopted a conservative (low) forecast.

The augmentation spend profile is a function of eight component projects, including security augmentation investments at the Newton-Queenstown and Waddamana-Palmerston corridors that contribute to higher spend in 2015–16 and 2016–17; and a large 2017–18 (50 per cent weighted) allowance for dynamic reactive support in northern Tasmania. The requirement for dynamic reactive support project is still uncertain, and dependent on future large load and/or generation patterns. Under previous Rules this project would have been classified as contingent. However the contingent project threshold is now $30 million. The project has therefore been probability weighted, resulting in half the total estimated $17 million cost being included in the 2014-19 expenditure forecast.

The connection forecast includes six projects. Increased connection spend in 2015–16 is the result of a fault level mitigation program to address safety and other compliance issues in a number of distribution network connections; investment to meet reliability standards at the North Hobart 11 kV Substation serving Hobart's central business district, and increasing transformer capacity at the Rosebery Substation connection that serves both distribution network customers and MM Group Rosebery. Connection expenditure is presently forecast to be highest at the end of the period, largely due to construction of a new Bridgewater 110/33 kV connection point to support the distribution network.

Table 3.3 provides details of our proposed development projects with a value greater than $5 million over the forthcoming five year period.

Table 3.3 Forecast development capital projects greater than $5 million ($2013–14)

Project Description	Estimated total project cost ($m)	Category	Description	Investment need		
				Security	Connection Enquiry	Market Benefit
Waddamana - Palmerston 220 kV Security Augmentation	21	Augmentation	Establishment of a third 220 kV circuit in the single north – south transfer corridor to improve the security of supply, in particular to southern Tasmania.	✓		✓
Northern Dynamic Reactive Support	17	Augmentation	Installation of dynamic reactive support at George Town Substation 220 kV bus to improve network security.	✓[10]		✓[11]
Kingston Area Transmission Line Security Augmentation	15	Augmentation	Construction of a 110 kV transmission circuit from Creek Road Substation to Kingston Tee to improve the security of supply to the growing centres south of Hobart served by the distribution network.	✓		
Newton - Queenstown Security Augmentation	14	Augmentation	Establishment of a second 110 kV injection point to Newton and Queenstown substations on the west coast of Tasmania to improve the security of supply.	✓		✓
Bridgewater Substation new 110/33kV connection point	18	Connection	Establishment of a new 110/33 kV connection point at Bridgewater Substation to cater for demand growth and increase the reliability and security of supply in the area. This project responds to a connection application from the distribution network service provider.		✓	
Rosebery Substation transformer capacity augmentation	6	Connection	Replacement of the existing 110/44-22 kV transformers at Rosebery Substation with larger transformers to improve the reliability of supply. This project addresses the forecast load growth, including load identified in a connection enquiry.	✓	✓	✓

[10] This project would only proceed if required to provide a market benefit and/or meet other obligations.
[11] ibid

3.7.2 Renewal and enhancement

In the present regulatory period renewal/enhancement capital expenditure is forecast to be approximately $31 million higher than the AER's allowance. We continued our program of renewing critical system assets as they approach the end of their useful lives. Renewals in the present period focussed on a number of substations originally commissioned in the 1950s and 60s. This included substation redevelopments at Creek Road (serving central Hobart), Knights Road (serving the Huon Valley), Tungatinah and Meadowbank (serving generation and load in the Upper Derwent), Palmerston (serving generation and load in the central north area), Burnie and Emu Bay (serving the greater Burnie area), and Newton (serving generation and load on the West Coast). A small number of these projects are still underway, with commissioning and post-commissioning works to be completed in the next regulatory period.

During the current regulatory period, we also renewed the Knights Road to Electrona transmission line that had been previously affected by bushfires and was in poor condition. We renewed a number of overhead earth wires that protect transmission lines from lightning strikes, and enhanced earth wire coverage across the 220 kV backbone. This investment strengthened the resilience of the network to lightning events, improved protection and control communications capability and brought us in line with the rest of the NEM.

We continued to apply our best-practice approach to dynamic rating of our transmission lines, supported by a network of weather stations providing detailed real-time information to allow us to safely utilise our assets to their full capacity. This provides increased energy transfers across the transmission system, with minimal capital expenditure.

Table 3.4 Annual renewal/enhancement capital expenditure forecast by category ($m 2013–14)

Category	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Asset renewal/enhancement	18.8	43.1	44.4	68.9	74.8	32.7	25.6	28.7	33.9	19.4
Physical security/compliance	5.2	2.3	3.7	2.2	1.3	2.5	2.9	3.0	3.0	3.0
Inventory/spares	9.7	0.0	0.0	0.1	0.1	1.6	8.7	4.5	0.2	0.2
Operational support systems	2.0	2.9	6.1	3.3	3.6	8.1	10.2	7.4	4.6	3.3

As we move forward, a critical investment phase is nearing completion. We have cleared a backlog of renewal projects and our renewal program is returning to a more typical level. Our forecast renewal/enhancement capital expenditure for the forthcoming regulatory period is lower than the current period.

Our next regulatory period includes a number of renewal programs for key asset classes. For example, our largest program is $13 million to replace transmission line insulator assemblies, to maintain service levels, keep people safe and mitigate risks associated with bushfires. There is increased reinvestment in telecommunications assets that have reached the end of their service lives. Transend has worked hard to achieve extended lives for these assets, however many are no longer supported by manufacturers and are of obsolete technology. The renewal of these assets is partially funded by our non-regulated telecommunications customers, in accordance with our cost allocation methodology.

Increases in the inventory/spares category in 2015–16 and 2016–17 principally reflect the purchase of three strategic spare transformers with varying transformation voltages, together with a mobile 110/33/22/11 kV substation. This is a result of Transend's policy to extend the life of a number of in-service transformers and substation assets, but with strategic spares available to manage failure or unforeseen rapid deterioration in condition.

Slightly increased forward expenditure in operational support systems partially reflects prudent deferral of some projects in the present regulatory period—such as the asset management information system renewal—to derive synergies from systems developed as part of the TasNetworks merged network business. There is also increased investment in systems to strengthen our condition information and progress our smart transmission grid development program.

In Transend's long term vision for Tasmania's transmission network, we considered the future of a number of 110 kV transmission lines serving southern Tasmania, predominantly built from the 1930s to the 1950s to connect power stations in the Upper Derwent, and now approaching end of life. Rather than replace the existing assets like for like, our strategy aims to drive the 220 kV network harder to improve energy transfers and reduce renewal costs. This is our next phase of transmission line renewals, termed the 'southern redevelopment strategy' and programmed to commence towards the end of the forthcoming regulatory period.

The renewal expenditure for the forthcoming regulatory period predominantly comprises programs of work for key infrastructure groups, with projects and programs with a value of greater than $5 million summarised in Table 3.5.

Table 3.5 Forecast renewal capital projects and programs greater than $5 million ($2013–14)

Project Description	Estimated total project cost ($m)	Category	Description	Investment needs			
				Reliability and security	Safety and environment	Compliance	Technical requirements
Transmission line insulator assembly	13	Asset Renewal (Program)	Replacement of insulators.	✓	✓	✓	
Substation Disconnector and Earth Switch	9	Asset Renewal (Program)	Replacement of 220 kV disconnectors.	✓			✓
Telecommunications multiplexer system	7	Asset Renewal (Program)	Renewal of multiplexers.	✓		✓	✓
Transformer protection	6	Asset Renewal (Program)	Renewal of transformer protection schemes.	✓	✓	✓	✓
George Town substation 110 kV redevelopment	7	Asset Renewal (Project)	Replacement of 110 kV primary assets.	✓			✓
Lindisfarne Substation transformer replacement	6	Asset Renewal (Project)	Replacement of Lindisfarne Substation transformers T2 and T3.	✓	✓		✓
Telecommunications bearer system	6	Asset Renewal (Program)	Renewal of telecommunications bearer system.	✓		✓	✓
Transmission line K-pole	6	Asset Renewal (Program)	Renewal of K-poles on the Triabunna Spur 110 kV transmission line.	✓	✓		✓
Transmission line support assembly refurbishment	6	Asset Renewal (Program)	Refurbishment of support assemblies.	✓	✓		✓
Transmission line foundation	5	Asset Renewal (Program)	Renewal of transmission line foundations.	✓	✓		✓
Strategic spare mobile 110/33/22/11 kV substation	7	Inventory / Spares	Procurement of a system spare mobile substation.	✓			✓
Enterprise Asset Management system	6	Operational Support Systems	Replacement of Transend's Asset Management Information System.	✓	✓	✓	✓
Information Technology applications program	6	Operational Support Systems	Renewal of applications that support the operation of the transmission system.	✓	✓	✓	✓
Information technology infrastructure program	6	Operational Support Systems	Renewal of IT infrastructure that supports the operation of the transmission system.	✓	✓	✓	✓

3.7.3 Support the business

In this period Support the business (or 'non-network') capital expenditure is forecast to be approximately $7 million lower than the AER's allowance.

Table 3.6 Annual capital expenditure forecast by category ($m 2013–14)

Category	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Information technology	2.3	2.4	1.0	0.3	0.6	2.3	2.1	1.7	1.8	0.6
Business support	9.7	11.2	1.4	0.8	2.0	0.9	1.0	1.5	0.7	0.9

Slightly increased forward expenditure in information technology partially reflects prudent deferral of some projects in the present regulatory period—such as the information management system renewal—to derive synergies from systems developed as part of the TasNetworks merged network business.

3.8 Indicative annual capital expenditure forecasts for 2014–15 to 2018–19

Table 3.7 shows our capital requirements over the five-year period from 2014–15 to 2018–19 by expenditure category together with actual expenditure over the current regulatory period for comparative purposes. The indicative forecasts are the sum of category forecasts described in the preceding sections.

Table 3.7 Annual capital expenditure forecast by category ($m 2013–14)

Category	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Augmentation	89.0	37.1	49.5	10.1	5.0	1.1	14.3	23.6	9.5	2.0
Connection	11.8	27.2	27.2	2.4	0.1	2.8	11.0	2.1	7.7	13.5
Land and easements	0.0	0.0	0.1	0.2	0.7	0.0	0.0	0.0	0.0	0.0
Asset renewal/enhancement	18.8	43.1	44.4	68.9	74.8	32.7	25.6	28.7	33.9	19.4
Physical security/compliance	5.2	2.3	3.7	2.2	1.3	2.5	2.9	3.0	3.0	3.0
Inventory/spares	9.7	0.0	0.0	0.1	0.1	1.6	8.7	4.5	0.2	0.2
Operational support systems	2.0	2.9	6.1	3.3	3.6	8.1	10.2	7.4	4.6	3.3
Total Network	**136.5**	**112.6**	**130.9**	**87.2**	**85.7**	**48.8**	**72.6**	**69.1**	**58.7**	**41.4**
Information technology	2.3	2.4	1.0	0.3	0.6	2.3	2.1	1.7	1.8	0.6
Business support	9.7	11.2	1.4	0.8	2.0	0.9	1.0	1.5	0.7	0.9
Total non-network	**12.1**	**13.6**	**2.4**	**1.1**	**2.6**	**3.2**	**3.1**	**3.3**	**2.5**	**1.5**
Total	**148.5**	**126.2**	**133.3**	**88.3**	**88.2**	**52.0**	**75.7**	**72.4**	**61.2**	**42.9**

Our proposed capital program for the next regulatory period is 48 per cent lower than for the present period, with the forecast expenditure oriented towards asset renewal and network security augmentation projects. Compared with the present period, the forthcoming period sees a significant reduction in both the number of development projects and the development program value. This 'lumpy' expenditure profile is common in transmission businesses.

Indicative capital expenditure forecasts over the next regulatory period are significantly lower in the major categories of augmentation, connection and asset renewal/enhancement expenditure. Many categories of expenditure have relatively constant spend profiles; reflecting ongoing investment to meet identified needs.

The following diagram is replicated from section 3.2, now including the forecast average annual expenditure amounts over the 2014–19 regulatory period in the relevant categories.

Figure 3.3 Indicative forecast annual average capital expenditure ($m 2013–14)

Total Annual Average Capital Expenditure $60.8m								
Network $58.1m							Non-network $2.7m	
Development $17.5m			Renewal/enhancement $40.6m				Support the business $2.7m	
Augmentation $10.1m	Connection $7.4m	Land and easements $0.0m	Asset renewal/ enhancement $28.0m	Physical security/ compliance $2.9m	Inventory/ spares $3.0m	Operational support systems $6.7m	Information technology $1.7m	Business support $1.0m

The capital expenditure forecasts presented are consistent with the detailed information set out in our most recent Annual Planning Report, updated as a result of more recent information in some instances. The forecasts reflect ongoing discussions with our customers about their requirements.

Given subdued demand projections and uncertainty of future peak demand growth, we have adopted a conservative (low) forecast. The result sees significant development expenditure reductions compared with the current period. After a significant phase of renewing a backlog of aged assets in poor condition, our renewal program is also reducing and returning to a more typical level.

We will continue to deliver required capital works efficiently, and our capital cost estimates for the next regulatory period include efficiency gains that require further savings: our forecasts commit us to keep working hard to find ways to sustainably reduce our costs. This continued efficiency drive will assist our Tasmanian customers and the broader national electricity market.

TRANSEND

Our mission is transmission

4 Indicative operating expenditure forecasts

4 Indicative operating expenditure forecasts

4.1 Introduction

This chapter presents our indicative forecast operating expenditure for the 2014–19 period.

The forecast reflects continuous improvement of all business processes and practices to achieve better cost and performance outcomes. The hard work we have undertaken in recent years will continue to deliver benefits over the forthcoming regulatory period and beyond.

We are also committed to find future efficiencies to offset upward pressure on our operating expenditure requirements. This commitment recognises the importance of minimising the costs of transmission services. However, the level of cost savings factored in to the forecasts will be very challenging to achieve.

In forecasting our operating expenditure requirements an appropriate balance is struck between the pressure to reduce expenditure and the importance of maintaining service performance and managing network risks.

The remainder of this chapter is structured as follows:

- Section 4.2 describes our operating expenditure categories.
- Section 4.3 explains our operating expenditure forecasting approach.
- Section 4.4 outlines the key variables and assumptions and issues underpinning the operating expenditure forecasts.
- Section 4.5 presents our indicative operating expenditure forecasts for the next regulatory period and a comparison with the allowance and actual operating expenditure in the current regulatory period.
- Section 4.6 provides a breakdown of our annual operating expenditure requirements, and a comparison with the actual operating expenditure in the current regulatory period.
- Section 4.7 sets out the incentive payments arising from the application of the efficiency benefit sharing scheme for the current regulatory period.

4.2 Categorisation of operating expenditure

Our indicative operating expenditure forecasts comprise two categories: ‘Controllable operating expenditure’ and ‘Other operating expenditure’.

Controllable operating expenditure includes:

- direct operating and maintenance expenditure, which comprises costs directly attributable to maintaining and operating the transmission system; and
- other controllable expenditure, which comprises the costs of activities and services not directly related to maintaining or operating the system, but that provide necessary support functions.

Other operating expenditure consists of network support costs associated with the payment for non-system alternatives to system augmentations, insurance and self-insurance, and benchmark debt raising cost allowances. Figure 4.1 provides a pictorial overview of the expenditure categories.

Figure 4.1 Transend's operating expenditure categories

<table>
<tr><th colspan="8">Total Operating Expenditure</th></tr>
<tr><td colspan="5">Controllable Operating Expenditure</td><td colspan="3">Other Operating Expenditure</td></tr>
<tr><td colspan="3">Direct Operating & Maintenance</td><td colspan="2">Other Controllable</td><td colspan="2">Other</td><td>Benchmark Allowances</td></tr>
<tr><td>Field Operations & Maintenance</td><td>Transmission Services</td><td>Transmission Operations</td><td>Business support (Corporate)</td><td>Asset Management</td><td>Network Support</td><td>Insurance & Self-insurance</td><td>Debt Raising</td></tr>
</table>

4.3 Forecasting approach for operating expenditure

In broad terms, our operating expenditure forecasting methodology follows the approach adopted by the AER in its recent revenue cap decisions. In particular, under the operating expenditure forecasting methodology:

- the audited 2012–13 prescribed Controllable operating expenditure is used as a starting point for projecting future Controllable operating expenditure requirements; and
- Other prescribed operating expenditure (network support, insurance premiums, self-insurance and debt raising costs) requirements are forecast separately.

The forecasting methodology used to determine our indicative operating expenditure requirements is detailed in the document we submitted to the AER in November 2013.

In summary, our Controllable operating expenditure forecast has been developed using a base-step-trend approach. Under this approach, non-recurrent costs, such as cyclical revenue reset costs, are deducted from the 2012–13 expenditure to determine an efficient base year starting point.

This base year expenditure is then adjusted in future years by known cost changes (or step changes), such as increased expenditure associated with the AER's Better Regulation program and changes to our operating agreement with AEMO. The cyclical revenue reset costs are also added to the forecasts in the relevant future years.

Forecast changes in costs (or trend changes) are applied based on forecast labour cost movements and cost increases due to network growth.

We have then applied annual productivity factors in anticipation of our ongoing cost saving initiatives and efficiency improvements, including those arising from the merger of Transend and Aurora Energy's distribution business) to produce our Controllable operating expenditure forecast.

Other operating expenditure items (including network support, insurance and self-insurance premiums and debt raising costs) have been forecast utilising a zero-based (or bottom up) methodology.

The Controllable and Other operating expenditure forecasts are combined to produce our total forecast operating expenditure in $June 2014 terms.

4.4 Key variables and assumptions

The following are key variables and assumptions that underpin our indicative operating expenditure forecasts.

- 2012–13 base-year Controllable costs are efficient for that point in time, and therefore provide a reasonable basis for projecting future operating expenditure requirements.
- We have deducted the non-recurrent 2012–13 revenue reset costs to derive efficient base year Controllable expenditure.

- The impact of known regulatory changes, such as the AER's Better Regulation program, and other future changes on our future operating expenditure requirements are reflected in the expenditure forecasts.
- We have assessed the cost impact of asset growth on operating expenditure and applied an asset growth factor accordingly.
- We have estimated and applied labour and non-labour operating expenditure input escalation rates for the forthcoming regulatory period.
- We have applied a forecast productivity improvement factor and cost savings (including operating expenditure synergies expected to arise from the merger of Transend and Aurora Energy's distribution business), which assume that our operating environment, including external factors beyond our control, will be conducive to achieving the anticipated improvements.
- Our asset management plans and strategies inform the forecast scope of efficient field operations and maintenance expenditure.

4.5 Actual and forecast operating expenditure

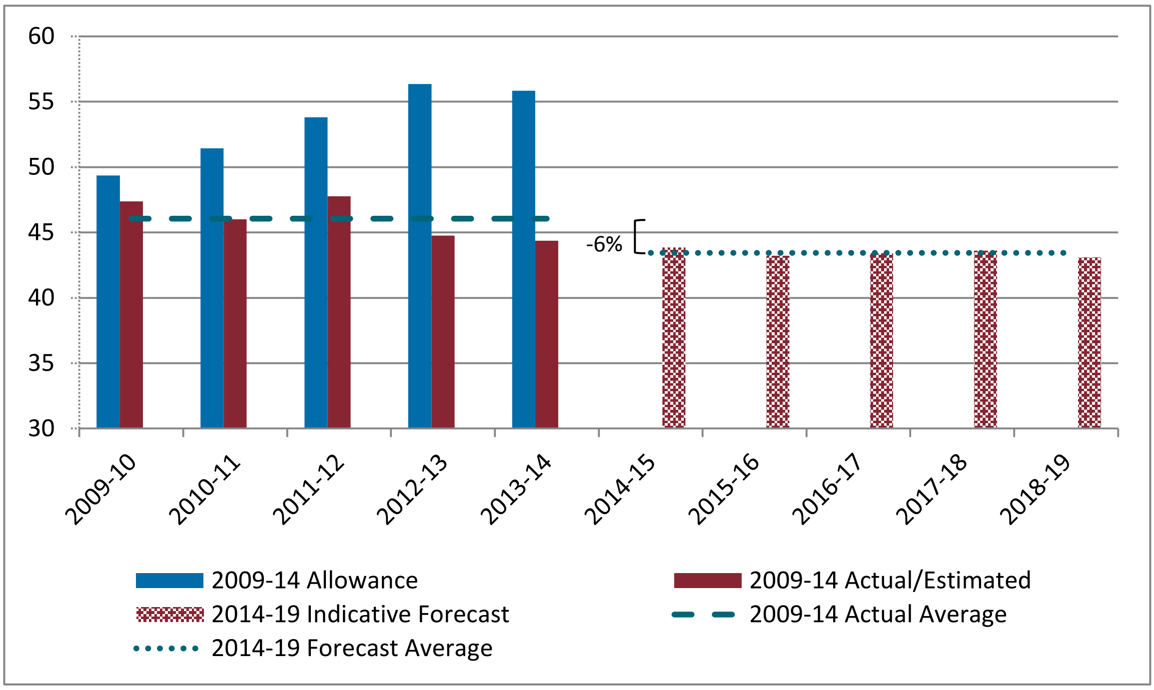
Table 4.1 shows the total allowance and actual expenditure for the current regulatory period and the forecast expenditure for the next regulatory period by category. Debt raising costs have been excluded from the table because the allowance is provided on a benchmark basis and actual costs are accounted for as part of financing costs, not operating expenditure.

Table 4.1 Actual and forecast operating expenditure by category ($m 2013–14)

Category	2009–14 Allowance	Actual expenditure 2009–14	Forecast 2014–19
Field operations and maintenance	98.7	79.9	75.3
Transmission services	44.9	41.3	36.1
Transmission operations	29.4	25.3	25.8
Asset management	45.2	41.0	40.5
Business support (Corporate)	48.5	42.7	39.4
Total Controllable expenditure	**266.8**	**230.2**	**217.1**
Network support	7.5	6.8	0.0
Insurance premiums	6.5	4.9	5.1
Self-insurance	4.6	4.6	4.5
Total Operating expenditure (excluding debt raising costs)	**285.3**	**246.6**	**226.7**

Figure 4.2 compares the allowance, and actual and estimated Controllable operating expenditure for the current regulatory period and the indicative forecast Controllable operating expenditure for the next regulatory period.

Figure 4.2 Controllable operating expenditure ($m 2013–14)



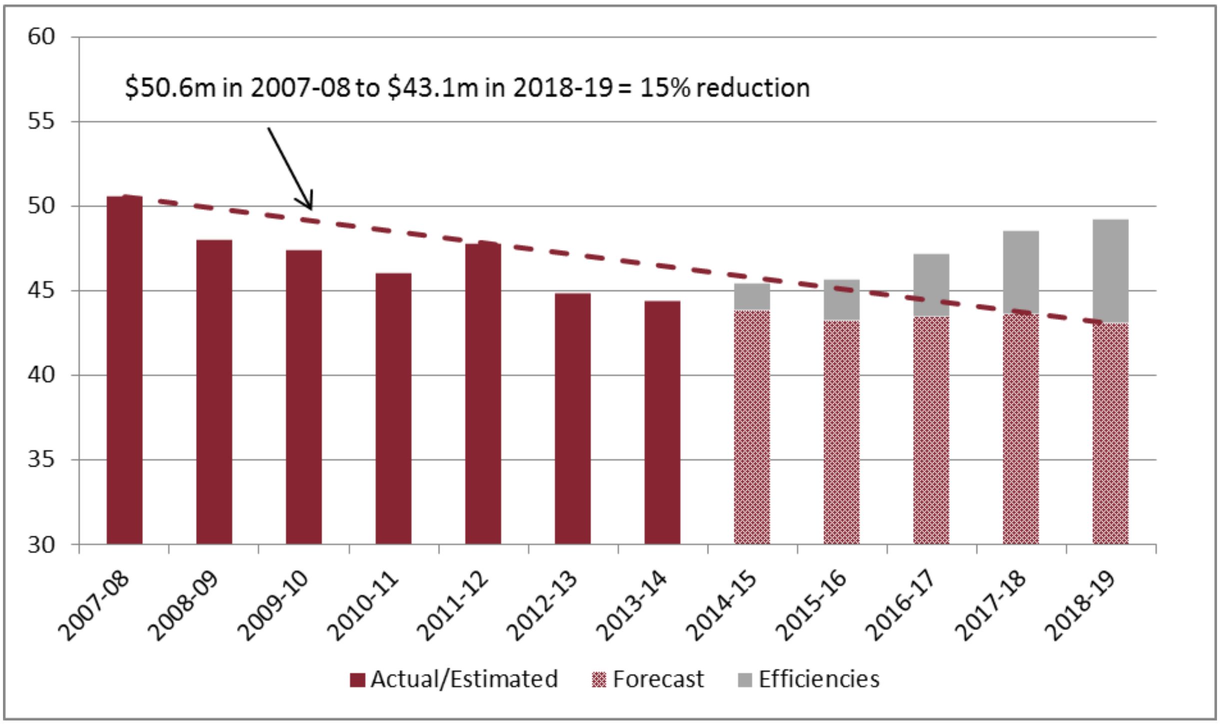
Estimated actual Controllable operating expenditure during the current regulatory period of $230.2 million is approximately $37 million or 14 per cent less than the allowance. These savings resulted from organisational transformation that lead to reductions in both contracted services and head count. We have made difficult decisions, including about redundancies, and found innovative ways to manage risks. We have made these decisions because we understand that Tasmanian customers are facing a number of economic challenges and our business sustainability is linked to the sustainability of our customer base.

We have worked diligently to drive costs down; specifically we have:

- reviewed and refined asset management strategies including prudent extension of maintenance intervals in some circumstances;
- rationalised fault response rosters for substation primary and transmission line asset incidents;
- refined a number of resourcing arrangements including internally resourcing the critical protection and control and operational communications functions;
- embedded a number of processes associated with the revenue reset as business as usual functions leading to reductions in resource requirements;
- made a number of improvements to business support processes and systems leading to improved efficiencies; and
- implemented a dedicated cost savings program which identified a number of opportunities to reduce costs including a review of resourcing requirements.

Figure 4.3 shows there has been a steady real reduction in operating expenditure. The exception was in 2011–12 when costs rose due to factors including termination costs associated with staff reductions, a reduction in capitalised overheads and a statutory asset revaluation.

Figure 4.3 Controllable operating expenditure 2007-08 to 2018-19 ($m 2013–14)



Our proposal continues Transend's track record of working hard to find operating savings, by including a number of prospective cost-saving initiatives and efficiency improvements. Our operating expenditure continues to fall in real terms, with forecast Controllable operating expenditure a further 6 per cent below expenditure in the current regulatory period.

Forecast efficiency improvements in each year of the next period result in Controllable expenditure savings that contribute more than $6 million, or 12.5 per cent of unadjusted expenditure, by the final year, 2018–19. This is illustrated in Figure 4.3. These efficiencies require the absorption of labour cost increases and scope changes (including new costs associated with the AER's Better Regulation program and our operating agreement with AEMO).

The result is that, in an environment with increasing obligations, more assets on the ground to maintain and operate, and input costs rising at levels above CPI, Transend's Controllable operating expenditure forecast in 2018–19 is 15 per cent lower than the 2007–08 expenditure. Merger and other future efficiencies are required to deliver these challenging targets.

4.6 Operating expenditure forecasts for 2014–15 to 2018–19

Our operating expenditure plans are focused on meeting our customer obligations and the operating expenditure objectives set out in the Rules, whilst continuing to achieve efficiency gains. Planned maintenance programs sustain our existing reliability levels.

Table 4.2 presents our indicative operating expenditure forecasts for each expenditure category together with the actual expenditure for the current regulatory period for comparative purposes.

Table 4.2 Annual operating expenditure forecasts ($m 2013–14)

Category	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Field operations and maintenance	16.1	16.8	16.9	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Transmission services	9.1	8.9	8.9	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Transmission operations	5.0	4.7	5.4	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Asset management[12]	8.7	7.7	8.1	8.1	8.4	8.1	7.7	8.1	8.5	8.2
Business support (Corporate)	8.5	7.9	8.5	9.2	8.5	8.3	8.1	7.9	7.7	7.4
Total Controllable expenditure	**47.4**	**46.0**	**47.8**	**44.8**	**44.4**	**43.8**	**43.2**	**43.4**	**43.6**	**43.1**
Network support	4.2	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance premiums	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Self-insurance	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total Operating expenditure (excluding debt raising costs)	**53.5**	**50.5**	**49.7**	**46.7**	**46.3**	**45.7**	**45.1**	**45.3**	**45.5**	**45.0**
Debt Raising Costs (benchmark)[13]						0.9	0.9	0.9	0.9	0.9
Total Operating expenditure						**46.6**	**46.0**	**46.2**	**46.4**	**45.9**

The following diagram is replicated from section 4.2, now including the forecast average annual expenditure amounts over the 2014–19 regulatory period in the relevant categories.

Figure 4.4 Indicative forecast annual average operating expenditure ($m 2013–14)

- **Total Annual Average Operating Expenditure $46.2m**
  - **Controllable Operating Expenditure $43.4m**
    - Direct Operating & Maintenance $27.4m
      - Field Operations & Maintenance $15.1m
      - Transmission Services $7.2m
      - Transmission Operations $5.2m
    - Other Controllable $16.0m
      - Business support (Corporate) $7.9m
      - Asset Management $8.1m
  - **Other Operating Expenditure $2.8m**
    - Other $1.9m
      - Network Support $0.0m
      - Insurance & Self-insurance $1.9m
    - Benchmark Allowances $0.9m
      - Debt Raising $0.9m

Controllable operating expenditure over the next five years is forecast to be less than our actual expenditure in the current regulatory period due to the application of efficiency gains. This will be very challenging to achieve—even with a network merger—and should provide assurance that the indicative forecasts presented can be relied upon for the purpose of setting the placeholder revenue.

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12 The asset management category includes the cyclical revenue reset costs.

13 Actual debt raising costs are accounted for as part of financing costs, not operating expenditure.

4.7 Efficiency benefit sharing scheme outcome

The efficiency benefit sharing scheme (EBSS) is an incentive mechanism which rewards sustained operating savings (efficiency gains) and penalises sustained operating expenditure increases (efficiency losses) compared to forecast efficient levels set by the AER.

Under the scheme, annual cost efficiency gains or losses are retained by the network business for a five year period. The scheme is designed to provide regulated companies with a consistent incentive to deliver efficiency improvements throughout the regulatory period. For the current regulatory period, we are subject to the EBSS set out in the AER's EBSS Final Decision for TNSPs in September 2007.

As part of the operation of this EBSS, an adjustment is made if the actual demand growth is outside the range of scenarios modelled in the approved forecast capital expenditure. We have updated the EBSS targets to reflect the lower than expected demand during the current regulatory period. The effect of this adjustment is to reduce the EBSS efficiency payments we receive.

The tables below set out the EBSS calculation for the current regulatory period, and the efficiency carryover amount that will apply in the forthcoming regulatory period. The calculations accord with the EBSS arrangements described above. Under the AER's scheme, the incremental gain or loss for 2013–14 cannot be determined until the conclusion of that year.

Table 4.3 Actual EBSS performance ($m 2013–14)

	2009–10	2010–11	2011–12	2012–13	2013–14
EBSS target	49.3	51.4	53.8	56.2	55.6
Actual EBSS expenditure	47.4	46.0	47.8	44.8	44.2
Incremental gain/loss	2.0	3.4	0.6	5.4	na

Table 4.4 Efficiency carryover ($m 2013–14)

	2009–10	2010–11	2011–12	2012–13	2013–14
Efficiency carryover	11.4	9.4	6.0	5.4	0.0

Further detail on the calculation of the efficiency carryover methodology is included in Appendix 2.

The efficiency carryover rewards us for sustainably reducing our operating cost base. Customers also benefit, as operating expenditure is based on revealed efficient costs—saving customers more than $10 million per annum compared to the forecast considered efficient by the AER in its previous revenue decision, and $50 million over a five year regulatory period. Transend's efficiency carryover is an incentive payment for delivering a $50 million Controllable operating expenditure saving to customers over the forthcoming period.

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5 Regulatory asset base

5 Regulatory asset base

5.1 Introduction

This chapter presents our indicative regulatory asset base (RAB), which has been calculated in accordance with the Rules, specifically clause S6A.1.3(5) and schedule 6A.2.

Due to prudent investment in the present regulatory period, customers will benefit from a lower opening asset base and in turn, relatively lower revenues and prices in the next regulatory period.

In addition, lower future investment in the transmission system means that the asset base is forecast to fall in real terms. This provides further downward pressure on revenues and pricing.

In the AER's 2009 Final Decision for Transend, the AER applied its roll forward methodology in determining a value for our opening RAB of $951.4 million, in nominal terms as at 1 July 2009. For revenue setting purposes, it is necessary to estimate an opening RAB as at 1 July 2014 and for the subsequent four years.

This chapter is structured as follows:

- Section 5.2 explains the methodology for rolling forward the asset base value to 1 July 2014.
- Section 5.3 provides an explanation of the derivation of the estimated opening and closing RAB value for each year of the forthcoming five-year regulatory period.

5.2 Regulatory asset base as at 1 July 2014

Our regulatory asset base as at 1 July 2014 has been calculated in accordance with the roll forward model provided by the AER and the requirements of schedules S6A.2.1 and S6A.2.4, and clause 11.6.9 of the Rules.

In summary, our regulatory asset base as at 1 July 2014 is derived by:

- removing the benefit associated with any difference between forecast and actual capital expenditure and assets under construction in the 1 July 2009 opening value of $951.4 million; and
- rolling forward the 1 July 2009 value for actual additions, disposals, inflation escalation and deductions of actual depreciation using the AER's roll forward model.

Table 5.1 shows the derivation of the RAB value as at 1 July 2014 (that is, the closing RAB as at 30 June 2014), in accordance with this methodology.

The regulatory approach to recognising capital expenditure changed from an 'as commissioned' basis in the 2004 to 2009 regulatory period to an 'as incurred' basis in the current regulatory period. The adjustment for differences between forecast and actual capital expenditure and assets under construction in the 2008–09 financial year recognises the 'as commissioned' approach that applied at that time. The approach ensures that Transend and customers are unaffected by forecasting errors in that year.

Table 5.1 Roll forward of regulatory asset base from 1 July 2009 to 30 June 2014 ($m nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	951.4	1,068.6	1,170.9	1,271.0	1,335.5
Net capital expenditure as incurred	139.5	121.1	131.2	89.0	91.4
Inflation on opening RAB	27.5	35.6	18.6	31.8	33.4
Straight-line depreciation	-49.8	-54.4	-49.7	-56.3	-62.4
Closing RAB	1,068.6	1,170.9	1,271.0	1,335.5	1,397.9
Add difference between actual and forecast 2008–09 net capex					-12.4
Add return on difference in 2008–09 net capex					-7.7
Add difference between actual and forecast assets under construction as at 30 June 2009					24.1
Add return on difference in assets under construction as at 30 June 2009					14.9
Closing RAB					**1,416.8**

As shown in Table 5.1, the RAB value as at 1 July 2014 (in nominal dollars) is $1,416.8 million. Capital expenditure for 2013–14 is a forecast.

5.3 Forecast of regulatory asset base over the forthcoming regulatory period

Table 5.2 presents a summary of the amounts, values and inputs used by us to derive our indicative RAB value for each year of the forthcoming regulatory control period. In accordance with S6A.2.1(f)(4) of the Rules, only actual and estimated capital expenditure properly allocated to the provision of prescribed transmission services in accordance with our cost allocation methodology has been included in the RAB.

Table 5.2 Regulatory asset base roll forward 1 July 2014 to 30 June 2019 ($m)

	2014–15	2015–16	2016–17	2017–18	2018–19
RAB (start period) - nominal	1,416.8	1,449.8	1,502.2	1,548.9	1,583.9
Nominal capex as incurred	54.8	81.8	80.2	69.5	50.0
Inflation on opening RAB	35.4	36.2	37.6	38.7	39.6
Nominal straight-line depreciation	-57.3	-65.6	-71.1	-73.3	-74.9
RAB (end period) - nominal	1,449.8	1,502.2	1,548.9	1,583.9	1,598.6
RAB (end period) - $June 2014	**1,414.4**	**1,429.9**	**1,438.4**	**1,434.9**	**1,412.9**

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6 Cost of capital and taxation

6 Cost of capital and taxation

6.1 Introduction

The AER has recently published a guideline setting out its proposed approach to estimating the weighted average cost of capital (WACC) or rate of return. The guideline is an important element of the AER's Better Regulation reform program, following the AEMC's changes to the rate of return provisions in the Rules. The new Rules include the following objective, which must guide the rate of return estimate:

> "The allowed rate of return objective is that the rate of return for a Transmission Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Transmission Network Service Provider in respect of the provision of prescribed transmission services."

The new Rules give the AER greater discretion in estimating the allowed rate of return. In exercising this discretion, the AER must have regard to a wide range of relevant estimation methods, financial models, market data and other evidence as well as considering inter-relationships between parameter values.

We are not required to provide a detailed analysis of the rate of return for the purpose of this transitional proposal. Instead, we must propose an indicative range, which takes into account available market information and expected market trends, and has regard to the Rate of Return Guideline published by the AER.

In addition to presenting an indicative range for the rate of return, to calculate our revenue requirements we must also provide a single point estimate. The AER will revisit the allowed rate of return when it completes its determination for the subsequent regulatory control period. The AER will backdate its decision at that time by adjusting our revenue allowance if its rate of return decision differs from the estimate employed for the transitional period.

The remainder of this section is structured as follows:

- Section 6.2 presents a summary of our proposed point estimate and range for the rate of return.
- Section 6.3 sets out our forecast allowance for corporate tax.

6.2 Rate of return

We propose a rate of return or weighted average cost of capital (WACC) of 8.43 per cent, as set out in Figure 6.1. It is referred to as the 'weighted' average cost of capital because it combines the cost of equity and the cost of debt.

Figure 6.1 Proposed WACC

Weighted Average Cost of Capital		
Component	**Debt**	**Equity**
Gearing	60%	40%
	x	x
Cost	7.40%	9.98%
	=	=
Contribution	4.44%	3.99%
WACC	8.43%	

To calculate the cost of equity and the cost of debt, it is necessary to estimate a number of parameters, as shown in Table 6.1. An upper and lower bound for each parameter is presented, together with our proposed point estimate.

Table 6.1 Proposed WACC range and point estimate for the transitional period

Parameter	Lower bound	Upper Bound	Proposed
Risk free rate (nominal)	4.06%	4.06%	4.06%
Market risk premium	6.50%	8.14%	6.50%
Equity beta	0.82	1.00	0.91
Cost of equity	9.39%	12.20%	9.98%
Cost of debt - 10 year BBB+ (nominal)	7.40%	7.40%	7.40%
Expected inflation	2.50%	2.50%	2.50%
Gearing (D/V)	60%	60%	60%
Gamma	0.25	0.25	0.25
Corporate tax rate	30%	30%	30%
Vanilla WACC (nominal)	**8.20%**	**9.32%**	**8.43%**

Our proposed estimation approach differs to the AER's Rate of Return Guideline in relation to the equity beta and the value of gamma, which is used to estimate our regulatory allowance for tax. Appendix 3 provides a more detailed discussion of each of the parameters in Table 6.1 and the method for estimating the rate of return.

6.3 Forecast allowance for corporate tax

We have calculated our regulatory allowance for tax in accordance with the formula as set out in the Rules (Clause 6A.6.4). This formula assesses the benchmark entity's effective tax rate and calculates the income tax payable each year. An adjustment is then made to reduce the tax allowance for the benchmark value of imputation credits.

Table 6.2 shows the resulting regulatory allowance for tax.

Table 6.2 Forecast tax allowance from 1 July 2014 to 30 June 2019 ($m nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19
Income tax payable	12.4	13.2	14.2	14.5	15.5
Imputation credit	-3.1	-3.3	-3.6	-3.6	-3.9
Tax allowance	**9.3**	**9.9**	**10.7**	**10.9**	**11.6**

7 Depreciation

7 Depreciation

7.1 Introduction

This chapter sets out our indicative assessment of the allowable depreciation (for revenue determination purposes) on regulated assets during the forthcoming regulatory control period. The remainder of this chapter is structured as follows:

- Section 7.2 describes our depreciation methodology.
- Section 7.3 describes our approach to determining remaining asset lives.
- Section 7.4 sets out our standard asset lives.
- Section 7.5 presents our indicative depreciation forecast.

7.2 Depreciation methodology

Clause 6A.6.3 sets out the regulatory requirements for calculating depreciation. In particular, clause 6A.6.3(b)(1) of the Rules requires us to use a profile of depreciation that reflects the nature of the asset or category of assets over the economic life of that asset or category of assets. For statutory accounting purposes, depreciation must conform to Accounting Standard AASB 116 (property, plant and equipment).

Our depreciation methodology is consistent with AASB 116, and accords with the requirements of clause 6A.6.3 of the Rules. We use economic depreciation, based on a straight-line method and standard asset lives, for each regulatory asset class. Straight-line depreciation is a well-established method used to reflect the decline in the service potential of an asset over its economic life.

To determine an indicative annual depreciation allowance, we have applied the post-tax revenue model (PTRM) using:

- the estimated asset base value as at 30 June 2014 derived from the roll forward model;
- the remaining lives of assets in existence as at 30 June 2014;
- the indicative capital expenditure forecasts set out in chapter 3; and
- the standard asset lives set out below.

7.3 Remaining asset lives

The roll forward model has been used to establish the remaining lives of assets in existence as at 30 June 2014 except for the transmission lines and cables asset class. This asset class was used until 30 June 2009 and since that time no further capital expenditure has been applied.

The roll forward model calculated an asset value for this asset class of $257.4 million with an average remaining life of 16 years as at 30 June 2014.

In reviewing the appropriate remaining lives of our assets, we reassessed the weighted average remaining life of the assets in the transmission lines and cables asset class. We have determined an amended average remaining life of 33 years. This amendment reduces the annual depreciation allowance for this class during the next regulatory period by an average of $9 million per annum.

7.4 Standard asset lives

Our standard asset lives, set out in Table 7.1, reflect the economic life of each asset class. The asset classes and standard asset lives are consistent with the AER’s 2009 Decision, with the exception of the communication asset classes, which are new asset class inclusions. Communication assets were rolled into the RAB in 2011–12 when the communications business ceased to be a ring-fenced business.

We capitalise assets at a less aggregated unit of plant than some other entities. We refer to these units of plant as units of property. We group the units of property with common characteristics and expected lives into asset classes. Substation assets, for example, are grouped into components of substations that have a long life (60 years), medium life (45 years) and short life (15 years).

Table 7.1 Transend's standard asset lives

Asset class	Standard life (years)
Transmission line assets—long life (60)	60
Transmission line assets—medium life (45)	45
Transmission line assets—short life (10)	10
Substation assets—long life (60)	60
Substation assets—medium life (45)	45
Substation assets—short life (15)	15
Protection and control—short life (15)	15
Protection and control—very short life (4)	4
Transmission operations—short life (10)	10
Transmission operations—very short life (4)	4
Communication assets—medium life (45)	45
Communication assets—short life (10)	10
Communication assets—very short life (5)	5
Other—medium life (40)	40
Other—short life (9)	9
Other—very short life (4)	4
Land	N/A

7.5 Depreciation forecasts

Our indicative depreciation forecast reflects:

- the methodology and standard asset lives outlined above; and
- the opening asset base and forecast RAB values described in chapter 5, which include indicative estimates of capital expenditure and disposals.

The PTRM has been used to calculate the indicative depreciation forecast on a straight-line basis.

Table 7.2 Total depreciation forecast from 1 July 2014 to 30 June 2019 ($m nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19
Straight-line depreciation	57.3	65.6	71.1	73.3	74.9
Indexation	-35.4	-36.2	-37.6	-38.7	-39.6
Regulatory depreciation	**21.8**	**29.3**	**33.5**	**34.5**	**35.3**

TRANSEND

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8 Maximum allowed revenue

8 Maximum allowed revenue

8.1 Indicative range for MAR

We have estimated our indicative maximum allowed revenue requirements by applying the post-tax building block approach, in accordance with the requirements outlined in chapter 6A of the Rules and post tax revenue model (PTRM). Each of the building block components is indicative, as described in the preceding chapters.

Table 8.1 shows our indicative revenue requirements for the period from 2014–15 to 2018–19.

Table 8.1 Components of the annual building block revenue requirement, 2014–15 to 2018–19 ($m nominal)

Component	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Return on capital	119.4	122.2	126.6	130.6	133.5	**632.4**
Return of capital (regulatory depreciation)	21.8	29.3	33.5	34.5	35.3	**154.5**
Total operating expenditure	47.8	48.3	49.8	51.2	51.9	**249.0**
Efficiency carryover	11.7	9.9	6.4	5.9	0.0	**33.9**
Net tax allowance	9.3	9.9	10.7	10.9	11.6	**52.4**
Annual building block revenue requirement—unsmoothed	**210.0**	**219.7**	**227.0**	**233.1**	**232.4**	**1,122.2**

Table 8.2 and Table 8.3 show the indicative unsmoothed and smoothed revenue requirements for the 2014–15 to 2018–19 period in nominal and real 2013–14 terms respectively.

Smoothed revenue for the transitional year (2014–15) is 15.22 per cent lower in real terms than our revenue allowance for 2013–14.

As noted previously we decided not to recover our full revenue entitlement in the current regulatory period. In accordance with that decision, we will not recover $26 million of allowed prescribed revenue in 2013–14. The indicative revenue requirement for 2014–15 is 5.1 per cent lower in real terms than the expected revenue to be recovered in 2013–14. For the four years after the transitional year, our indicative revenue requirement falls in real terms by 0.5 per cent per annum.

Table 8.2 Annual building block revenue requirement, maximum allowed revenue, and X factors 2014–15 to 2018–19 ($m nominal)

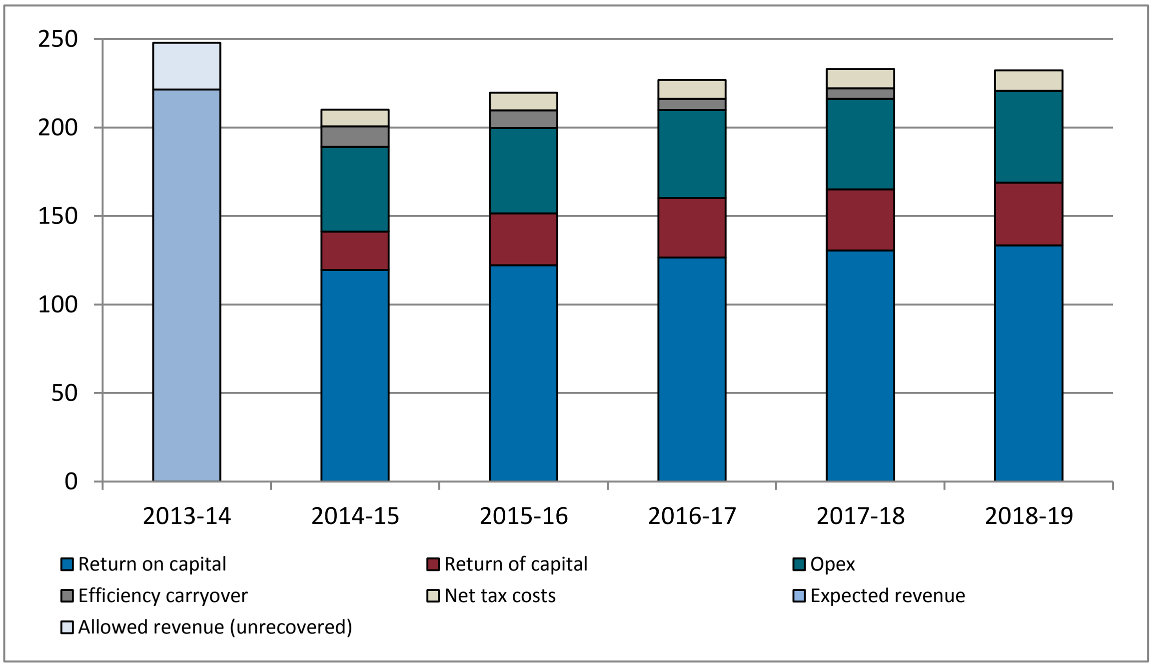
	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	Total revenue
Annual building block revenue requirement (unsmoothed)		210.0	219.7	227.0	233.1	232.4	1,122.2
Maximum allowed revenue (smoothed)	247.9	215.5	219.7	224.1	228.6	233.1	1,121.0
X factor		15.22%	0.50%	0.50%	0.50%	0.50%	

Table 8.3 Annual building block revenue requirement, maximum allowed revenue, and X factors 2014–15 to 2018–19 ($m 2013-14)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	Total revenue
Annual building block revenue requirement (unsmoothed)		204.9	209.1	210.8	211.2	205.4	1,041.4
Maximum allowed revenue (smoothed)	247.9	210.2	209.2	208.1	207.1	206.0	1,040.6
X factor		15.22%	0.50%	0.50%	0.50%	0.50%	

Figure 8.1 provides a further presentation of the annual building block revenue requirements.

Figure 8.1 Annual building block revenue requirement components ($m nominal)



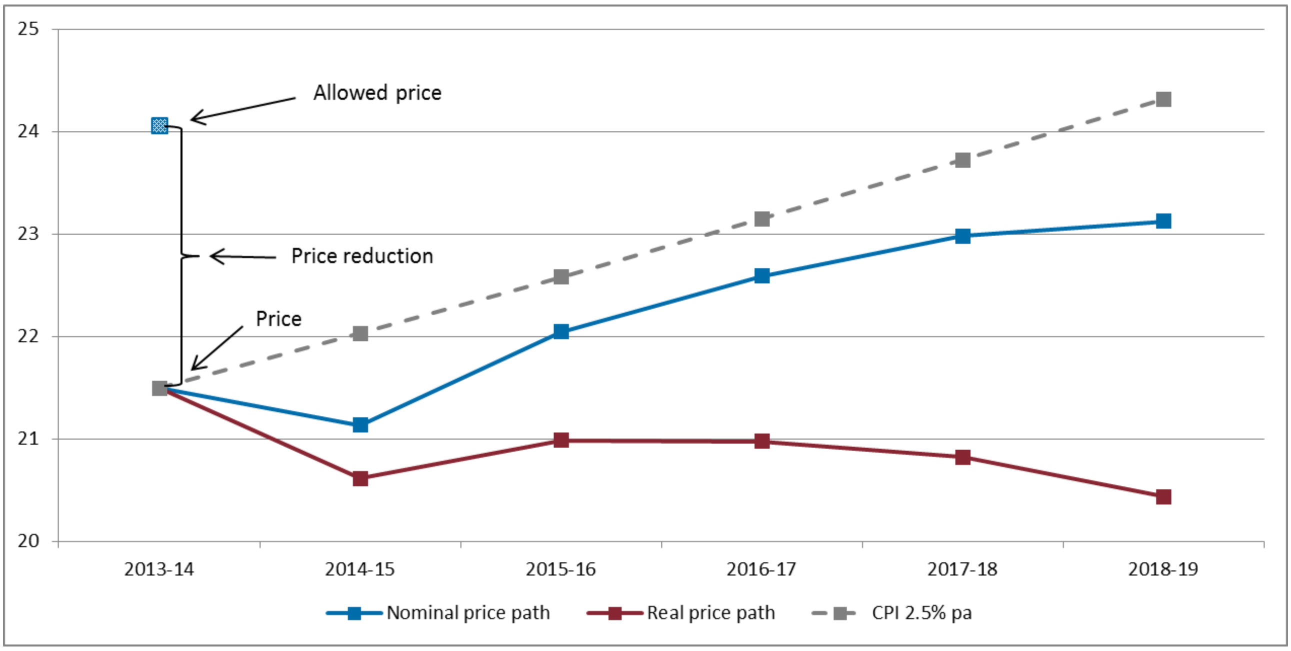
We have met with our customers and consumer representatives to discuss our revenue proposals and the likely path for future prices. In a series of presentations to customers, we explained that our expenditure plans coupled with our estimate of the cost of capital, are likely to lead to a reduction in revenue in July 2014. We further explained that the path of revenue increases from 1 July 2015 is likely to be below the CPI.

Prices for customers depend on total revenues and future energy and demand. Table 8.4 and Figure 8.2 show the proposed average price path per MWh of energy delivered in Tasmania over the next five years. This is compared to our revenue entitlement and expected revenue for the 2013–14 year.

Table 8.4 Average price impact of revenue proposal

		2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Nominal revenue ($m)	2013–14 Allowed revenue	247.9	215.5	219.7	224.1	228.6	233.1
	2013–14 Expected revenue	221.5					
Real revenue ($m) ($2013–14)	2013–14 Allowed revenue	247.9	210.2	209.2	208.1	207.1	206.0
	2013–14 Expected revenue	221.5					
Load forecast[14]	MWh ('000)	10,305	10,196	9,967	9,922	9,946	10,081
Nominal price ($/MWh)	2013–14 Allowed revenue	24.06	21.13	22.05	22.59	22.98	23.12
	2013–14 Expected revenue	21.49					
Real price ($/MWh) ($2013–14)	2013–14 Allowed revenue	24.06	20.62	20.98	20.97	20.82	20.44
	2013–14 Expected revenue	21.49					

Figure 8.2 Average price impact of revenue proposal ($/MWh)



Noting that, in constant dollars, our asset base is reducing and our operating and capital costs are falling, the biggest uncertainty in future revenue requirements is the cost of capital. It depends on financial markets and benchmark rates of return. Also, the AER will update the cost of debt component of the WACC, and consequently the maximum allowed revenue, annually throughout the next regulatory period.

Under the Rules we are required to provide a range of maximum allowed revenue outcomes, for different cost of capital scenarios. Table 8.5 and Table 8.6 present lower and upper maximum allowed revenue outcomes based on the lower and upper bound WACCs noted in Table 6.1. Our proposed maximum allowed revenue as presented in Table 8.2, falls within this range.

[14] The load forecast is based on AEMO's medium forecast contained in its 2013 National Electricity Forecasting Report, less estimated average annual transmission system losses of 2.54 per cent per annum.

Table 8.5 Maximum allowed revenue – lower bound WACC ($m nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	Total revenue
Annual building block revenue requirement (unsmoothed)		205.8	215.3	222.4	228.4	227.5	1,099.4
Maximum allowed revenue (smoothed)	247.9	211.1	215.3	219.6	223.9	228.4	1,098.3
X factor		16.93%	0.50%	0.50%	0.50%	0.50%	

Table 8.6 Maximum allowed revenue – upper bound WACC ($m nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	Total revenue
Annual building block revenue requirement (unsmoothed)		226.3	236.4	244.3	251.1	250.8	1,208.9
Maximum allowed revenue (smoothed)	247.9	232.1	236.7	241.4	246.2	251.1	1,207.4
X factor		8.68%	0.50%	0.50%	0.50%	0.50%	

All our revenue scenarios are based on challenging expenditure forecasts and benchmark rates of return for shareholders of transmission network businesses.

This proposal demonstrates that Transend is responding to customer and consumer feedback by balancing the need for reliable and secure provision of essential infrastructure with a continued focus on cost control.

In the current regulatory period we have:

- improved operating practices and implemented effective cost controls;
- prudently allocated capital to fund required investments;
- been innovative about managing risk to reduce expenditure;
- delivered record levels of energy; and
- delivered required services for less than the operating and capital expenditure allowances.

We have acted in the interests of our customers by under-recovering maximum allowed revenue. We continue to act in the long-term interests of our customers. In the next regulatory period we will maintain service levels while delivering:

- a significantly lower capital investment program;
- further reductions in real operating costs;
- capital and operating cost savings that require us to drive our business even harder; and
- real decreases in revenues.

Achieving the proposed cost savings will be difficult—even allowing for savings arising from the merger of Transend and Aurora Energy’s distribution business. We have put forward challenging expenditure targets because we understand that Tasmanian customers are also facing a number of economic challenges: our business sustainability is linked to the sustainability of our customer base.

Our proposal puts further downward pressure on prices for all electricity consumers. Reducing expenditure levels any further would allocate too much risk to our customers, in particular risk to service levels. Reductions would also compromise our ability to provide appropriate returns to the people of Tasmania, the ultimate owners of our business. We are confident the proposal strikes the right balance for Tasmania’s future.

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9 Cost pass through provisions

9 Cost pass through provisions

9.1 Introduction

Clause 6A.7.3 of the Rules defines any of the following as a pass through event for a transmission determination:

- a regulatory change event;
- a service standard event;
- a tax change event;
- an insurance event; and
- any other event specified as a pass through event in a transmission determination.

In effect, the pass through provisions allows the TNSP to recover (or pass back to customers) materially higher (or lower) costs in providing prescribed transmission services that have arisen as a result of the pass through event occurring.

In accordance with clause 11.57.2(a) the above provisions apply in relation to the transitional regulatory control period. In addition, we note that clause 11.58.3(4) requires the AER's determination to specify the "terrorism event", as defined in the Rules immediately prior to the date the National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012 came into force, as an additional pass through event that is to apply for the transitional regulatory control period.

In relation to 6A.6.7(5), we nominate the following pass through events for the transitional regulatory period:

- Natural disaster event; and
- Insurance cap event.

Each of these pass through provisions are discussed in turn below.

9.2 Natural disaster event

Any major fire, flood, earthquake or other natural disaster beyond the reasonable control of Transend that occurs during the 2014–19 regulatory control period and materially increases the costs to Transend of providing prescribed transmission services.

The term ‘major’ in the above paragraph means an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is, one per cent of the TNSP's maximum allowed revenue in that year).

Note: In assessing a natural disaster event pass through application, the AER will have regard to the:

i. insurance premium proposal submitted by Transend in its transitional revenue proposal;

ii. forecast expenditure allowances approved by the AER in relation to the transitional year; and

iii. reasons for that decision.

9.3 Insurance cap event

Whereby:

1. Transend makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy;
2. Transend incurs costs beyond the relevant policy limit; and
3. The costs beyond the relevant policy limit materially increase the costs to Transend of providing prescribed transmission services.

For this insurance cap event:

4. The relevant policy limit is the greater of:
   a. Transend’s actual policy limit at the time of the event that gives rise to the claim, and
   b. the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.
5. A relevant insurance policy is an insurance policy held during the transitional regulatory control period or a previous regulatory control period in which Transend was regulated.

   Note: For the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6A.7.3, the AER will have regard to:

   i. the insurance premium proposal submitted by Transend in its transitional revenue proposal;
   ii. the forecast operating expenditure allowance approved by the AER in relation to the transitional year; and
   iii. the reasons for that decision.

TRANSEND

Our mission is transmission

10 Incentive schemes

10 Incentive schemes

Clause 11.58.3(a)(2) of the Rules requires that the transmission determination for a transitional regulatory period must "*specify that no capital expenditure sharing scheme or small-scale incentive scheme applies to the affected TNSP for the transitional regulatory control period*".

Clause 11.58.3(a)(3) requires that the efficiency benefit sharing scheme and service target performance incentive scheme that applied during the current regulatory control period will apply for the transitional regulatory control period subject to such modifications as are set out in the framework and approach paper.

Whilst the framework and approach paper is not scheduled for publication until 31 January 2014, the AER's preliminary position is that the STPIS[15] and EBSS will apply as detailed below.

10.1 Service Target Performance Incentive Scheme

The Service Target Performance Incentive Scheme (STPIS) comprises three components; the service component, the market impact component and the network capability component. Each of these components and its application to us is outlined below.

10.1.1 Service component

The service component provides an incentive of up to +/- 1 per cent of maximum allowed revenue each year. The service component parameters and targets that apply in the current regulatory period will also apply in 2014–15. The parameters and targets as outlined in version 4 of the STPIS published by the AER in December 2012 will apply from 2015–16.

10.1.2 Market impact component

The market impact component (MIC) operates as a bonus only scheme that provides an incentive of up to 2 per cent of maximum allowed revenue each year. It is designed to provide an incentive to TNSPs to minimise planned transmission outages that can affect wholesale market outcomes.

The MIC as outlined in version 4 of the STPIS will apply from 1 July 2014.

10.1.3 Network capability component

The network capability component provides an incentive of 1.5 per cent of maximum allowed revenue each year, subject to completion of projects that improve the capability of the transmission network at times most needed. The component is designed to influence a TNSP's operation and management of its network assets to develop one-off projects that can be delivered through low cost operational and capital expenditure (up to a total of 1 per cent of the proposed revenue per year). AEMO plays a role in prioritising the projects to deliver best value for money for consumers.

In the transitional year, the AER has indicated that it will assess and approve the number of priority projects based on an estimate of our proposed revenue. This assessment and approval will be updated in the revenue determination to account for differences between the proposed revenue and actual revenue approved.

This submission includes our network capability incentive parameter action plan (NCIPAP) at Appendix 1. The action plan:

- outlines key network capability limitations on each transmission circuit or load injection point on our network;

[15] AER, *Final position, Service target performance incentive scheme for transmission businesses, Early application of version 4*, December 2013.

- includes a list of priority projects designed to improve, through operational and/or minor capital expenditure, some of the network capability limitations identified; and
- includes the value of the priority project improvement target for the projects.

Transend has a long history of releasing capacity through innovation and is the Australian leader in the application of dynamic ratings and use of control schemes. The NCIPAP is based on the continuation of our existing practice. The STPIS explanatory statement specifically states that TNSPs should be rewarded for historical investment in dynamic ratings or other systems that release significant additional market capability.

We have consulted with AEMO in developing the action plan, with one project still undergoing review. AEMO supports all projects reviewed as providing benefit. However, AEMO considers that some projects to sustain existing schemes should be funded from the operating and/or capital allowance. This interpretation seems at odds with the AER's explanatory statement. Given the difference of view, for works to sustain existing systems:

- operating and capital expenditure forecasts do not include any expenditure associated with NCIPAP projects endorsed by AEMO; and
- expenditure remains in the base year for projects not endorsed by AEMO.

The final decision about projects to include in the NCIPAP is a matter for the AER, including associated adjustments to other expenditure allowances.

10.2 Efficiency Benefit Sharing Scheme

The Efficiency Benefit Sharing Scheme (EBSS) will apply from 1 July 2014 in accordance with the AER's scheme published on 29 November 2013.

Whilst the scheme will apply in the 2014–15 transitional year, the target for that year will not actually be known until April 2015, near the end of the year, when the final decision for the full regulatory period is made.

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Appendix I

Network capability incentive parameter action plan

Appendix 1

Network capability incentive parameter action plan

Table A1.1 Network capability incentive parameter action plan ($'000 2013–14)

Project priority	Project description	Project circuit /Injection point	Annualised market benefit ($'000)	Expenditure 2014–15	2015–16	2016–17	2017–18	2018–19	Total ($'000)	Expenditure type	AEMO endorsement	Comments
1	Continued operation & maintenance of existing transmission line dynamic rating systems	Whole network	15,200	160	160	160	160	160	800	Opex	No	Increased power transfer capability
2	Maintenance of prescribed special protection schemes	Various circuits and connection sites across the network		30	30	30	30	30	150	Opex	No	Refer to note 1 for additional comments
3	Fifteen minute transient ratings for transmission lines	All transmission lines that are currently controlled through AEMO's generation dispatch	6 - 84 per line	40	-	-	-	-	40	Capex	Yes	Increased power transfer capability
4	Dynamic rating of Knights Road supply transformers	Knights Road Substation	456	150	-	-	-	-	150	Capex	Yes	Increased power transfer capability
					4	4	4	4	16	Opex	Yes	
5	Dynamic rating of Boyer Substation supply transformers	Boyer Substation	507	180	-	-	-	-	180	Capex	Yes	Increased power transfer capability
				-	5	5	5	5	20	Opex	Yes	
6	Installation of new line fault indicators	Farrell-Que-Savage River-Hampshire, Farrell-Rosebery-Queenstown, Norwood-Scottsdale-Derby and Lindisfarne-Sorell-Triabunna 110 kV transmission circuits	588	30	100	100	-	-	230	Capex	Yes	Reduced unplanned outage duration
				-	1	4	7	7	19	Opex	Yes	
7	Review and optimisation of Operational Margins for Transend limit equations	All transmission circuits whose flow is controlled by AEMO constraint equations	79 - 396	35	-	-	-	-	35	Opex	Yes	Increased power transfer capability

Project priority	Project description	Project circuit /Injection point	Annualised market benefit ($'000)	Expenditure 2014–15	2015–16	2016–17	2017–18	2018–19	Total ($'000)	Expenditure type	AEMO endorsement	Comments
8	Line fault indicator (LFI) remote communications	Palmerston-Avoca and Knights Road-Huon River-Kermandie 110kV transmission circuits	88	60	-	-	-	-	60	Capex	Yes	Reduced unplanned outage duration
9	George Town automatic voltage control scheme (GTAVCS) 2.0	Basslink Tasmania-Victoria interconnector	424	480	-	-	-	-	480	Capex	Yes	Improved power quality and efficiency gains
10	Dynamic rating of all 220/110 kV network transformers	All 220/110kV network transformers	750	-	350	350	200	-	900	Capex	Yes	Increased power transfer capability
				-	-	10	21	27	58	Opex	Yes	
11	Restring P1 bay conductor at Palmerston Substation	Waddamana-Palmerston No 2 110kV transmission circuit	25	50	-	-	-	-	50	Capex	Yes	Increased power transfer capability
12	Replace disconnectors, CT and bay conductor to achieve line rating increase and reduce market constraints	Sheffield-George Town 220 kV transmission line	493	350	770	-	-	-	1,120	Capex	Yes	Increased power transfer capability
13	Weather station telemetry renewal	Weather stations at Creek Road, Chapel Street, Devonport, Trevallyn, Hadspen, Sheffield, and Farrell substations	223	150	300	150	150	300	1,050	Capex	Yes	Increased power transfer capability
14	Upgrade of dead end fittings on selected transmission lines.	Liapootah-Waddamana-Palmerston No 1, Liapootah-Cluny-Repulse-Chapel Street No 1, Liapootah-Chapel Street No 2 and George Town-Comalco No 4 & 5 220 kV transmission circuits. Hadspen-Norwood No 1 & 2 110 kV transmission circuits.	175	200	340	300	-	-	840	Capex	Yes	Increased power transfer capability
15	Installation of second 220 kV bus coupler circuit breaker at Farrell Substation	Farrell Substation	94	665	-	-	-	-	665	Capex	Yes	Reduced customer impact in the event of a circuit breaker failure
				-	30	30	30	30	120	Opex	Yes	

Project priority	Project description	Project circuit /Injection point	Annualised market benefit ($'000)	Expenditure 2014–15	2015–16	2016–17	2017–18	2018–19	Total ($'000)	Expenditure type	AEMO endorsement	Comments
16	Castle Forbes Bay Tee Switching Station disconnector upgrade	Castle Forbes Bay Tee Switching Station	31	-	-	250	-	-	250	Capex	Yes	Reduced planned and unplanned outage duration
17	Transmission line surge diverter installation and tower footing earthing improvements	Sheffield-Farrell 1 & 2, Farrell-Reece 1 & 2, Farrell-John Butters 220kV and Farrell-Rosebery-Queenstown 110 kV transmission circuits	68	150	350	50	-	-	550	Capex	Yes	Reduced unplanned outage frequency and market constraints in the event of lightning storms.
18	Substandard spans verification and rectification	Multiple	287	824	724	724	724	724	3,720	Capex	Yes	Maintain compliance and increase line ratings.
19	Installation of modern fault location functionality for more accurate fault location on the identified circuits	Palmerston-Hadspen No 1 & 2, Palmerston-Sheffield and Sheffield-Burnie No 1 220 kV transmission circuits	9	60	60	-	-	-	120	Capex	Yes	Reduced unplanned outage duration
				-	2	4	4	4	14	Opex	Yes	
20	Install a second 110 kV bus coupler dead tank circuit breaker in series with the existing bus coupler circuit breaker	Chapel Street Substation	25	-	-	-	-	450	450	Capex	Yes	Reduced customer impact in the event of a circuit breaker failure.
21	George Town Substation replacement of 220 kV disconnectors with remotely operable disconnectors	George Town Substation	80	-	-	1,100	2,200	-	3,300	Capex	Yes	Reduced planned and unplanned outage durations.

Note 1: AEMO has recommended that these activities should be included within Transend's operational expenditure submission within the transitional Revenue Proposal. Transend has communicated to AEMO that the STPIS explanatory statement specifically states that TNSPs should be rewarded for historical investment in dynamic ratings or other systems that release significant additional market capability. Transend proposes retaining this project in the NCIPAP to be submitted to the AER (as allowed by the STPIS guideline), for the AER to make a decision.

Table A1.2 Total Network Capability Incentive Parameter Action Plan expenditure ($’000 2013–14)

	Expenditure					
	2014–15	2015–16	2016–17	2017–18	2018–19	Total ($'000)
Total Expenditure	**3,614**	**3,226**	**3,271**	**3,535**	**1,741**	**15,387**
Capex	3,389	2,994	3,024	3,274	1,474	14,155
Opex	225	232	247	261	267	1,232

The above total expenditure equates to approximately 1.5 per cent of Transend’s proposed revenue.

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Appendix 2

Efficiency Benefit Sharing Scheme 2009–14 outcome

Appendix 2

Efficiency Benefit Sharing Scheme 2009–14 outcome

Table A2.1 Actual EBSS performance ($m 2013–14)

Category	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
EBSS target	49.3	51.4	53.8	56.2	55.6					
Actual EBSS expenditure	47.4	46.0	47.8	44.8	44.2					
Incremental gain/loss	**2.0**	**3.4**	**0.6**	**5.4**	**na**					
Efficiency carryover										
2009–10		2.0	2.0	2.0	2.0	2.0				
2010–11			3.4	3.4	3.4	3.4	3.4			
2011–12				0.6	0.6	0.6	0.6	0.6		
2012–13					5.4	5.4	5.4	5.4	5.4	
2013–14						0.0	0.0	0.0	0.0	0.0
Total efficiency carryover						**11.4**	**9.4**	**6.0**	**5.4**	**0.0**

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Appendix 3

Cost of capital

Appendix 3

Weighted Average Cost of capital

As explained in chapter 6, as the transitional period is concerned with setting ‘placeholder’ revenue for a one year period, it is not appropriate to provide a detailed submission in this transitional Revenue Proposal in relation to the WACC. Instead, in accordance with clause 11.58.2(b)(2) of the Rules, we have provided an indicative range for the rate of return, which takes into account available market information and expected market trends, and has regard to the Rate of Return Guideline published by the AER.

This appendix provides further detailed information on our approach to estimating the WACC range for this transitional proposal. The remainder of this appendix is structured as follows:

- Section A3.1 discusses the AER’s overall approach to estimating the rate of return.
- Section A3.2 presents our cost of equity estimate.
- Section A3.3 presents our cost of debt estimate.
- Section A3.4 presents our inflation forecast.
- Section A3.5 addresses the value of imputation credits.
- Section A3.6 presents a summary of our proposed range and point estimate for the cost of capital.

A3.1 AER’s estimation approach

The AER’s Rate of Return Guideline indicates that the AER will calculate the nominal WACC by applying the following vanilla WACC formula:

$$WACC_{vanilla} = E(k_e)\frac{E}{V} + E(k_d)\frac{D}{V}$$

where:

$E(k_e)$ is the expected return on equity;

$E(k_d)$ is the expected return on debt;

$\frac{E}{V}$ is the proportion of equity in total financing (comprising equity and debt); and

$\frac{D}{V}$ is the proportion of debt in total financing, and is equal to the AER’s proposed benchmark efficient entity gearing ratio of 0.6.

The AER will set the return on equity for the duration of the regulatory control period, but the allowed return on debt will be updated annually. As a consequence, the AER will also update the overall rate of return annually.

A3.2 Cost of equity

A3.2.1 Estimation approach

In this section, we set out our point estimate and indicative range for the cost of equity component of the WACC to be applied in our transitional Revenue Proposal. We recognise that the cost of equity can never be observed and must be inferred from models of investor behaviour and from other insightful market sources.

In our opinion, no financial model perfectly estimates the cost of equity and each model has strengths and weaknesses. As a result, it is our view that regard should be had to a range of estimates of the cost of equity.

In developing the indicative range for the cost of equity we have been guided by clause 11.58.2(b)(2) of the Rules that requires us to submit:[16]

> an indicative range for the rate of return […], which takes into account available market information and expected market trends, and has regard to the Rate of Return Guideline published by the AER.

The AER's method for determining the cost of equity is described in the Rate of Return Guideline and is summarised as follows:

- The Sharpe-Lintner Capital Asset Pricing Model (CAPM) is adopted as the 'foundation model'.
- The parameters of the Sharpe-Lintner CAPM are specified using:
    - the yield on 10-year Commonwealth Government Securities (CGS), measured over a short (20 business day) period as close as practicably possible to the commencement of the regulatory period as the proxy for the risk free rate; and
    - a reasonable range and point estimate of each of the market risk premium and equity beta.
- A wide range of 'other information' is used to inform:
    - the estimation of parameters within the foundation model; and
    - where within the return on equity range, set by the foundation model, the final return on equity point estimate should fall.
- The additional information and evidence that will inform the estimation of the return on equity is evaluated.
- When departing from the point estimate derived using the Sharpe-Lintner CAPM, the AER will choose a cost of equity that is a multiple of 25 basis points, in recognition of the uncertainty of this estimate.

As described in the next section, we have adopted this general framework to determine both our indicative range and point estimate of the cost of equity.

A3.2.2 Range and point estimates

As noted above, the Rate of Return Guideline states that the Sharpe-Lintner CAPM is to be the 'foundation model' for determining the cost of equity for regulated energy networks. The functional form of the Sharpe-Lintner CAPM is:

$$\mathrm{E}(R_j) = R_f + \beta_j[\mathrm{E}(R_m) - R_f],$$

where

$E(Rj)$ = the expected return to asset j;

R_f = the risk free rate;

β_j measures the contribution of asset j to the risk of the market portfolio. If $\beta_j > 1$ ($\beta_j < 1$), adding a small position in asset j to the market portfolio will create a new portfolio with more (less) risk, measured by standard deviation of return.

$E(R_m)$ = the expected return to the market portfolio of risky assets.

Consistent with the Rate of Return Guideline, we have adopted the annualised yield on 10-year Commonwealth Government Securities (CGS) over 20 business days to 31 October 2013 as the indicative risk free rate, being 4.06 per cent. This rate has been applied in deriving the indicative lower and upper

[16] Rule 11.58.2(b)(2) of the National Electricity Rules.

bounds of the cost of equity as well as our point estimate. This risk free rate will be updated closer to the transitional period final decision.

The Rate of Return Guideline provides for the inputs to the CAPM to be informed by a range of models and other information. The details of the models and information that may be used to inform the estimated cost of equity are set out in tables 5.2 and 5.3 of the Rate of Return Guideline. For the purpose of this transitional Revenue Proposal, however, it is not appropriate to examine each of the estimation approaches in detail. Instead, for the purpose of setting placeholder revenue, we have adopted a more limited application of the Rate of Return Guideline.

In relation to the equity beta, the AER examined a range of evidence for the purpose of setting an indicative range in its Rate of Return Guideline. The AER concluded that the beta point estimate should be 0.7. We note that the AER's indicative beta estimate is lower than previous transmission revenue determinations. Furthermore, the Rate of Return Guideline provides for the equity beta to be informed by historical equity beta estimates and the Black CAPM. In this regard, we note that:

- SFG Consulting (SFG) recommended an equity beta of 0.82 which was based on:[17]
    - a sample of nine Australian listed firms with significant regulated energy network revenues;
    - a sample of 56 US listed power and gas firms for which at least 50 per cent of their assets were regulated; and
    - where each Australian-listed firm had twice the weight as a US listed firm.
- NERA Economic Consulting's (NERA) empirical analysis of the Black CAPM shows that regardless of the beta estimates for a particular firm, the best estimate of the expected return for that firm is the expected return on the market portfolio.[18] This implies that the beta estimate should be 1.0.

In light of the above observations, we propose a range for the equity beta of 0.82 to 1.0.

In relation to the Market Risk Premium (MRP), the AER's Rate of Return Guideline concludes that an MRP estimate of 6.5 per cent provides an appropriate balance between the various sources of evidence. We note, however, that there is considerable evidence to support an MRP above 6.5 per cent. In particular:

- Competition Economists Group (CEG) recommended adopting the average return on the market of 11.56 per cent (ie, an average real return on the market of 8.84 per cent between 1883 and 2011 plus expected inflation of 2.5 per cent);[19] and
- The following estimates of the prevailing return on the market portfolio have been derived from Dividend Growth Model (DGM) analysis:[20]
    - the AMP Capital DGM estimate of 11.8 per cent;[21]
    - the corrected Lally DGM that results in a range between 10.7 per cent and 13.2 per cent;[22]
    - the SFG DGM estimate of 12.2 per cent;[23] and
    - the published Bloomberg DGM estimate of the market return adjusted for imputation credits of 12.6 per cent.[24]

[17] SFG, *Regression-based estimates of risk parameters for the benchmark firm*, 24 June 2013, pages 9-10 and 16.
[18] NERA, *Estimates of the zero beta premium*, June 2013.
[19] CEG, *Estimating the return on the market*, June 2013, page 31.
[20] Note that all DGM estimates assume a 0.35 value of theta and a 0.25 value for gamma.
[21] CEG, *Estimating the return on the market*, June 2013, page 30.
[22] *Ibid.*
[23] See return excluding imputation credits of 11 per cent and a gamma value of 0.25, SFG, *Dividend discount model estimates of the cost of equity*, June 2013, pages 5 & 40.
[24] SFG, *Dividend discount model estimates of the cost of equity*, June 2013, page 36 and the gamma adjustment table on page 40.

The historic market returns and the DGM estimates cited above indicate that the estimated return on the market portfolio between 11.56 per cent and 12.2 per cent is reasonable, which implies an MRP range between 7.50 per cent and 8.14 per cent.

In light of the DGM analysis set out above, our view is that the upper range for the MRP is likely to be 8.14 per cent. As already noted, however, it is not appropriate to undertake a comprehensive analysis of this parameter for the purpose of this transitional Revenue Proposal. In these circumstances, therefore, we have adopted a point estimate of 6.5 per cent, which is consistent with the Rate of Return Guideline.

Table A3.1 Indicative cost of equity range and point estimate

Parameter	Lower bound	Upper bound	Point estimate
Risk free rate[25]	4.06%	4.06%	4.06%
Equity beta	0.82	1.00	0.91
Estimated return on the market portfolio	11.56%	12.20%	11.88%
Market risk premium	6.50%	8.14%	6.50%
Cost of equity	9.39%	12.20%	9.98%

Figure A3.1 Proposed cost of equity

Cost of Equity		
Risk free rate	+	Market risk premium x equity beta
4.06%	+	6.50% x 0.91
4.06%	+	5.92%
	9.98%	

A3.3 Cost of debt

As noted above, the AER's Rate of Return Guideline adopts a trailing average approach to the cost of debt. The guideline proposes that the yearly average will be calculated over a period of 10 or more consecutive business days using yield estimates from an independent third party service provider for a seven year debt term and the closest proximate for a BBB+ credit rating.

The Rate of Return Guideline proposes a gradual transition from the current approach of using prevailing rates as close as possible to the start of the regulatory control period (the 'on the day' approach) to the trailing average portfolio approach. The transition will occur over a period of ten years.

The transitional Revenue Proposal relates to the first year in which the AER's new approach for estimating the cost of debt will be applied. Under the AER's transitional arrangements, the allowed return on debt in the first year is the prevailing rate 'on the day'. Conceptually, the 'on the day' approach reflects the return on debt of the benchmark efficient entity that raises all debt required to satisfy its financing needs once, at a point in time just prior to the start of each regulatory control period.

In estimating the cost of debt, we have adopted a 10 year term, which is consistent with the AER's Rate of Return Guideline. Our estimated cost of debt reflects the RBA's published yield of 7.27 per cent (expressed on a semi-annualised basis) for BBB bonds at the end of October 2013. This equates to an annualised cost of debt of 7.40 per cent.

[25] The indicative risk free rate has been measured over the 20 business days to the 31 October2013.

Figure A3.2 Proposed cost of debt

Cost of Debt
10 year BBB+ corporate bond rate
7.40%

A3.4 Forecast inflation

The expected inflation rate is not an explicit parameter in the return on capital calculation, but it is an inherent aspect of the nominal risk free rate and is implicit in the nominal cost of debt. In addition, forecast inflation has several uses in the PTRM. Its primary use is to convert real inputs to nominal values, and to convert the nominal WACC to a real WACC.

In its most recent revenue determinations, the AER determined that a methodology that is likely to result in the best estimate of inflation over a 10 year period is to:

- apply the RBA's short-term inflation forecasts, currently extending out to two years; and
- adopt the mid-point of the RBA's target inflation band beyond that period (i.e. 2.5 per cent) for the remaining years of the 10 year period.

We have applied the AER's approach to derive an inflation forecast of 2.5 per cent for this transitional Revenue Proposal.

A3.5 Value of imputation credits

In order to estimate the benchmark corporate income tax allowance in accordance with the formula as set out in Clause 6A.6.4 of the Rules, the value of imputation credits (gamma) must be estimated. The Rate of Return Guideline states that value of imputation credits is to be estimated as the product of:

- a payout ratio; and
- a utilisation rate.

The AER's Guideline states that the available evidence suggests that gamma is 0.5, based on a payout ratio of 0.7 and a utilisation rate of 0.7.

We concur with the AER that a reasonable estimate of the payout ratio is 0.7. As explained below, however, we regard 0.35 as the best available estimate of the utilisation rate.

The AER Guideline explains that the utilisation rate will be estimated using the body of relevant evidence, having regard to its strengths and weaknesses, checked against a range of supporting evidence. The guideline proposes an estimate of 0.7 based on:

- the equity ownership approach— with current evidence, this suggests an estimate of 0.7;
- tax statistic estimates— with current evidence, this suggests an estimate between 0.45 and 0.8;
- implied market value studies— with current evidence, this suggests an estimate between 0 and 1; and
- other supporting evidence—including observations about market practice, government tax policy, imputation equity funds etc.

In adopting an estimate for the utilisation rate of 0.7, the AER contrasted its approach to the approach of the Australian Competition Tribunal[26]:

> "In contrast, in reaching its decision on the utilisation rate, the Tribunal relied on a single study from this single class of evidence. We consider this leads to an outcome that does not promote the long

[26] AER, Rate of Return Guideline, Explanatory Statement, December 2013, page 177.

> term interests of users of electricity or natural gas. This is a significant factor in our proposal to depart from the Tribunal's estimate."

While we concur with the AER that the Australian Competition Tribunal relied on a single study undertaken by SFG, the AER's description underplays the importance of that study. The Australian Competition Tribunal made the following comments in relation to the robustness of the SFG report:

> "In respect of the model specification and estimation procedure, the Tribunal is persuaded by SFG's reasoning in reaching its conclusions. Indeed, the careful scrutiny to which SFG's report has been subjected, and SFG's comprehensive response, gives the Tribunal confidence in those conclusions. In that context, the Tribunal notes that in commissioning such a study, it hoped that the results would provide the best possible estimates of theta and gamma from a dividend drop-off study. The terms of reference were developed with the intention of redressing the shortcomings and limitations of earlier studies as far as possible."[27]

> "The Tribunal is satisfied that SFG's March 2011 report is the best dividend drop-off study currently available for the purpose of estimating gamma in terms of the Rules. Its estimate of a value of 0.35 for theta should be accepted as the best estimate using this approach. In particular, the Tribunal cannot accept the submission of the AER that either minor issues in the construction of the database or multicollinearity argue for giving the SFG study less weight and the Beggs and Skeels study some weight. The Beggs and Skeels study, despite not being subjected to anything like the same level scrutiny, is known to suffer by comparison with the SFG study on those and other grounds."[28]

> "The Tribunal finds itself in a position where it has one estimate of theta before it (the SFG's March 2011 report value of 0.35) in which it has confidence, given the dividend drop off methodology. No other dividend drop-off study estimate has any claims to be given weight vis-à-vis the SFG report value." [29]

While we accept the AER's view that a range of evidence should be employed to estimate the utilisation rate, we consider that the decision of the Australian Competition Tribunal should be given considerable weight in that assessment. For the purpose of this transitional proposal, we consider it appropriate to continue to apply the findings of the Australian Competition Tribunal. Accordingly, for the purpose of this transitional Revenue Proposal we have adopted a value for gamma of 0.25, being the product of a payout ratio of 0.7 and an utilisation rate of 0.35.

A3.6 Indicative post-tax nominal WACC

We propose applying a post-tax nominal vanilla WACC range between 8.20 per cent and 9.32 per cent, and a point estimate of 8.43 per cent for the purpose of determining the placeholder revenue for the transitional Revenue Proposal. The key parameters and variables underlying the cost of capital calculation are summarised in the tables below.

[27] Australian Competition Tribunal, *Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9*, 12 May 2011, paragraph 22.
[28] Ibid, paragraph 29.
[29] Ibid, paragraph 38.

Table A3.2 Proposed WACC range and point estimate for the transitional period

Parameter	Lower bound	Upper Bound	Proposed
Risk free rate (nominal)	4.06%	4.06%	4.06%
Market risk premium	6.50%	8.14%	6.50%
Equity beta	0.82	1.00	0.91
Cost of equity	9.39%	12.20%	9.98%
Cost of debt - 10 year BBB+ (nominal)	7.40%	7.40%	7.40%
Expected inflation	2.50%	2.50%	2.50%
Gearing (D/V)	60%	60%	60%
amma	0.25	0.25	0.25
Corporate tax rate	30%	30%	30%
Vanilla WACC (nominal)	**8.20%**	**9.32%**	**8.43%**

Table A3.3 Proposed WACC

Weighted Average Cost of Capital		
Component	**Debt**	**Equity**
Gearing	**60%**	**40%**
	x	**x**
Cost	**7.40%**	**9.98%**
	=	**=**
Contribution	**4.44%**	**3.99%**
WACC	**8.43%**	

Appendix 4

References

Appendix 4

References

The following references can be found on Transend's external website, www.transend.com.au

- Expenditure Forecasting Methodology
- Transend Annual Report 2013
- Transmission System Management Plan 2013–19
- Pricing Methodology
- Pricing Methodology factsheet
- Negotiating Framework
- Annual Planning Report 2013
- Transend's Cost Allocation Methodology

The following references can be found on the Office of the Tasmanian Economic Regulator's external website, www.economicregulator.tas.gov.au

- Transend Electricity transmission Licence 14 December 2012

The following references can be found on the Australian Energy Regulator's external website, www.aer.gov.au

- Transend – Determination 2009–14
- Better Regulation reform program - AER Guidelines

The following references can be found on the Australian Energy Market Operator's external website, www.aemo.com.au

- National Electricity Forecasting Report (NEFR) 2013
- Operating Agreement, Schedules for Delegations