Tasmanian Transmission Revenue Proposal

Regulatory control period
1 July 2014 – 30 June 2019

31 May 2014

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TRANSEND

Tasmanian Networks Pty Ltd

Transend Networks Pty Ltd

Contact

This document is the responsibility of the Corporate Strategy and Compliance Group, Transend Networks Pty Ltd.

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Executive Summary

Highlights

This proposal supports lower electricity prices for consumers.

In the current regulatory period:

- Our transmission 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 less than half the expenditure during the current period, in real terms.
- We will deliver savings from the transmission and distribution merger and work hard to make further reductions to operating costs.
- We have made an adjustment to our depreciation profile which results in a reduction in transmission charges over the next five years.
- We have accepted a lower return on equity and proposed a significantly lower cost of capital.
- Consumers benefit immediately—in the first year our revenue drops.

Introduction

This document presents the Revenue Proposal for the Tasmanian electricity transmission network, for the five year period commencing on 1 July 2014. It is submitted in accordance with the National Electricity Rules (the Rules).

At the time of this submission, Transend Networks Pty Ltd (Transend) owns and operates the electricity transmission network in Tasmania. Our core business is providing safe, reliable and efficient electricity transmission services in the 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 electricity transmission network service provider (TNSP) from 1 July 2014.

The Tasmanian Government established the following objectives for the merger:

- lowest sustainable electricity bills;
- 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.

This Revenue Proposal is consistent with these objectives

This document follows on from the earlier submission of our transitional Revenue Proposal. The purpose of the transitional Revenue Proposal was to establish ‘placeholder’ revenue for the first year of the forthcoming regulatory period, to enable the finalisation of a number of important guidelines by the Australian Energy Regulator (AER) under its Better Regulation program.

This Revenue Proposal outlines how we intend to manage the Tasmanian transmission network to ensure it continues to provide safe and reliable services while meeting consumer demands for efficiencies and moderation in price increases.

Responding to changed market conditions

Since we lodged our previous Revenue Proposal in 2008, significant changes have taken place in the energy market, and across the Australian economy more broadly. The price of delivered energy throughout Australia has increased significantly. Customers have responded by seeking improved energy efficiency, and embracing distributed generation, resulting in a reduction in energy demand compared to forecasts.

Across Australia, a number of 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.

In response to the weaker-than-expected growth in demand, we have worked closely with our customers to review investment needs, and we have deferred a number of projects:

- Planned investments have been deferred at the Emu Bay and Wesley Vale Substations, and also at substation connections to the distribution network at Penguin, Westbury and Bridgewater.
- The planned acquisition of easements to facilitate a major 220 kV upgrade to the north-west has been deferred.

During the current period, projects required to strengthen both reliability and security of supply were efficiently delivered, notably the Waddamana-Lindisfarne 220 kV transmission line to Hobart’s eastern shore, and establishment of the new St Leonards Substation and associated transmission line connections. We also continued our program of renewing aging and deteriorating assets. A critical investment phase associated with renewing our assets is now nearing completion.

In addition to critically reviewing capital investment needs, we have worked hard to reduce our operating costs despite continued increases in our obligations as a transmission network service provider. We have cut our operating expenditure through reductions in contracted services and employee numbers.

During the current regulatory period, we maintained a high standard of safety and transmission system performance, while our actual capital and controllable operating expenditures were well below the regulatory allowances over the 5 year period. In particular, in real terms:

- Capital expenditure was about 17 per cent, or $115 million lower than the allowance.
- Controllable operating expenditure was about 14 per cent, or $37 million below the allowance.

In view of these savings, and in response to the changed market and economic conditions faced by our customers, in 2012 we decided to not fully recover our maximum allowed revenue. Under that decision, we have foregone the recovery of $11 million of allowed revenue in 2012–13, and $26 million of allowed revenue in 2013–14.

In the context of our annual revenue allowance of approximately $250 million in 2013-14, these are significant reductions. Our revenue reductions provided customers with an immediate share of the cost savings we achieved.

In addition, these cost savings lead to a lower opening asset base and a lower operating cost base for the forthcoming regulatory period, thereby ensuring that customers will continue to benefit from the savings we have already achieved.

Our approach to engaging with consumers

In preparing this Revenue Proposal we have sought to understand the needs and preferences of all Tasmanian electricity consumers.

We have met face-to-face with all our directly-connected transmission customers to:

- outline the key elements of our proposal;
- listen to feedback; and
- discuss the ways in which we might address that feedback.

In addition, we commissioned specialist community engagement expertise to assist us in designing and implementing a consumer engagement program, targeting a wide cross-section of consumers who are connected to the distribution network. Our consumer engagement provided useful insights to the optimal trade-off between price and reliability. In particular, consumers indicated that:

- The risk of a less reliable service was not acceptable as a trade-off for lower prices.
- By the same token, an increase in reliability was also not supported if it came at a higher price.

Our Revenue Proposal responds to this feedback by delivering lower costs whilst maintaining existing service levels.

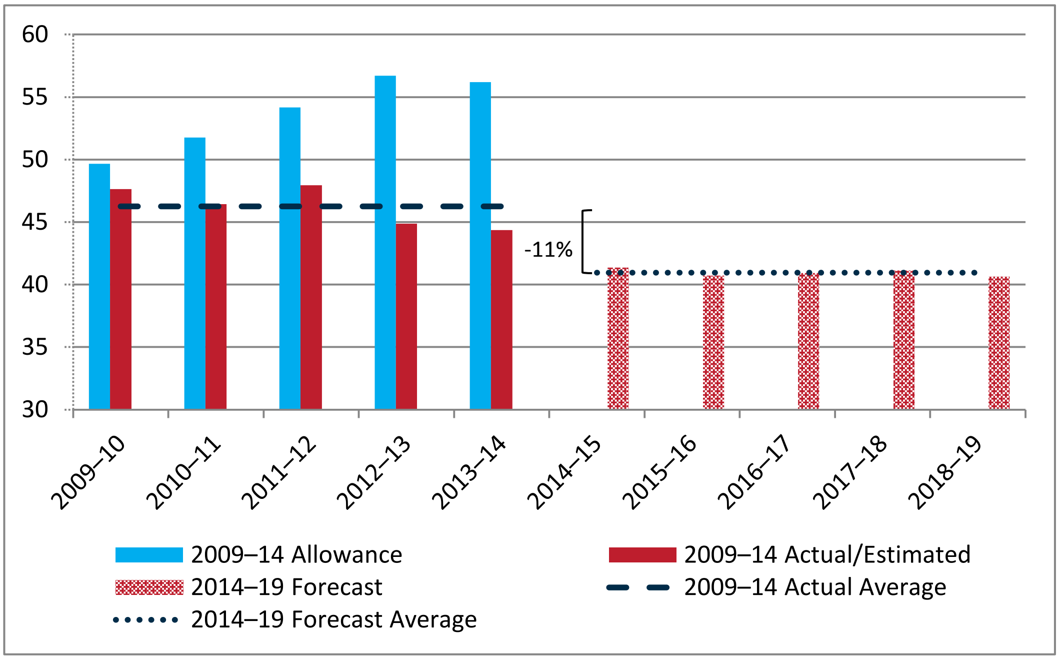
Working hard to achieve further efficiencies

We will achieve efficiency improvements through the merger of Transend's transmission network with Aurora's distribution network. These efficiencies are incorporated in our expenditure forecasts and will benefit customers in the forthcoming regulatory period.

Some efficiency initiatives will be implemented with immediate effect, most notably as a result of staff redundancies. We expect those efficiency improvements to deliver a regulated (or 'prescribed') transmission operating cost saving of $2.5 million in 2014–15. Further efficiency gains will be achieved over time as the new company rationalises duplicate systems and finds better ways of delivering services to its customers.

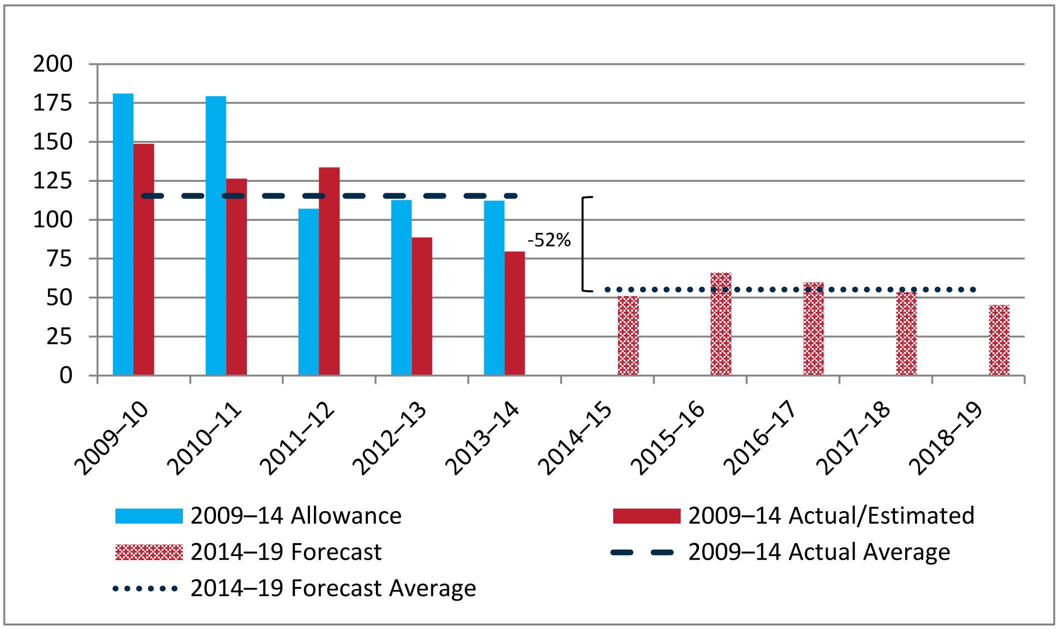
As a consequence, our forecast total controllable operating expenditure for the next regulatory period of $204.8 million is $26.4 million (11 per cent) lower than actual expenditure of $231.2 million in the current period, in real terms. Figure E.1 shows the 11 per cent lower forecast average annual controllable operating expenditure.

Figure E.1 Overview of forecast and actual Controllable operating expenditure ($m 2013–14)



We are also forecasting significant reductions in our future capital expenditure requirements. Figure E.2 shows that our average annual capital expenditure for the next regulatory period is expected to be 52 per cent lower in real terms than our actual expenditure in this period. This reflects the changed market environment described earlier, which leads to a reduced need for network augmentation, and the conclusion of a significant renewal investment phase in the Tasmanian transmission system.

Figure E.2 Overview of forecast and actual capital expenditure ($m 2013–14)



Our forecast total capital expenditure for the next regulatory period of $275.9 million is $301.3 million (52 per cent) lower than actual expenditure of $577.2 million in the current period, 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.

Better Regulation

The transitional Revenue Proposal was introduced for a one year period in order to provide sufficient time for the AER to finalise a number of important guidelines in its Better Regulation reform program. This followed a number of changes to the National Electricity Rules that govern the way our revenues and prices are regulated.

An important aspect of these Rule changes and guidelines is the introduction of new incentive arrangements that promote more efficient outcomes in terms of cost savings and service performance improvements. This Revenue Proposal incorporates these incentive schemes, and we will continue to pursue initiatives to deliver the outcomes that these schemes support.

In terms of its impact on our revenue requirements, the most important guideline issued by the AER relates to the method for estimating the cost of capital, which is a weighted average of the cost of equity and the cost of debt.

In preparing our estimate of the cost of equity, we engaged an independent expert to provide opinions on the appropriate parameter values and an overall point estimate. These independent opinions indicate that there is strong evidence to support a cost of equity estimate above the value estimated using the AER's parameter values in its Rate of Return Guideline.

While we accept the views expressed by the independent expert, we must also consider the impact of a higher cost of equity on our customers. We are particularly mindful of the commercial pressures currently facing our customer base in Tasmania.

Consequently, our estimate of the cost of capital reflects the parameter values set out in the AER's guidelines. It results in a nominal vanilla cost of capital estimate of 7.58 per cent.

Our proposed cost of capital of 7.58 per cent is materially below the value adopted in the current regulatory period (10.00 per cent). While some of this reduction is attributable to lower market interest rates, the reduction in our proposed cost of capital also reflects our acceptance of a lower return on equity (8.7 per cent nominal). This compares to the current period return on equity of 11.8 per cent.

In contrast to previous regulatory periods, the AER will update the cost of debt component of the cost of capital on an annual basis. While this creates some uncertainty in terms of future revenue allowances (as revenue will also be updated annually), we consider that the AER's approach will lead to less price shock between regulatory periods, and will therefore deliver a better outcome for customers.

Our proposed revenue

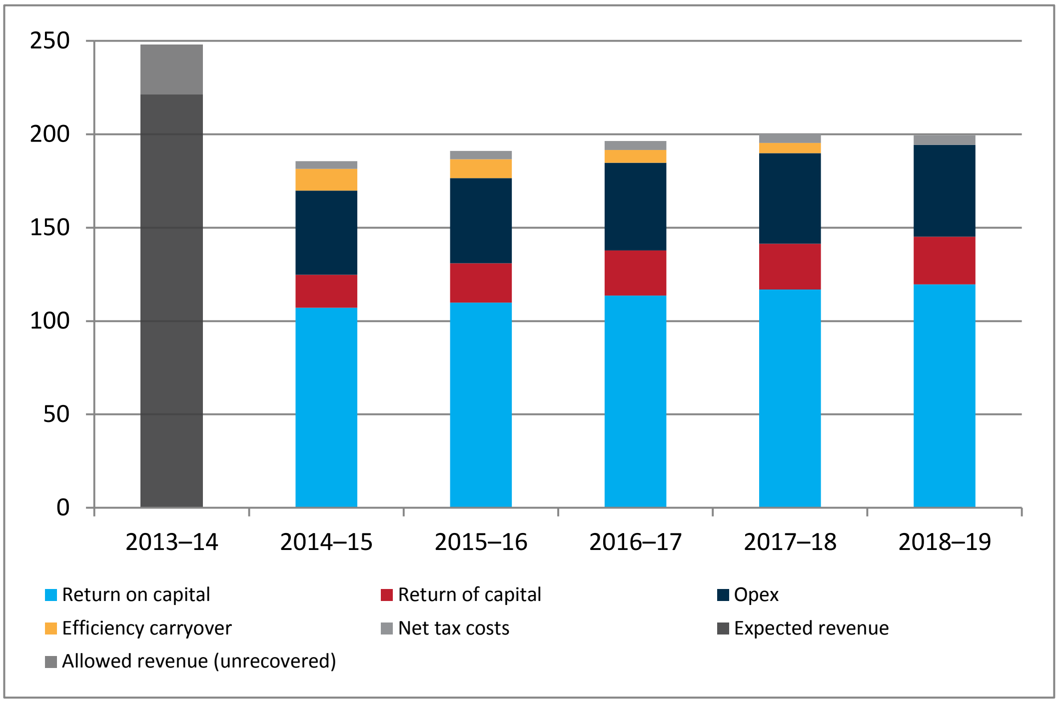
Our proposed revenue reflects the anticipated efficiencies built into our reduced capital and operating expenditure forecasts, as well as our reduced return on equity for the coming period. In addition, we have adjusted our depreciation profile to reduce transmission charges over the next five years. Our 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	107.1	109.8	113.6	116.8	119.6	**567.0**
Return of capital (regulatory depreciation)	17.6	21.1	24.2	24.6	25.6	**113.1**
Total operating expenditure	45.1	45.6	47.0	48.5	49.1	**235.4**
Efficiency carryover	11.7	10.1	6.9	5.5	0.0	**34.1**
Net tax allowance	4.1	4.4	4.8	4.8	5.2	**23.3**
Annual building block revenue requirement—unsmoothed	**185.6**	**191.1**	**196.4**	**200.2**	**199.5**	**972.9**

Figure E.3 provides a chart showing the annual building block revenue requirements for the forthcoming regulatory period, compared to our allowed and expected revenue for 2013–14.

Figure E.3 Annual building block revenue requirements ($m nominal)



Based on these building block revenue requirements, Table E.2 presents:

- the unsmoothed building block revenue requirement in nominal terms;
- the smoothed maximum allowed revenue in nominal and real terms; and
- the proposed X factors (the annual percentage reductions relative to CPI) for the forthcoming regulatory period.

Table E.2 Revenue and X factors, 2014–15 to 2018–19 ($m)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	Total revenue
Building block revenue requirement (unsmoothed) in $nominal		185.6	191.1	196.4	200.2	199.5	**972.9**
Maximum allowed revenue (smoothed) in $nominal	247.9	186.9	190.7	194.5	198.4	202.4	**973.0**
Maximum allowed revenue (smoothed) in $2013–14	247.9	182.3	181.4	180.5	179.6	178.7	**902.6**
X factor		26.46%	0.50%	0.50%	0.50%	0.50%	

As noted earlier, we decided to recover $26 million less than our allowed revenue in 2013–14. The smoothed revenue in 2014–15 is therefore:

- 26.5 per cent lower in real terms than our $247.9 million allowed revenue allowance for 2013–14;
- 17.7 per cent lower than the $221.5 million actual revenue we expect to recover in 2013–14; and
- $18 million lower than the AER's $205.1 million placeholder revenue for 2014-15.

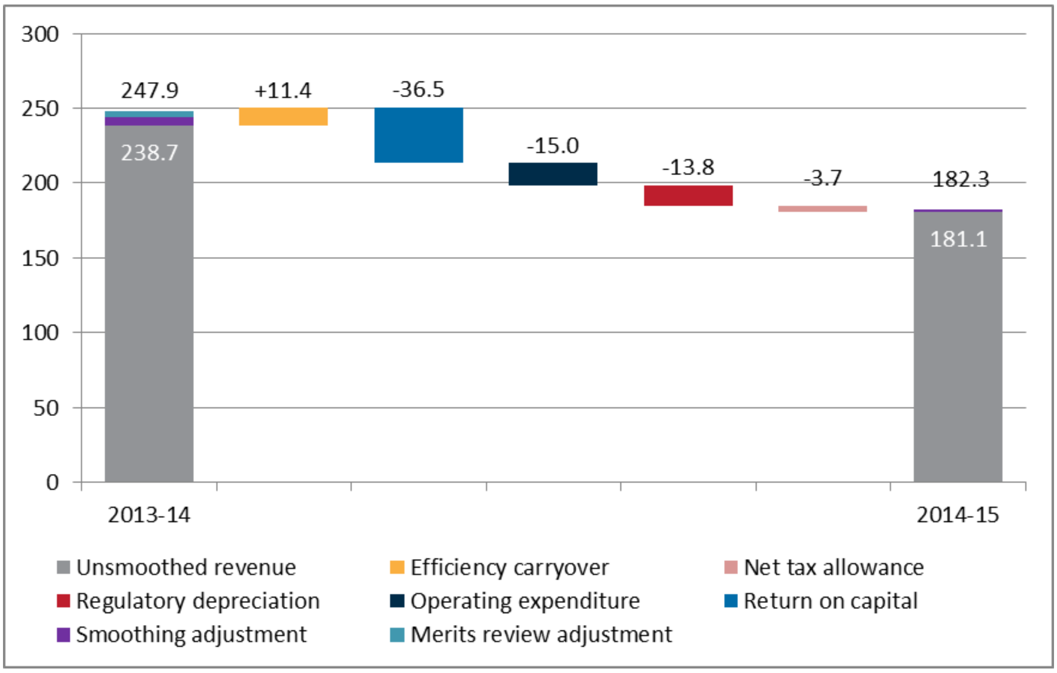
The 2014–15 reduction reflects our decision to adopt lower expenditure forecasts, depreciation and cost of capital allowances, compared to the indicative forecasts included in our transitional proposal.

We have taken the view that transmission prices for 2014–15 should be set to recover our updated revenue requirement of $186.9 million (smoothed), rather than the higher placeholder amount. Beyond the first year, our proposed revenue reduces further, by 0.50 per cent per annum each year, in real terms.

Figure E.4 shows the various elements that contribute to the difference between the maximum allowed revenue for 2013–14, and our proposed maximum allowed revenue for 2014–15. It is noted that:

- A technical "smoothing adjustment' is applied to the building block revenue in each year in accordance with the Rules. For 2013–14, the adjustment also includes a bonus payment for better-than-target service performance,
- The "merits review adjustment" in 2013–14 removes the revenue impact of a determination by the Australian Competition Tribunal to true-up revenue, which ceases to have effect from 1 July 2014; and
- The 2014-15 revenue will be adjusted upwards by $1.3 million to reflect the incentive payment for good service performance in the 2013 calendar year.

Figure E.4 Differences between 2013–14 and 2014–15 revenues ($m 2013–14)



How total revenue requirements convert to customer price outcomes depends on future energy consumption and demand, as well as other adjustments such as the amount of intra-regional settlements revenue recovered each year from AEMO. It also depends on the impacts of the service incentive scheme.

Figure E.5 shows the proposed average price path per megawatt hour (MWh) of energy delivered in Tasmania over the next five years based on the amounts in Table E.2. This is compared with our revenue entitlement and expected revenue for the 2013–14 year. Energy delivered is based on our medium energy consumption forecast.

Figure E.5 Average price impact of Revenue Proposal ($/MWh)

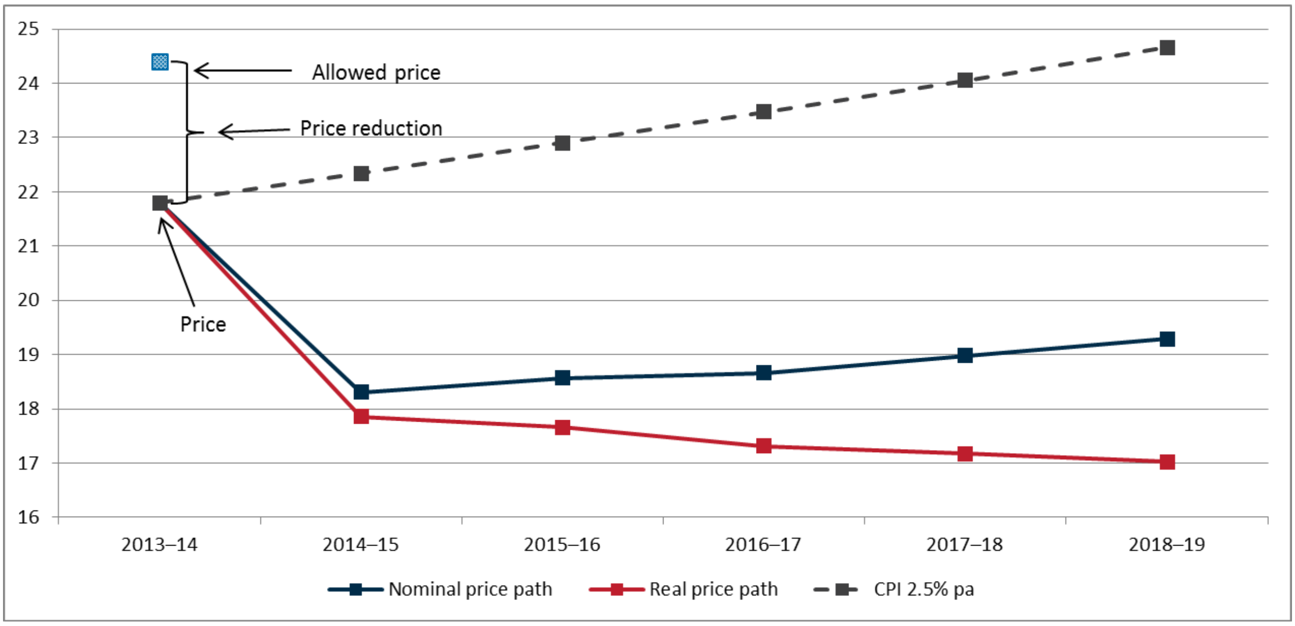


Figure E.5 shows that average transmission prices are expected to fall in 2014–15 and then increase slightly thereafter in nominal terms (the blue line).

Average prices in nominal terms at the end of the next period are expected to be less than in 2013–14.

Compared to inflation (the grey line), average transmission prices will be well below the forecast CPI of 2.5 per cent per annum. As a consequence, average transmission prices in real terms (the red line) are expected to decline.

Table E.3 shows the approximate impact of our Revenue Proposal on average residential and business customer bills. It illustrates that this proposal will result in a drop in prices initially, followed by annual increases that are below inflation. In other words, against a basket of other goods and services, average transmission prices will become relatively cheaper over the coming five years.

Table E.3 Average annual price impact on customers ($nominal)

		Average annual charge 2013–14[1]	Impact on annual charge				
			2014–15	2015–16	2016–17	2017–18	2018–19
Weighted average residential annual charge	Total	$2,256	-$54	+$4	+$1	+$5	+$5
	Transmission component	$338	-$54 (-16.0%)	+$4 (+1.4%)	+$1 (+0.5%)	+$5 (+1.7%)	+$5 (+1.6%)
Weighted average small business annual charge	Total	$3,782	-$91	+$7	+$2	+$8	+$8
	Transmission component	$567	-$91 (-16.0%)	+$7 (+1.4%)	+$2 (+0.5%)	+$8 (+1.7%)	+$8 (+1.6%)

The actual prices paid by particular customers will be determined by our transmission pricing methodology, and therefore will differ from the indicative average set out above.

1 Total charges are from AER fact sheet, Transitional decisions: TransGrid and Transend 2014–15, March 2014. Transmission component is 15 per cent as per Tasmanian Economic Regulator, Comparison of 2014 Australian standing offer energy prices, March 2014.

Conclusions

We are responding to customer and consumer feedback by balancing the need for reliable and secure provision of electricity supply with a continued focus on efficiency and cost control.

In the current regulatory period we have:

- improved operating practices, increased efficiency and implemented effective cost controls;
- prudently allocated capital to fund required investments;
- been innovative about managing risk to reduce expenditure; 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;
- 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 and reduced the return from our assets 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. To protect our customers, we have taken the initiative to propose the lowest sustainable maximum allowed revenue; we have not left this responsibility to the AER.

Our proposal puts further downward pressure on prices for all electricity consumers. Reducing expenditure levels any further would result in excessive 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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1 Introduction

1.1 Purpose of this document

Under the National Electricity Law (NEL) and the National Electricity Rules (the Rules), the Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission services.

In accordance with the Rules, the AER conducts a periodic review every five years to determine our revenue requirements for provision of prescribed electricity transmission services. This submission sets out the main elements of our Revenue Proposal for the five-year period from 1 July 2014 to 30 June 2019. Our Revenue Proposal also includes:

- An overview paper which explains the Revenue Proposal in plain language and explains how we have engaged with consumers; and
- Completed templates and supporting information as required by the Rules and the AER's Regulatory Information Notice (RIN).

This Revenue Proposal follows the earlier submission of our transitional Revenue Proposal that covers the first year of this five-year regulatory period. The purpose of the transitional Revenue Proposal was to establish 'placeholder' revenue for the transitional year. We submitted our transitional Revenue Proposal on 31 January 2014 in accordance with the Rules and the AER made its transitional decision on 31 March 2014.

In reviewing our Revenue Proposal, the AER will revisit our transmission revenue requirements for the transitional year, 2014–15. Depending on the AER's further review, adjustments may be made to our revenue allowance to reflect the AER's updated decision.

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.
- Chapter 3 discusses our customer engagement process and the issues arising.
- Chapter 4 discusses our recent cost and service performance.
- Chapters 5 and 6 explain our capital and operating expenditure forecasts.
- Chapter 7 presents details of the operation of the expenditure incentive schemes applying to us.
- Chapter 8 provides information regarding the value of the regulated asset base.
- Chapter 9 describes the depreciation allowance.
- Chapter 10 explains the weighted average cost of capital and regulatory tax allowance.
- Chapter 11 presents our total revenue requirement for the regulatory control period and the resulting average price path.
- Chapter 12 outlines our proposed cost pass through arrangements.
- Chapter 13 describes the service target performance incentive scheme that will apply in the forthcoming regulatory period.

The actual and forecast expenditures in this proposal relate to the provision of prescribed transmission services. The forecasts reflect our cost allocation methodology as approved by the AER, and are consistent with:

- our capitalisation policy, which remains unchanged from the current regulatory period; and

- the application of the AER's incentive schemes that encourage cost and service efficiencies over time.

It should be noted that:

- 'Actual' operating and capital expenditure for 2013–14 are latest estimates.
- All monetary values presented in this proposal exclude GST, and numbers and tables throughout the proposal may not add up due to rounding.
- The expenditure forecasts do not contain any costs arising from transactions with related parties.

We do not claim confidentiality in relation to any part of this Revenue Proposal document. Where confidentiality is claimed in respect of any appendices or supporting documents, a redacted version is provided along with details of the claim for confidentiality.

2 Business and operating environment

2.1 About Transend and TasNetworks

At the time of this submission Transend is the electricity 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 Tasmanian 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 the distribution network; and generation imports from other NEM states across Basslink. Our transmission network delivers energy to the distribution network and to directly-connected industrial customers. Basslink is also a load point on the Tasmanian transmission system when energy is being exported to Victoria.

From 1 July 2014 Transend will merge with the distribution business of Aurora Energy, creating TasNetworks, a state-owned company incorporated and operated in Australia. TasNetworks is owned by two shareholder Ministers who hold shares on behalf of the State of Tasmania. It is governed by a board of non-executive directors, and managed by the TasNetworks leadership team.

TasNetworks will become the electricity TNSP in the Tasmanian region of the NEM. Transend has therefore prepared this Revenue Proposal on behalf of TasNetworks, in consultation with the TasNetworks board and leadership team. The new organisation will be focused on finding opportunities to improve performance, including through engagement with customers. In terms of the maintenance, operation and planning of the transmission system, however, the transition to the new business should be a seamless one. References in this submission to 'we', 'our' and 'us' may either be references to Transend or TasNetworks, depending on the context.

2.2 Focus

TasNetworks' vision is to be trusted by our customers to deliver today and create a better tomorrow. Building on the foundations established by its predecessors, TasNetworks will create a customer-focused, vibrant, efficient and sustainable business with engaged, high performing staff.

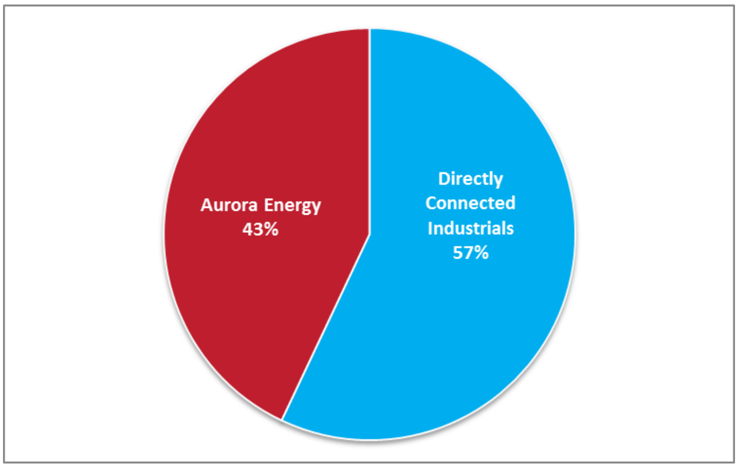
A key aim is to create a single business that operates a single network in terms of planning, capital investment, operations and maintenance, while recognising the distinct transmission and distribution responsibilities under the Rules. Our initial focus is to:

- care for our assets, delivering a safe and reliable network service;
- engage with and understand our customers, making them central to all we do;
- work with our people to enable them to deliver value, and to develop the values, culture and behaviours to support our objectives; and
- transform our business through developing a plan to streamline practices, processes and systems to realise the efficiencies from a single network business.

2.3 Customers

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

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



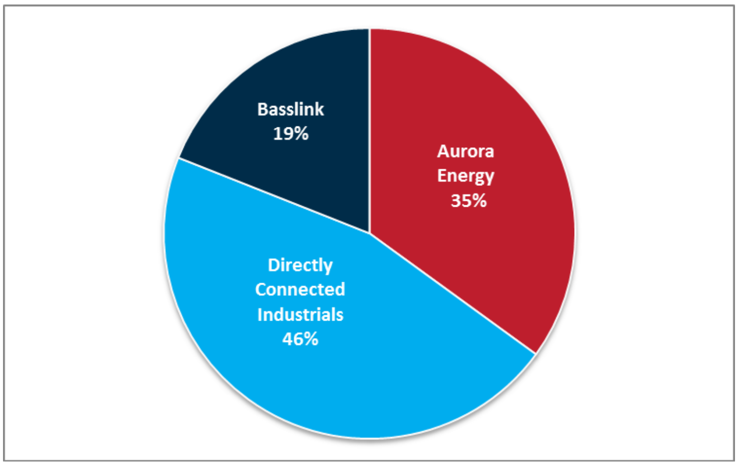
Our customers operate across a range of business sectors. They have a diverse range of operational requirements that affect their demands on the transmission system and how we interact with them in terms of managing outages and emergency response. Our current customers are identified in Table 2.1. Some 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	timber processing and veneer plant
Grange Resources Tasmania	open cut mine at Savage River and iron ore pelletising plant at Port Latta
Gunns (liquidator appointed)	woodchip mill
Hellyer Gold Mine	underground mine and primary ore processing plant
Norske Skog	newsprint mill
Nyrstar	zinc smelter
MM Group Rosebery	underground mine and primary ore processing plant
TEMCO	ferromanganese and silicomanganese smelting furnaces and sinter plant
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 across Bass Strait

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[2]. This will increase the volatility of Tasmanian transmission prices and is discussed further in section 2.7.4 below.

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)[3]

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%**

2.4 Tasmanian transmission system

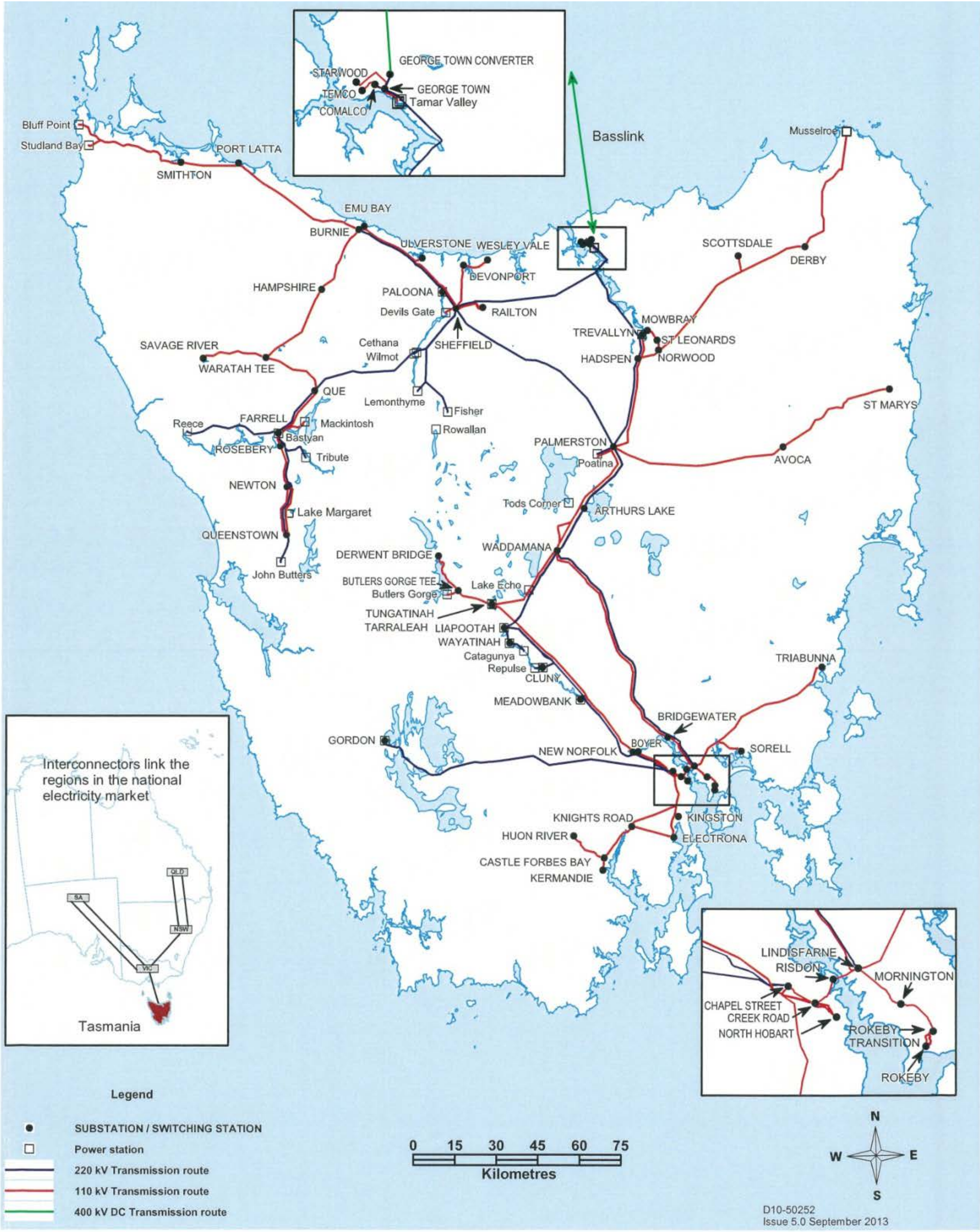
The Tasmanian electricity transmission system is characterised by a backbone network predominantly operating at 220 kV that links the main generators to major load centres, including major industrial customers. A transmission network operating predominantly at 110 kV connects other generators and regional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

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

[3] As at November 2013.

Figure 2.3 Tasmanian transmission system 2013



Tasmania's transmission system was developed predominantly to connect remotely located hydro 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. Lower voltage assets such as these are typically characterised by higher operating costs relative to their asset value. This reflects that the lower voltage assets tend to have lower capital costs, but similar operating costs.

Our 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. This also reflects that the lower voltage assets tend to have lower capital costs, but similar operating costs. 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.

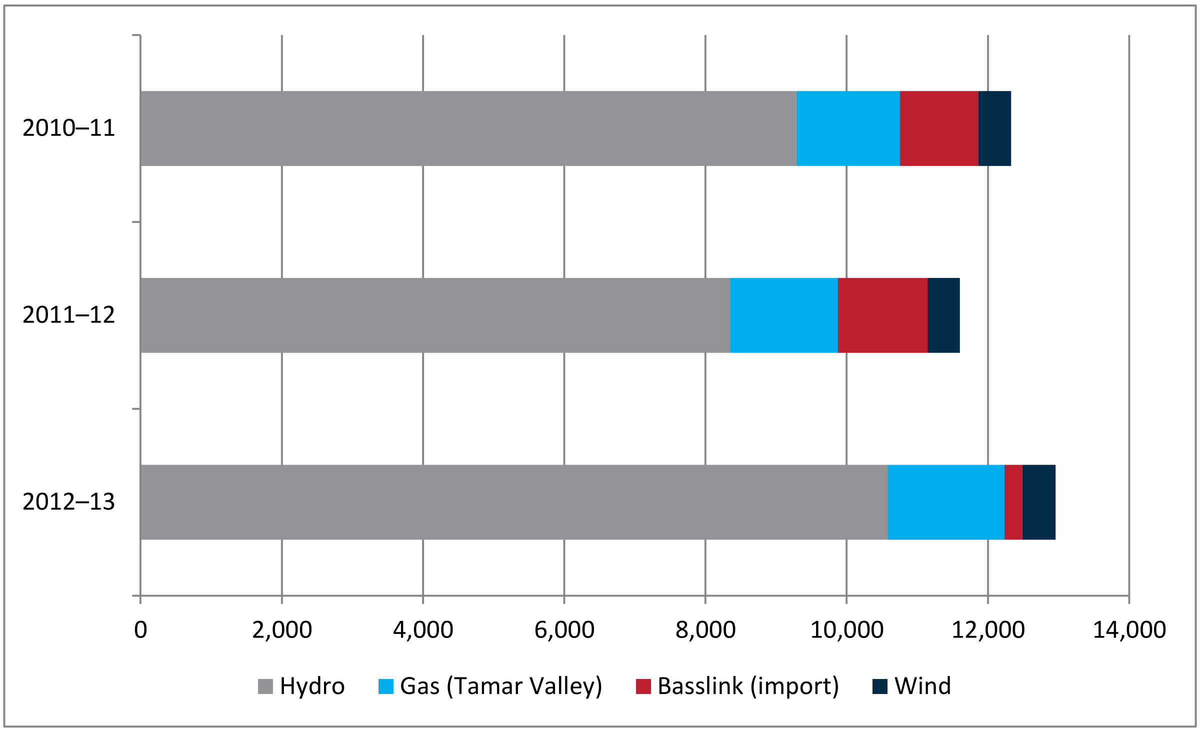
Many of our assets are in remote, mountainous terrain which contributes to increased construction, maintenance and operational response costs. Construction costs in Tasmania are also affected by the cost of transporting equipment to Tasmania, a smaller market for design, construction and maintenance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

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. 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.

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



The electricity transmission system telecommunications network is a vital component of the transmission system, providing operational and business telecommunications services.

The telecommunications network enables remote operation of the system, facilitates protection, control and monitoring of assets, and provides the means of communicating generation and metering data to enable Tasmania's operation in the national electricity market. The telecommunications network also supports efficient operation of the business through voice and data services.

The extent of the telecommunications network is illustrated in Figure 2.5.

Figure 2.5 Tasmanian communications network

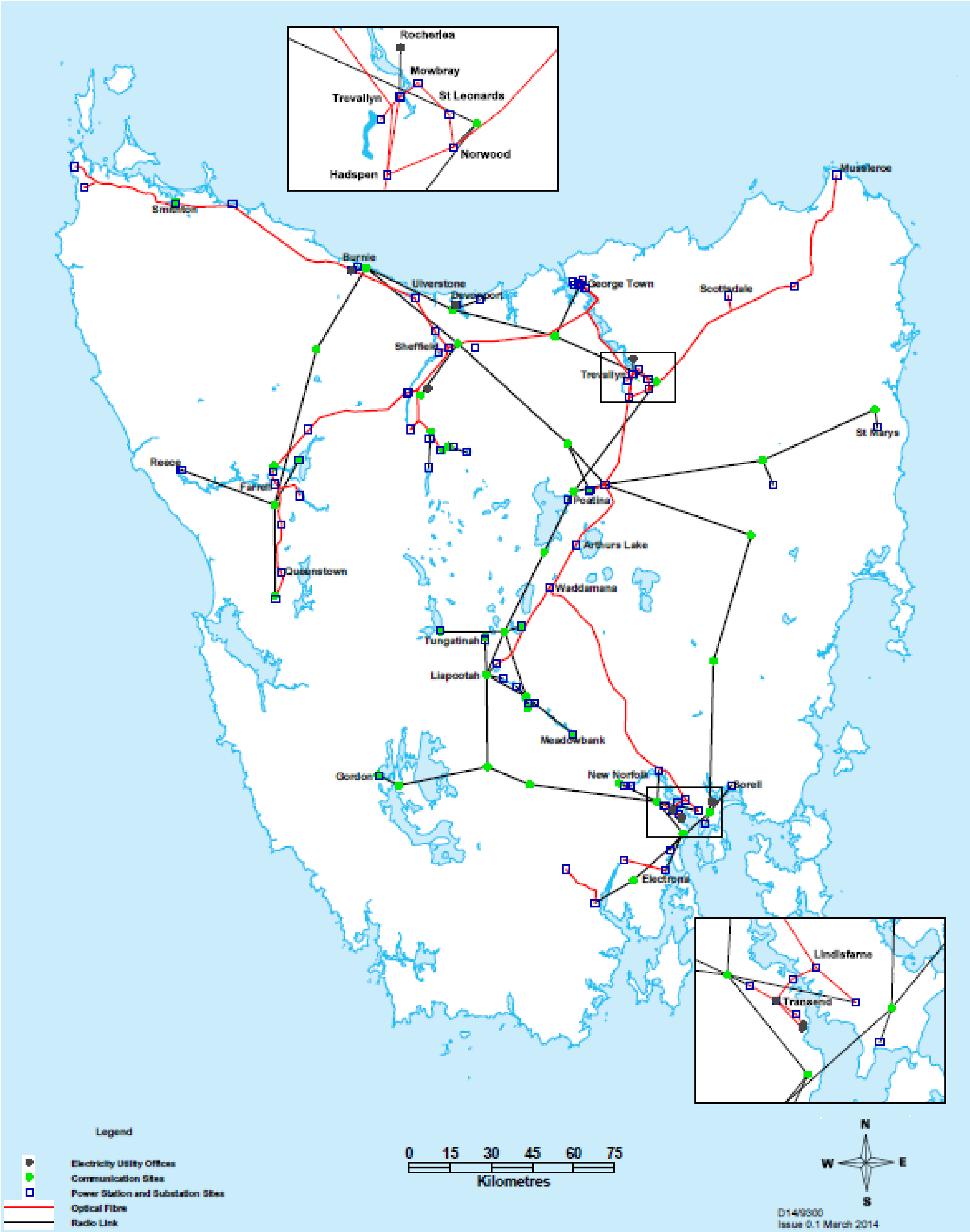


Table 2.3 lists the main components of our transmission system.

Table 2.3 Tasmanian 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

2.5 Recent market conditions

Transend lodged its last Revenue Proposal in a pre-GFC world: Asian markets were flourishing; commodity prices were booming; and electricity networks throughout Australia were delivering very large investment programs to renew aging networks and meet 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).

Policy regarding the pricing of carbon pollution was being developed and debated, however a flourishing renewable energy industry, supported by renewable energy targets had developed. Tasmania had been in drought, with electricity imports from Victoria across the Basslink interconnector supporting Tasmanian energy needs.

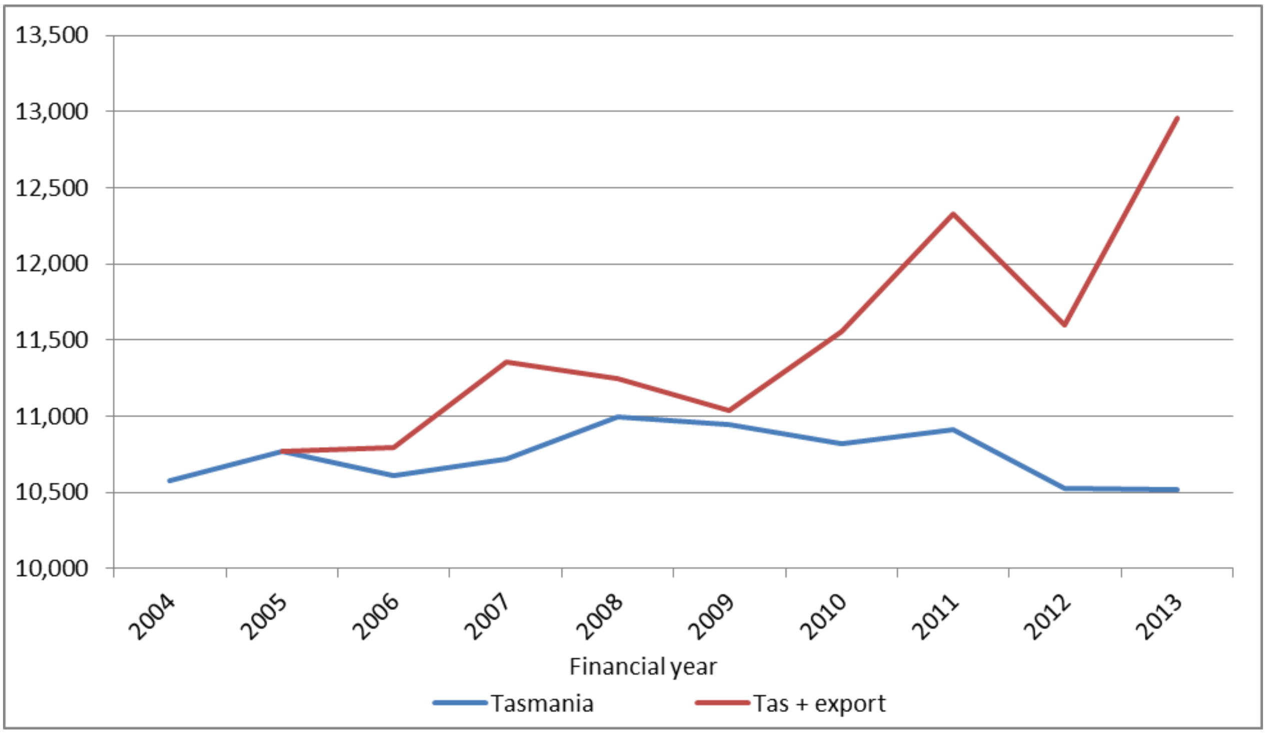
In the intervening years, there has been a marked increase in delivered energy prices throughout Australia. Customers have responded with increased energy efficiency measures and a move to distributed generation, with uptake of solar photo-voltaic (PV) equipment contributing to a fall in energy delivered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

A price on carbon was introduced by the Gillard Government in 2012. A new gas-fired generator and higher rainfall in Tasmania contributed to increased Tasmanian water storages, and record levels of energy flows to the Victorian region of the NEM occurred as Hydro Tasmania exported carbon-free energy to the rest of the NEM.

Across Australia, significant structural changes are occurring within 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.

Figure 2.6 presents annual data on total energy transmitted in Tasmania over the past 10 years. Local electricity consumption peaked in 2008 at almost 11,000 GWh and has been trending down since then. Despite the fall in local sales, the total amount of energy transmitted by us has increased, reflecting the transmission network's role in exporting electricity to the rest of the NEM.

Figure 2.6 Energy transmitted (GWh)



Despite the growth in energy exports, state-wide peak demand 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 NEM. Many of our customers continue to face challenging market conditions, amid an uncertain economic outlook in Tasmania. In view of these market conditions, to support our customers we under-recovered our revenue entitlement in the current period. Our Revenue Proposal for the forthcoming regulatory period is focused on further reducing our total revenue requirements in real terms by delivering efficiency savings in controllable operating and capital expenditure.

2.6 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 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 some of AEMO's functions and recover the cost from prescribed transmission customers; and
- specific obligations arise from our transmission licence, which is issued by the Tasmanian Economic Regulator.

The Tasmanian Economic Regulator licences us, under section 19 of the ESI Act, to operate as a TNSP in Tasmania[4]. The transmission licence requires us 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 our 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[5].

2.7 Industry and regulatory development

TasNetworks and our customers face some important industry and regulatory changes over the forthcoming regulatory period. A number of these developments will have longer term operational and pricing implications. In this section, we highlight the following developments:

- Transend's merger with Aurora Energy's distribution business;
- 'Better Regulation' Rule changes which have introduced new provisions and obligations;
- The Australian Energy Market Commission's (AEMC) Transmission Frameworks Review;
- The introduction of inter-regional transmission charges; and
- Tasmanian transmission reliability standards.

Each of these important developments is discussed in turn below.

2.7.1 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;
- 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 a number of sources:

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

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

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

Transend and Aurora Energy have already been operating under a collaboration model, which has provided opportunities to reduce duplication between the two businesses. Full network integration is the next step in delivering network service efficiency savings.

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 transmission revenue requirements include efficiency improvements from the merger.

2.7.2 '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;
- the assessment of the expenditure forecasts contained in revenue proposals;
- 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 data and information, for both ongoing reporting and as part of this Revenue Proposal.

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. Despite the improvements we've made, we receive feedback that our customers want even more engagement. As part of TasNetworks, we will continue to work closely with electricity consumers and improve engagement.

2.7.3 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 Revenue Proposal.

2.7.4 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.

While 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.

2.7.5 Reliability standards

In Tasmania, transmission planning criteria are set out in the Electricity Supply Industry (Network Planning Requirements) Regulations 2007. These regulations set out minimum Network Planning Requirements covering situations where there are supply interruptions during normal operating conditions and for exposure when a network element has been withdrawn from service. Broadly, an N-1 reliability standard applies in Tasmania combined with parameters relating to maximum loss of load (MW) or unserved energy (MWh).

In 2013, we supported amendments to the transmission reliability standards in Tasmania. The amended regulations provide for a lower standard to apply where there is insufficient customer benefit to justify an augmentation that has been proposed in Transend's Annual Planning Review. The amended regulations set out a process under which the affected customers can agree to accept the lower reliability standard. If customers agree that the augmentation should not proceed, Transend would be precluded from proposing the augmentation for a period of five years.

Transend considers that the amended transmission reliability standards provide an additional assurance that an augmentation will only proceed if it delivers a net benefit to customers. Our capital expenditure forecasts in this Revenue Proposal include only those projects that satisfy this requirement.

In addition to the recent amendments to the Tasmanian reliability standards, the AEMC has recently completed a review that examined the national framework for setting transmission reliability standards. The AEMC has recommended a framework, which it considers will deliver the following benefits for customers[6]:

- economically determined reliability standards so that customers, as a group, pay for a level of reliability consistent with their preferences;
- transparency around the reliability standard setting process to facilitate stakeholder understanding and to enable customers to contribute to the process of determining the appropriate level of reliability; and
- consistency in how reliability performance is reported, to improve understanding and facilitate benchmarking.

The full implementation of the framework for transmission reliability is likely to require a number of changes to the Rules, jurisdictional legislation, the National Electricity Law and the Australian Energy Market Agreement. In its December 2013 meeting communiqué, the Standing Council on Energy and Resources (SCER) noted that Ministers welcomed the AEMC's reports on transmission and distribution reliability standards and agreed to further work on the national frameworks.

In considering the impact of the national framework for transmission reliability standards on our capital expenditure plans, we note that:

- the detailed design and application of the framework in Tasmania is yet to be developed; and
- the implementation timeframes are such that the new framework is unlikely to be implemented in the forthcoming regulatory period.

We also note that our capital expenditure forecasts in the forthcoming regulatory period are modest, reflecting low demand growth projections. Therefore, even if the new framework were introduced more quickly than expected, it may not have a material impact on our expenditure plans for the forthcoming regulatory period.

[6] AEMC, Final Report, Review of the national framework for transmission reliability, 1 November 2013, page v.

3 Consumer engagement

3.1 Introduction

This chapter explains how we have engaged with consumers in the course of developing our Revenue Proposal, and how the feedback we have received has shaped our Revenue Proposal and plans for the future.

The chapter is structured as follows:

- Section 3.2 outlines our approach to consumer engagement.
- Section 3.3 describes the activities we have undertaken to engage with our directly-connected transmission customers, and the outcomes of those activities.
- Section 3.4 describes the outcomes of our engagement with consumers that are connected to the distribution network.
- Section 3.5 outlines our future direction for consumer engagement.

3.2 Our approach – strengthening relationships

In November 2012, a change to the National Electricity Rules—'Economic Regulation of Network Service Providers'—introduced new provisions aimed at improving engagement between network businesses and consumers. The Rule change is founded on the view that effective engagement will assist network businesses in providing services that are aligned with consumers' long term interests.

Following the Rule change the AER published a consumer engagement guideline, which sets out a framework for network companies to better engage with consumers. The guideline is based on the following best practice principles, to achieve communication and consumer engagement that is:

- clear, accurate and timely;
- accessible and inclusive;
- transparent; and
- measurable.

Our approach to consumer engagement is consistent with the AER's guideline. In fact, we have a long-standing consultative approach in developing our forward plans.

In developing this Revenue Proposal, our approach has been informed by the core values adopted by the peak international body for consumer engagement, the International Association of Public Participation (IAP2). In particular, our approach is focused on ensuring that:

- we consider the needs and preferences of consumers in our business decisions; and
- we become more accessible, transparent and inclusive in our dealings with consumers.

For the purpose of undertaking consumer engagement, we divide consumers into two groups:

- transmission customers, those who are directly connected to the transmission network; and
- all other electricity consumers, those who are connected to the distribution network.

Our engagement approach is tailored to reflect the different requirements and preferences of these two groups. The information obtained through the engagement process informs our expenditure plans and, more broadly, our strategic direction. We recognise, however, that our consumer consultation practices are still developing and will continue to improve over time, as we work towards embedding better consumer engagement throughout our business.

Further information on the outcomes from our engagement process is provided in sections 3.3 and 3.4.

3.3 Engagement with transmission customers

3.3.1 Overview of engagement activities

Over many years we have developed strong relationships with our transmission customers to take account of their needs and preferences in our decision making.

The table below provides a summary of the engagement activities we have undertaken with our transmission customers.

Table 3.1 Our engagement activities—transmission customers

Timing	Activity
Ongoing	Operational and strategic interaction. Ongoing dialogue with customers through customer account managers and other staff on operational matters, strategic topics, relationship management and customer service. Face-to-face meetings and written communication with affected customers on identified network issues and potential solutions, including network investment and non-network options.
Annually (March)	Customer survey. We have surveyed our transmission customers since 2005 to gain an insight into their perception of our customer service. These surveys have been a valuable tool to help us determine where best to focus our efforts to improve customer satisfaction.
Annually (From May 2013)	Customer consultation on 2013 corporate plan. For the first time, we provided customers with a summary of our Corporate Plan. We highlighted that the strategy and planned expenditure was indicative of our future Revenue Proposal. The Corporate Plan outlined targets to be achieved in the key result areas of shareholders' value, customer service, people (including safety), organisational efficiency and effectiveness, market and regulatory framework, asset management and environmental excellence.
Annually (July to August)	Annual Planning Report consultation and forum, including publication of Fact Sheets. All customers are invited to provide feedback on the identified transmission system issues and proposed solutions, and may offer non-network alternatives to address the issues.
January 2014	Feedback sought from customers on Customer Charter.
	Engagement activities specifically related to this Revenue Proposal
In the lead up to this revenue proposal (July 2013–February 2014)	Face-to-face meetings with customers on the Revenue Proposal. Customer consultation on our proposed Forecasting Methodology. Customer consultation on our pricing methodology. Customer consultation on our negotiating framework. Customer consultation on our Transitional Revenue Proposal. Meetings with customers and their consultants and representative groups. This included meetings with the Major Employers Group, meetings and provision of materials to a consultant engaged by the Major Employers Group, and meetings with members of 'The Big Picture' campaign. Transmission customers also attended a number of other briefings and information sessions, including the Energy Users Association Tasmanian forum, where information on the Revenue Proposal was discussed and briefings offered.
March–April 2014	Review of outcomes of customer engagement, submissions received on the Transitional Revenue Proposal and consideration of issues raised, in finalising this Revenue Proposal.

As noted in Table 3.1, we have an ongoing dialogue with customers through customer account managers and with a range of other staff on operational matters, strategic topics, relationship management and customer service.

During the development of our Annual Planning Reports and in conducting our Annual Planning Forums we work closely with our transmission customers, to:

- identify emerging constraints and other network issues;
- assess the impacts of these issues; and

- consult on proposed solutions, including network investment and non-network solutions to address identified needs.

Our approach to planning and operating the network is focused on meeting the changing needs of our customers. We work closely with customers to obtain information on their plans and requirements, and to obtain specific feedback on our performance. For example, we try to coordinate customer maintenance outages and our outage planning. We have adopted a 'planning from the customer' approach, in which increased contact and information sharing is undertaken in the early stages of planning. This ensures that the solutions we deliver meet the needs of our customers.

We have consulted with customers who are directly impacted by each transmission network issue potentially requiring network solutions. As a result of this consultation, some network investment has been deferred or avoided, as the affected customers expressed a preference for us to maintain current service standards. In other cases, customers have actively supported strengthening the network in order to improve the level of service they receive.

In the course of preparing this Revenue Proposal we have met face-to-face with all our transmission customers to:

- outline the key elements of our proposal;
- listen to customer feedback; and
- discuss the ways in which we might address customer feedback.

The results of recent customer surveys demonstrate we have improved in terms of objective measures (such as reliability and availability) and in terms of subjective measures (such as customer satisfaction). We have significantly improved customer satisfaction, with overall satisfaction improving from 73 per cent in 2012 to 91 per cent in 2013, and slightly reducing to 86 per cent in 2014 (see Appendix 1). A small number of customers considered our service to them had worsened over the last year, whilst the significant majority have indicated service has lifted and or been maintained over the last year. These results reflect our commitment to focus on valued customer outcomes with a strong commitment to service. The survey results also indicate that there are areas where our engagement can be further improved.

To improve our service performance in response to the 2013 survey outcomes, we have implemented a number of initiatives including:

- development of individual customer service strategies and management plans;
- a customer relationship management system;
- a customer service training program for our staff; and
- a transmission customer service charter.

Although recent surveys indicate that customers consider our current communication to be good, we continue to seek to improve.

Section 3.3.2 summarises the feedback we have received from our transmission customers, and explains how we are responding. Section 3.3.3 provides some case studies which demonstrate how customer feedback has changed our plans.

3.3.2 Responding to customer feedback

Table 3.2 summarises the main messages we have received from our transmission customers, and the actions we are taking to address the issues raised.

Table 3.2 What customers are telling us, and what we are doing in response

<table>
<tr><th>Customer feedback</th><th>Our response</th></tr>
<tr><td>Prices
You should reduce prices so that we can maintain financial sustainability.</td><td>We agree and we have responded accordingly.
For the financial years ending 2013 and 2014, we have responded to customers' needs and charged less than the revenue allowed by the AER. The result is that over the last two years of the current regulatory period, our customers are collectively receiving a discount of more than $37 million.
Under our proposal, we plan to deliver further savings to electricity consumers. For example:
We will not recover the $37 million foregone.
We have factored in immediate operating cost savings from merger efficiencies, and set ourselves the target of achieving real controllable cost reductions for each of the following four years. This is in the face of significant new obligations from the AER and AEMO that make these savings harder to achieve.
We have improved our condition-based risk management approach to managing our assets, and used the information to reduce our replacement capital expenditure in certain areas.
We have proactively adjusted our depreciation profile, to reduce transmission charges by $13 million per annum.</td></tr>
<tr><td>Service
You should maintain the current level of service for the same or lower cost—you need to be more efficient.</td><td>We agree.
Over the next regulatory period we will reduce our revenue requirements, maintain current service performance and ensure the safety and security of supply.</td></tr>
<tr><td>Demand
Tasmanian demand is flat. Network augmentations are not required. You should seek new ways to manage demand, and work with your customers to seek non-network solutions.</td><td>Our analysis confirms that future augmentation requirements will be very much lower than the recent past.
We will monitor load growth and work with our customers to deliver efficient and innovative solutions to manage demand and meet system security requirements.</td></tr>
<tr><td>Asset utilisation
Latent capacity exists in the network. Maximise the way you use your existing assets and don't augment the system. Work with your customers to seek non-network solutions.</td><td>We will continue to apply dynamic line ratings, network control schemes and other industry–leading measures to ensure that we maximise the capacity of existing assets.
We will work closely with our customers and stakeholders to explore non-network solutions to address emerging constraints and other network issues efficiently.</td></tr>
<tr><td>Efficiency
Set yourselves tougher targets and seek innovative solutions to issues identified in the network.</td><td>We are reducing our operating costs.
We have factored in immediate operating cost savings from merger efficiencies, and set ourselves the target of achieving real controllable cost reductions for each of the following four years. This is in the face of significant new obligations from the AER and AEMO that make these savings harder to achieve.
We continue to review and refine our asset management practices and our capital estimating, programming and delivery, to incorporate best practice and deliver efficient solutions over the asset lifecycle.
We are setting ourselves challenging operating expenditure targets and will continue to seek innovative solutions to achieve further efficiencies in our operating and capital expenditure.</td></tr>
<tr><td>Rate of return
The rate of return is too high.</td><td>We understand our customers are facing economic challenges. We are prepared to accept a lower return on our capital over the next 5 years, to support longer-term customer sustainability.
In this Revenue Proposal we have adopted a cost of capital of 7.87 per cent, compared to 10 per cent in the current regulatory period. We have obtained independent expert advice indicating that there is strong evidence to support a cost of capital that exceeds our proposal.</td></tr>
<tr><td>Regulated asset value
The regulated asset base value should be reduced.</td><td>The current Rules provide reasonable certainty to network owners regarding the regulatory value of assets. This is intended to reduce risk associated with investing in very long-lived assets, thus promoting efficient investment in networks for the long term interests of electricity consumers.
We have proactively adjusted our depreciation profile, to defer the return of capital and reduce transmission charges by $13 million per annum. Our proposal means it will take us longer to recover the investment made in our assets. We have accepted this risk in order to reduce customer charges.</td></tr>
<tr><td>Transitional Revenue Proposal
Submissions to the AER on the Transitional Revenue Proposal.</td><td>We have reviewed the submissions to our Transitional Revenue Proposal and Appendix 2 summarises how we have responded to the feedback.</td></tr>
</table>

In summary, customers want existing service standards to be maintained at lower prices. We have responded to this feedback and constructed this Revenue Proposal with a view to delivering that outcome.

3.3.3 Case studies

Table 3.3 provides some case studies of our response to customers' needs and feedback in developing our Revenue Proposal, and in managing our business more broadly.

Table 3.3 Addressing customers' needs

Customer need / issue	Our response
Transmission costs should be reducing	We are aware of the challenging market conditions many of our customers face and the increases they have seen in their transmission charges over the last 10 years. As noted in the previous section, we have responded by reducing our revenue and cutting costs, with our customers collectively receiving a discount of more than $37 million over the last two years. We are targeting to continue to reduce revenue in real terms in the forthcoming period. We continue to look for innovative ways to drive down costs.
Balancing service and cost	Savage River Substation is supplied from a radial low capacity single 110 kV circuit. Under the jurisdictional network planning requirements a load of the size connected to Savage River Substation should be supplied with a more reliable arrangement than is currently the case. In addition, during hot windless periods in the summer, the safe capacity of the single circuit is reduced to below that needed to supply the full load. Our Annual Planning Reports in 2012 and 2013 identified that the supply to Savage River Substation did not meet the Tasmanian network planning requirements. A transmission customer and consumers connected to the distribution network in the areas around Savage River and Waratah are affected. To address the reliability issues, we initially considered a network solution that would increase the capacity of the existing 110 kV circuit to remove the summer constraints, and proposed a second circuit to meet the reliability requirement. Detailed analysis was provided to affected customers, including the likely price impacts. The consultation process resulted in a decision not to undertake the network augmentation. Affected customers decided to accept the current level of service and a risk of unplanned outages.
Exploring non-network solutions	The transmission link between the north and south of Tasmania— the Waddamana-Palmerston 220 kV corridor—has limited capacity and there is a need to address that limitation to deliver market benefits and meet the jurisdictional network planning requirements. We are consulting with major customers—and one in particular—to identify possible use of their loads to provide network support, to avoid or defer network augmentation. It is not yet clear whether a non-network solution will be feasible in this instance. However, this case study illustrates how effective consumer engagement is essential in exploring non-network solutions.

3.4 Consumer engagement

3.4.1 Overview of engagement activities

As explained in section 3.2, for the purpose of undertaking consumer engagement, we divide consumers into two groups:

- transmission customers, those who are directly connected to the transmission network; and
- all other electricity consumers, who are connected to the distribution network.

As an electricity transmission business, Transend had limited experience in engaging directly with consumers and worked with the distribution business, Aurora Energy, to understand the views of these consumers. Anticipating the finalisation of the AER's consumer engagement guideline in November 2013, we commissioned Straight Talk, a specialist community engagement consultancy, to assist us in designing and implementing a consumer engagement program.

The work undertaken by Straight Talk had two strands:

- To engage with consumers to understand their views on the potential impacts, risks and benefits to our Revenue Proposal.
- To work with us to develop an approach to consumer engagement based on best practice, with a view to embedding that approach into our business culture and processes.

Engagement with Straight Talk confirmed our understanding that:

- Consumers of electricity generally have a very poor understanding of the processes and organisations involved in electricity supply.
- A Revenue Proposal is a complex and technical document that is not readily accessible to consumers.

In view of these considerations, we decided to combine two approaches in order to achieve breadth and depth in the consumer consultation process: a survey and deliberative forums.

Firstly, a telephone survey of consumers was undertaken in December 2013 to reach a wide and representative sample of consumers. This method was adopted to obtain initial feedback on consumers' understanding of the electricity industry and broad priorities in relation to electricity services. Telephone surveys are the favoured tool for researching consumer preferences when a large random sample is required.

Survey respondents provide a 'top of mind' response and so surveys are limited in that respect. However the responses have helped us gauge some consumer insights—to understand what is important to consumers and start the conversation about the trade-off between price and reliability. The survey results are attached at Appendix 3.

To augment the information obtained from the telephone survey, Straight Talk facilitated two deliberative forums (one in Hobart and the other in Launceston). A deliberative approach recognises that consumers can provide important insights when provided with access to information and an environment in which they can deliberate and weigh up options. In order to ensure the approach had validity, participants were selected to match the demographics of Tasmanian electricity consumers.

The engagement activities facilitated by Straight Talk have been complemented by a range of other activities where electricity consumers are involved, such as:

- annual planning forums;
- meetings with consumer representatives;
- consultation on our Corporate Plan, Forecasting Methodology and Transitional Revenue Proposal; and
- trying new ways to communicate with consumers, including consumer-friendly fact sheets on price, supply-chain, demand forecasting, and reliability.

Preparation of this Revenue Proposal involved regular engagement with the Office of the Tasmanian Economic Regulator's Customer Consultative Committee, to inform members of the process and seek feedback on our plans. This committee comprises many peak consumer bodies, and all members were offered individual briefings.

We conducted briefings and engagement with the following consumer representative groups:

- Tasmanian Small Business Council;
- Energy Users Association of Australia;
- Tasmanian Council of Social Service;
- Tasmanian Farmers and Graziers Association; and
- Tasmanian Chamber of Commerce and Industry.

3.4.2 Summary of feedback from consumers

The key findings of our consumer engagement activities are that:

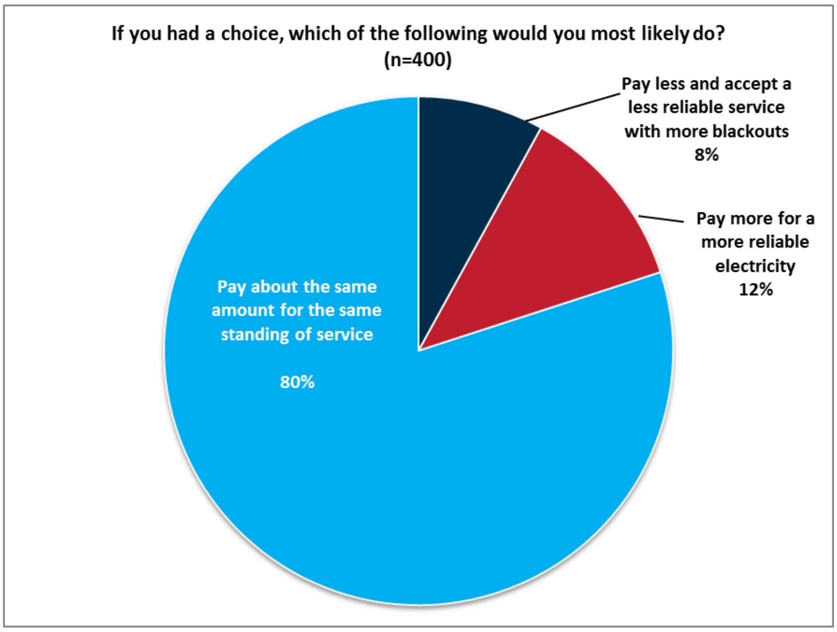
- While consumers are happy with the proposed reduction in transmission revenues, they remain concerned with the impact of electricity prices overall, particularly on those least able to pay and small businesses.
- Reliability was a major factor for all participants and, while consumers do not wish to pay more for improved reliability, they also feel that long outages are not acceptable.
- Improved communication is a major theme across both the Hobart and Launceston workshops. Consumers wanted to understand and learn more about the electricity industry, supply chain and markets so they can provide more detailed and considered feedback.
- Consumers considered us to be experts with regard to the technical decision making, and want us to be accountable for achieving what we say we intend to do.

Overwhelmingly, consumers connected via the distribution network want to see a reduction in the price of electricity. However, they were sceptical about how much difference a reduction in transmission costs would have for consumers, given that these costs only make up 15 per cent of the overall retail electricity price for the average residential consumers.

In terms of the price and reliability trade-off, there are no clear, unambiguous answers about whether price or reliability—the two major issues for consumers identified through both the telephone survey and the workshops—should be our primary objective. In particular, the risk of a less reliable service was not accepted as a trade-off for lower prices. By the same token, an increase in reliability was also not supported if it came at a higher price.

Figure 3.1 illustrates consumers' views of the trade-off between price and reliability.

Figure 3.1 Price and reliability trade-off



In analysing these results, Straight Talk observed:

> To the extent that consumers seem unable to bear a trade-off in either direction, it is possible that reliability and price happen to be an exactly optimum level, but it is more likely that "loss aversion" is dominating consumer thinking on these issues. Loss aversion is a well observed phenomenon where people feel losses more keenly than gains of equal objective magnitude. This means that we will satisfy consumers best by making sure neither price rises, nor falls in reliability, are experienced by customers.[7]

More detailed information on the consumer engagement methodology and feedback can be found in the consumer engagement outcomes report in Appendix 4.

3.4.3 Addressing consumers' feedback

A clear message from consumers is concern about rising electricity prices and the importance of maintaining existing service levels. This Revenue Proposal responds to this feedback by delivering lower costs whilst maintaining existing service levels. This will be very challenging to achieve—even with efficiencies we will deliver from the network merger. We recognise the importance of keeping downward pressure on prices for all electricity consumers.

Consumers want us to focus on communication, engagement and education. As noted in the following section, our engagement strategy and implementation plan takes this feedback into account.

[7] Straight Talk, Consultation with consumers- Outcomes Report: Transend's Revenue Proposal for the regulatory control period 1 July 2014 - 30 June 2019, 19 March 2014, page 17. See Appendix 4.

3.5 Future direction

To deliver the lowest sustainable prices for customers, our decision making will continue to focus on customer outcomes: driving customer value and a strong commitment to service. To deliver value to our customers we will continue to seek efficiencies and minimise costs to the extent there is no compromise to safety and reliability.

We recognise that our approach to consumer engagement will continue to develop over time. The insights and information gathered from Transend's recent engagement activities, together with activities undertaken by Aurora Energy, will assist TasNetworks to develop an ongoing consumer engagement plan.

Table 3.4 sets out the principles that will guide our approach to consumer engagement, based on the International Association for Public Participation principles, and our goal to each of these engagement principles.

Table 3.4 Principles to guide future consumer engagement

Public Participation Principles	Our goals
Public participation is based on the belief that those who are affected by a decision have a right to be involved in the decision making process.	We aim to engage with consumers on decisions and plans that may affect them. Recognising that the cost of consumer engagement is borne by the consumer, we will do this in a cost-effective way.
Public participation includes the promise that the public's contribution will influence the decision.	We will be clear about the level of influence consumers' input can have and communicate that at the outset. We will be clear about what is negotiable and what is not, and what we must do in order to meet its statutory and regulatory requirements.
Public participation promotes sustainable decisions by recognising and communicating the needs and interests of all participants, including decision makers.	We will facilitate conversations and utilise methods of communication to understand the needs, interests and preferences of consumers.
Public participation seeks out and facilitates the involvement of those potentially affected by or interested in a decision.	We will actively seek the input of consumers affected by or interested in a decision. This includes those who reflect the general population of electricity consumers in Tasmania as well as those who may potentially be directly affected by a particular decision.
Public participation seeks input from participants in designing how they participate.	We will seek the input of consumers on how we engage and what we engage on.
Public participation communicates to participants how their input affected the decision	We will provide all participants in any engagement process feedback on what was said and how that information has or has not influenced the final decision, and why. We are committed to continuously improving our engagement approach.

4 Cost and service performance during the current regulatory control period

4.1 Introduction

This chapter provides an overview of our cost and service performance during the current regulatory period.

Clauses 6A.6.6(e)(5) and 6A.6.7(e)(5) of the Rules require the AER, when assessing expenditure forecasts, to have regard to the actual and expected operating and capital expenditure of the TNSP during any preceding regulatory control periods. To assist the AER with this task, this chapter examines our cost and service performance during the current regulatory period, including differences between our forecast and actual performance. The chapter also provides important context for our expenditure forecasts for the forthcoming regulatory period, which are presented later in this Revenue Proposal.

The remainder of the chapter is structured as follows:

- Section 4.2 provides an overview of some of the efficiency initiatives we have put in place this period.
- Section 4.3 describes our capital expenditure performance for the current regulatory period.
- Section 4.4 describes our operating expenditure performance for the current period.
- Section 4.5 provides an overview of our service performance over the current period.
- Section 4.6 provides some high-level benchmarking information on our performance.
- Section 4.7 sets out concluding comments.

Throughout this chapter, expenditure data presented for 2013–14 represents our estimated actual expenditure.

4.2 Overview of our efficiency focus

Throughout the current regulatory period, we have operated and maintained the transmission system and delivered required capital works to provide a safe and reliable service. We have met our customer service obligations while maintaining a sharp focus on the efficiency of our operations.

A focus on efficiency is consistent with our organisational objectives and the design of the regulatory framework. We have undertaken a range of initiatives to ensure that every dollar is spent efficiently and have implemented initiatives to:

- Improve the governance and delivery of capital projects;
- Optimise our expenditure plans;
- Manage service performance, including through outage optimisation;
- Ensure that safety is never compromised;
- Find innovative ways to manage risks; and
- Reduce expenditure while promoting cultural change and performance improvements.

In the current regulatory period we have successfully delivered initiatives in each of these areas. For example:

- We completed a review of business processes for capital project initiation, development and finalisation and implemented improvements arising from it. We also reviewed our business management systems against the Australian Business Excellence Framework. Efficient business processes and systems help us deliver the capital and operating works program in a timely and cost-effective manner, for the long term benefit of our customers.

- We continue to identify ways to optimise our capital program through joint planning activities with our customers. In some cases this has led to projects being deferred or implementation of more cost-effective operational solutions to manage network contingencies and issues.
- In 2010–11, we consolidated our Hobart-based staff at the Maria Street site. This significant undertaking involved moving telecommunications services personnel and the Customer and Asset Management Group from leased premises in Moonah. Having all southern staff on one site and telecommunications services integrated into the organisational structure has provided operational efficiencies.
- In 2011–12 we implemented the Outage Optimiser tool, which enables outage scheduling for optimal network performance. It allows outages to be planned for times of least impact and helps to minimises the number of planned outages through enhanced coordination of the work plans of various parties. We expect this initiative to help us maintain our level of asset availability, whilst minimising operating expenditure.
- In 2011–12 the independent auditor certified that our safety system meets the criteria of the Australian Standard, AS 4801. Another notable achievement was the delivery of Safety Circle training to all employees and managers throughout the company.
- We have found innovative ways to manage risks. For example, we worked with the Tasmanian Government to review the Tasmanian transmission network planning requirements, to allow customers more say in the security (and consequent reliability) of service they receive relative to the cost. We also worked with our customers to better understand their businesses and operations, which helped us to find mutually beneficial ways to undertake work and manage customer issues.
- Our operating cost savings program has been highly successful in implementing efficiencies to drive down operating expenditure, despite continued increases in our obligations as a transmission network service provider. We have reduced our expenditure through reductions in both contracted services and employee numbers. We have made difficult decisions, which have involved staff redundancies, to sustainably reduce our cost base.

4.3 Capital expenditure performance

We have delivered the required capital program and invested significantly less than the regulatory allowance. Capital expenditure during the current regulatory period is expected to be $577.2 million, which is $115.3 million less than the AER's allowance of $692.5 million. Because we have not charged customers our full revenue entitlement, customers have only funded those works required during the period.

Table 4.1 provides a breakdown of our actual capital expenditure in the current regulatory period by category compared to the AER allowance.

Table 4.1 Allowed and actual capital expenditure by category ($m 2013–14)

Category	2009–14 Allowance	Historical expenditure 2009–14	Variance
Augmentation	242.1	190.5	-51.5
Connection	126.0	68.9	-57.1
Land and easements	24.1	0.6	-23.5
Development capex	**392.2**	**260.1**	**-132.1**
Asset renewal/enhancement	203.7	245.2	41.6
Physical security/compliance	22.1	14.4	-7.7
Inventory/spares	12.1	9.9	-2.3
Operational support systems	23.9	15.9	-8.0
Renewal/enhancement capex	**261.7**	**285.4**	**23.7**
Information technology	19.1	6.4	-12.7
Business support	19.5	25.3	5.8
Support the business capex	**38.6**	**31.7**	**-6.9**
Total	**692.5**	**577.2**	**-115.3**

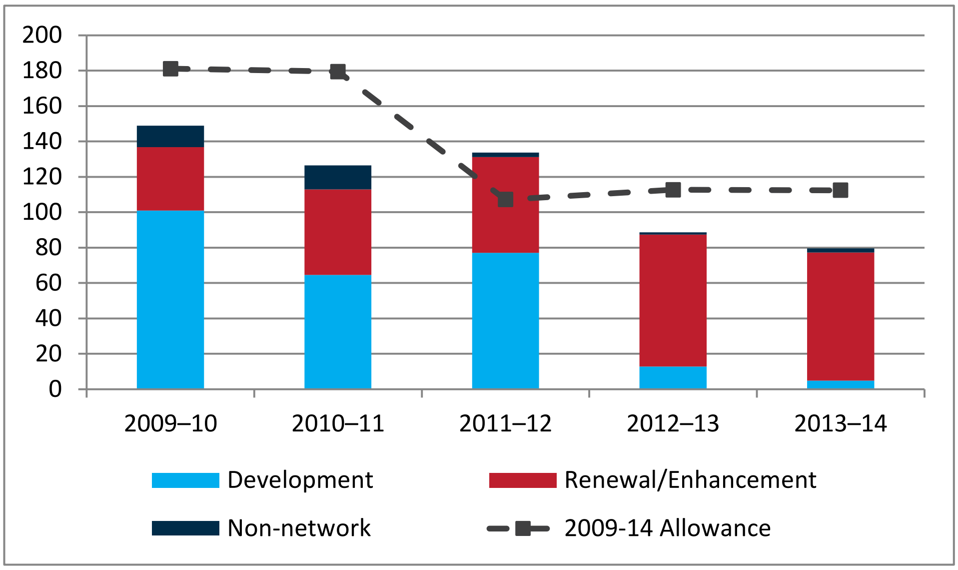
Table 4.2 provides a further breakdown of our historic capital expenditure by category for each year of the current period.

Table 4.2 Annual capital expenditure by category ($m 2013–14)

Category	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Augmentation	89.2	37.2	49.6	10.2	4.4	190.5
Connection	11.8	27.2	27.2	2.4	0.2	68.9
Land and easements	0.0	0.0	0.1	0.2	0.3	0.6
Asset renewal/enhancement	18.9	43.3	44.5	69.1	69.6	245.2
Physical security/compliance	5.2	2.3	3.7	2.2	1.0	14.4
Inventory/spares	9.7	0.0	0.0	0.1	0.1	9.9
Operational support systems	2.0	2.9	6.1	3.3	1.7	15.9
Total Network	**136.8**	**112.8**	**131.2**	**87.4**	**77.3**	**545.5**
Information technology	2.4	2.5	1.0	0.3	0.2	6.4
Business support	9.8	11.2	1.4	0.8	2.1	25.3
Total non-network	**12.1**	**13.7**	**2.4**	**1.1**	**2.4**	**31.7**
Total	**148.9**	**126.5**	**133.6**	**88.5**	**79.6**	**577.2**

Figure 4.1 provides a pictorial representation of our actual capital expenditure by major category and the AER's total allowance for the current regulatory period.

Figure 4.1 Capital expenditure ($m 2013–14)



As noted above, total capital expenditure in the current regulatory period ($577.2 million) is expected to be $115.3 million lower than the AER's allowance of $692.5 million. By expenditure category, the differences are as follows:

- Our development capital expenditure is expected to be approximately $132 million lower than the AER's allowance for the period.
- Our renewal/enhancement capital expenditure is expected to be approximately $24 million higher than the AER's allowance,
- Our support the business capital expenditure is expected to be approximately $7 million lower than the AER's allowance.

In its decision for the current regulatory period, the AER noted:

> The AER's project-specific conclusions should not be taken to bind Transend to a particular set of project-specific capex budgets. Transend has the ultimate discretion in how it spends its capex allowance. Transend is able to reorder its capital project priorities, including as a result of project delays, managing safety issues relating to its system assets and managing system reliability and security requirements.

Consequently, actual expenditure may differ to the AER's allowance for a number of reasons. Details of our actual expenditure in each of the three categories are set out below.

4.3.1 Development expenditure

Development capital expenditure in the current period is forecast to be approximately $132 million lower than the AER's allowance for the period.

During the period, a number of required development projects were delivered. The projects included the Waddamana-Lindisfarne 220 kV transmission line to Hobart's eastern shore, and establishment of the new St Leonards Substation and associated transmission line connections, 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 and Rosebery Substation; and new connections for our distribution customer at Mornington, Sorell, and Kingston. Importantly, our effective governance of these projects, together with changes in the contracting market, meant that we were able to deliver the projects required at lower than the expenditure forecast accepted by the AER.

Lower than forecast demand during the current regulatory period also reduced the level of investment required. Specifically, our total development capital expenditure was substantially lower than the AER's allowance because lower-than-forecast growth during the current period led to deferral of some augmentation and connection projects. 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 220 kV upgrade to the north-west should be deferred. This accounted for nearly all of the underspend in the land and easements category.

4.3.2 Renewal and enhancement expenditure

In the present regulatory period renewal/enhancement capital expenditure is forecast to be approximately $24 million higher than the AER's allowance.

During the period we continued our program of renewing critical system assets as they approached the end of their useful lives. A number of inputs determine an asset's useful life, including its condition; the cost to operate and maintain; whether or not the asset is compliant with obligations; and the likelihood and consequence of failure.

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 replaced 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. Implementing our optical fibre earth wire program contributed to higher than forecast renewal/enhancement costs.

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. Renewal and enhancements to these systems provides increased energy transfers across the transmission system, with minimal capital expenditure.

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

4.3.3 Support the business expenditure

In this period Support the business (or 'non-network') capital expenditure is forecast to be approximately $7 million lower than the AER's allowance. This under-expenditure was principally due to the prudent deferral of some projects—such as the information management system renewal—to enable longer-term synergies to be derived from systems developed from July 2014 to serve the merged TasNetworks business.

Operating expenditure performance

Table 4.3 provides a breakdown of our actual operating expenditure in the current regulatory period by category compared to the AER allowance.

Table 4.3 Allowed and actual operating expenditure by category ($m 2013–14)

Category	2009–14 Allowance	Actual expenditure 2009–14	Variance
Field operations and maintenance	99.4	80.3	-19.1
Transmission services	45.2	41.5	-3.7
Transmission operations	29.6	25.5	-4.1
Asset management	45.5	41.2	-4.3
Business support (Corporate)	48.8	42.8	-6.0
Total Controllable expenditure	**268.5**	**231.2**	**-37.3**
Network support (pass through of actual costs)	7.5	6.9	-0.6
Insurance premiums	6.6	4.9	-1.6
Self-insurance	4.6	4.6	0.0
Total Operating expenditure (excluding debt raising costs[8])	**287.1**	**247.7**	**-39.5**

Table 4.4 provides a breakdown of our annual historic expenditure by category.

Table 4.4 Annual operating expenditure by category ($m 2013–14)

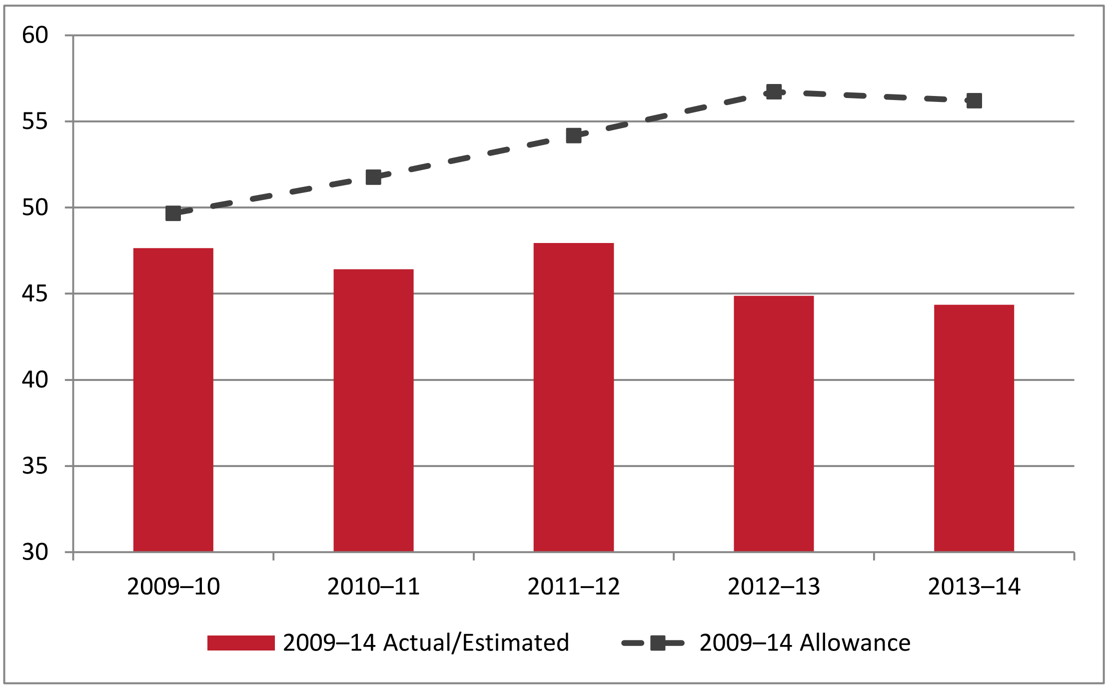
Category	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Field operations and maintenance	16.2	17.0	16.9	15.1	15.1	80.3
Transmission services	9.1	8.9	9.0	7.2	7.2	41.5
Transmission operations	5.0	4.7	5.4	5.2	5.2	25.5
Asset management[9]	8.8	7.8	8.1	8.1	8.4	41.2
Business support (Corporate)	8.6	8.0	8.5	9.2	8.4	42.8
Total Controllable expenditure	**47.6**	**46.4**	**47.9**	**44.9**	**44.4**	**231.2**
Network support (pass through of actual costs)	4.2	2.7	0.0	0.0	0.0	6.9
Insurance premiums	1.0	1.0	1.0	1.0	1.0	4.9
Self-insurance	0.9	0.9	0.9	0.9	0.9	4.6
Total Operating expenditure	**53.8**	**51.0**	**49.9**	**46.8**	**46.2**	**247.7**

Figure 4.2 provides a pictorial representation of our actual controllable operating expenditure and the AER's total allowance for the current regulatory period.

[8] An allowance of $3.3 million for debt raising costs was provided, however actual debt raising costs are accounted for as part of financing costs, not operating expenditure.

[9] The asset management category includes the cyclical revenue reset costs.

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



Our estimated actual Controllable operating expenditure during the current regulatory period is $231.2 million. This is $37.3 million or 14 per cent less than the allowance. We achieved these savings through more efficient processes and organisational transformation that led to reductions in both contracted services and employee numbers. We have made difficult decisions, which have involved staff redundancies, and we have found innovative ways to manage risks. We have made these changes 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.

Table 4.5 provides details of our Controllable operating expenditure compared to the AER allowance over the current regulatory period, including explanations of variances.

Table 4.5 Controllable operating expenditure for the current period compared to the AER allowance

Category	2009–14 Allowance	Historical expenditure 2009–14	Variance	Explanation of significant variances
Field operations and maintenance	99.4	80.3	-19.1	We have implemented a number of improvements to our maintenance strategies. We have also: • rationalised fault response rosters for substation primary and transmission line asset incidents; • reviewed and refined asset management strategies, and where it is prudent and efficient to do so, have extended maintenance intervals; and • refined a number of resourcing arrangements including internally resourcing the critical protection and control and operational communications functions. Our initiatives have enabled us to achieve significant reductions in field operations and maintenance costs. Our expenditure forecasts for the forthcoming period are built on this lower cost base.
Transmission services	45.2	41.5	-3.7	We implemented a dedicated cost savings program which identified a number of opportunities to improve efficiency and reduce costs, including a review of resourcing requirements.
Transmission operations	29.6	25.5	-4.1	Additional workload forecast to support the growing asset base has been absorbed through current period productivity improvements with further productivity improvements forecast into the next period.
Asset management	45.5	41.2	-4.3	We have embedded a number of revenue reset processes as business-as-usual functions, leading to reductions in ongoing resource requirements.
Corporate	48.8	42.8	-6.0	Additional workload forecast to support the growing asset base has been absorbed through current period productivity improvements with further productivity improvements forecast into the next period.
Total Controllable	**268.5**	**231.2**	**-37.3**	

4.4 Service performance

We have a clear focus on customer service, transmission system performance, and the efficient delivery of our capital and operating works programs. We aim to deliver a service that meets the needs and expectations of customers. The achievement of these aims is reflected in our performance against various service performance measures.

Measuring transmission service performance provides an assessment of the underlying ‘health’ of the transmission system and the level of service provided to customers.

Supply reliability and circuit availability elements of service are linked to the service target performance incentive scheme administered by the AER. The service target performance incentive scheme rewards us for improvements in performance above target levels, and penalises us where performance falls below target levels.

Table 4.6 provides details of calendar year performance against the service target performance incentive scheme targets. Further detail about the scheme, including definitions, is available at the AER’s website.

Table 4.6 Service performance

Parameter	Annual Performance					
	Target	2009 (6 mths)	2010	2011	2012	2013
Circuit availability (%)						
Transmission lines (critical)	99.13	99.92	99.47	98.34	99.69	99.41
Transmission lines (non-critical)	98.97	99.26	99.38	99.04	99.40	99.41
Transformers	99.28	99.28	99.11	98.95	98.86	99.50
Loss of supply events (number)						
Loss-of-supply > 0.1 system minute	≤ 15	5	9	11	10	10
Loss-of-supply > 1.0 system minute	≤ 2	2	2	6	2	1
Average outage duration (minutes)						
Transmission lines	326	168	275	412	120	266
Transformers	712	414	247	2,249	1,176	222

Table 4.7 provides a summary of outcomes under the service target performance incentive scheme (STPIS) during the current period.

Table 4.7 Service target performance incentive scheme outcomes

Parameter	Weighting % MAR	S-factors (%MAR)				
		2009 (6 mths)	2010	2011	2012	2013
Circuit availability						
Transmission lines (critical)	±0.20	0.20	0.11	-0.13	0.18	0.09
Transmission lines (non-critical)	±0.10	0.06	0.08	0.01	0.09	0.09
Transformers	±0.15	0.00	-0.04	-0.08	-0.10	0.05
Loss of supply events						
Loss-of-supply > 0.1 system minute	±0.20	0.20	0.20	0.13	0.17	0.17
Loss-of-supply > 1.0 system minute	±0.35	-0.35	0.00	-0.35	0.00	0.18
Average outage duration						
Average outage duration (transmission lines)	0.00	0.00	0.00	0.00	0.00	0.00
Average outage duration (transformers)	0.00	0.00	0.00	0.00	0.00	0.00
Total	±1.00	**0.11**	**0.35**	**-0.41**	**0.33**	**0.57**

Table 4.7 shows that throughout the current regulatory period, with the exception of 2011, our improved service meant that we received bonus payments under the STPIS.

Figure 4.3 on the following page shows details of our performance against the STPIS targets for each individual performance measure.

Figure 4.3 Annual performance against STPIS targets

Figure 4.3 shows that our performance against a number of measures deteriorated in 2011. The temporary reduction in critical transmission circuit availability in 2011 was primarily due to an increase in planned outages required to complete the following work:

- Palmerston Substation bay replacement;
- Provision of Optical Ground Wire on the Sheffield-Burnie 220 kV transmission corridor; and
- Corrective work to replace defective insulator strings on the Waddamana-Lindisfarne 220 kV transmission line.

The performance for loss of supply events greater than one system minute in 2011 was unexpectedly poor as a result of six loss of supply events recorded at different locations, with various causes including:

- ancillary equipment issues causing loss of supply at Kingston Substation;
- a transformer circuit tripping due to wildlife incursion during planned work, causing loss of supply at Sorell Substation;
- a transmission circuit tripping due to an unknown cause (suspected to be a cable), causing loss of supply at Rokeby Substation;
- a bus tripping due to low transformer oil level, causing loss of supply at Newton Substation;
- a transmission circuit tripping due to human error during planned work causing loss of supply at Boyer Substation; and
- a transmission circuit tripping several times due to unknown causes (suspected to be wind borne debris) with loss of supply at Kingston, Knights Road, Kermandie and Huon River Substations.

Although our loss of supply performance in 2011 was unsatisfactory, our service performance over the current period to date has generally met or exceeded targets. Our level of service performance therefore responds to the incentive scheme set by the regulator to meet the service needs and expectations of customers.

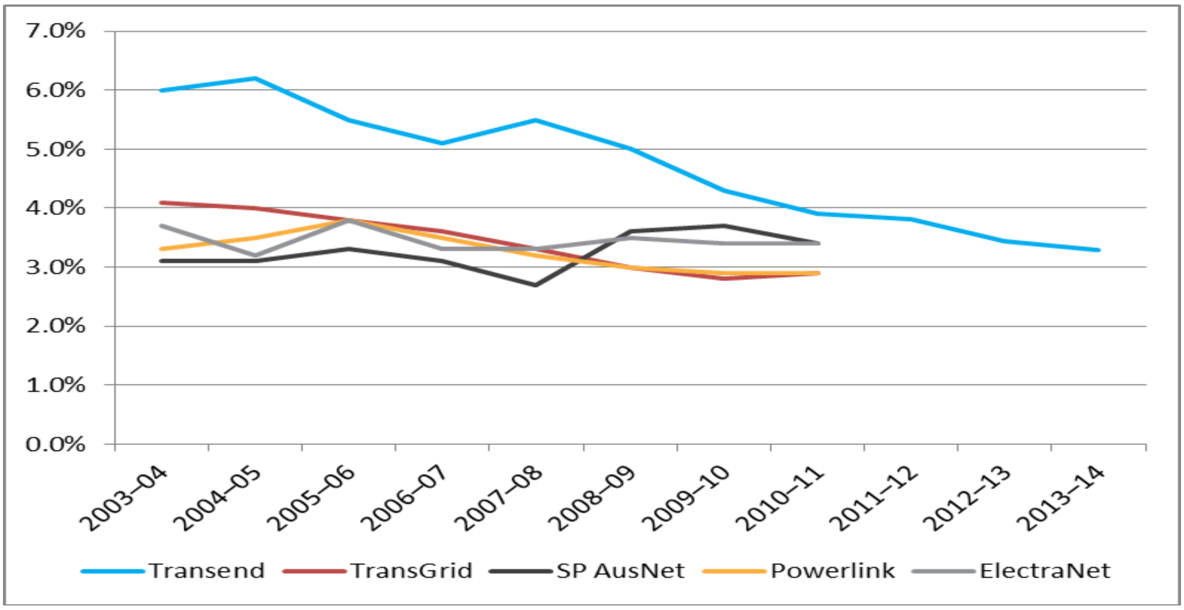
4.5 Benchmarking our performance

4.5.1 Introduction

Recent changes to the Rules increase the role of benchmarking in the regulatory process. Benchmarking is a recognised assessment technique in natural monopoly regulation as it provides all stakeholders with information to compare NSPs performance.

A useful high-level indicator of operating expenditure efficiency is the ratio of operating expenditure to the company's regulated asset base. The nature of the Tasmanian transmission system, generation and customer base, together with the scale of operations, mean that we have relatively higher operating costs relative to our asset value. The figure below shows the progress we have made compared to our peers in driving down operating expenditure as a percentage of the regulated asset base.

Figure 4.4 Ratio of prescribed opex to regulated asset base value



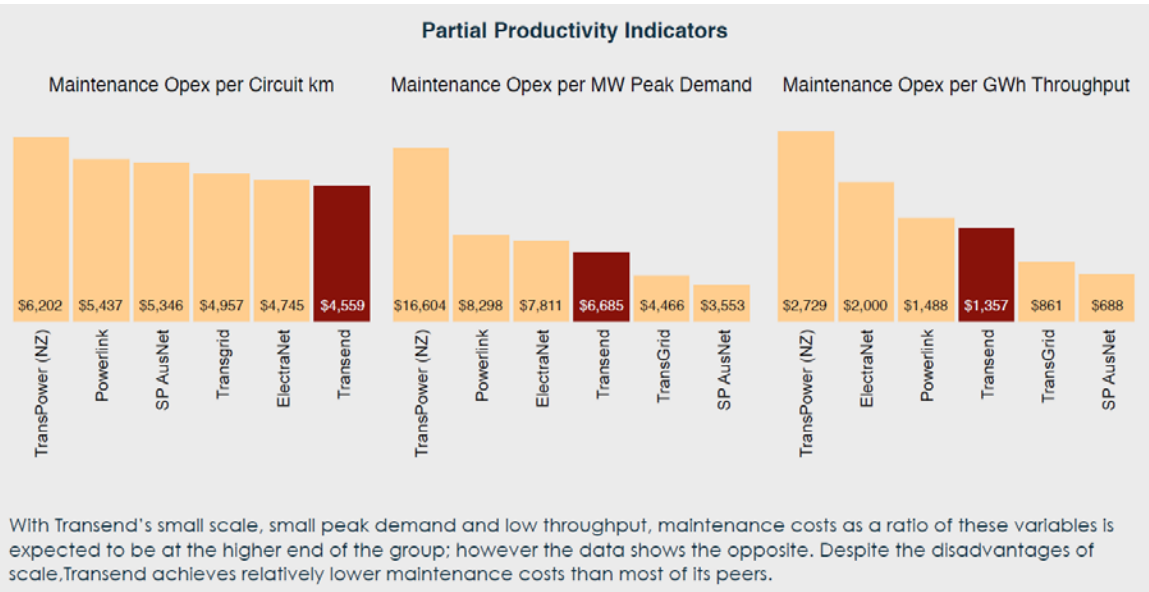
Given the complexity of undertaking benchmarking, we commissioned the Huegin Consulting Group to prepare a benchmarking study of the performance of Transend and its Australian and New Zealand peers. Huegin's report is provided at Appendix 5.

The following three sections provide a summary of Huegin's report, in terms of operating expenditure benchmarks, capital expenditure benchmarks, and overall conclusions. Section 4.5.5 briefly examines econometric benchmarking.

4.5.2 Operating expenditure benchmarks

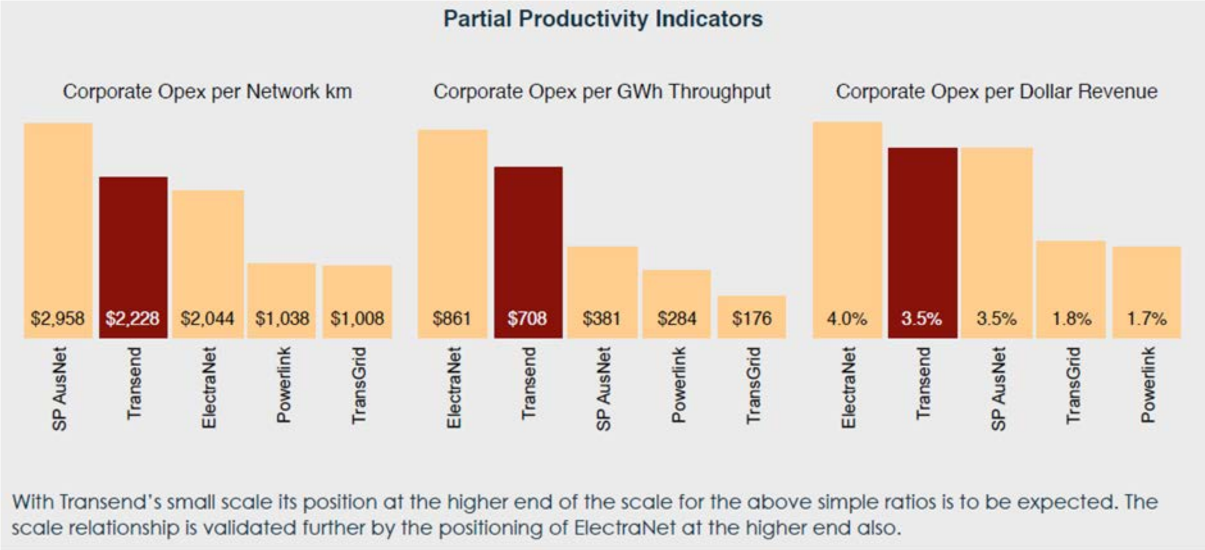
Figure 4.5 to Figure 4.9 below are reproduced from Huegin's report. They show partial productivity measures (that is, measures that consider one part of our cost base) for a range of operating and maintenance activities. The activities are grouped under the controllable operating cost categories used in this proposal. Brief commentaries on each measure are also provided.

Figure 4.5 Partial productivity indicator - Field operations and maintenance



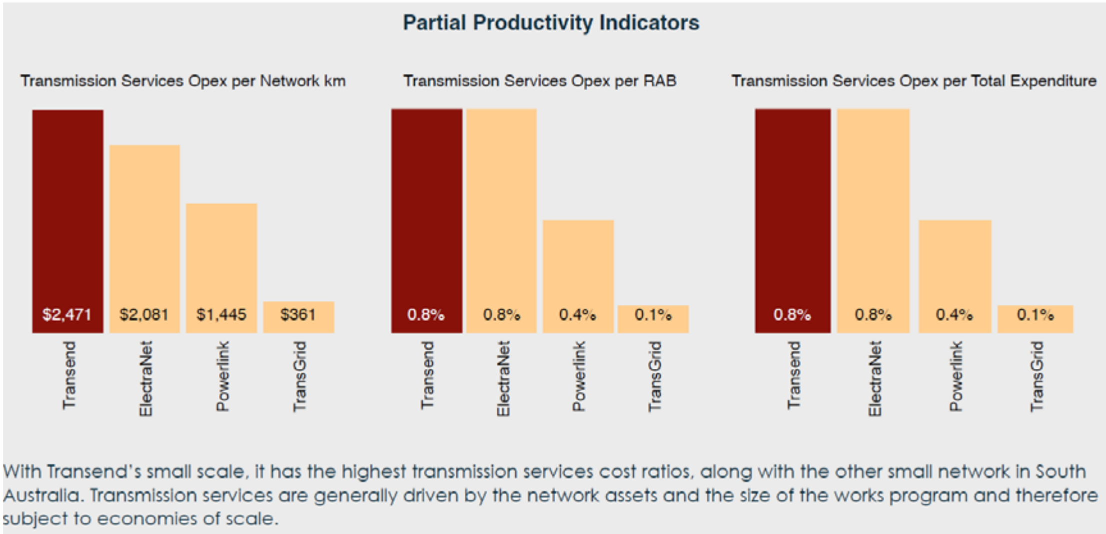
Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 30.

Figure 4.6 Partial productivity indicator - Corporate costs



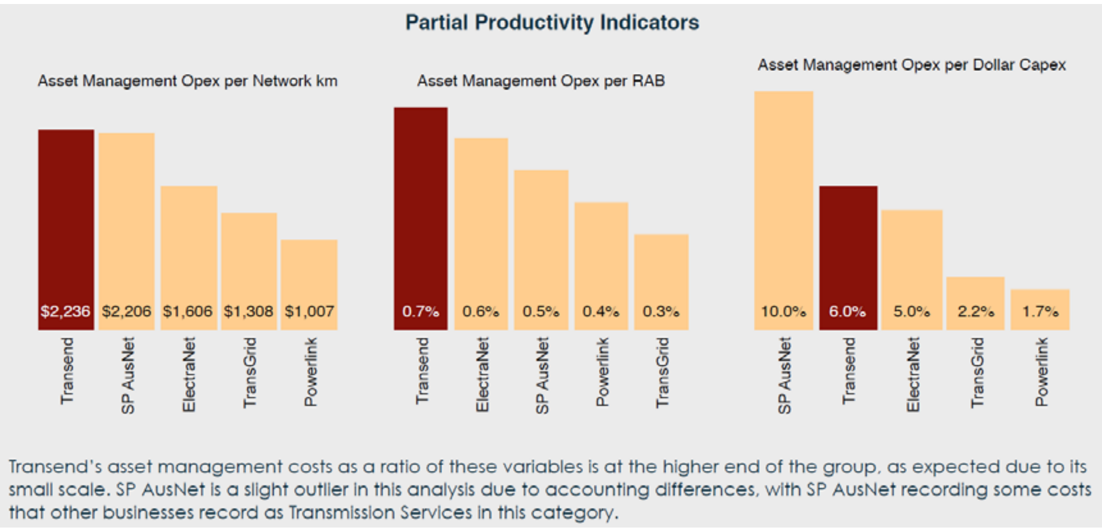
Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 34.

Figure 4.7 Partial productivity indicator - Transmission services



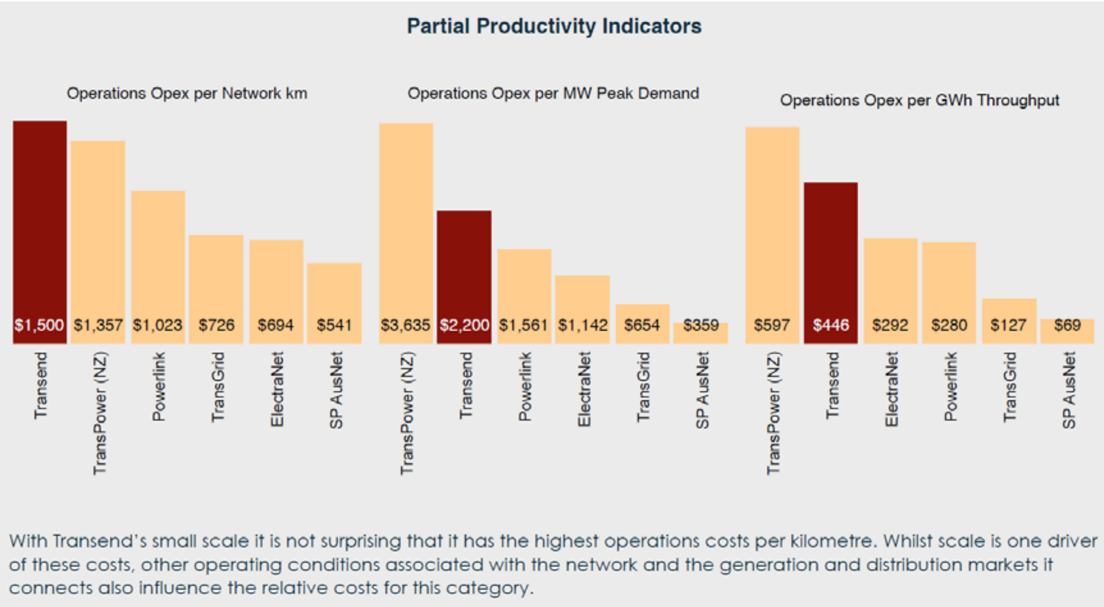
Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 38.

Figure 4.8 Partial productivity indicator - Asset management



Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 40.

Figure 4.9 Partial productivity indicator - Transmission operations

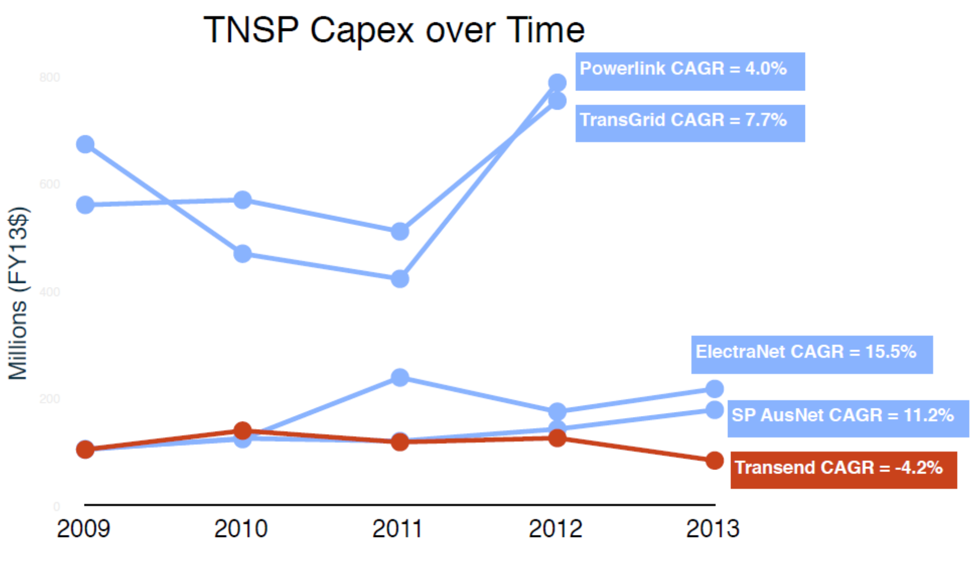


Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 42.

4.5.3 Capital expenditure benchmarks

Huegin's study also examined capital expenditure benchmarks, noting that the 'lumpy' nature and network-specific drivers of capital expenditure create significant challenges in benchmarking. Figure 4.10 shows that the compound annual growth rate (CAGR) of our capital expenditure over the four years from 2009 to 2013 was lower than the other Australian TNSPs.

Figure 4.10 TNSP capital expenditure from 2009 to 2013

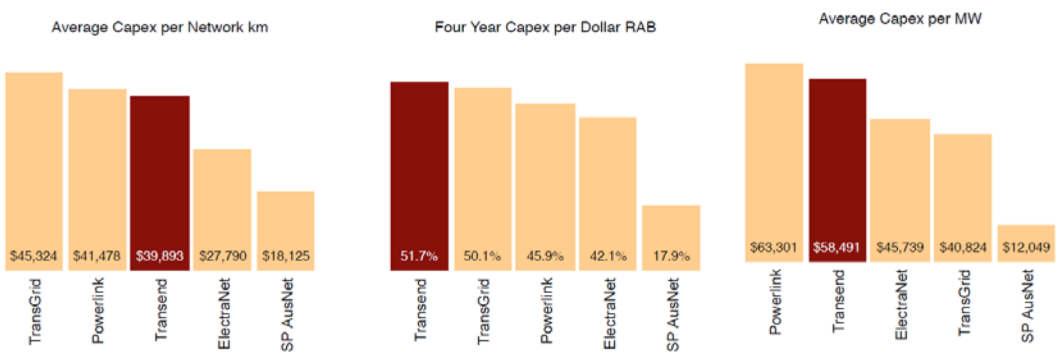


Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 48.

High level capex ratios for the four year period from 2009 to 2013 are shown in

Figure 4.11. Excluding SP AusNet (which does not include augmentation capex in its total under the unique Victorian transmission arrangements), the ranges of expenditure across Australian TNSPs are relatively similar.

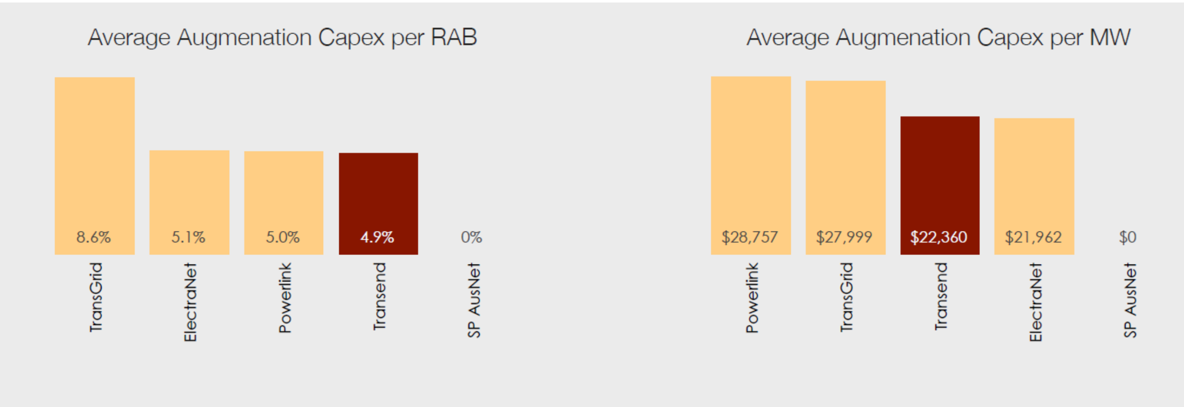
Figure 4.11 High-level capital expenditure ratios, 2009 to 2013



Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 48.

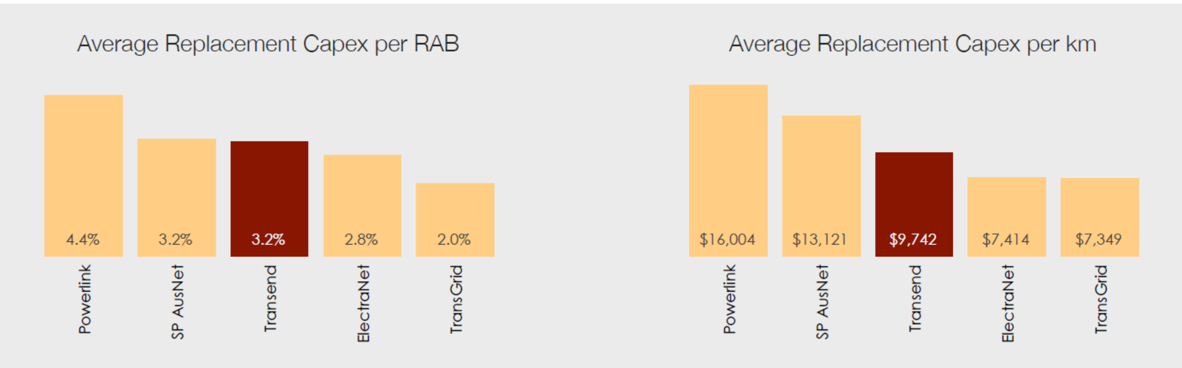
Figure 4.12 to Figure 4.15 below are reproduced from Huegin's report. They show partial productivity measures for various categories of capital expenditure.

Figure 4.12 Partial productivity - Augmentation capital expenditure, 2009 to 2013



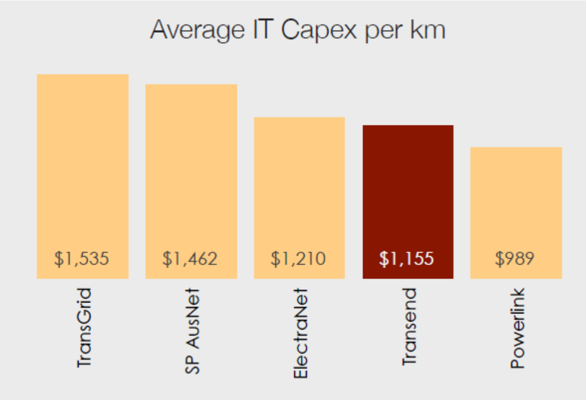
Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 49.

Figure 4.13 Partial productivity - Replacement capital expenditure, 2009 to 2013



Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 49.

Figure 4.14 Partial productivity - IT capital expenditure, 2009 to 2013



Source: Huegin, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 49.

4.5.4 Conclusions from Huegin benchmarking study

Huegin's report concluded that:

- Transend has had the least volatile operating expenditure over time; maintaining a relatively flat profile whilst others have increased—some significantly.
- Scale is Transend's most influential cost driver, with Corporate and Operations costs in particular subject to certain fixed costs of business that cannot be spread over a larger scope of activity.
- The scale influence leads to seemingly unfavourable benchmarking results when using traditional benchmarks based on network length and load—factors of scale. Using benchmarks that are more suited to Transend's operating circumstances provide far more reliable results.
- The unique market structure that exists in Tasmania drives higher levels of network complexity, which leads to high planning and operations costs. In particular, the large number of generators and significant spread of end users across the network requires a more complex network with more spurs of down to distribution-level assets than those states with fewer, larger generators and concentration of end users in major metropolitan areas.
- Despite the scale and complexity issues, Transend's maintenance costs (its major opex category) rate amongst the best in the NEM; in particular, Transend is the only business to keep maintenance costs from increasing as the regulated asset base (RAB) has grown.
- Whilst some of the smaller costs that are more susceptible to scale effects have exhibited a level of variation over time, there is nothing to suggest that Transend is inefficient compared to its peers. Using changes in the cost base over time, one can argue that Transend has managed to keep costs contained to a greater degree than its peers whilst experiencing a greater array of exogenous factors.[10]

4.5.5 Econometric analysis

Econometric analysis is quantitative analysis applied to data sets to extract simple relationships. It involves statistical modelling of economic systems using assumed relationships between quantities of input and output variables. These relationships can be used to benchmark performance and/or forecast performance.

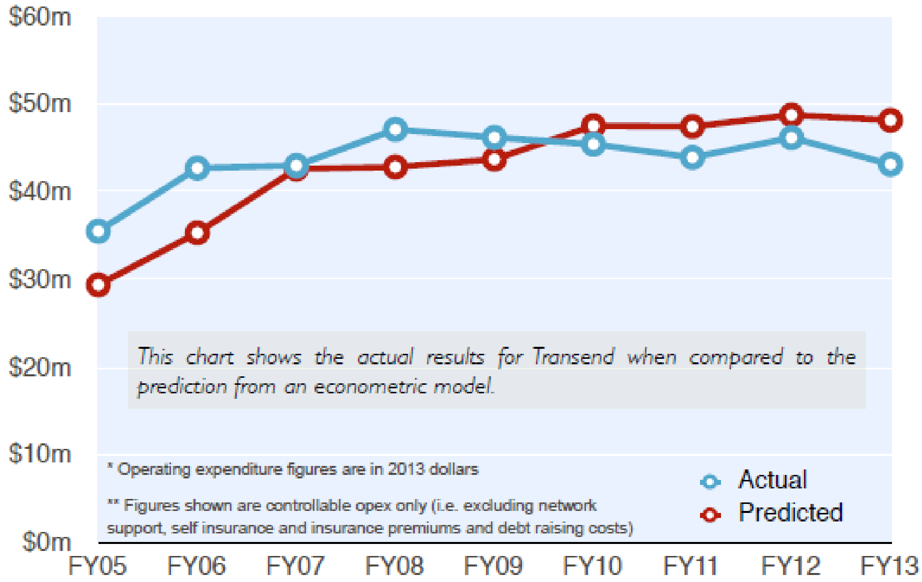
In a report completed recently for us[11], Huegin Consulting Group constructed an econometric model to predict our Controllable operating expenditure. The Huegin report explains that our actual Controllable

[10] Huegin Consulting Group, Transmission Benchmarking Study 2013: Report for Transend, March 2014, page 3, Appendix 5.

[11] Huegin Consulting Group, Transend Base Year Operating Expenditure Efficiency. A copy of the report is provided as Appendix 6.

operating expenditure is lower than that predicted by the econometric model (as shown in the Figure 4.15). This is another indicator of the efficiency of our Controllable operating expenditure.

Figure 4.15 Econometric Analysis - Predicted and Actual Opex



4.6 Concluding comments

In the current regulatory period we have implemented initiatives to:

- optimise our expenditure plans, and reduce our overall level of expenditure;
- improve the governance and delivery of capital projects; and
- manage service performance, in response to service performance targets.

Benchmarking confirms that we have become more efficient in terms of cost and service performance. Indeed, over the current regulatory period, we have performed very strongly in terms of cost management:

- our Controllable operating expenditure is $37 million or nearly 14 per cent less than the regulatory allowance.
- our capital expenditure over the period is $115 million or nearly 17 per cent less than the regulatory allowance, due to lower-than-expected demand and improvements in the efficiency of our capital works delivery.

In achieving these efficiency improvements, we have retained a strong focus on safety, and we have delivered services that meet the needs and preferences of customers.

Our expenditure forecasts for the forthcoming regulatory period build on the significant efficiency gains we have already achieved, and reflect further gains we anticipate making over the next period.

As a result, we expect to see further improvements in our benchmarked performance during the next regulatory period. In this regard, the merger of Transend and Aurora's distribution business will result in further efficiency gains in those areas where our small scale has affected past performance, such as corporate support functions.

5 Forecast capital expenditure

5.1 Introduction

This chapter outlines our capital expenditure requirements for the forthcoming regulatory period. It explains that our expenditure plans are focused on efficiently achieving the capital expenditure objectives specified in the Rules. These objectives include the requirement to provide safe and reliable transmission services to our customers and to comply with our regulatory obligations.

Our capital expenditure requirements will be much lower over the next five years compared to the current regulatory period. This reflects the changed market environment as described in chapter 2 of this Revenue Proposal. It also reflects the significant progress we have made in clearing a backlog of asset renewals in the Tasmanian transmission system.

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 deliver our planned renewal/enhancement capital expenditure efficiently, as assets reach the end of their useful lives. Since 1998 around $600 million has been invested to clear the backlog of investment required to renew ageing assets in poor condition and consequently to improve the security and reliability of the transmission system.

Our investments have delivered a 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 constraining transmission revenues and prices. Our capital expenditure plans for the forthcoming regulatory period ensure that we build on these efficiency savings.

The remainder of this chapter is structured as follows:

- Section 5.2 provides a brief overview of the principal compliance obligations, which are important inputs to our capital expenditure plans.
- Section 5.3 explains the capital expenditure categories.
- Section 5.4 provides an overview of our capital expenditure forecasting methodology.
- Section 5.5 outlines the key variables and assumptions underpinning the capital expenditure forecasts.
- Section 5.6 outlines our demand forecasting methodology.
- Section 5.7 presents our maximum demand forecasts.
- Section 5.8 explains our approach to defining project scopes and cost estimates.
- Section 5.9 explains the cost escalation risk factors that are applied to our forecasts.
- Section 5.10 sets out the cost escalation rates for labour and non-labour inputs.
- Section 5.11 provides information on network support and non-network options.
- Section 5.12 discusses the interaction between capital and operating expenditure.
- Section 5.13 provides an overview of our capital expenditure forecasts, and how they compare with our recent actual expenditure.
- Section 5.14 provides detailed information on our capital expenditure forecasts.
- Section 5.15 presents our annual capital expenditure forecasts for the forthcoming regulatory period.
- Section 5.16 discusses the deliverability of our capital expenditure forecasts.
- Section 5.17 provides concluding comments.

5.2 Compliance obligations

Compliance with regulatory obligations is an important driver of our capital expenditure. We are required by law to comply with and satisfy a suite of requirements contained in national legislation including the National Electricity Rules. We must also comply with a range of state-based obligations including our licence, and Electricity Supply Industry legislation, codes, statutory instruments and regulatory guidelines[12].

The Electricity Supply Industry (Network Planning Requirements) Regulations 2007 set out the minimum standards that we must meet in planning the transmission system. In addition to the network planning requirements set out in the Regulations, we are required to satisfy national and international standards, codes of practice, safety standards and guidelines generally accepted as appropriate by the Australian electricity supply industry. These standards and guidelines relate to a range of matters including the design and operation of assets. We also face compliance obligations relating to management of environmental impacts, occupational health and safety, information management, and financial reporting.

In considering network and non-network solutions to meet our compliance obligations, we consider all mandatory obligations including environmental, safety and planning approval processes. Our capital expenditure plans for the forthcoming period are focused on customer service outcomes that meet our compliance obligations.

5.3 Categorisation of capital expenditure

Our capital expenditure forecasts comprise three investment categories: Development, Renewal/enhancement and Non-network (support the business). These investment categories are broken down into sub-categories as shown in Figure 5.1.

Figure 5.1 Capital expenditure categories

<table>
<tr><th colspan="9">Total Capital Expenditure</th></tr>
<tr><td colspan="7">Network</td><td colspan="2">Non-network</td></tr>
<tr><td colspan="3">Development</td><td colspan="4">Renewal/enhancement</td><td colspan="2">Support the business</td></tr>
<tr><td>Augmentation</td><td>Connection</td><td>Land and easements</td><td>Asset renewal/ enhancement</td><td>Physical security/ compliance</td><td>Inventory/ spares</td><td>Operational support systems</td><td>Information technology</td><td>Business support</td></tr>
</table>

In addition to these expenditure categories, a Revenue Proposal may include proposed contingent capital expenditure. Contingent projects are large projects (now required to be of a value in excess of $30 million or 5 per cent of the regulatory asset base) that may proceed in the forthcoming regulatory period, but are not certain to do so. The Rules require the TNSP to specify ‘trigger events’ that would cause a contingent project to proceed.

In contrast to previous regulatory periods, and with the higher threshold for contingent projects, our transmission planning indicates that no projects satisfy the contingent project provisions in the Rules for the 2014–2019 regulatory period. Therefore, this Revenue Proposal does not include any contingent project expenditure.

5.4 Overview of forecasting methodology

Our capital expenditure plans are designed to deliver safe and reliable transmission services to our customers efficiently and in accordance with our compliance requirements. The purpose of this section is to provide an overview of the forecasting methodology we employ to ensure that our forecasts satisfy this objective.

[12] An overview of our compliance obligations is set out in section 2.6.

Our capital expenditure forecasting process is integrated into the budgetary, planning and governance processes used in the normal running of the business. In addition to the internal controls governing these 'business-as-usual' processes, the capital expenditure forecasting process includes rigorous internal review of project scopes and cost estimates by technical experts, and management sign-off.

These quality assurance steps aim to identify and rectify any errors, and ensure that the inputs to our forecasting model are soundly based and consistent with efficient expenditure. In addition, our capital expenditure model has been reviewed independently by Motorbis Pty Ltd, to ensure that any errors in the model have been identified and addressed.

In November 2013 we provided detailed information to the AER on our capital and operating expenditure forecasting methodologies[13]. To recap, our capital expenditure forecasting methodology comprises several activities[14]:

- 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 investigate the scope for more cost effective non-network solutions;
- develop potential solutions, assess alternative implementation dates, produce project cost estimates and select preferred solutions on the basis of maximising net present value;
- confirm preferred solutions as projects or programs of work, or contingent projects, with further customer consultation where applicable;
- consider all of the projects in the capital works program and operating and maintenance work plan to optimise cost (by combining projects into programs of work), and timing (having regard to 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 understand and reflect their needs and priorities in our expenditure plans. We value the feedback we receive and regard customer engagement as an iterative component of our expenditure forecasting methodology.

Our asset management plans and strategies are a key input to our capital expenditure forecasts. These plans and strategies recognise that the following factors affect our capital expenditure requirements:

- 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, in accordance with the AER's regulatory investment test for transmission;
- unacceptable risk, 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.

[13] Transend Networks Pty Ltd, 2014–19 Revenue Proposal Forecasting Methodology, November 2013, Appendix 7

[14] Note that not all steps are applicable to all three capital expenditure categories noted in section 5.3 and the specific detail of the methodology differs across the investment types.

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.

5.5 Key variables and assumptions

There are a number of variables and assumptions that underpin our 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 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.
- We have applied forecast labour and non-labour escalation rates for the forthcoming regulatory control period.
- We have included cost estimation risk factors in our capital expenditure forecasts.

In addition to the above matters, which are discussed in further detail below, our forecasts are based on the following:

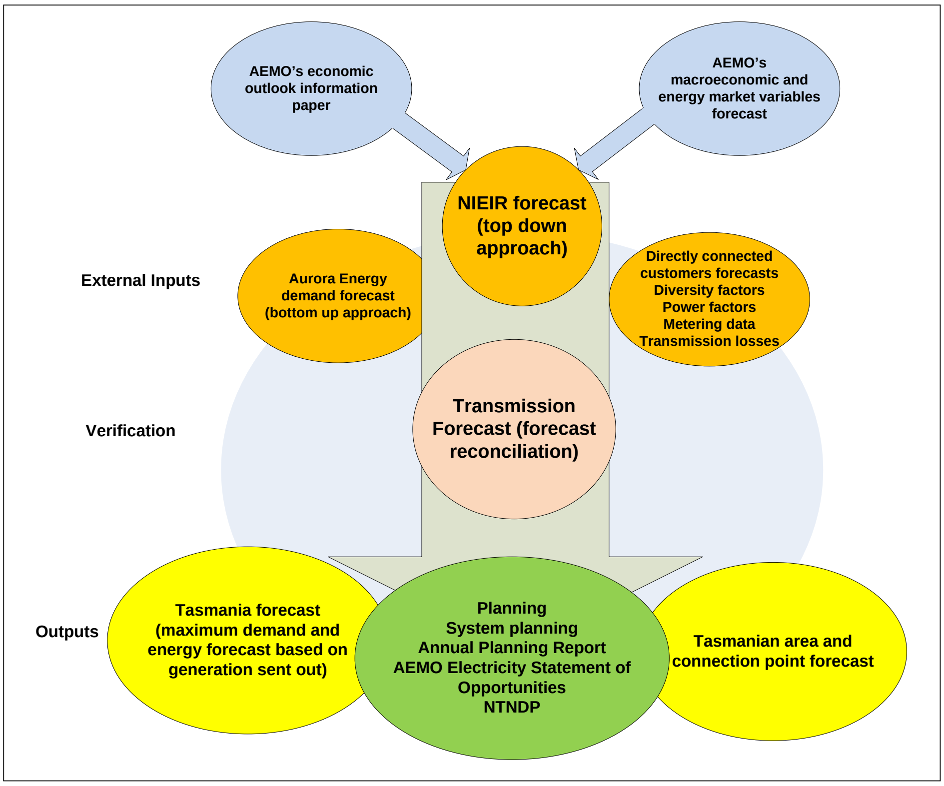
- Our asset management plans and strategies inform the forecast scope of efficient renewal/enhancement expenditure. We will manage the transmission system and supporting business assets to deliver operational and capital efficiency outcomes.
- We assume that we will continue to provide transmission services to the four largest major industrial customers (Bell Bay Aluminium, Norske Skog, Nyrstar, and TEMCO) who together account for more than half the energy consumption in Tasmania.
- We will continue to implement efficiencies and take managed risks to drive down costs.
- We assume that our operating environment, including external factors beyond our control, will be conducive to delivering the planned expenditure within the forecast amounts and planned timeframes.
- We will meet our compliance obligations, including those relating to reliability requirements, physical security, safety and the environment. 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 are reflected in the expenditure forecasts.
- We do not expect regulatory changes currently underway, including Rule changes and reviews, to have a material impact on our capital expenditure requirements in the forthcoming regulatory period.

In accordance with schedule S6A.1.1(5) of the Rules, the directors have provided a certification of the reasonableness of the key assumptions in Appendix 8. It should be noted that although these assumptions are reasonable, there is no guarantee that they will eventuate. If our assumptions prove to be incorrect, this may have a material impact on our actual capital expenditure.

5.6 Load forecasting methodology

As explained in our forecasting methodology overview, load forecasting is an important input to our capital expenditure plans. Our load forecasting process is set out in Figure 5.2.

Figure 5.2 Load forecasting methodology



In 2012, as we commenced preparations for the Revenue Proposal, we asked consultants Parsons Brinckerhoff (PB) to review our load forecasting methodology. In its report[15], PB stated that both Transend and Aurora have significantly improved their forecasting processes since our previous revenue cap review in 2008. The report concluded that the current forecasting approach is reasonable and likely to produce realistic forecasts. A copy of PB's report is included in Appendix 9.

To briefly summarise the load forecasting approach:

- We produce a 30 year load forecast for each substation, each geographical area and the state. Inputs to the load forecast are obtained from the Tasmanian distribution business in relation to substations; from directly connected customers; and from consultants, NIEIR, in relation to the state maximum demand forecasts.
- We reconcile the substation level forecast with the state maximum demand forecast by scaling the substation forecast to take account of diversity factors and loss factors.

As noted above, the report from PB provides confidence that our forecasts are reasonable.

We receive forecast economic scenarios from AEMO, which describe key energy market policies and economic conditions. Ordinarily, these scenarios would be provided to NIEIR for the preparation of the regional energy and demand forecasts for Tasmania. However, AEMO's 2014 macroeconomic and energy market variables forecast was not available in time to be included in the development of our 2014 demand forecast. Therefore, we requested NIEIR to develop forecasts of these variables for the purpose of preparing the demand forecast for this Revenue Proposal.

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[15] Parsons Brinckerhoff, Review of Transend load forecasting process and methodology, 8 October 2012, Appendix 9.

The medium economic growth load forecast represents an estimate of how the future energy and demand may develop given known and anticipated changes, and the application of the median economic growth forecast for the state. The high and low economic growth forecasts present a possible boundary of the future based around the medium forecast.

5.7 Maximum demand forecasts

5.7.1 Tasmanian maximum demand

Meeting maximum demand is generally the key driver of transmission network augmentation investment. This applies for area maximum demand (which drives shared network transmission augmentation) or individual connection point maximum demand (which drives augmentation for individual connection points). Positive market benefit, which is dependent upon maximum and average demand, is also a driver of transmission augmentation. Forecasts of maximum demand are therefore a key input into our capital expenditure forecasts.

Whilst augmentation decisions are not made on the basis of total system demand, total system demand is an indicator of trends in demand across the state.

Peak demand on the Tasmanian system occurs in winter. The winter maximum demand forecasts have a strong correlation with low average daily temperatures during winter business days. The Tasmanian winter maximum demand (MD) forecast has been prepared by NIEIR using the methodology described in the previous section. The forecast represents the generation output required to meet the maximum demand. This forecast includes losses in the transmission and distribution systems but excludes power station loads.

The winter maximum demand forecast for Tasmania from 2014 to 2029 is presented in Figure 5.3 for high, medium and low economic growth scenarios. It is important to note that the differences between the high, medium and low growth scenarios reflect different underlying economic growth conditions and their impact on customers connected directly to the transmission network. Maximum demand forecasts are generally presented in terms of the probability of exceedance (PoE) of the demand value.

Figure 5.3 Forecast of Tasmanian winter maximum demand (MW) [10 per cent PoE]

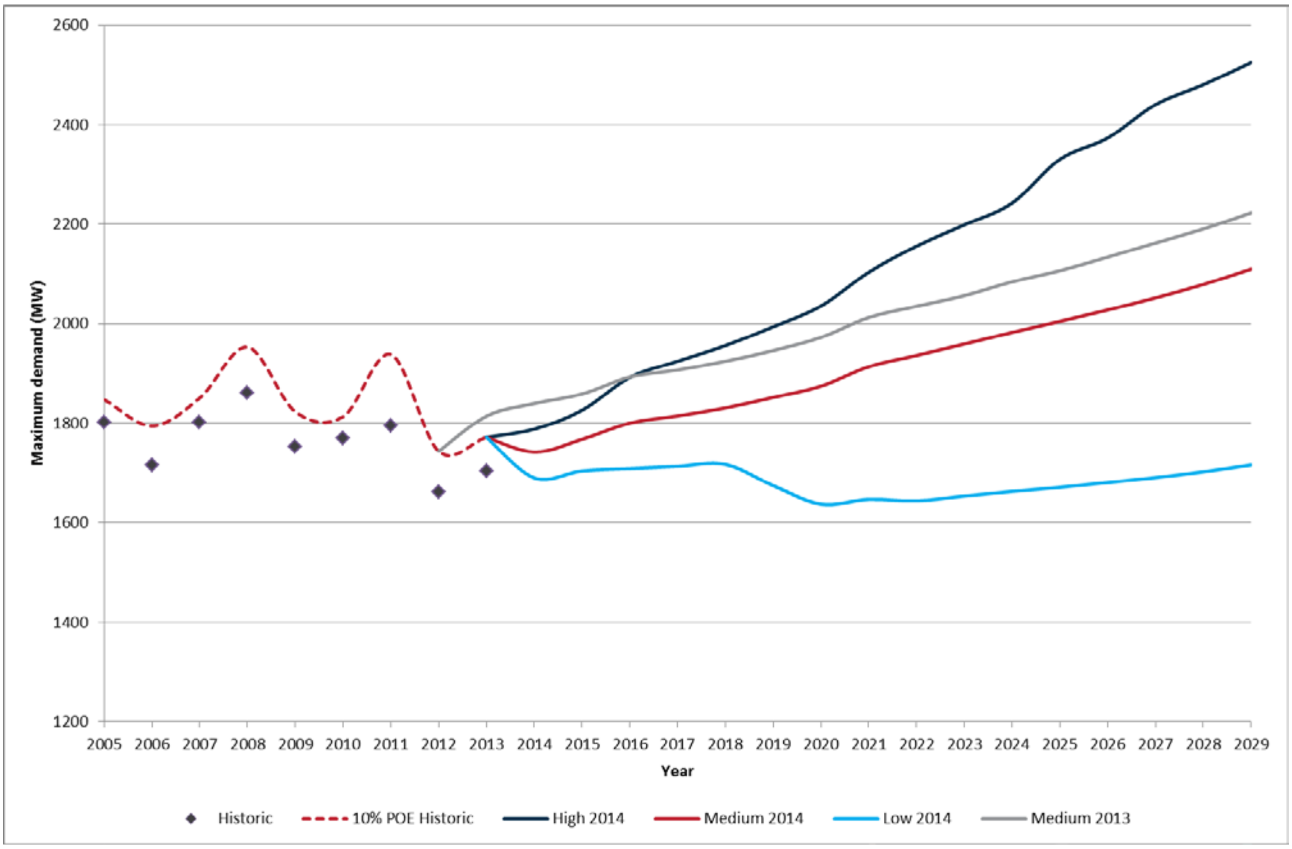

Figure 5.3 illustrates a material reduction in demand from 2011 to 2012, which was influenced by milder winters, customer efficiency measures and the following specific events:

- closure of Hellyer mine near Queenstown in 2011;
- reduction in demand for three months by TEMCO manganese smelter in 2012;
- commissioning of an embedded 7.9 MW co-generation plant at Ulverstone in 2012; and
- closure of timber mills at Scottsdale and Hampshire in 2012.

The winter maximum demand (medium economic growth scenario 10 per cent PoE) forecasts for Tasmania for 2014 to 2019 calendar years are presented in Table 5.1.

Table 5.1 Forecast Tasmanian winter maximum demand (MW)—medium scenario 10 per cent PoE: 2014–2019 calendar years

	2014	2015	2016	2017	2018	2019
Maximum demand (MW)	1,742	1,768	1,800	1,815	1,831	1,852

Compared to forecasts prepared for the 2013 Annual Planning Report:

- the average growth rate in winter maximum demand for the next 15 years has increased slightly to 1.29 per cent per annum for the medium scenario compared to the 2013 maximum demand (medium) forecast.
- the growth in demand is starting from a lower value in the 2014 forecast compared to the 2013 forecast.
- due to the lower starting point, the forecast demand for each calendar year in the 2014 forecast lower than in the 2013 forecast.

The low, medium and high forecasts take account of different economic conditions. For example, the high scenario assumes that a major new customer connects to the transmission network, while the low scenario assumes the loss of a major customer.

More detailed information about maximum demand forecasts is included in Annual Planning Reports published at the end of June each year.

5.7.2 Connection point demand forecasts

Whilst the Tasmanian maximum demand forecast indicates the trend in average demand for the whole state, it is the load connection point demand forecasts, considered with the state's highly variable power generation, which determines the need for development of the transmission network. We produce connection point forecasts after consultation with, and input from customers directly connected to the transmission network, including Aurora for distribution network load forecasts.

The results for our connection point and area load forecasts are provided annually in the Annual Planning Report. The development projects included in this revenue proposal are based on our 2014 connection point forecasts, which were completed in March 2014.

The 2014 connection point forecasts show a decline in load growth in several areas, which has resulted in the deferral of several projects from Transend's development plans since the Transitional Revenue Proposal was submitted in January 2014.

5.7.3 AEMO and Transend maximum demand forecasts

AEMO produced a maximum demand forecast for Tasmania for 2013, and in 2014 it will for the first time produce a Tasmanian transmission connection point forecast. Through consultation with AEMO it is evident that the models and assumptions used by AEMO and TasNetworks are different.

For example, AEMO demand forecasting includes assumptions about energy efficiency improvement programs based on national trends. These national trends may not be applicable to typical existing Tasmanian businesses and households where capital may be less likely to be spent on energy efficiency investments. We also understand that AEMO is applying the national energy efficiency factor to the model outcomes, whereas Transend uses a forecast where energy efficiencies are included in the economic variables used to generate the forecasts. For these reasons, the 2014 AEMO state and connection point maximum demand forecasts may differ from our forecasts.

We will continue to work with AEMO as we develop our respective load forecasts. Before making investment decisions, we also undertake sensitivity analysis to understand the impacts of different load forecasts on investment requirements.

5.8 Project scopes and estimates

We have prepared project definitions and supporting information for each project included in the capex program, to enable the estimation of efficient project costs. The project scopes and estimates are based on reasonable assumptions about future requirements, given the information presently available to us. Where proposed or potential projects directly affect customers connected to the transmission network, project scopes and estimates have been discussed with them and options have been explored to identify the most efficient option.

As noted in sections 5.4 and 5.5 our project cost estimates are supported by well-documented project scopes and mature estimating practices that reflect efficient costs. Specifically, cost estimates are based on actual costs of recent similar projects or procured assets. Where applicable, estimates also include the cost of equipment procured through period contracts, which reflect recent market trends. Contracts for the delivery of our capital projects are established through either formal ‘closed’ tender or ‘open book’ negotiations which reflect competitive prices. Equipment period contracts are established through formal tender processes. Negotiated contracts include components, such as civil works, that are tendered by the chosen contractor and selected by us.

We engaged Evans & Peck to conduct an assessment of our project cost estimating processes and their application to a range of project types[16]. A comparison of cost estimates was made based on a sample of five projects,

In summary, Evans & Peck’s cost estimation risk analysis concludes that our estimating process appears to be at least as detailed and robust as equivalent regulatory and strategic estimating processes observed in comparable organisations. The Evans & Peck report is provided as Appendix 10.

5.9 Cost estimation risk factor

Cost estimation risk analysis is a statistical approach for understanding the uncertainty associated with project cost estimates. It recognises the inherent uncertainties in the cost estimating process, and the well established principle in project management that there is generally a higher probability that costs will increase rather than decrease, due to unforeseen factors. The cost estimation risk analysis process therefore recognises that there exists, on average, an asymmetric cost outcome on projects between an initial concept level cost estimate, and final outturn cost.

We engaged Evans & Peck to conduct a cost estimation risk analysis of our portfolio of forecast capital projects. Portfolio risk analysis captures the average cost impact of risk diversified at a portfolio level across the overall capital expenditure forecast. The analysis determines a number of risk factors that are applied to the estimated cost of projects to ensure that the overall capital expenditure forecast is an unbiased, central estimate.

In summary, the approach adopted by Evans & Peck takes into account:

- the range of potential cost outcomes for each item of known scope (inherent risk), based around the project cost estimates;
- the probability of occurrence of each identified risk event outside of the known scope of work and the probable range of costs (contingent risks); and

[16] Evans and Peck conducted the project cost analysis as part of a cost estimation risk analysis of our portfolio of forecast capital projects; refer to section 5.9 for further details

- the potential combinations of the costs of all of these risks to develop a likely range of costs for the overall project portfolio.

Evans & Peck's cost estimation risk analysis concludes that inherent risk factors for different project types should be included in our forecast capital expenditure, while contingent risk factors have been excluded. The Evans & Peck report is provided as Appendix 10. The result of Evans and Peck's risk factors being applied to individual projects is an average risk factor of 1.65 per cent to the forecast capital expenditure.

5.10 Escalation rates

Expected escalation in the costs of labour, materials and land over the forthcoming period has an impact on our capital expenditure forecasts. This section explains our approach to assessing these cost escalation rates.

5.10.1 Labour cost escalation

Labour cost increases have a significant influence on our capital expenditure forecast.

We engaged Independent Economics to provide forecasts of labour cost escalators for Tasmania for the purpose of this Revenue Proposal[17]. It sets out forecasts Tasmanian utilities sector and also 'general labour'. However, for the first two years we have used the Transend enterprise agreement as the basis for labour escalation in those years. A copy of Independent Economics' report is provided as Appendix 11.

Independent Economics notes that:

- The current softness in the Australian economy has resulted in weak labour demand. Accordingly, employment grew by 1.3 per cent in 2012–13, and is expected to grow by only 1.1 per cent in 2013–14. From this weak position, labour demand is expected to strengthen in the forecast period.
- The recent weakness in the labour market has seen growth in wages slow. For example, the Wage Price Index (WPI) grew by a comparatively low 2.6 per cent over the 12 months to December 2013. This compares to its average annual growth over the decade of 3.8 per cent.
- However, the recovery in the labour market is expected to lead to a similar recovery in wages growth. Annual WPI inflation is forecast to average 4.0 per cent in the five years from 2014–15 to 2018–19. This is close to the historical norm for WPI inflation of 3.8 per cent.

Independent Economics provided forecasts of the WPI and Average Weekly Earnings (AWE):

- AWE wages are expected to grow on average by 4.3 per cent in the five years between the start of 2014–15 and the end of 2018–19.
- WPI wages have been rising faster in the utilities industry than for the economy as a whole, and this is expected to continue.

5.10.2 Non-labour cost escalation

We engaged CEG to provide forecasts of non-labour input cost movements[18]. Escalation rates for the following inputs were estimated by CEG:

- Aluminium
- Copper
- Steel

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[17] Independent Economics, Labour cost escalators for NSW, the ACT and Tasmania, 18 February 2014, Appendix 11.

[18] CEG, Escalation factors affecting expenditure forecasts, December 2013, Appendix 12.

- Crude oil
- Construction costs (including concrete, demolition, establishment, buildings, plant hire).

CEG's report sets out a detailed explanation of the methodologies applied in developing these forecasts. The CEG report is provided as Appendix 12.

5.10.3 Land value escalation

Although our expenditure forecasts do not contain a separate amount for acquisition of land and easements, some capital projects will require the acquisition of small parcels of rural land. The cost of these land acquisitions is included in the cost estimates of the relevant capital projects. For the purpose of developing robust cost estimates for those projects we have obtained a report from GHD, which provides an updated forecast of escalation rates for Tasmanian rural land values[19].

GHD expects rural land value escalation rates in Tasmania to range between 4.7 per cent and 5.3 per cent per annum (real) between 2014 and 2032. GHD notes that in the coming five years land prices will be influenced by structural adjustment occurring in mainland rural water allocations and the trend towards increased foreign investment. A copy of GHD's report is attached as Appendix 13.

5.10.4 Non-transmission system cost escalation

We have assumed that non-transmission system costs will increase by inflation.

5.10.5 Summary of escalation rates

Table 5.2 provides a summary of forecast escalation rates applied in deriving our capital expenditure forecasts.

Table 5.2 Escalation factors for labour and non-labour cost inputs (per cent real)

Input	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19
Tas utilities labour	0.2	-0.3	1.0	2.0	2.0	2.0
General labour	1.0	0.5	1.0	1.6	1.7	1.8
Aluminium	-0.2	4.2	5.8	5.0	4.2	3.6
Copper	-0.8	-0.9	1.1	0.3	-0.3	-0.7
Steel	-0.1	0.6	3.2	0.6	0.3	-0.1
Crude oil	18.8	-0.5	2.8	2.6	2.1	1.8
Construction costs	0.5	0.5	0.7	0.5	0.4	0.1
Land	-4.0	4.7	4.8	4.9	5.0	5.1

5.11 Network support and non-network options

No viable network support option has yet been identified that is capable of deferring capital works and satisfying the regulatory investment test for transmission. Transend has performed joint planning with Aurora Energy distribution planners, and undertaken consultation with customers and other stakeholders, to reach this conclusion.

However, as noted earlier in this document, we continue to progress analysis where credible non-network solutions may exist. We are consulting with one of our major customers to consider possible use of its load to provide network support to avoid or defer the proposed Waddamana-Palmerston 220 kV augmentation.

[19] GHD, Tasmanian Rural Land Escalation Rate Forecast: Updated Report for Transend Networks, November 2013.

We also consider non-network options that satisfy our planning obligations. For example, Transend received formal notification of acceptance of lower security and reliability from the Savage River Substation from all customers connected to the substation. In the forthcoming regulatory period we will therefore not implement a network augmentation solution to the reliability issues at this substation. There are no transmission network support costs associated with this approach.

5.12 Interaction between capital and operating expenditure

While this chapter is concerned with capital expenditure, in considering our future expenditure requirements it is important to note the interaction between capital and 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 may have a positive impact on operating expenditure in terms of reducing the frequency of removing assets from service to undertake planned maintenance—for instance, protection relays and other ancillary equipment may have self-diagnostic and remote monitoring capabilities.
- 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 also recognise the impact of economies of scale and scope when forecasting our additional operating expenditure requirements.

The Transmission System Management Plan outlines our framework and strategies for optimising the life cycle costs and performance of our assets. Asset specific management plans provide detailed information and strategies for achieving the optimised costs and performance.

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

With the introduction of the new network capability incentive, discussed further in section 13.5, we have 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.

The total value of projects that are funded under the network capability incentive scheme is 1 per cent of the allowed revenue. Therefore, decisions made by the AER in setting the total revenue will affect the value and number of projects that are funded under the incentive scheme.

All projects included under the network capability incentive scheme provide a customer benefit. Therefore, to the extent that a project is not funded under the scheme due only to a forecast lower revenue outcome, it should be added to the ex ante capital expenditure allowance.

5.13 Overview of forecasts and comparison with current period

Before we turn to explaining the detail of the forecast capital expenditure it is worthwhile to compare the forecast with the expenditure in the current regulatory period and to outline the major differences.

Our forecast capital expenditure is 52 per cent below the actual expenditure in the current regulatory period. Figure 5.4 also shows that our actual capital expenditure was lower than the AER's benchmark for the current regulatory period.

Figure 5.4 Overview of forecast and actual capital expenditure ($m 2013–14)

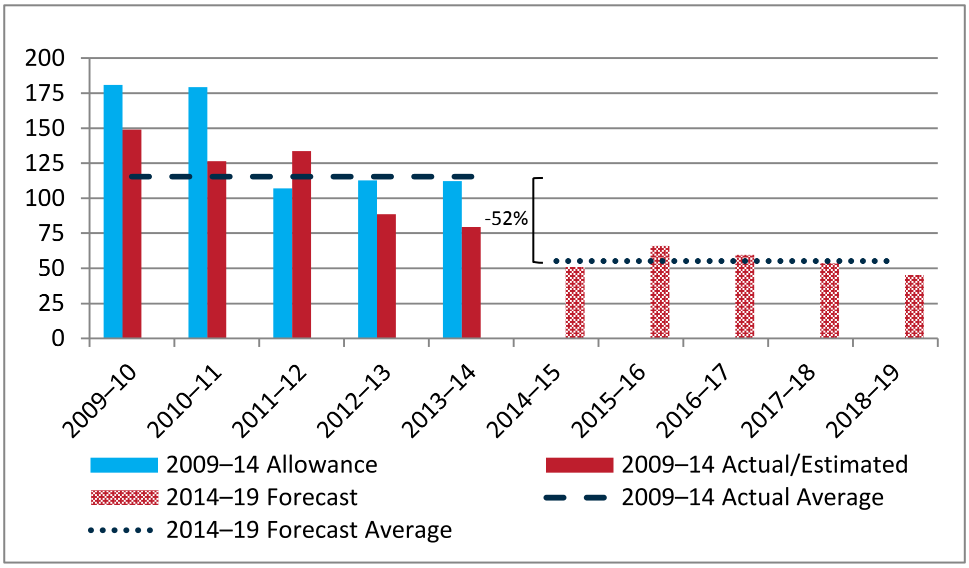

Table 5.3 provides a further breakdown by expenditure category.

Table 5.3 Actual and forecast capital expenditure by category ($m 2013–14)

Category	2009–14 Allowance	Actual expenditure 2009–14	Forecast expenditure 2014–19
Augmentation	242.1	190.5	36.8
Connection	126.0	68.9	19.0
Land and easements	24.1	0.6	0.0
Development capex	**392.2**	**260.1**	**55.8**
Asset renewal/enhancement	203.7	245.2	145.4
Physical security/compliance	22.1	14.4	14.4
Inventory/spares	12.1	9.9	15.1
Operational support systems	23.9	15.9	32.5
Renewal/enhancement capex	**261.7**	**285.4**	**207.4**
Information technology	19.1	6.4	7.0
Business support	19.5	25.3	5.7
Support the business capex	**38.6**	**31.7**	**12.7**
Total	**692.5**	**577.2**	**275.9**

The key points to note from the above table are that our capital expenditure in the current period is forecast to be $577.2 million compared to the AER's allowance of $692.5 million; in the next period, our forecast capital expenditure reduces further, to $275.9 million.

Figure 5.5 shows our forecast capital expenditure for the forthcoming regulatory period by major category compared to the actual expenditure for the 2009–14 period.

Figure 5.5 Comparison of past and forecast capital expenditure by major category ($m 2013–14)

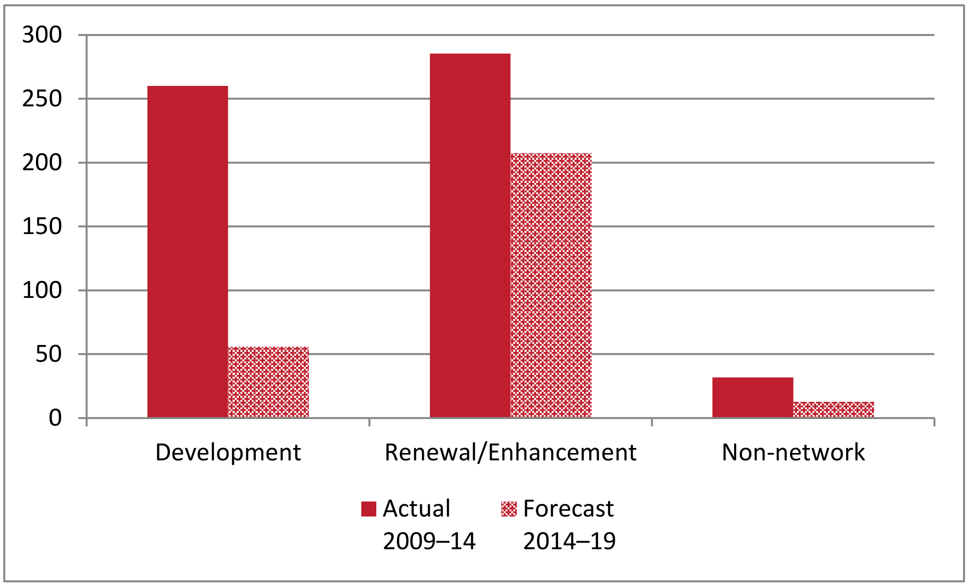

Figure 5.5 illustrates the reduction in forecast expenditure in all categories for the 2014–19 period, compared to the current period, with particularly significant reductions in development and renewal/enhancement expenditure.

The substantial reduction in forecast capital expenditure compared to recent actual levels should provide all stakeholders with confidence that our proposed expenditure is efficient in accordance with the Rules requirements.

5.14 Details of our forecast capital program

The following sections provide a summary of the different components of our forecast capital program. We have also, in accordance with the requirements of the Regulatory Information Notice, provided detailed data and information about each of the proposed projects that make up the forecast capital expenditure. This information includes documents containing technical and economic justification of each of the projects and asset management plans. These documents contain extensive information about the assets in our transmission network and the strategies for managing these assets over their life cycles.

The supporting documents outline the options considered and how we have selected the most cost effective option. The cost estimates for the projects have been based on procurement of competitively priced services.

5.14.1 Development expenditure

Table 5.4 shows our annual actual and forecast development capital expenditure.

Table 5.4 Annual actual and forecast development capital expenditure 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	89.2	37.2	49.6	10.2	4.4	0.4	4.7	11.3	9.2	11.3
Connection	11.8	27.2	27.2	2.4	0.2	2.9	11.3	3.8	1.1	0.0
Land and easements	0.0	0.0	0.1	0.2	0.3	0.0	0.0	0.0	0.0	0.0

It can be seen that in the next regulatory period, development capital expenditure is forecast to be substantially lower than historic levels. Our 2014 demand forecasts for the state and for our transmission connection points provide the basis for the capital expenditure forecasts presented in this Revenue Proposal. The 2014 (medium) demand forecasts predict a slightly lower peak demand compared to the 2013 forecasts adopted in our transitional Revenue Proposal.

Augmentation projects

The augmentation spend profile is a function of three separate projects. Two of these projects are reliability augmentations involving security augmentation investments to address Tasmanian ESI reliability planning requirements in the Waddamana-Palmerston and Newton-Queenstown transmission corridors[20]. These projects are also expected to provide net market benefits. The timing of these two projects accounts for the higher spend in 2016–17 to 2018–19. Both projects will be subject to the Regulatory Investment Test for Transmission. This process has not yet commenced for either project. The specific criteria of the Tasmanian ESI reliability planning that will be met by the projects are identified in the separate project justification documents provided as supporting documentation for the revenue proposal.

Waddamana-Palmerston 220 kV Security Augmentation

The Waddamana-Palmerston transmission corridor connects the north and south of the transmission network and consists of two 220 kV circuits and one, smaller capacity, 110 kV circuit. In the event of loss of the 220 kV circuits the power transfer is restricted to the capacity of the 110 kV circuit and the frequency could, in some circumstances, drop below 47 Hertz and therefore not meet the Tasmanian Frequency Operating Standards. In addition there is a risk that certain failures within the corridor could black out the whole of the southern Tasmanian system (a *System Black* event as defined in the Rules). Therefore, in the absence of action being taken to address these issues, clause 5(1)(a)(iii) of the Tasmanian ESI (Network Planning Requirements) Regulations 2007 would not be met. For these reasons, this project is classified under the Rules as a reliability augmentation.

The $21 million Waddamana-Palmerston 220 kV Security Augmentation project, proposed for completion by June 2019, would address these compliance issues. In addition, it is expected to provide a net market benefit based on the reduced load at risk. Investigations into whether there is a credible non-network solution are also continuing.

Newton-Queenstown Security Augmentation

The existing supply to Newton and Queenstown substations on Tasmania's west coast currently does not meet clause 5(1)(a)(iv) of the Tasmanian ESI (Network Planning Requirements) Regulations 2007 in that a contingent event could result in more than 300 MWh of unserved load. In addition the single circuit radial 110 kV transmission line between Queenstown and Newton substations, which was commissioned in 1936, is in poor condition and would require extensive refurbishment/replacement to extend its service life.

The $14 million Newton-Queenstown Security Augmentation project, proposed for completion by June 2017, will address these issues, thus ensuring that the Tasmanian ESI reliability planning requirements are met. This project is therefore classified under the Rules as a reliability augmentation; its implementation also provides a net market benefit in terms of reduced unserved energy at risk. The project comprises:

- installation of a 220/110 kV 30/50 MVA network transformer at Queenstown Substation;
- connection of the transformer to the Farrell–John Butters 220 kV circuit;
- construction of a loop-in-loop-out 110 kV connection to Newton Substation from the Farrell–Rosebery–Queenstown 110 kV circuit; and
- dismantling of the Queenstown–Newton 110 kV circuit.

Deferred augmentation projects

Our transitional Revenue Proposal included an indicative forecast, with several projects to address supply security issues included in years two to five of the next regulatory period. Three of these projects are no longer required. Specifically:

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[20] Under the Rules, a "reliability augmentation" is defined as: "work to enlarge or increase the capacity of the transmission system necessitated principally by an inability to meet the minimum network performance requirements set out in schedule 5.1 or in relevant legislation, regulations or any statutory instrument of a participating jurisdiction."

- The Kingston Area Security Upgrade and Derby Security Upgrade projects have been removed from our forecast capital program as the reduction in forecast connection point demands in those areas means the existing supplies should be able to meet the Tasmanian ESI reliability planning requirements until late in the next regulatory period (2019–23) or beyond.
- A network security driven project (Northern dynamic reactive support) that had a 50 per cent probability of proceeding has been removed. Further analysis indicates there is insufficient market benefit from this project, and that alternative options can be implemented to manage the possible system issues, such as constraining generation under certain conditions. The dynamic reactive support project could potentially proceed as a non-regulated solution.

Connection projects

The connection forecast capital expenditure includes connection projects at five existing sites with total expenditure of $19 million. There are no new connection point projects envisaged for the 2014–19 regulatory period.

Higher connection spend in 2015–16 is the result of a fault level mitigation program to address safety and other compliance issues at 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. Further information on the Rosebery Substation project is set out in Table 5.5 below.

Deferred connection projects

Our transitional Revenue Proposal included construction of a new Bridgewater 110/33 kV connection point, at an estimated cost of $18 million, to support the distribution network in the latter years of the 2014–19 period. The lower 2014 connection point forecast for the Bridgewater and Northern Hobart areas mean the project is not expected to be needed until at least 2023, and therefore it has been removed from our plans for the forthcoming regulatory period.

Development projects with a value greater than $5 million

Table 5.5 provides details of our proposed development projects with a value greater than $5 million over the forthcoming five year period. Clause 5.16.3(a)(2) of the Rules provides that these projects are subject to assessment under the Regulatory Investment Test for Transmission. Further information on these projects is included in Appendix 13.

Table 5.5 Forecast development capital projects greater than $5 million ($2013–14)

Project Description	Estimated total project cost ($m)	Commissioning year	Category	Description	Main drivers of investment need		
					Reliability/Security	Connection Enquiry	Market Benefit
Waddamana - Palmerston 220 kV Security Augmentation	21	2018–19	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. This project addresses a Tasmanian ESI reliability planning requirement and provides a net market benefit. The Regulatory Investment Test for transmission process has not yet commenced.	✓		✓
Newton - Queenstown Security Augmentation	14	2016–17	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. This project addresses a Tasmanian ESI reliability planning requirement and provides a net market benefit. The Regulatory Investment Test for transmission process has not yet commenced.	✓		✓
Rosebery Substation transformer capacity augmentation	6	2016–17	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. This project addresses a Tasmanian ESI reliability planning requirement (Clause 5(1)(a)(iv)–the unserved energy to load that is interrupted consequent on damage to a network element resulting from a credible contingency event is not to be capable of exceeding 300 MWh at any time) and provides a net market benefit. The Regulatory Investment Test for transmission process has not yet commenced.	✓	✓	✓

5.14.2 Consistency of Transend's Revenue Proposal with AEMO's most recent NTNDP

AEMO released its latest National Transmission Network Development Plan (NTNDP) on 31 December 2013. The NTNDP aims to provide an independent, strategic view of the efficient development of the National Electricity Market (NEM) transmission network over a 25-year planning horizon. The plan generally considers only the bulk (major national flow path) transmission network.

The capital expenditure forecasts contained in this Revenue Proposal are consistent with the December 2013 NTNDP, with the exception of the inclusion of the Waddamana–Palmerston 220 kV Security Augmentation project. The 2013 NTNDP did not flag any limitations on the main transmission network in Tasmania within its 25-year planning horizon (see Table A-2 of the NTNDP). However, this Revenue Proposal includes the Waddamana–Palmerston 220 kV Security Augmentation project, because it is required to address performance requirements of the Tasmanian Electricity Supply Industry (Network Planning Requirements) Regulations 2007. In addition, we have undertaken probabilistically based economic analysis and found this project has a net market benefit.

TasNetworks understands that the (N-1) assessment contained in the NTNDP considers only steady state response to credible contingencies. However, the need for the Waddamana-Palmerston 220 kV Security Augmentation is driven by the potential for widespread loss of supply following a double-circuit fault or circuit breaker fail event. These events are not considered by AEMO in its NTNDP study methodology. Whilst such events are rare, the system impacts are very large. Therefore, analysis conducted for the NTNDP will not identify the network issues that give rise to the need for this particular project.

5.14.3 Renewal and enhancement

As noted in section 4.3.2, we are coming to the end of a period of relatively high renewal and enhancement capital expenditure. Our forecast renewal/enhancement capital expenditure for the forthcoming regulatory period is lower than the current period. Replacement of assets at the end of their useful life, determined on the basis of condition and risk, continues to be a major expenditure driver for us. In replacing assets, modern equivalent equipment often provides enhanced quality and functionality compared to the originally installed assets.

Table 5.6 shows our actual and forecast renewal and enhancement capital expenditure.

Table 5.6 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	18.9	43.3	44.5	69.1	69.6	33.7	26.4	28.3	32.8	24.3
Physical security/compliance	5.2	2.3	3.7	2.2	1.0	2.4	2.9	3.0	3.0	3.1
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	1.7	6.9	9.2	6.7	5.1	4.7

Asset renewal/enhancement

Whilst our forecast expenditure on asset renewal/enhancement of $145 million is our largest category of capital expenditure, the forecast is a reduction of $100 million from actual expenditure in the current period.

The next regulatory period includes a number of renewal programs for key asset classes. For example, our largest program is $13.5 million to replace transmission line insulator assemblies, in order to maintain service levels, keep people safe and mitigate risks associated with bushfires.

There is increased investment required in telecommunications assets that have reached the end of their service lives. We have 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 AER-approved cost allocation methodology.

In our long term vision for Tasmania's transmission network, we considered the future of a number of 110 kV transmission lines serving southern Tasmania. These lines were built from the 1930s to the 1950s to connect power stations in the Upper Derwent River power scheme, and are now approaching end of life.

Rather than replacing the existing assets on a like-for-like basis, our strategy is to connect Upper Derwent generation into the adjacent 220 kV network and reduce renewal costs by removing the need to refurbish and maintain the aging 110 kV network. This is the next phase of transmission line renewals, termed the 'Southern Transmission System Rationalisation Program' and it is programmed to commence towards the end of the forthcoming regulatory period.

Physical security/compliance

The forecast expenditure within this sub-category will address the physical protection security of our assets and the safety of employees and the public. Projects include the renewal of fire suppression systems in substations, implementation of fall arrestor systems and warning signs on transmission towers, and renewal of transmission line access tracks and access security systems.

Inventory/spares

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 investment accords with our policy of extending the life of a number of in-service transformers and substation assets, but with strategic spares being held for multiple sites to manage failure or unforeseen rapid deterioration in condition.

Operational support systems

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 and geographical information, enhance our risk management and asset analysis tools, renew our operational systems to extract the optimum capacity and life from our assets, and to progress our smart transmission grid development program.

Renewal/enhancement projects and programs

The renewal expenditure for the forthcoming regulatory period predominantly comprises programs of work for key infrastructure groups. Projects and programs with a value of greater than $5 million are summarised in Table 5.7.

The asset renewal/enhancement programs and projects over $5 million, as listed in Table 5.7, total $54 million. The remainder of the expenditure in this category comprises a large number of smaller programs with forecast expenditure less than $5 million each. The full set of programs cover most asset classes in our regulated asset base.

Table 5.7 Forecast renewal capital projects and programs greater than $5 million ($2013–14)

Project Description	Estimated total project cost ($m)	Category	Description	Main drivers of investment needs			
				Asset Reliability	Safety and environment	Compliance	Technical requirements
Transmission line insulator assembly	13	Asset Renewal (Program)	Replacement of insulators on a number of lines.	✓	✓	✓	
Substation Disconnector and Earth Switch	9	Asset Renewal (Program)	Replacement of 220 kV disconnectors.	✓			✓
Lindisfarne Substation transformer replacement	7	Asset Renewal (Project)	Replacement of Lindisfarne Substation transformers T2 and T3.	✓	✓		✓
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	6	Asset Renewal (Project)	Replacement of 110 kV primary assets.	✓			✓
Transmission line K-pole	6	Asset Renewal (Program)	Renewal of K-poles on the Triabunna Spur 110 kV transmission line.	✓	✓		✓
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 the Asset Management Information System.	✓	✓	✓	✓
Information Technology applications program	5	Operational Support Systems	Renewal of applications that support the operation of the transmission system.	✓	✓	✓	✓

Note: The George Town substation 110 kV redevelopment project is currently underway. The estimated total cost of the project is approximately $13 million, with forecast expenditure of $6 million to occur in the forthcoming regulatory period.

5.14.4 Support the business

Table 5.8 shows our actual and forecast annual capital expenditure on IT and business support.

Table 5.8 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	2.4	2.5	1.0	0.3	0.2	1.7	1.1	1.3	2.0	0.8
Business support	9.8	11.2	1.4	0.8	2.1	1.5	1.9	1.1	0.4	0.9

The forecasts have been based on efficient information technology and business support investments, to meet obligations, and to deliver operating and ongoing capital expenditure savings.

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 avoid re-work and derive synergies from systems developed as part of the TasNetworks merged network business.

5.15 Capital expenditure forecasts for 2014–15 to 2018–19

5.15.1 Summary of forecast capital expenditure

Table 5.9 shows our capital expenditure requirements over the five-year period from 2014–15 to 2018–19 by category together with actual expenditure over the current regulatory period for comparative purposes. The forecasts are the sum of category forecasts described in the preceding sections.

Table 5.9 Annual actual and forecast capital expenditure by category ($m 2013–14)

	Current period (actual)					Forthcoming period (forecast)				
Category	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Augmentation	89.2	37.2	49.6	10.2	4.4	0.4	4.7	11.3	9.2	11.3
Connection	11.8	27.2	27.2	2.4	0.2	2.9	11.3	3.8	1.1	0.0
Land and easements	0.0	0.0	0.1	0.2	0.3	0.0	0.0	0.0	0.0	0.0
Asset renewal/enhancement	18.9	43.3	44.5	69.1	69.6	33.7	26.4	28.3	32.8	24.3
Physical security/compliance	5.2	2.3	3.7	2.2	1.0	2.4	2.9	3.0	3.0	3.1
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	1.7	6.9	9.2	6.7	5.1	4.7
Total Network	**136.8**	**112.8**	**131.2**	**87.4**	**77.3**	**47.8**	**63.1**	**57.5**	**51.3**	**43.5**
Information technology	2.4	2.5	1.0	0.3	0.2	1.7	1.1	1.3	2.0	0.8
Business support	9.8	11.2	1.4	0.8	2.1	1.5	1.9	1.1	0.4	0.9
Total non-network	**12.1**	**13.7**	**2.4**	**1.1**	**2.4**	**3.2**	**3.0**	**2.4**	**2.4**	**1.7**
Total	**148.9**	**126.5**	**133.6**	**88.5**	**79.6**	**51.0**	**66.1**	**59.9**	**53.7**	**45.3**

Our proposed capital program for the next regulatory period is 52 per cent lower than for the present period, with the forecast expenditure oriented towards asset renewal and network security augmentation projects.

Capital expenditure forecasts over the next regulatory period are significantly lower in the major categories of augmentation, connection and asset renewal/enhancement expenditure. In particular, 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.

Figure 5.6 is replicated from section 5.2, but expanded to include the forecast average annual expenditure amounts over the 2014–19 regulatory period in the relevant categories. The categories of transmission service provided by this proposed expenditure is presented in Table 2.1 of our 2014–19 Revenue Proposal Expenditure Forecasting Methodology.

Figure 5.6 Forecast annual average capital expenditure ($m 2013–14)

Total Annual Average Capital Expenditure $55.2m								
Network $52.7m							Non-network $2.5m	
Development $11.2m			Renewal/enhancement $41.5m				Support the business $2.5m	
Augmentation $7.4m	Connection $3.8m	Land and easements $0.0m	Asset renewal/ enhancement $29.1m	Physical security/ compliance $2.9m	Inventory/ spares $3.0m	Operational support systems $6.5m	Information technology $1.4m	Business support $1.1m

The capital expenditure forecasts presented above are consistent with the detailed information that will be published in our 2014 Annual Planning Report in June 2014. The expenditure forecasts reflect input from our customers as explained in Chapter 3.

5.15.2 Forecast map of the transmission system and planned changes to ratings

Figure 5.7 shows a map of the transmission system for the forthcoming regulatory period.

The planned changes to the transmission lines are modest and mainly involve modifying or disconnecting existing transmission assets. The small changes are between Queenstown and Newton, Palmerston and Waddamana, and Butlers Gorge and Derwent Bridge and reflect a few kilometres of new lines to connect existing assets.

Figure 5.7 Forecast Transmission System at the end of the 2014-19 regulatory period

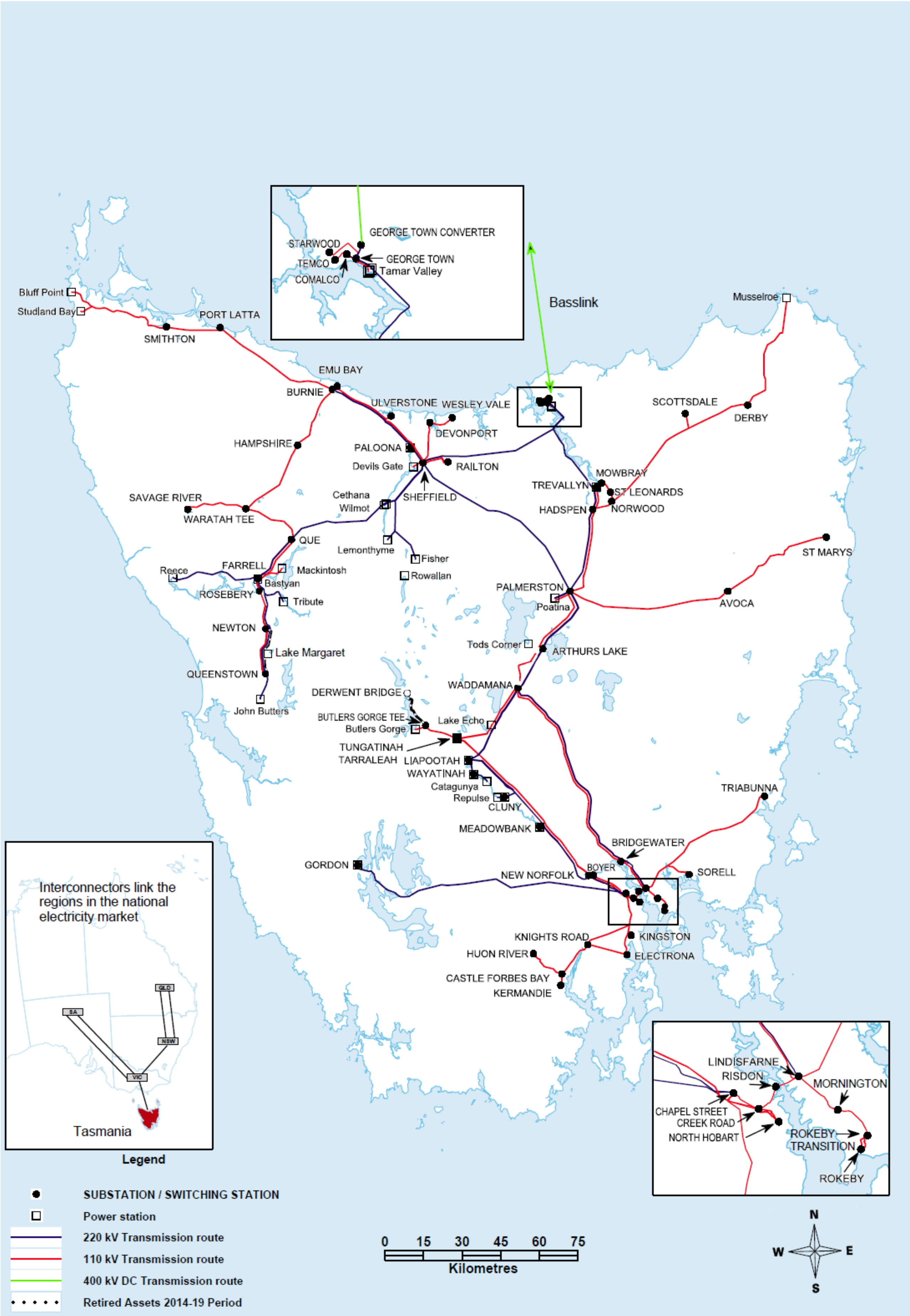


Table 5.10 identifies the major network assets that will have their ratings modified in the forthcoming regulatory period. This information is provided in accordance with clauses 25.1 and 25.2 of the revenue reset regulatory information notice.

Table 5.10 Major network asset rating modifications for forthcoming regulatory period

Project description	Nominal rating (MVA) (winter/summer)		Category	Description
	Existing	New		
Transmission line rating modifications for the forthcoming regulatory control period				
Waddamana–Palmerston security augmentation	138/ 138[21]	376/334	Augmentation	Existing 110 kV transmission line converted to 220 kV to improve security of the Waddamana–Palmerston 220 kV transmission corridor
Power transformer rating modification for the forthcoming regulatory control period				
Lindisfarne Substation transformer T2 and T3 replacement	30/45	30/60	Asset renewal	Replace supply transformers at end of life
Queenstown Substation transformer T1 replacement	15/22.5	17/25	Asset renewal	Replace supply transformers at end of life
Rosebery Substation transformer capacity augmentation	20/30	30/60	Connection	Replacement of both 110/44 kV supply transformers to cater for load growth
St Marys Substation transformer capacity augmentation	10	20/30	Connection	Replace supply transformers with those recovered from the replacement at Rosebery Substation to cater for load growth
New major network assets to be constructed over the forthcoming regulatory control period				
Newton – Queenstown security augmentation	N/A	30/50	Augmentation	Install new 220/110 kV network transformer to provide a second 110 kV supply and increase security to Newton and Queenstown substations

5.16 Deliverability of capital expenditure

Prior to the start of the current period, we implemented a range of initiatives to ensure that the capital program would be delivered prudently and efficiently. These initiatives included:

- Establishment of a work planning and coordination team focussed on capital program management, planning and reporting;
- Strengthening of internal resource levels for provision of technical advice, contract account management and project support services;
- Insourcing of the critical function of protection and control field based services;
- Establishment of contractors panels to sustain a service provision market in Tasmania;
- Standardisation of design to reduce project duration; and
- Increasing lead times for equipment procurement to ensure certainty of timing of project delivery.

Over the current regulatory period we have delivered capital projects totalling approximately $577 million, compared to proposed capital expenditure in the forthcoming period of $276 million. Given the success of our delivery strategy in the current period, there are no major changes to our delivery strategy, except for a reduction in levels of resourcing to match the reduced program of work.

Our performance in delivering our capital works over the current period demonstrates our ability to efficiently deliver the forecast capital works over the forthcoming regulatory period.

[21] Circuit rating is constrained by terminal equipment

5.17 Concluding comments

Our maximum demand forecasts for 2014 for the state and our transmission connection points indicate a lower rate of demand growth compared to the forecasts used for the 2009–14 Revenue Proposal. Accordingly, our forecast development expenditure is significantly lower than for the current period.

After a significant phase of renewing a backlog of aged assets in poor condition and enhancing earth-wire coverage, our renewal program is also lower compared to our 2009–14 actual expenditure. We continue to renew assets at the end of their service lives, based on condition and risk. We also continue to invest in assets that support our efficient business operation, including our information systems.

We will deliver required capital works efficiently, and our capital cost estimates for the next regulatory period are based on efficient forecasts. We will pursue non-network alternatives where these provide better customer outcomes. Our continued efficiency drive and customer focus will assist our Tasmanian customers and the broader national electricity market.

6 Forecast operating expenditure

6.1 Introduction

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

Under the Rules, our operating expenditure forecast must achieve the operating expenditure objectives, which include the requirement to provide safe and reliable transmission services to our customers and to comply with our regulatory obligations. As explained in this chapter, we have applied a methodology that produces expenditure forecasts that meet the operating expenditure objectives specified in the Rules.

In this chapter, we explain that significant operating expenditure efficiencies have been achieved in the current regulatory period by improving our business processes and reducing staff levels. In addition, further efficiencies and resulting cost reductions are planned in the forthcoming regulatory period, primarily resulting from the merger with Aurora Energy's distribution network business. The operating expenditure forecasts presented in this chapter incorporate these expected efficiency improvements, with anticipated savings benefitting customers with immediate effect.

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. For the reasons set out in this chapter, we believe that we have got this balance right.

The remainder of this chapter is structured as follows:

- Section 6.2 describes our operating expenditure categories.
- Section 6.3 explains our operating expenditure forecasting approach.
- Section 6.4 outlines the key variables and assumptions and issues underpinning the operating expenditure forecasts.
- Section 6.5 identifies the base year we have selected to develop our forecasts of recurrent operating expenditure, and demonstrates that the proposed base year expenditure is efficient.
- Section 6.6 explains the expenditure forecasts associated with step changes.
- Section 6.7 describes the approach we have taken in applying growth factors in the development of our operating expenditure forecasts.
- Section 6.8 describes our zero-based forecast of Controllable operating expenditure items
- Section 6.9 sets out the cost escalation rates used in the operating expenditure forecasts.
- Section 6.10 explains the approach we have taken in deriving and applying efficiency improvement targets in our operating expenditure forecasts.
- Section 6.11 provides a summary of our forecast of Controllable operating expenditure.
- Section 6.12 sets out our forecasts of Other operating expenditure.
- Section 6.13 sets out our operating expenditure forecasts for the next regulatory period, and a comparison with our actual operating expenditure in the current regulatory period.
- Section 6.14 provides concluding comments.

6.2 Categorisation of operating expenditure

Our operating expenditure forecasts comprise two categories: 'Controllable operating expenditure' and 'Other operating expenditure'.

Controllable operating expenditure consists of:

- 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 business and asset management 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 6.1 provides a pictorial overview of the expenditure categories.

Figure 6.1 Operating expenditure categories

Total Operating Expenditure							
Controllable Operating Expenditure					Other Operating Expenditure		
Direct Operating & Maintenance			Other Controllable		Other		Benchmark Allowances
Field operations & maintenance	Transmission services	Transmission operations	Business support (Corporate)	Asset management	Network support	Insurance & Self-insurance	Debt raising

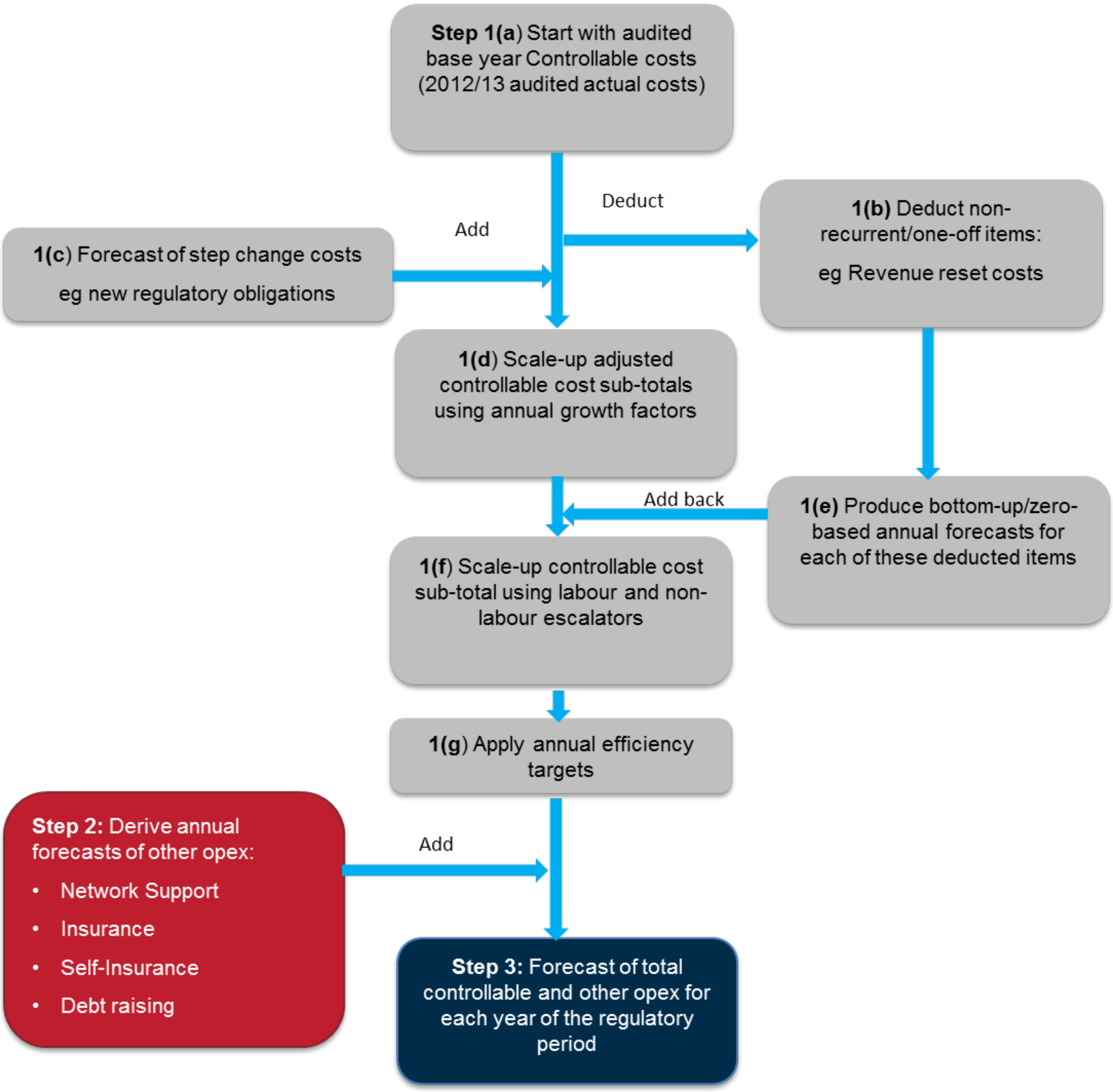
6.3 Forecasting approach for operating expenditure

In broad terms, our operating expenditure forecasting methodology follows the approach adopted by the AER in its recent revenue cap decisions. It is unchanged from the approach that we set out in the document we submitted to the AER in November 2013. In particular, under the prescribed operating expenditure forecasting methodology:

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

A pictorial overview of the development of our forecast operating expenditure using the forecasting methodology is illustrated in Figure 6.2.

Figure 6.2 Operating expenditure forecasting methodology



6.4 Key variables and assumptions

The following are the key variables and assumptions that underpin our operating expenditure forecasts:

- We have adopted 2012–13 as an efficient base year for estimating future expenditure.
- We have identified the step changes that will affect our operating expenditure in the forthcoming regulatory period.
- We have assessed the cost impact of asset growth on operating expenditure and applied an asset growth factor accordingly.
- We have applied forecast labour and non-labour escalation rates for the forthcoming regulatory period.
- We have applied forecast efficiency improvements and cost savings (including operating expenditure synergies expected to arise from the merger of Transend and Aurora Energy's distribution network).

In addition to the above matters, which are discussed in more detail below, our forecasts are based on the following:

- We assume that our operating environment, including external factors beyond our control, will be conducive to achieving the anticipated efficiency improvements.
- 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 on our future operating expenditure requirements is reflected in the expenditure forecasts.
- We do not expect regulatory changes currently underway, including Rule changes and reviews, to have a material impact on our operating expenditure requirements in the forthcoming regulatory period.

In accordance with schedule S6A.1.2(6) of the Rules, the directors have provided a certification of the reasonableness of these key assumptions in Appendix 8. It should be noted that although these key assumptions are reasonable, there is no guarantee that they will eventuate. If our assumptions prove to be incorrect, there may be a material impact on our operating expenditure.

6.5 Base year efficiency [Steps 1(a) and (b)]

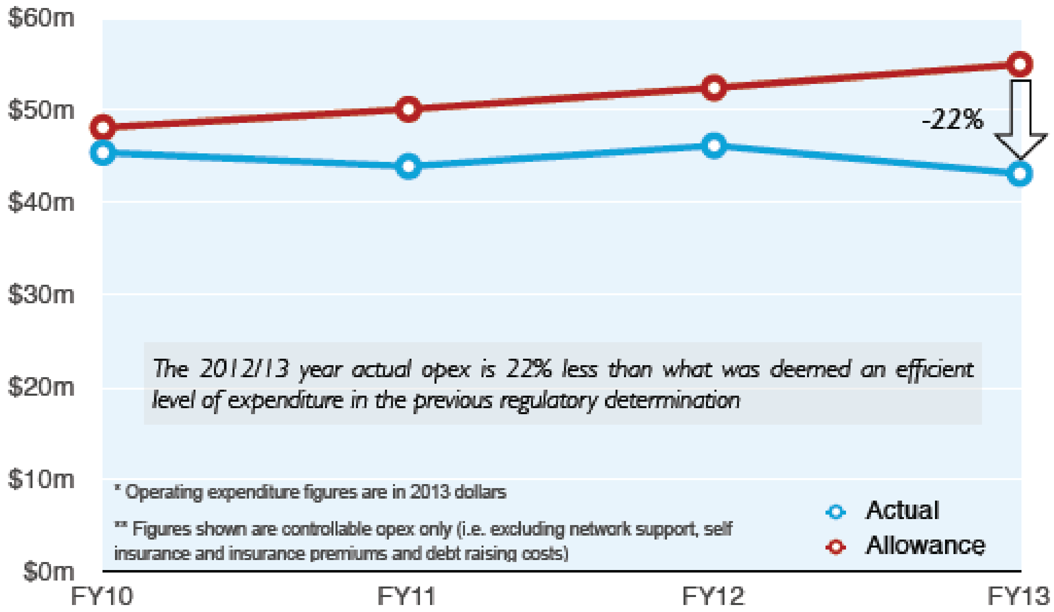
Our forecasting methodology explained that the first step in estimating our Controllable operating expenditure requirements is to establish that the 'base year' is efficient. We engaged consulting firm Huegin to consider whether our proposed base year of 2012–13 is appropriate. We summarise Huegin's findings in this section, noting that Huegin's full report is provided as Appendix 6 to this Revenue Proposal.

In considering the efficiency of our 2012–13 operating expenditure, Huegin noted that it compares favourably in the context of the company's historical performance and also relative to the broader industry. In particular, Huegin found:

- We benchmark well, given our unique circumstances within the industry.
- We have decreased our operating expenditure in the current period—to the point where the proposed base year is similar to the level of expenditure in 2006–07, being the base year for the previous period.
- We have achieved a decrease in operating expenditure during a period where the industry (based on the five major TNSPs) on average has experienced an increase.
- Given that the 2012–13 year is the most recent audited financial year and also reflects the latest year of a period of operating cost reductions, Huegin concludes that it is an appropriate base year for the purposes of forecasting future operating expenditure.

To illustrate the efficiencies that we have achieved in the current regulatory period, Huegin compared our actual operating expenditure with the allowance provided by the AER, as shown in Figure 6.3.

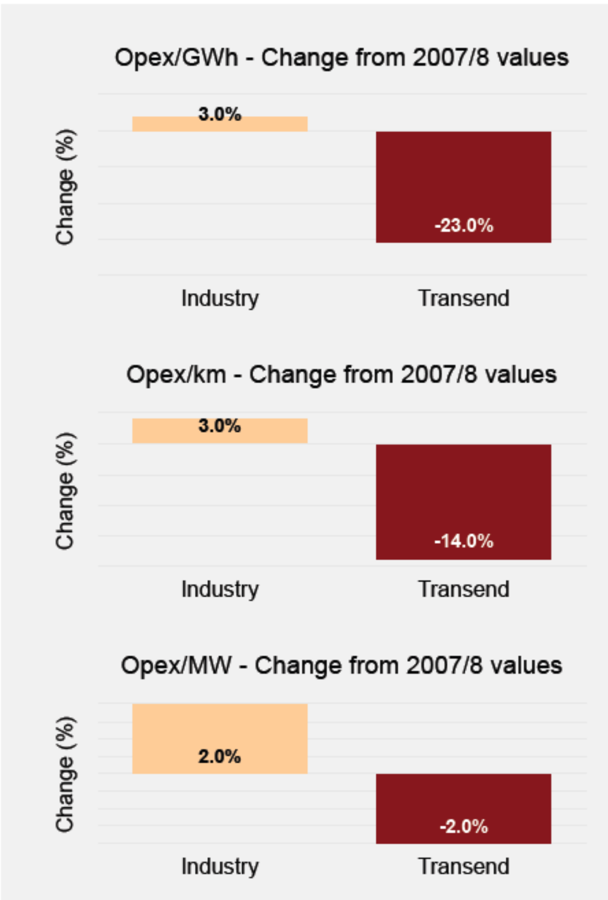
Figure 6.3 Controllable Opex – Actual and Allowance



Source: Huegin, Transend Base Year Operating Expenditure Efficiency- Transend, 21 February 2014, page 11.

Huegin also benchmarked our operating expenditure against other TNSPs in Australia. To compare our performance with other TNSPs, the percentage change in three alternative cost ratios was examined, as shown in the Figure 6.4.

Figure 6.4 Change in operating expenditure measures since 2007–08



Source: Huegin, Transend Base Year Operating Expenditure Efficiency- Transend, 21 February 2014, page 16.

Huegin's analysis shows that our operating expenditure per unit of output, measured in three alternative ways, is lower in 2012–13 compared to 2007–08. Furthermore, other TNSPs have experienced cost increases in these measures over the same period.

In light of Huegin's analysis and conclusions, we have adopted 2012–13 as the 'base year' for the purpose of forecasting our Controllable operating expenditure requirements.

Table 6.1 shows our base year operating expenditure, with an adjustment to remove the costs of the revenue reset process, which is cyclical in nature. This reflects steps 1(a) and 1(b) of our operating expenditure forecasting methodology (explained in section 6.3 above).

Table 6.1 Step 1(b) Deduct non-recurrent/one-off items from base year operating expenditure ($m 2013–14)

Category	2012–13	Adjusted	Comments
Field operations and maintenance	15.1	15.1	no change
Transmission services	7.2	7.2	no change
Transmission operations	5.2	5.2	no change
Asset management	8.1	7.7	Remove non-recurrent revenue reset costs from base
Corporate	9.2	9.2	no change
Total Controllable	**44.9**	**44.4**	

In accordance with our forecasting methodology, under step 1(e) an allowance for reset costs is included later in the forecasting process.

6.6 Step (or scope) changes [Step 1(c)]

Our forecasts of Controllable operating expenditure should include the effect of any step changes, which are material changes to the scope of our operating activities. Step changes may arise if there is a new obligation for which no costs were incurred in the base year, or the costs in the base year are not representative of efficient costs over the five year forecast period.

In the forthcoming regulatory period, there are two step changes that will affect our costs relative to the base year:

- New obligations under the AER's Better Regulation program.

  The additional costs are driven by new obligations, which require us to undertake new activities including development and on-going administration of a robust consumer engagement strategy, and collation and provision of detailed data to facilitate the AER's benchmarking activities. These costs are recurrent in nature.

- Changes to our operating agreement with AEMO.

  These changes require us to recover the cost of providing services from transmission customers. AEMO had previously recovered these costs from customers as market fees. These costs are recurrent in nature. The costs to be recovered from transmission customers are consistent with the charges that had previously been paid by AEMO under our operating agreement. This demonstrates that the additional costs to be recovered by us from transmission customers are prudent and efficient.

These two step changes entail Controllable operating cost increases that are unavoidable. Accordingly, if an allowance for these costs is not included in our operating expenditure forecast, then:

- our total forecast operating expenditure will not reasonably reflect the criteria in clause 6A.6.6(c) of the Rules; and
- our ability to achieve the objectives in clause 6A.6.6(a) of the Rules will be impeded.

Our estimates of the costs of undertaking the activities associated with these step changes are consistent with delivering the required outputs in a prudent and efficient manner. Our forecast of the additional Controllable operating expenditure arising from these step changes, in accordance with step 1(c) of our forecasting methodology, is set out in Table 6.2.

Table 6.2 Forecast step changes and add to base costs ($m 2013–14)

Item	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	Total 2014–19
AEMO operating agreement	0.4	0.4	0.4	0.4	0.4	0.4	1.9
Better Regulation program	0.4	0.4	0.4	0.4	0.4	0.4	2.1
Total step changes	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**4.0**

6.7 Growth factors [Step 1(d)]

Our operating expenditure requirements are affected by the size of our asset base. In broad terms an increase in the number of assets creates an increase in operating expenditure. However, there is not a one-to-one relationship between asset growth and operating expenditure. Because of the impact of scale economies, some operating cost categories, such as operations and business support, will change more slowly than changes to the asset base.

Our approach to estimating the impact of asset growth on our operating expenditure requirements is consistent with the approach accepted by the AER at our last full revenue review. In this regard, yearly asset growth is calculated in percentage terms. It is based on the value of new transmission assets that augment the network, relative to the replacement value of the existing network.

Our forecast of asset growth in percentage terms over the forthcoming regulatory period is set out in Table 6.3. The asset growth is determined by our capital expenditure plans, which are explained in Chapter 5 of this Revenue Proposal. Section 5.14.2 noted that our capital expenditure plans are consistent with AEMO's NTNDP, where relevant. It follows that the growth factors presented below, and the resulting operating expenditure forecasts, are similarly consistent with the NTNDP.

Table 6.3 Asset growth escalation factors (per cent real)

Item	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19
Asset growth	0.0	0.0	0.0	0.1	0.1	0.3

As already noted, the impact of asset growth on our operating costs is offset by the application of the economies of scale factors. Our estimated economies of scale factors are set out in Table 6.4. These are consistent with those used by the AER for the current period.

Table 6.4 Estimated economies of scale factors

Activity	Scale Factor (%)	Rationale
Field operations and maintenance	95	Almost a one-for-one increase in maintenance effort with some efficiency available through common overhead of service providers and use of existing systems
Transmission services, Transmission operations and Asset management	25	Economies of scale are possible for the existing scope of work through efficient management of this activity
Business Support	10	Economies of scale are possible for the existing scope of work through efficient management of this activity

The dollar impact of asset growth on our Controllable operating expenditure requirements (step 1(d) in our forecasting methodology) is outlined in section 6.11.

6.8 Controllable operating expenditure – zero based [Step 1(e)]

As explained in section 6.3, some elements of our Controllable operating expenditure are cyclical in nature, and therefore the expenditure on such items in the base year may not provide a good proxy for the efficient annual expenditure allowance. For such items, under step 1(f) of our forecasting methodology, it is necessary to provide a zero-based estimate of efficient future requirements.

For the forthcoming regulatory period, we have only one such item—revenue reset costs—in this category. Our forecasts reflect the expected pattern of expenditure associated with the five-yearly cycle of our revenue cap review. The forecast revenue reset costs are outlined in section 6.11.

6.9 Escalation rates [Step 1(f)]

Our Controllable operating expenditure requirements must take account of forecast changes in our input costs. As explained in relation to our capital expenditure forecasts, escalation rates for labour and materials should be factored into our operating expenditure forecasts.

6.9.1 Labour cost escalation

As explained in section 5.10.1, we engaged Independent Economics to provide forecasts of labour cost escalators for Tasmania for the purpose of this Revenue Proposal[22]. A copy of the report is provided as Appendix 11.

As noted in relation to labour escalation for capital expenditure, Independent Economics explains that:

- The current softness in the Australian economy has resulted in weak labour demand, and slower growth in labour costs.
- From this weak position, however, labour demand is expected to strengthen which is expected to lead to a similar recovery in wages growth.
- Annual wage growth is forecast to average 4.0 per cent (nominal) in the five years from 2014–15 to 2018–19.

Table 6.5 provides the annual labour escalation rates used in deriving our operating expenditure forecasts. These are real escalation rates, so reflect the labour cost increase or decrease above or below forecast CPI.

Table 6.5 Escalation factors for labour cost inputs (per cent real)

Input	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19
Tas utilities labour	0.2	-0.3	1.1	2.0	2.0	2.0

6.9.2 Non-labour cost escalation

Non labour operating expenditure components are assumed to increase in line with the CPI.

Section 6.11 includes the application of these labour and non-labour escalators, under step 1(g) of our forecasting methodology.

6.10 Efficiency improvements [Step 1(g)]

As already noted, we will deliver efficiency improvements through our merger with Aurora’s distribution network. Efficiencies from the merger are included in our expenditure forecasts and will be passed back to customers in the proposed revenue.

22 Independent Economics, Labour cost escalators for NSW, the ACT and Tasmania, 18 February 2014, Appendix 11.

The merger will take effect on 1 July 2014. Some efficiency initiatives will be implemented with immediate effect, most notably as a result of staff redundancies where functions are duplicated. We have forecast the efficiency improvements expected to arise immediately, and the share of savings applicable to prescribed transmission operating costs. We forecast an immediate prescribed transmission operating cost saving of $2.5 million in 2014–15.

Further efficiency gains will be achieved over time as the new company rationalises duplicate systems and finds better ways of delivering services to its customers. The new organisation will also develop optimal business processes and practices, with these efficiencies achieved over time. The plans to realise these savings are still to be developed, as TasNetworks is yet to commence operations.

In the absence of these efficiency improvement plans, a performance objective has been set to achieve continued operating cost reductions beyond 2014–15. We have set a target to continue to reduce controllable operating expenditure by 0.50 per cent each year in real terms, excluding cyclical revenue reset costs.

This target will require us to find savings that offset forecast cost increases, including future labour cost movements, and the $0.8 million additional expenditure required to fund known new obligations imposed by the AER Better Regulation program and the AEMO operating agreement.

This will be challenging to achieve.

Table 6.6 shows the annual and cumulative efficiency savings.

Table 6.6 Efficiency improvements ($m 2013–14)

Item	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19
Annual efficiency	1.7	2.6	0.6	1.0	1.0	1.1
Cumulative efficiency	1.7	4.2	4.8	5.9	6.9	7.9

These cost efficiencies total $29.8 million over the forthcoming regulatory period.

These forecast operating expenditure efficiencies are reflected in our controllable operating expenditure forecasts, which are set out in section 6.11.

6.11 Summary of Controllable Operating Expenditure

Table 6.7 provides details of the derivation of our Controllable operating expenditure forecasts.

Table 6.7 Controllable operating expenditure ($m 2013–14)

Item	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	Total 2014–19
Base year extrapolation (exc Revenue Reset Costs)	44.4	44.4	44.4	44.4	44.4	44.4	222.1
Plus step changes	0.8	0.8	0.8	0.8	0.8	0.8	4.0
Plus asset growth	0.0	0.0	0.0	0.1	0.1	0.3	0.5
Plus labour growth	0.1	0.0	0.3	1.1	1.8	2.6	5.8
Pre-efficiencies forecasts	**45.3**	**45.2**	**45.6**	**46.4**	**47.2**	**48.0**	**232.4**
Efficiency improvements	-1.7	-4.2	-4.8	-5.9	-6.9	-7.9	-29.8
Total Controllable expenditure (exc Revenue Reset costs)	**43.6**	**40.9**	**40.7**	**40.5**	**40.3**	**40.1**	**202.6**
Plus revenue reset costs	0.7	0.4	0.0	0.4	0.8	0.5	2.2
Total Controllable expenditure	**44.4**	**41.4**	**40.7**	**40.9**	**41.1**	**40.6**	**204.8**

Our forecast Controllable operating expenditure for the forthcoming regulatory period is 11 per cent below the actual operating expenditure in the current regulatory period. Figure 6.5 shows that, in the absence of our forecast efficiency improvements, Controllable operating expenditure would gradually increase over the forthcoming regulatory period. However, providing that we achieve our forecast efficiency savings, our Controllable operating expenditure will continue the trend reduction which commenced in 2007–08.

Figure 6.5 Controllable operating expenditure 2007–08 to 2018–19 ($m 2013–14)

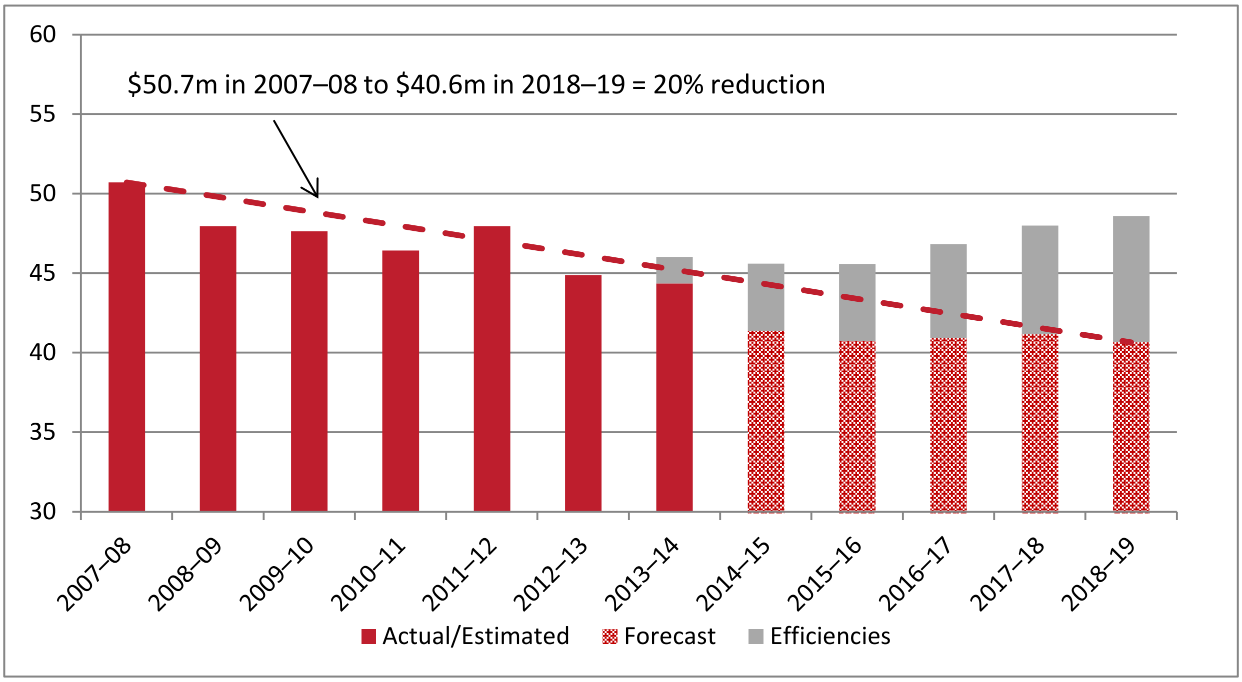
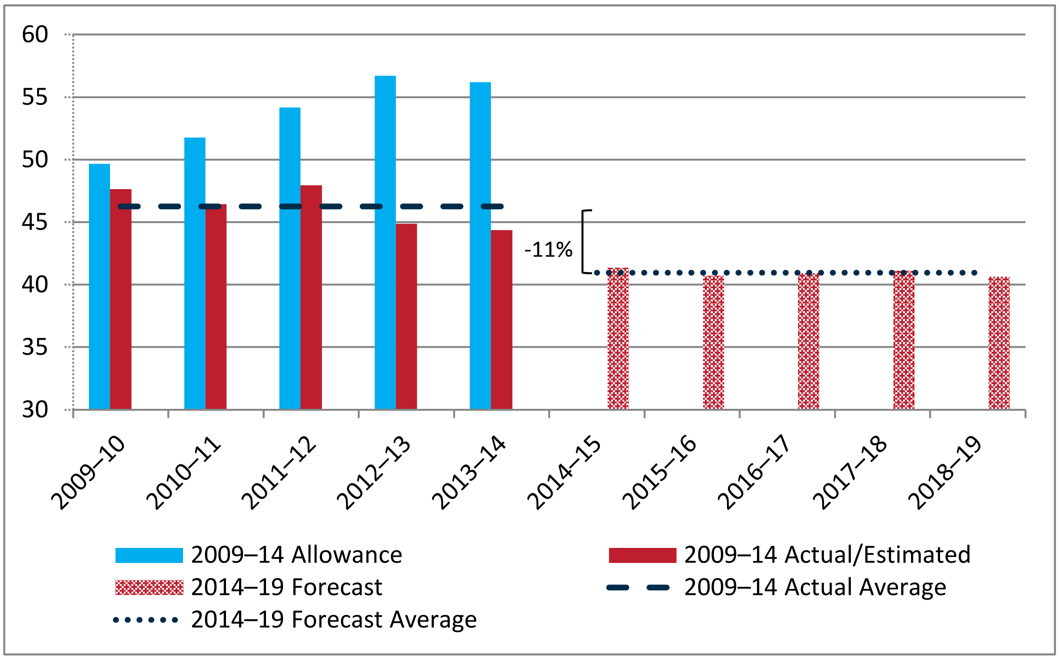


Figure 6.6 shows our forecast Controllable operating expenditure compared to the actual expenditure and AER allowance during the current period.

Figure 6.6 Controllable operating expenditure ($m 2013–14)



6.12 Other Operating Expenditure [Step 2]

As explained in section 6.2, our total operating expenditure requirements comprise Controllable operating expenditure and 'Other operating expenditure'. This section addresses our 'Other operating expenditure' requirements, which include:

- Network Support;

- Insurance;
- Self-insurance; and
- Debt raising costs.

6.12.1 Network Support

Network support is an alternative to transmission network augmentation. In conducting the regulatory investment test for transmission a network support alternative may arise as the option that satisfies the test. The Rules require the pass through of network support costs subject to the relevant factors set out in clause 6A.7.2.

We are currently not forecasting a requirement for network support payments for the forthcoming regulatory control period. However, this does not preclude us from seeking a pass-through for any prudent network support expenditure we may incur over this period. Under the Rules framework, network support pass-through adjustments will be made for the difference between allowed and actual network support payments, after approval by the AER.

6.12.2 Insurance and self-insurance

We engaged Marsh Australia (Marsh)—experts in insurance markets—to provide estimates of appropriate allowances for our insurance and self-insurance costs over the forthcoming regulatory period. The reports prepared by Marsh are provided as appendices 15 and 16 to this Revenue Proposal.

In estimating our future insurance premiums, Marsh examined the following factors for each class of insurance:

- Historical changes in insurance cover
- Historical variation in exposure
- Historical claims experience
- Forecasts of exposure
- Inflationary impacts
- Expected market outlook
- Other historical market factors (eg changes in insurers, changes in insurer profit margins, industry claims experience, etc.) to the extent that historical premium trends are observed which cannot be directly attributable to other factors.

Marsh noted that, as present insurance arrangements are managed cooperatively between Transend and Aurora's distribution business, no further insurance savings are anticipated as a result of the merger of the network businesses.

In establishing an allowance for self–insurance, Marsh recommended an allowance that reflects the average annual cost of:

- 'below deductible' and 'uninsured losses' that have occurred historically during the past 10 to 15 years; and
- 'below deductible' and 'uninsured costs' arising from various scenario events (between one-in-25 to one-in-100 year likelihoods) that have not occurred.

Marsh expressed the view that any other events were likely to be extreme in nature, and would be most appropriately addressed by the cost-pass through mechanisms.

Marsh also explained that its estimated self-insurance allowance is the expected annual cost of funding future losses, inflated to 30 June 2014 values, and is exclusive of any allowance for volatility, cost of capital or expenses relating to settlement of losses. For this reason, they are most likely lower than the cost of any commercial insurances, as insurers would most likely be pricing for the expected cost of losses, as well as expenses and profit margin.

We accept Marsh's expert opinion in relation to the expenditure allowances for insurance and self-insurance. On this basis, we have included allowances (in 2013–14 dollars) of approximately $1 million per annum for insurance premiums, and $0.7 million per annum for self-insurance.

6.12.3 Debt raising costs

Debt raising costs are benchmarked costs that reflect the costs arising from raising or refinancing debt. These costs include underwriting fees, legal fees, company credit rating fees and other transaction costs.

A report prepared in June 2013 by PricewaterhouseCoopers[23] estimated the total benchmark debt raising cost for a debt portfolio of $1,000 million to be 25 basis points per annum (bppa). This is comprised of:

- Direct costs of 10.9 bppa. These costs consist mainly of the arrangement fees that are paid to the organisation responsible for the bond issue to prepare and market the issue, and other direct debt raising transaction costs such as legal costs, rating and agency fees.
- Indirect costs of 14.1 bppa. These costs relate to liquidity reserves (ie spare funding capacity) that credit rating agencies require corporate borrowers to hold, and credit rating agencies' requirements regarding management of refinancing risk.

We consider that the PwC report provides a robust estimate of the total direct and indirect debt raising costs that a prudent service provider acting efficiently would incur, because it:

- identifies the types of transaction cost that a prudent service provider acting efficiently would incur in raising debt; and
- quantifies the level of these costs (using benchmark assumptions) with reference to market rates for the relevant services.

That said, as explained earlier, our Revenue Proposal for the forthcoming regulatory period is focused on reducing our total revenue requirements in real terms by delivering efficiency savings in controllable operating and capital expenditure. For this Revenue Proposal, we therefore propose to include an allowance to recover the direct debt raising costs only, with indirect debt raising costs to be absorbed by the business.

PwC's estimate of direct debt raising costs of 10.9 bppa applies to a $1,000 million debt portfolio. PwC has also estimated the direct debt raising costs of a $500 million debt portfolio to be 12.5 bppa. Our benchmark debt value (of approximately $840 million) lies between these two values. Interpolating between these two values indicates a direct debt raising cost of 11.5 bppa. Accordingly, we have included an allowance of 11.5 bppa in relation to our direct debt raising costs.

As debt raising costs are based on a benchmark entity, no change in allowance is anticipated as a result of network merger.

6.13 Operating expenditure forecasts for 2014–15 to 2018–19 [Step 3]

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

Table 6.8 provides a breakdown of our forecast operating expenditure compared to our actual expenditure and allowance for the current regulatory period.

[23] PwC, Debt financing costs: report for Energy Networks Association, June 2013.

Table 6.8 Operating expenditure by category ($m 2013–14)

Category	2009–14 Allowance	Actual expenditure 2009–14	Forecast 2014–19
Field operations and maintenance	99.4	80.3	75.5
Transmission services	45.2	41.5	35.5
Transmission operations	29.6	25.5	25.1
Asset management	45.5	41.2	37.9
Business support (Corporate)	48.8	42.8	30.8
Total Controllable expenditure	**268.5**	**231.2**	**204.8**
Network support (pass through of actuals)	7.5	6.9	0.0
Insurance premiums	6.6	4.9	5.2
Self-insurance	4.6	4.6	3.5
Total Operating expenditure (excluding debt raising costs)	**287.1**	**247.7**	**213.5**
Debt raising costs[24](benchmark)	3.3		4.8
Total Operating expenditure (including debt raising costs)	**290.5**		**218.3**

The table above shows that our forecast total operating expenditure (excluding debt raising costs) is 14 per cent lower than actual expenditure in the current period. Including debt raising costs, forecast total operating expenditure is 12 per cent lower than actual expenditure in the current regulatory period. This reduction reflects our focus on delivering further operating expenditure efficiencies in the forthcoming period.

Table 6.9 presents our operating expenditure forecasts for each expenditure category together with the actual expenditure for the current regulatory period for comparative purposes.

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

Table 6.9 Annual operating expenditure forecasts ($m 2013–14)

	Current period (actual)					Forthcoming period (forecast)				
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	16.2	17.0	16.9	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Transmission services	9.1	8.9	9.0	7.2	7.2	7.1	7.1	7.1	7.1	7.1
Transmission operations	5.0	4.7	5.4	5.2	5.2	5.0	5.0	5.0	5.0	5.0
Asset management[25]	8.8	7.8	8.1	8.1	8.4	7.6	7.1	7.6	8.0	7.7
Business support (Corporate)	8.6	8.0	8.5	9.2	8.4	6.6	6.4	6.2	6.0	5.7
Total Controllable expenditure	**47.6**	**46.4**	**47.9**	**44.9**	**44.4**	**41.4**	**40.7**	**40.9**	**41.1**	**40.6**
Network support	4.2	2.7	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	1.1	1.1
Self-insurance	0.9	0.9	0.9	0.9	0.9	0.7	0.7	0.7	0.7	0.7
Total Operating expenditure (excluding debt raising costs)	**53.8**	**51.0**	**49.9**	**46.8**	**46.2**	**43.1**	**42.5**	**42.7**	**42.9**	**42.4**
Debt Raising Costs (benchmark)[26]						1.0	1.0	1.0	1.0	1.0
Total Operating expenditure						**44.0**	**43.4**	**43.6**	**43.9**	**43.4**

Appendix 15 provides more detailed breakdowns of the derivation of the operating expenditure forecasts by category, including the application of step changes, asset growth, labour escalation and efficiency reductions.

[25] The asset management category includes the cyclical revenue reset costs.

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

The following diagram is replicated from section 6.2, updated to include the forecast average annual expenditure amounts over the 2014–19 regulatory period in the relevant categories. It is noted that clause S6.A.1.2(1) of the Rules requires our Revenue Proposal to identify the categories of transmission service that will be provided by each category of operating expenditure. Table 3.1 of our 2014–19 Revenue Proposal Expenditure Forecasting Methodology sets out this information.

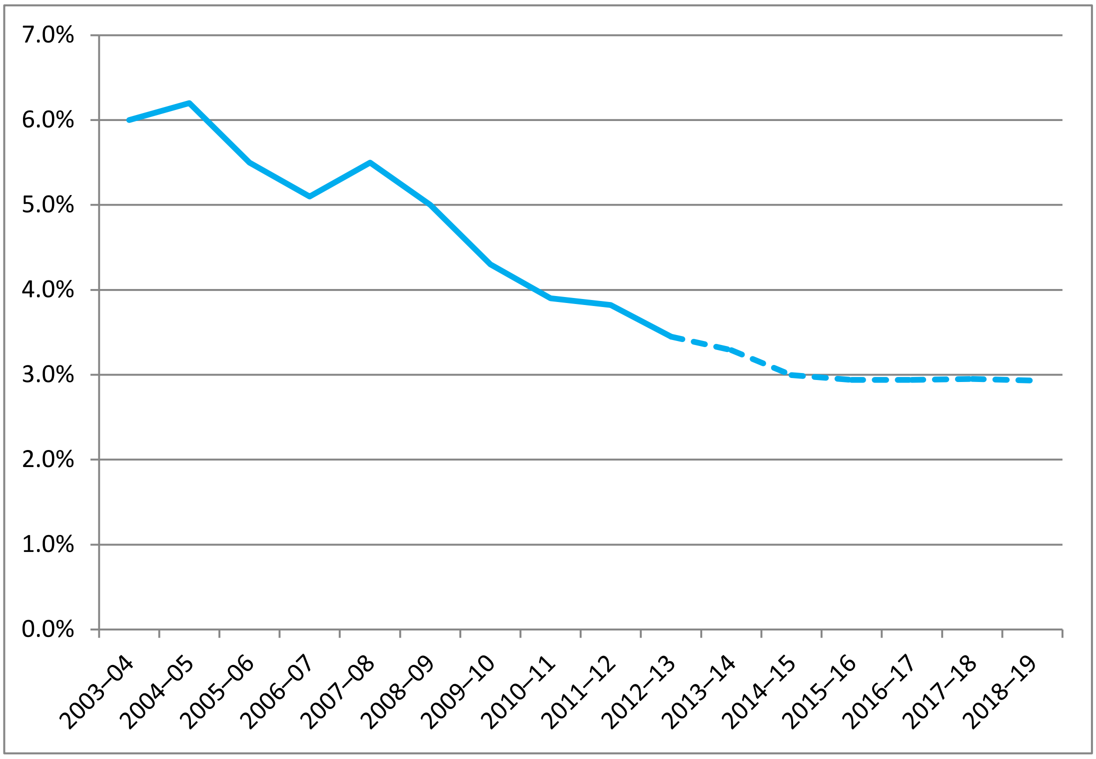
Figure 6.7 Forecast annual average operating expenditure ($m 2013–14)

<table>
<tr><th colspan="8">Total Annual Average Operating Expenditure
$43.7m</th></tr>
<tr><td colspan="5">Controllable Operating Expenditure
$41.0m</td><td colspan="3">Other Operating Expenditure
$2.7m</td></tr>
<tr><td colspan="3">Direct Operating & Maintenance
$27.2m</td><td colspan="2">Other Controllable
$13.7m</td><td colspan="2">Other
$1.7m</td><td>Benchmark Allowances
$1.0m</td></tr>
<tr><td>Field operations & maintenance
$15.1m</td><td>Transmission services
$7.1m</td><td>Transmission operations
$5.0m</td><td>Business support (Corporate)
$6.2m</td><td>Asset management
$7.6m</td><td>Network support
$0.0m</td><td>Insurance & Self-insurance
$1.7m</td><td>Debt raising
$1.0m</td></tr>
</table>

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

Figure 6.8 indicates that the prescribed opex to RAB ratio continues the downward trend over the next regulatory period to below 3 per cent in 2018–19.

Figure 6.8 Ratio of prescribed opex to regulated asset base value to 2018–19



This illustrates the positive impact of the operating efficiency gains we have achieved to date, and the anticipated further improvements which have been factored into our operating expenditure forecasts.

6.14 Concluding comments

We have achieved significant operating expenditure efficiencies in the current regulatory period by improving our business processes and reducing staff levels. We plan to deliver further cost reductions in the forthcoming regulatory period, primarily driven by the merger with Aurora Energy's distribution network business. The operating expenditure forecasts presented in this chapter reflect the achieved and expected efficiency improvements. The savings arising from our planned efficiency gains will benefit customers with immediate effect.

In forecasting our operating expenditure requirements an appropriate balance must be reached between the pressure to reduce expenditure and the importance of maintaining service performance and managing network risks. For the reasons set out in this chapter, we believe that we have this balance right.

Under the Rules, our operating expenditure forecast must achieve the operating expenditure objectives, which include the requirement to provide safe and reliable transmission services to our customers and to comply with our regulatory obligations. As explained in this chapter, we have applied a methodology that produces expenditure forecasts that meet the operating expenditure objectives specified in the Rules.

7 Expenditure Incentive Schemes

7.1 Introduction

The Rules provide for two expenditure incentive schemes, as follows:

- The efficiency benefit sharing scheme (EBSS) is an incentive mechanism which rewards sustained operating expenditure savings (efficiency gains) and penalises sustained operating expenditure increases (efficiency losses) compared to forecast efficient levels set by the AER. The scheme is designed to provide regulated companies with a consistent incentive to deliver efficiency improvements in operating expenditure throughout a regulatory period. The EBSS applied to us in the current period, and will apply from 1 July 2014 in the forthcoming period.
- The capital expenditure sharing scheme (CESS) is a scheme that provides Transmission Network Service Providers with an incentive to undertake efficient capital expenditure during a regulatory period. The CESS did not apply in the current period but in accordance with the Rules, it will apply to us from 1 July 2015 (after the 2014–15 transitional regulatory period).

This chapter presents information relating to the application of these incentive schemes. It is structured as follows:

- Section 7.2 presents details of the calculation of the incentive payments arising from the application of the EBSS for the current regulatory period.
- Section 7.3 sets out our proposals regarding the EBSS parameters for application in the forthcoming regulatory period.
- Section 7.4 describes the CESS which is to apply from 1 July 2015.

7.2 Financial outcomes from the current EBSS

As explained in the previous chapter, we have achieved significant operating expenditure efficiencies in the current regulatory period by improving our business processes and reducing staff levels. As a consequence, the application of the EBSS in the current period gives rise to incentive payments (rewards for efficiency improvements) which are to be included in our revenue allowance for the forthcoming period.

Under the EBSS, annual cost efficiency gains or losses are retained by the business for a five year 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.

Table 7.1 and Table 7.2 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 7.1 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	47.5	46.4	47.3	44.8	44.2
Incremental gain/loss	1.8	3.2	1.4	5.0	na

Table 7.2 Efficiency carryover ($m 2013–14)

	2009–10	2010–11	2011–12	2012–13	2013–14
Efficiency carryover	11.4	9.6	6.4	5.0	0.0

Further detail on the calculation of the efficiency carryover methodology is included in Appendix 18.

The efficiency carryover rewards us for sustainably reducing our operating cost base. Customers also benefit, as operating expenditure is based on revealed efficient costs.

In the next period transmission customers will see operating costs that are more than $10 million lower per annum than the forecast considered efficient by the AER in its previous revenue decision. This equates to reductions of more than $50 million over a five year regulatory period. The efficiency carryover is an incentive payment over the forthcoming period for delivering this $50 million controllable operating expenditure reduction.

7.3 Proposed EBSS for the forthcoming period

The AER's Framework and Approach paper explains that the AER proposes to apply the current (September 2007) EBSS to TasNetworks in the 2014–15 transitional regulatory control period, with modifications to align it with version 2 of the EBSS (the new EBSS).

In effect, the new EBSS applies in both the transitional and subsequent periods, ie for the full five year regulatory period, 2014–19.

The AER explains that:

> The new EBSS retains the same form as the current EBSS, and merges the distribution and transmission schemes. Changes in the new EBSS relate to the criteria for adjustments and exclusions under the scheme. (We will no longer allow for specific exclusions such as uncontrollable opex or for changes in opex due to unexpected increases or decreases in network growth.) We may also exclude categories of opex not forecast using a single year revealed cost approach from the scheme on an ex post basis if doing so better achieves the requirements of the rules. We also amended the scheme to provide flexibility to account for any adjustments made to base year opex to remove the impacts of one-off factors. The new EBSS also clarifies how we will determine the carryover period. These revisions affect how we will calculate carryover amounts for future regulatory control periods.[27]

Consistent with the AER's statement above regarding categories of opex not forecast using a single year revealed cost approach, we propose the following exclusions from the EBSS:

- Network support;
- Insurance premiums;
- Self-insurance; and
- Debt raising costs.

Table 7.3 presents the forecast controllable opex to be used for calculating the EBSS carryover amounts at the end of the forthcoming regulatory control period. The forecasts do not include the exclusions listed above.

[27] AER, Framework and approach paper - Transend, January 2014, page 16.

Table 7.3 Operating expenditure for EBSS purposes ($m, 2013–14)

	2014–15	2015–16	2016–17	2017–18	2018–19
Total opex	44.0	43.4	43.6	43.9	43.4
Less: Network support	0.0	0.0	0.0	0.0	0.0
Less: Insurance premiums	-1.0	-1.0	-1.0	-1.1	-1.1
Less: Self-insurance	-0.7	-0.7	-0.7	-0.7	-0.7
Less: Debt raising costs	-1.0	-1.0	-1.0	-1.0	-1.0
Controllable opex for EBSS purposes	41.4	40.7	40.9	41.1	40.6

Consistent with the AER's new EBSS, any opex efficiencies realised during the forthcoming period will be carried over for the carryover period of five years. Conversely, TasNetworks will be penalised for any reduction in operating cost efficiency.

7.4 Capital expenditure sharing scheme

The AER's Framework and Approach paper explains that:

- The capital expenditure sharing scheme (CESS) provides financial rewards for TNSPs whose capex becomes more efficient, and it applies penalties for those that become less efficient.
- Consumers benefit from improved efficiency through lower regulated prices in the future.
- The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between TNSPs and network users.[28]

The AER explains:

> The CESS works as follows:
>
> - We calculate the cumulative underspend or overspend for the current regulatory control period in net present value terms.
> - We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend to work out what the TNSP's share of the underspend or overspend should be.
> - We calculate the CESS payments taking into account the financing benefit or cost to the TNSP of the underspends or overspends. We calculate benefits as the benefits to the TNSP of financing the underspend, since the amount of the underspend can be put to some other income generating use during the period. Losses are similarly calculated as the financing cost to the TNSP of the overspend. We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
> - The CESS payments will be added or subtracted to the TNSP's regulated revenue as a separate building block in the next regulatory control period.
>
> Under the CESS a TNSP retains 30 per cent of an underspend or overspend, while consumers retain 70 per cent of the underspend on overspend. This means that for a one dollar saving in capex the TNSP keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.[29]

The Framework and Approach paper states that:

- The AER intends to apply the CESS as set out in the capex incentives guideline[30] to TasNetworks in the subsequent regulatory control period.

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[28] AER, Framework and approach paper - Transend, January 2014, page 24.

[29] AER, Framework and approach paper - Transend, January 2014, page 24.

[30] AER, Capital expenditure incentive guideline for electricity network service providers, pages 5–9.

- The AER cannot apply the CESS in the transitional regulatory control period. This is because the transitional rules provide that the AER must not apply a CESS in a transmission determination made for a TNSP for the transitional regulatory control period.[31]

Therefore, the CESS will apply to TasNetworks from 1 July 2015. Table 7.4 presents our proposed capital expenditure for CESS purposes.

Table 7.4 Capital expenditure for CESS purposes ($m, 2013–14)

	2014–15	2015–16	2016–17	2017–18	2018–19
Capex for CESS purposes	na	66.1	59.9	53.7	45.3

[31] AER, Framework and approach paper - Transend, January 2014, page24.

8 Regulatory asset base

8.1 Introduction

This chapter presents our 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 remain relatively unchanged during the next regulatory period, 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 8.2 explains the methodology for rolling forward the asset base value to 1 July 2014.
- Section 8.3 provides an explanation of the derivation of the estimated opening and closing RAB value for each year of the forthcoming five-year regulatory control period.

8.2 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 (RFM) provided by the AER and the requirements of schedules S6A.2.1 and S6A.2.4, and clause 11.6.9 of the Rules. We have made some minor modifications to the RFM, and these are set out in explanatory notes in the completed model submitted as part of this Revenue Proposal.

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.

We have also removed assets totalling $1.1 million from the closing RAB as a result of a change of service classification associated with these assets. Specifically these assets now provide a negotiated service rather than a prescribed service.

Table 8.1 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 TasNetworks and customers are unaffected by forecasting errors in that year.

Table 8.1 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	82.7
Inflation on opening RAB	27.5	35.6	18.6	31.8	39.1
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	1,394.9
Add difference between actual and forecast 2008–09 net capex					-12.4
Add return on difference in 2008–09 net capex					-7.8
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					15.1
Assets removed from prescribed services					-1.1
Closing RAB					**1,412.9**

As shown in Table 8.1, the RAB value as at 1 July 2014 (in nominal dollars) is $1,412.9 million. Capital expenditure for 2013–14 is an estimate.

8.3 Forecast of regulatory asset base over the forthcoming regulatory period

Table 8.2 presents a summary of the amounts, values and inputs used by us to derive our 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 8.2 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	1,412.9	1,448.9	1,498.9	1,540.9	1,577.0
Nominal capex as incurred	53.6	71.2	66.1	60.8	52.5
Inflation on opening RAB	35.7	36.6	37.8	38.9	39.8
Nominal straight-line depreciation	-53.3	-57.7	-62.0	-63.6	-65.5
RAB (end period) - nominal	1,448.9	1,498.9	1,540.9	1,577.0	1,603.9
RAB (end period) - $June 2014	**1,413.2**	**1,426.0**	**1,429.8**	**1,427.3**	**1,415.9**

9 Regulatory Depreciation

9.1 Introduction

This chapter sets out our 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 9.2 describes our depreciation methodology.
- Section 9.3 provides information on the remaining lives of our assets.
- Section 9.4 sets out details of our standard asset lives.
- Section 0 presents our depreciation forecast.

9.2 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 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 assessed remaining lives of assets in existence as at 30 June 2014;
- the capital expenditure forecasts set out in chapter 5; and
- the standard asset lives set out below.

We note that Schedule S6A.1.3(7) of the Rules requires us to provide the depreciation schedules by location. We understand that this requirement relates to clause 6A.6.3, which requires special treatment of assets dedicated to one user or a small group of users (not being a DNSP) with value exceeding $20 million. TasNetworks does not have any transmission assets that fall within this category.

9.3 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 substation asset classes. Those particular asset classes were used until 30 June 2009, at which time they were subdivided into separate classes reflecting different standard asset lives of transmission line and substation assets[32]. Since that time no capital expenditure has been applied to the original transmission lines and substation asset classes.

In reviewing the appropriate remaining lives of our assets, we reassessed the weighted average remaining life of the pre-30 June 2009 transmission line and substation assets, and we have amended

[32] Section 9.4 describes our standard asset lives.

the remaining lives of those asset classes accordingly. Compared to the roll forward model calculation, these amendments increase the average remaining lives of these asset classes.

The effect of this amendment is that depreciation will be recovered over a longer period, resulting in a reduction to the depreciation allowance for the 2009–14 regulatory period. This change results in a net reduction in the total revenue allowance over the 2009-14 regulatory period of approximately $13 million per annum.

This proactive adjustment to our depreciation profile results in a reduction in transmission charges over the next five years. While it will take us longer to recover the investment made in our assets, we have accepted this risk in order to reduce customer charges now.

9.4 Standard asset lives

Our standard asset lives, set out in Table 9.1, 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 engaged SKM to review our standard asset lives and their report is included in Appendix 19.

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 9.1 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

9.5 Depreciation forecasts

Our depreciation forecast reflects:

- the opening asset base and forecast RAB values described in chapter 8, which include estimates of capital expenditure and disposals;
- the methodology outlined in section 9.2 above;
- the amended asset remaining lives, as described in section 9.3; and
- the standard asset lives set out in section 9.4.

The PTRM has been used to calculate the depreciation forecast on a straight-line basis. Table 9.2 sets out the regulatory depreciation forecast.

Table 9.2 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	53.3	57.7	62.0	63.6	65.5
Indexation	-35.7	-36.6	-37.8	-38.9	-39.8
Regulatory depreciation	**17.6**	**21.1**	**24.2**	**24.6**	**25.6**

10 Cost of capital and taxation

10.1 Introduction

This chapter sets out our weighted average cost of capital (WACC) or rate of return, and the allowance for the cost of corporate tax. The remainder of this chapter is structured as follows:

- Section 10.2 provides an overview the AER's guideline in relation to the rate of return and taxation.
- Section 10.3 presents a summary of our proposed point estimate for the rate of return.
- Section 10.4 sets out our forecast allowance for corporate tax.

10.2 Overview of the Rate of Return Guideline

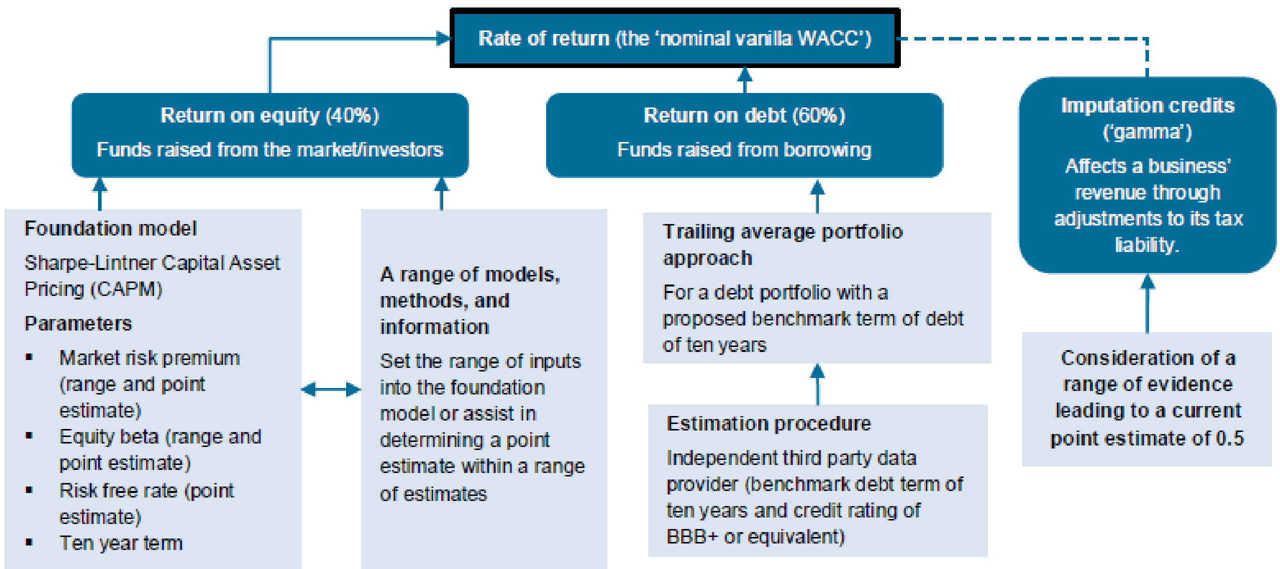
The AER has recently published a guideline setting out its proposed approach to estimating the weighted average cost of capital (WACC) or rate of return. The Rate of Return Guideline is an important element of the AER's Better Regulation reform program, following the AEMC's changes to the rate of return 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.

The following diagram (reproduced from the AER's 'factsheet' for the Rate of Return Guideline) provides a summary of the AER's proposed approach to determining the WACC.

Figure 10.1 Overview of the AER's Rate of Return guideline



Under the new guideline, the WACC is estimated for a benchmark efficient entity, being a 'pure play', regulated energy network business operating within Australia. Benchmark gearing is assumed to be 60 per cent debt to total capital. Under the WACC formulation to apply, the costs of equity and debt are estimated separately and weighted according to the benchmark gearing to derive a vanilla WACC. It is noted that these features of the methodology are consistent with the AER's previous approach.

In relation to estimating the cost of equity, the AER will continue to apply the Sharpe-Lintner CAPM as the 'foundation model'. The AER will also have regard to alternative models and other data to inform:

- the estimation of input parameters to the foundation model; and
- the appropriate point estimate of the cost of equity.

For example, the Rate of Return Guideline explains that the AER will have regard to: historical excess returns; brokers' return on equity estimates; takeover/valuation reports; debt spreads; comparison with return on debt; implied volatility; and other regulators' cost of equity estimates. The AER will also have regard to the model proposed by Professor Stephen Wright (the "Wright Approach"), which argues that the cost of equity is relatively stable over time, and that it is appropriate to recognise this stability in estimating the cost of equity.

The cost of equity allowance will be set (and fixed) for the duration of the regulatory control period. Given the uncertainty inherent in estimating expected equity returns, the final return on equity estimate will reflect either the foundation model point estimate (rounded to a single decimal point), or an alternative value that is a multiple of 25 basis points. The AER has stated that this approach is intended to "disavow the pursuit of false precision".

In the AER's explanatory statement that accompanies the Rate of Return Guideline, the AER sets out its reasoning for adopting parameter values for the market risk premium (6.5 per cent) and equity beta (0.7) in estimating the cost of equity. The AER also proposes a value for gamma (0.5), which is the key parameter for estimating the tax allowance. We discuss these parameter values in section 10.3.

The Rate of Return Guideline explains that the cost of debt will be estimated using a trailing average approach, which establishes an average cost of debt by assuming that one-tenth of the network business' debt is re-financed annually. The trailing average approach will be introduced over a 10 year transitional period. The cost of debt allowance will be updated annually.

Apart from the adoption of a trailing average method, the AER's process for estimating the cost of debt is otherwise unchanged. Specifically, the AER will estimate the cost of debt using:

- The published yields from an independent third party data provider.
- A credit rating of BBB+.
- A term to maturity of debt of 10 years.

10.3 Rate of return

In preparing our estimate of the cost of equity, we engaged an independent expert to provide opinions on the appropriate parameter values and an overall point estimate. These independent opinions indicate that there is strong evidence to support a cost of equity estimate above the value estimated using the AER's parameter values in its Rate of Return Guideline. The independent expert report is provided as Appendix 20 to this Revenue Proposal.

While we accept the views expressed by the independent expert, we must also consider the impact of a higher cost of equity on our customers. We are particularly mindful of the commercial pressures currently facing our customer base in Tasmania. A balance must be struck between the objective of ensuring that the true cost of equity is recognised in our revenue allowance, and the need to establish a price path that is sustainable for our customers. In weighing these considerations, we propose to adopt the parameters values identified by the AER in its Rate of Return Guideline and explanatory statement.

We therefore propose a rate of return or weighted average cost of capital (WACC) of 7.58 per cent, as set out in Figure 10.2. It is referred to as the 'weighted' average cost of capital because it combines the cost of equity and the cost of debt by weighting these two components in proportion to the benchmark capital structure. Our proposed cost of equity of 8.7 percent is 310 basis points lower than the cost of equity allowance of 11.8 per cent provided in the current regulatory period. While approximately half this reduction is due to a decline in market interest rates, we are proposing a further substantial reduction in the return on equity. Our acceptance of a lower return on equity is a significant contribution to lower transmission revenue in the forthcoming regulatory period.

Figure 10.2 Proposed WACC

Weighted Average Cost of Capital		
Component	**Debt**	**Equity**
Gearing	**60%**	**40%**
	x	**x**
Cost	**6.84%**	**8.7%**
	=	**=**
Contribution	**4.10%**	**3.48%**
WACC	**7.58%**	

Table 10.1 shows the parameter values we have adopted for the purpose of calculating the WACC. A brief explanation of the basis for each parameter value is also provided.

Table 10.1 Proposed WACC parameters

Parameter	Proposed value	Basis of parameter value
Risk fee rate (nominal)	4.11%	This is the average annualised yield on 10 year Commonwealth bonds (CGS) over the period from 28 February 2014 to 30 April 2014, as shown in the Reserve Bank of Australia's statistical publication "F2 Capital Market Yields - Government Bonds". In accordance with the AER's Rate of Return Guideline, this value is to be updated to reflect CGS yields as close as practicably possible to the commencement of the regulatory period.
Market risk premium	6.50%	This value is consistent with the AER's Rate of Return Guideline explanatory statement, and theoretical and empirical evidence including historical excess returns, dividend growth model estimates, and survey evidence.
Equity beta	0.70	This value is consistent with the AER's Rate of Return Guideline. There is significant evidence to suggest that the value of the equity beta should be higher than 0.7. However, for the reasons outlined above, we consider it appropriate to adopt a lower value for the equity beta (which reduces our revenue allowance) in order to deliver a sustainable price path for our customers.
Cost of equity	8.7%	This point estimate is derived from the application of the above CAPM parameters. It is rounded to a single decimal point in accordance with the Rate of Return Guideline.
Cost of debt - 10 year BBB+ (nominal)	6.84%	This is the annualised yield on 10-year BBB-rated corporate debt averaged over the period from February 2014 to April 2014 inclusive, as shown in the Reserve Bank of Australia's statistical publication "F3 Aggregate Measures of Australian Corporate Bond Spreads and Yields: Non-financial Corporate Bonds". We will agree with the AER (on a confidential basis) the measurement periods to be applied for the purpose of estimating the cost of debt allowance.
Expected inflation	2.52%	This is a 10-year forecast of inflation based on the geometric average of the RBA's short–term inflation forecasts for the next two years (as published in the RBA's February 2014 Statement on Monetary Policy) and the mid-point (2.5 per cent) of the RBA's target inflation band for the remaining years in the 10-year forecast period.
Gearing (Debt / total capital)	60%	In accordance with the AER's Rate of Return Guideline.
Gamma	0.50	This value is consistent with the AER's Rate of Return Guideline. There is significant evidence to suggest that the value of gamma should be 0.25 as outlined in the SFG Consulting report at Appendix 27. However, for the reasons outlined above, we consider it appropriate to adopt a higher value for gamma (which reduces our revenue allowance) in order to deliver a sustainable price path for our customers.
Corporate tax rate	30%	This is the statutory corporate income tax rate applied in the calculation of the forecast allowance for tax, as set out in section 10.4 below.
Vanilla WACC (nominal)	**7.58%**	

The values we have adopted for each parameter are consistent with the AER's Rate of Return Guideline, and therefore the AER should accept the resulting WACC estimate, once updated to reflect market data from the nominated debt and equity averaging periods.

10.4 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 10.2 shows the resulting regulatory allowance for tax.

Table 10.2 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	8.3	8.9	9.5	9.6	10.4
Imputation credit	-4.1	-4.4	-4.8	-4.8	-5.2
Tax allowance	**4.1**	**4.4**	**4.8**	**4.8**	**5.2**

11 Total Revenue and X Factor

11.1 Introduction

Our Revenue Proposal is based on the post-tax building block approach outlined in clause 6A.5.4 of the Rules, the post-tax revenue model (PTRM), and the roll forward model (RFM). We have made some minor modifications to the PTRM and RFM. These are set out in explanatory notes in the completed models submitted as part of this Revenue Proposal. Information explaining and substantiating the various building block components has been set out in the preceding chapters of this Revenue Proposal.

The building block formula to be applied in each year of the regulatory period is:

MAR = return on capital + return of capital + Opex + EBSS + Tax

= (WACC x RAB) + D + Opex + EBSS + Tax

where:

MAR = Maximum allowed revenue

WACC = Post tax nominal weighted average cost of capital

RAB = Regulatory Asset Base

D = Economic depreciation (nominal depreciation – indexation of the RAB)

Opex = Operating and maintenance expenditure

EBSS = Revenue increments for the year arising from the operation of the efficiency benefit sharing scheme

Tax = Cost of corporate income tax of the regulated business

The annual revenue stream derived using the building block formula is then smoothed with an X factor in accordance with the requirements of clause 6A.6.8 of the Rules.

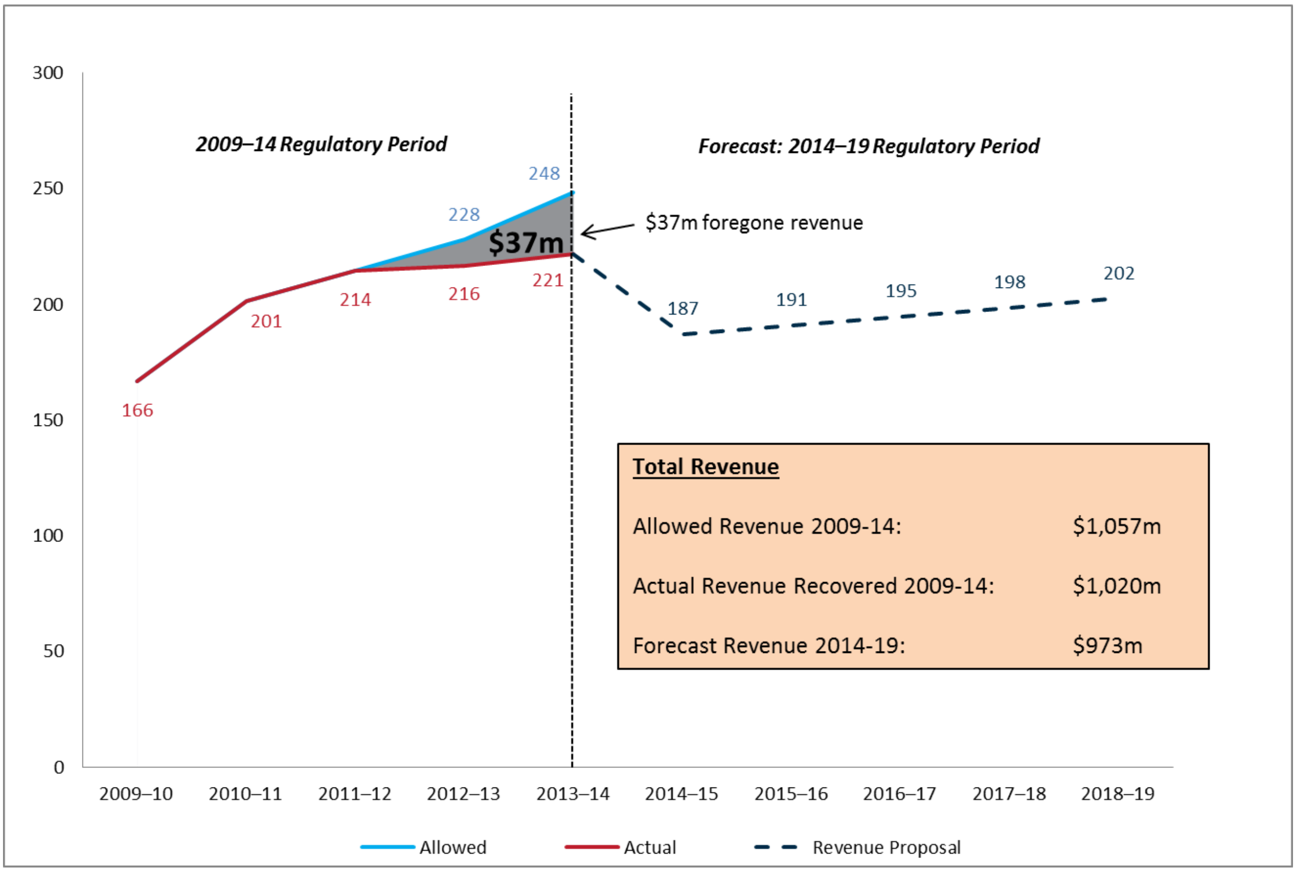
This chapter provides information on our total revenue, X factors and average price outcomes. The remainder of the chapter is structured as follows:

- Section 11.2 provides an overview of our revenue requirements in the current and forthcoming regulatory periods.
- Section 11.3 explains our revenue requirements and X factor calculations.
- Section 11.4 provides information on average pricing outcomes for consumers.
- Section 11.5 sets out concluding comments.

11.2 Overview of our revenue requirements

Figure 11.1 sets out our revenue requirements in the current and forthcoming regulatory periods in nominal terms. It shows that we plan to recover $37 million less revenue than allowed by the AER in the current regulatory period.

Figure 11.1 Revenue requirements for the current and forthcoming regulatory period ($m nominal)



Our proposed revenue path for the forthcoming regulatory period demonstrates our commitment to delivering efficiency savings to our customers. The calculations that underpin our revenue requirement for the forthcoming regulatory period are explained in the remainder of this chapter.

11.3 Revenue requirements and X factors

The figure below depicts our annual building block revenue requirements for the forthcoming regulatory period, compared to our allowed and expected revenue for 2013–14. In calculating our revenue requirements, we have applied the post-tax building block approach, in accordance with the requirements outlined in chapter 6A of the Rules and the post-tax revenue model (PTRM).

Figure 11.2 Annual building block revenue requirement components ($m nominal)

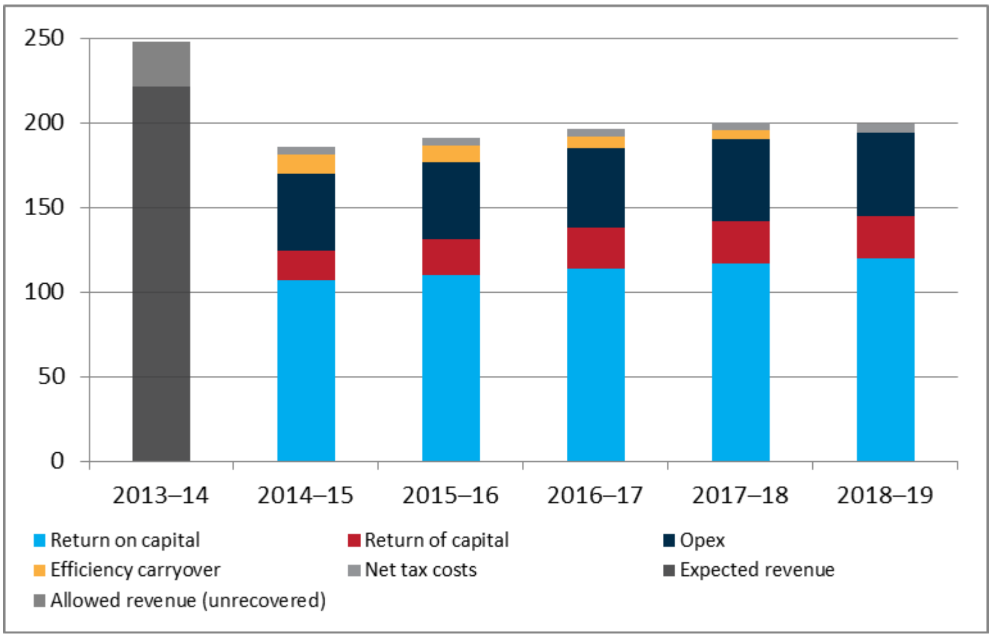


Table 11.1 presents our revenue requirements in tabular form.

Table 11.1 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	107.1	109.8	113.6	116.8	119.6	**567.0**
Return of capital (regulatory depreciation)	17.6	21.1	24.2	24.6	25.6	**113.1**
Total operating expenditure	45.1	45.6	47.0	48.5	49.1	**235.4**
Efficiency carryover	11.7	10.1	6.9	5.5	0.0	**34.1**
Net tax allowance	4.1	4.4	4.8	4.8	5.2	**23.3**
Annual building block revenue requirement—unsmoothed	**185.6**	**191.1**	**196.4**	**200.2**	**199.5**	**972.9**

Based on these building block revenue requirements, Table 11.2 presents

- the unsmoothed building block revenue in nominal terms;
- the smoothed maximum allowed revenue in nominal and real terms; and
- the proposed X factors (the annual percentage reductions relative to CPI) for the forthcoming regulatory period.

Table 11.2 Revenue and X factors, 2014–15 to 2018–19 ($m)

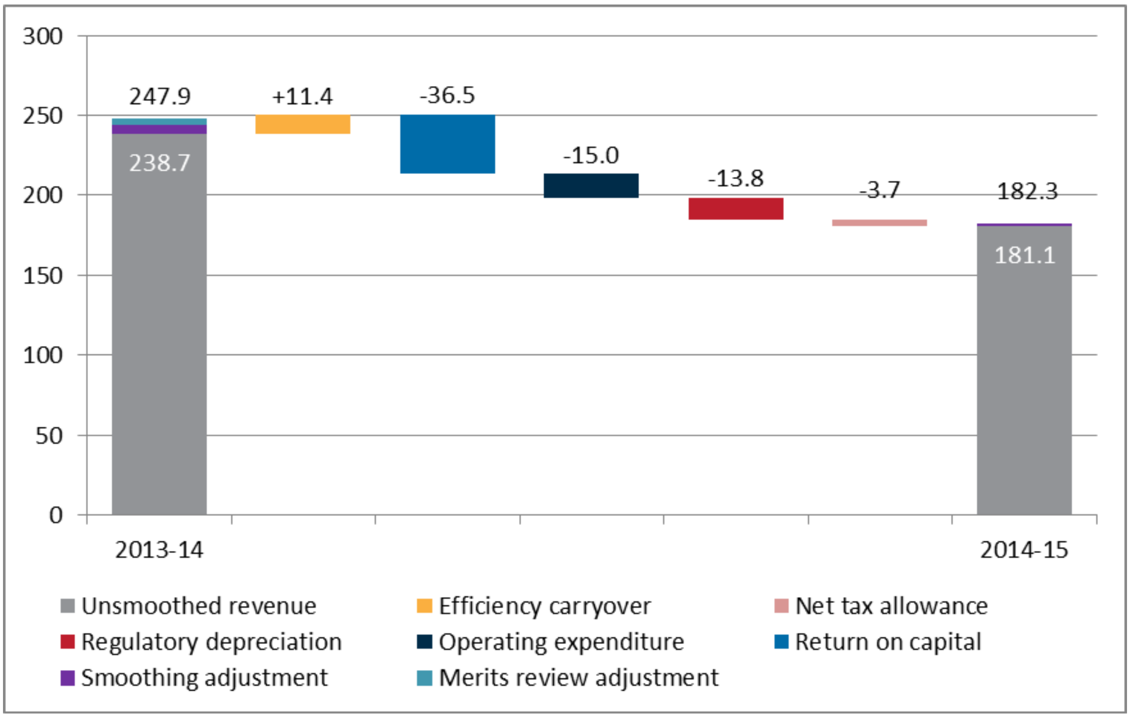
	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total revenue
Building block revenue requirement (unsmoothed) in $nominal		185.6	191.1	196.4	200.2	199.5	**972.9**
Maximum allowed revenue (smoothed) in $nominal	247.9	186.9	190.7	194.5	198.4	202.4	**973.0**
Maximum allowed revenue (smoothed) in $m 2013-14	247.9	182.3	181.4	180.5	179.6	178.7	**902.6**
X factor		26.46%	0.50%	0.50%	0.50%	0.50%	

The smoothed revenue for 2014–15 is 26.5 per cent lower in real terms than our regulated revenue allowance for 2013–14. However, as noted previously, we decided not to recover $26 million of our allowed revenue in 2013–14. As a consequence, the effective reduction compared to our actual revenue in 2013–14 is 17.7 per cent in real terms. For the four years after the transitional year, our revenue requirement declines in real terms by 0.50 per cent per annum.

Figure E.4 shows the various elements that contribute to the difference between the maximum allowed revenue for 2013–14, and our proposed maximum allowed revenue for 2014–15. It is noted that:

- A technical "smoothing adjustment' is applied to the building block revenue in each year in accordance with the Rules. For 2013–14, the adjustment also includes a bonus payment for better-than-target service performance,
- The "merits review adjustment" in 2013–14 removes the revenue impact of a determination by the Australian Competition Tribunal to true-up revenue, which ceases to have effect from 1 July 2014; and
- The 2014-15 revenue will be adjusted upwards by $1.3 million to reflect the incentive payment for good service performance in the 2013 calendar year.

Figure E.3 Differences between 2013–14 and 2014–15 revenues ($m 2013–14)



For the transitional year, 2014–15, the AER determined that our placeholder revenue should be $205.1 million, compared to our smoothed revenue requirement of $186.9 million presented in Table 11.2. The main reasons for the reduction of $18.2 million in our 2014-15 revenue requirement are the adoption of lower expenditure forecasts, depreciation and cost of capital allowances.

Our prices for the 2014-15 financial year will be set to recover our proposed smoothed revenue of $186.9 million for that year. We note, however, that the AER's forthcoming decision for the 2014-19 regulatory period will reconsider our approved transitional year maximum allowed revenue (MAR) and may conclude that the MAR for 2014-15 should have been different to our proposed $186.9 million.

We propose that the AER, in its final determination, should calculate the MAR for the subsequent regulatory control period taking into account the difference between the smoothed MAR that we propose to recover in 2014-15 ($186.9 million), rather than the approved MAR of $205.1 million as set out in the AER's transitional determination. In those circumstances, the AER will calculate the revenue cap for the remaining years to take account of any such difference. This will be done so that customers are no better or worse off as a result of any difference between the revenue we propose to recover in 2014-15 and the AER's final determination in relation to our 2014-15 revenue requirement.

As explained in chapter 10, the maximum allowed revenue set out above will be adjusted as the AER updates our cost of debt allowance annually. A number of other adjustments to our revenue will be made during the regulatory period as explained in section 11.4.

11.4 Transmission pricing

Transmission pricing is concerned with converting the maximum allowed revenue set by the AER into prices that are paid by our customers, being generators, directly-connected customers and distribution network companies.

For the purpose of establishing the amount of revenue used for setting transmission prices, the maximum allowed revenue described in section 11.2 is subject to a number of annual adjustments. The most significant adjustments are to:

- Deduct the intra-regional settlements residue, which has varied between $3 million and $14 million per annum, which is approximately between 1.5 and 7.5 per cent of the maximum allowed revenue.
- Add (or deduct) any under- (or over-) recovery of revenue from previous years. The most likely source of an under- or over-recovery is a forecasting error in relation to the intra-regional settlements residue.
- Add bonuses (or deduct penalties) payable under the service incentive scheme. In 2014–15, our bonus in respect of better than target service performance in 2013 will be $1.3 million or approximately 0.7 per cent of the maximum allowed revenue. As explained in chapter 13, the service incentive scheme will be strengthened from 2015–16 onwards, allowing a maximum bonus of approximately $9 million per annum.
- Add (or deduct) any pass through amount in accordance with the arrangements set out in chapter 12.
- Add (or deduct) an amount in respect of inter-regional transmission use of system pricing from 2015–16 onwards. The impact of this change is difficult to estimate at this stage.

In practice the factors listed above will result in our transmission prices being set to recover revenue that differs from the maximum allowed revenue. However, the revenue recovered in any particular year will be affected by the specific adjustments in that year, and the impact of under- or over-recoveries in prior years. As a consequence, it is difficult to predict annual price changes with any degree of precision. In broad terms, however, we can provide an indication of how average prices may change, in the absence of material adjustments.

In developing our proposal, we met with our customers and consumer representatives to discuss a range of issues, including 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 indicated that on average there would be a reduction in revenue and prices in July 2014.

Table 11.3 and Figure 11.2 confirm this outcome, showing the forecast average price path per MWh of energy delivered in Tasmania over the next five years, excluding the adjustments noted above, and our allowed and actual revenue in 2013–14.

Table 11.3 Average price impact of Revenue Proposal

		2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Nominal revenue ($m)	2013–14 Allowed revenue	247.9	186.9	190.7	194.5	198.4	202.4
	2013–14 Expected revenue	221.5					
Real revenue ($m) ($2013–14)	2013–14 Allowed revenue	247.9	182.3	181.4	180.5	179.6	178.7
	2013–14 Expected revenue	221.5					
Load forecast[33]	MWh ('000)	10,163	10,212	10,271	10,424	10,457	10,497
Nominal price ($/MWh)	2013–14 Allowed revenue	24.40	18.31	18.57	18.66	18.98	19.29
	2013–14 Expected revenue	21.79					
Real price ($/MWh) ($2013–14)	2013–14 Allowed revenue	24.40	17.85	17.66	17.32	17.18	17.02
	2013–14 Expected revenue	21.79					

Figure 11.4 Average price impact of Revenue Proposal ($/MWh)

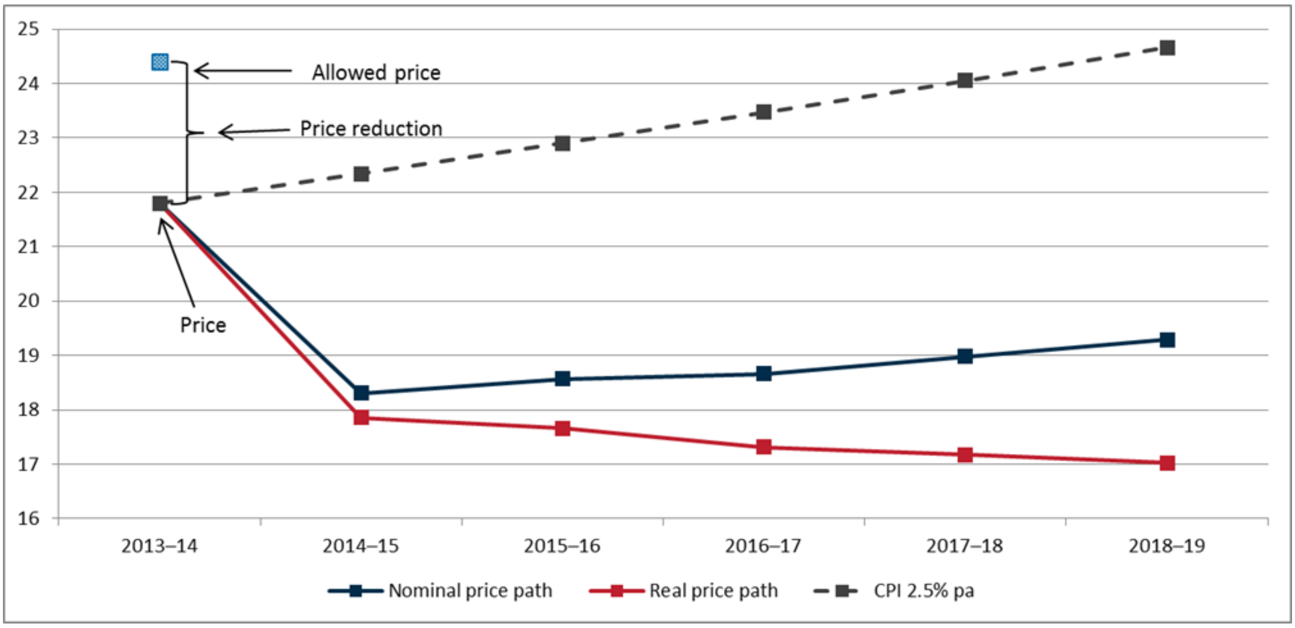


Figure 11.4 shows that average transmission prices are expected to fall in 2014–15 and then increase slightly thereafter in nominal terms (the blue line). Average prices in nominal terms at the end of the next period are expected to be less than in 2013–14.

Compared to inflation (the grey line) average transmission prices will be well below the forecast CPI of 2.5 per cent per annum. As a consequence, average transmission prices in real terms (the red line) are expected to decline. In other words, against a basket of other goods and services, average transmission prices will become relatively cheaper over the forthcoming regulatory period.

Table 11.4 provides the approximate impact of our Revenue Proposal on average residential and business customer bills.

[33] The load forecast is the energy delivered based on our medium scenario forecast.

Table 11.4 Average annual price impact on customers ($nominal)

		Average annual charge 2013–14[34]	Impact on annual charge				
			2014–15	2015–16	2016–17	2017–18	2018–19
Weighted average residential annual charge	Total	$2,256	-$54 (-2.4%)	+$4 (+0.2%)	+$1 (+0.1%)	+$5 (+0.2%)	+$5 (+0.2%)
	Transmission component		-$54 (-16.0%)	+$4 (+1.4%)	+$1 (+0.5%)	+$5 (+1.7%)	+$5 (+1.6%)
Weighted average small business annual charge	Total	$3,782	-$91 (-2.4%)	+$7 (+0.2%)	+$2 (+0.1%)	+$8 (+0.2%)	+$8 (+0.2%)
	Transmission component		-$91 (-16.0%)	+$7 (+1.4%)	+$2 (+0.5%)	+$8 (+1.7%)	+$8 (+1.6%)

The actual prices paid by particular customers will be determined by our transmission pricing methodology, and therefore will differ from the indicative average set out above. Our proposed pricing methodology is submitted to the AER for approval alongside this Revenue Proposal.

Due to the 2014–15 transitional year, the proposed pricing methodology will apply for four years from 1 July 2015.

Only a small number of minor changes are proposed to be made to the current pricing methodology, largely based on feedback received from customers in recent years. These changes are to:

- permit that reductions to contract agreed maximum demand be applied to reduce charges in the prevailing financial year where the reduction is not temporary in nature (section 6.11.3); and
- include specific standby provisions to encourage customers to better manage their peak demand and reduce the impact on the transmission network at times of high network utilisation (section 6.12).

Customers were consulted about the changes to the proposed pricing methodology and were supportive of the proposed changes, noting that the present Rules framework provides limited scope for transmission network service provider discretion.

Prior to its commencement, the proposed pricing methodology will be updated to include the new inter-regional transmission charging arrangements that also commence on 1 July 2015. Our updated pricing methodology will comply with the AER's amend pricing methodology guideline, which is to be published by 30 September 2014.

Reviewing transmission pricing Rules

As part of our consultation on the revenue proposal, a number of customers voiced their dissatisfaction in the unpredictable and volatile transmission price outcomes from year to year. This volatility results from annual adjustments to the maximum allowable revenue and the process for setting transmission prices under the Rules, outlined in section 11.3.

For example, prices are affected by volatile intra-regional settlement residue outcomes that neither customers nor the transmission business can effectively manage. Introduction of inter-regional transmission charging may provide a net benefit to Tasmanian customers, but is likely to increase pricing volatility.

We note our customers' feedback and support a review of the transmission pricing Rules to achieve more predictable and stable customer price outcomes. We are working with peer network businesses to consider an industry approach.

[34] Total charges are from AER fact sheet, Transitional decisions: TransGrid and Transend 2014–15, March 2014. Transmission component is 15 per cent as per Tasmanian Economic Regulator, Comparison of 2014 Australian standing offer energy prices, March 2014.

11.5 Concluding comments

This Revenue Proposal demonstrates that we are 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 our 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 and reduced the return from our assets 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 expose consumers to the risk of a less reliable transmission service— a risk that our consumers are concerned about. 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.

12 Cost pass through provisions

12.1 Introduction

The cost pass through provisions set out in clauses 6A.6.9 and 6A.7.3 of the Rules allow a 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 a defined pass through event occurring. Clause 6A.7.3(a1) of the Rules defines any of the following as a pass through event for a transmission determination:

(1) a regulatory change event;

(2) a service standard event;

(3) a tax change event;

(4) an insurance event; and

(5) any other event specified as a pass through event in a transmission determination.

This chapter sets out our proposals for specified pass through events that are to apply in accordance with clause 6A.7.3(a1)(5) for the regulatory period.

Our proposals were developed with the assistance of Marsh Australia (Marsh), who applied the following criteria to identify the events to be nominated for the cost pass through mechanism:

- Quantification of such an event, by attaching frequency or severity, cannot be ascribed by reasonable means and is subject to significant uncertainty;
- There has been no past incidences of similar type of such event, or similar events of such magnitude for Transend, hence could be regarded as an unforeseen event; and
- Such an event is beyond the control of TasNetworks, or TasNetworks has taken appropriate and reasonable means in order to prevent or reduce the probability of its occurrence.[35]

Marsh stated that in circumstances where these three criteria are satisfied, the adoption of the cost pass through mechanism will likely be the most effective approach in achieving on an ex-ante basis, an adequate balance between:

- having the incentive mechanisms in place to ensure that prices for consumers are no more than necessary to provide an appropriate level of service;
- whilst still providing TasNetworks with a reasonable opportunity to recover efficient costs associated with events that are outside of their reasonable control.[36]

Accordingly, we propose the following additional pass through events:

- Terrorism event
- Natural disaster event
- Insurance cap event

The reminder of this chapter is structured as follows:

- Section 12.2 sets out our proposals for the inclusion of ‘terrorism event’ as a defined pass-through event.
- Section 12.3 sets out our proposals in relation to the definition of ‘natural disaster event’.
- Section 12.4 describes our proposed definition of ‘insurance cap event’.

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[35] Marsh Australia, Quantification of Self-Insurance Costs for Transend Networks Pty Ltd, January 2014, page 20. A copy of the March report is provided as an Appendix 15.

[36] Ibid, page 20.

12.2 Terrorism event

Our transitional Revenue Proposal noted 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.

We note that the 2012 Rule change relating to pass through arrangements - which applies to our full Revenue Proposal - removed "terrorism event" as a defined cost pass through event. We also note that in determining that the terrorism pass through event should be removed from the list in clause 6A.7.3, the AEMC commented that its removal did not imply that terrorism should not be treated as a pass through event. Instead, the AEMC explained that the intention was to recognise that the cost pass through regime may not always be the most efficient mechanism to manage this type of risk[37].

While we accept the AEMC's rationale for removing terrorism events from clause 6A.7.3, it remains the case that a pass through mechanism is currently the most appropriate regulatory approach for addressing the costs arising from a terrorism event. The nature of a terrorism event is such that the associated costs are impossible to forecast with a reasonable degree of accuracy. A pass through mechanism has the advantage of allowing the AER to evaluate the efficient costs arising from a terrorism event after the event has occurred. A pass through mechanism therefore avoids the need to make a prior allowance for the costs of a terrorism event, either by including a forecast cost as an operating expenditure or through a self-insurance premium.

As already noted, we engaged Marsh - who are insurance market experts - to provide estimates of appropriate allowances for our insurance and self-insurance costs over the forthcoming regulatory period[38]. Applying the criteria listed in section 12.1, Marsh recommended that 'terrorism event' be included as a cost pass-through event.

We therefore propose that the terrorism pass through event should continue to apply for the remainder of the 2014–2019 regulatory period. Our proposed definition of this event is as follows:

> An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to TasNetworks of providing prescribed transmission services.

We note that the AER adopted this definition of a terrorism pass through event in its most recent determination for SP AusNet. In approving the terrorism pass through event, the AER explained that it had regard to the *nominated event pass through considerations* in accordance with 6A.6.9(b) of the Rules. The AER also noted that the proposed definition was consistent with the previous definition of terrorism event in the Rules[39].

12.3 Natural disaster event

Applying the criteria listed in section 12.1, Marsh recommended that 'natural disaster event' be included as a cost pass-through event. On the basis of that recommendation, and having regard to the

37 AEMC, Final Determination, National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012, page 24.

38 The reports prepared by Marsh are provided as Appendices 15 and 16 to this Revenue Proposal.

39 AER, Draft Determination, ElectraNet Transmission determination 2013–14 to 2017–18, November 2012, page 271.

nominated pass through event considerations referred to in clause 6A.6.9 of the Rules, we propose the following definition of 'natural disaster event':

> Any major fire, flood, earthquake or other natural disaster beyond the reasonable control of TasNetworks that occurs during the 2014–19 regulatory control period and materially increases the costs to TasNetworks 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 in our transitional Revenue Proposal;

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

iii. reasons for that decision.

We note that the proposed definition of 'natural disaster even' is consistent with that accepted by the AER in its most recent transmission determination for SP AusNet.

12.4 Insurance cap event

Applying the criteria listed in section 12.1, Marsh recommended that 'insurance cap event' be included as a cost pass-through event. On the basis of that recommendation, and having regard to the nominated pass through event considerations referred to in clause 6A.6.9 of the Rules, we propose the following definition of "insurance cap event".

Whereby:

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

For this insurance cap event:

4. The relevant policy limit is the greater of:
    a. TasNetworks' 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 regulatory control period or a previous regulatory control period in which TasNetworks 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 TasNetworks in its Revenue Proposal;

ii. the forecast operating expenditure allowance approved by the AER in its Final Decision; and

iii. the reasons for that decision.

We note that the proposed definition of 'insurance cap event' is consistent with that accepted by the AER in its most recent transmission determination for SP AusNet.

13 Service Target Performance Incentive Scheme

13.1 Introduction

This chapter sets out information on the application of the Service Target Performance Incentive Scheme (STPIS).

The purpose of the STPIS is to give us incentives to maintain or improve service levels. The STPIS comprises three components: the service component, the market impact component and the network capability component. The scheme includes incentives to provide greater transmission network reliability when network users place greatest value on reliability, and to improve and maintain the availability of the elements of the transmission network most important to determining spot prices. The incentive is provided by means of an adjustment (either an increment or decrement) to our revenue depending on our service performance.

Each of the three scheme components and their application to us are outlined in this chapter, which is structured as follows:

- Section 13.2 provides an overview of the STPIS that is to apply to us in the next regulatory period.
- Section 13.3 provides details of the service component of the STPIS.
- Section 13.4 provides information on the market impact component (MIC).
- Section 13.5 provides details of the network capability component (NCC).

13.2 STPIS to apply in the next regulatory period

The AER's Framework and Approach paper explains that Version 2 of the STPIS, which currently applies to us, was superseded by version 3 which was published on 31 March 2011. Version 3 of the STPIS did not apply to us as we were mid-way through the 2009–2014 regulatory control period. Since that time, the AER has conducted a comprehensive review of the STPIS for TNSPs, publishing its final decision—version 4—in December 2012.

As part of the transitional arrangements, the Rules states the STPIS that applied in the current regulatory control period will continue to apply for the transitional year subject to any modifications set out in the Framework and Approach paper.

Version 2 of the STPIS (which, as noted above, applies to us for the current regulatory period) consists of the service component and the MIC. For the transitional regulatory control period, the existing version 2 service component will continue to apply to us, but the scheme will be modified to, in effect, apply the NCC and MIC of version 4 of the STPIS.

The AER will apply version 4 of the STPIS to us in the subsequent regulatory control period.

Table 13.1 (reproduced from the Framework and Approach Paper) provides an overview of the STPIS arrangements that will apply to us.

Table 13.1 Application of STPIS components for the transitional and subsequent regulatory control periods

Component	Transitional period	Subsequent period
Service component	Current version 2	version 4
MIC	Based on version 4	version 4
NCC	Based on version 4	version 4

Source: AER, Framework and approach paper - Transend, January 2014, page 6.

13.3 Service component

The service component parameters and targets that apply in the current regulatory period will also apply in the transitional period (2014–15).

For the subsequent regulatory control period, the various service component parameters applying to us, and the maximum revenue increment or decrement that we can receive for a given level of performance will be those prescribed in version 4 of the scheme. The service component provides an incentive of up to +/- 1 per cent of maximum allowed revenue each year.

Our proposed performance targets, caps, collars and weightings for the parameters in accordance with version 4 of the STPIS are provided in Table 13.2.

In calculating our proposed performance targets, we have utilised the methodologies specified by the AER within the STPIS, version 4, and the accompanying STPIS Explanatory Statement.

In establishing targets for the service component of the STPIS, we determined our average performance over the last five years and used this to calculate the mean. We initially calculated a cap and collar varying two standard deviations above and below the mean, however it was found that this resulted in some collars with a negative value.

To address the issue we modelled caps and collars using a standard deviation of 1.5 and 1.0. We found that a standard deviation of 1.5 provides a more practical cap and collar, and strikes a good balance between incentivising us to improve performance, while appropriately penalising us in the event that performance deteriorates. The utilisation of 1.5 standard deviations is consistent with the methodology approved by the AER for use in calculating the caps and collars that currently apply to us. It also provides a consistent point of comparison between the current and future regulatory control periods.

Table 13.2 Proposed STPIS values

Parameter/sub-parameter	Weighting (% MAR)	Collar	Target	Cap
Average circuit outage rate	**±0.50**			
Lines outage rate – fault	±0.20	53	31	10
Transformers outage rate – fault	±0.20	17	12	6
Reactive plant outage rate – fault	±0.10	15	3	0
Lines outage rate – forced outage	0.00	18	10	2
Transformers outage rate – forced outage	0.00	5	3	1
Reactive plant outage rate – forced outage	0.00	33	14	0
Loss of supply event frequency	**±0.30**			
> 0.1 system minute	±0.15	12	10	8
> 1.0 system minute	±0.15	6	3	0
Average outage duration	**±0.20**	**165**	**112**	**58**
Proper operation of equipment	**0.00**			
Failure of protection system	0.00	15	9	4
Material failure of supervisory control and data acquisition (SCADA) system	0.00	68	37	6
Incorrect operational isolation of primary or secondary equipment	0.00	6	4	2

13.4 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. It measures performance against the market impact parameter, which is the number of dispatch intervals where an outage on the TNSP's network results in a network outage constraint with a marginal value greater than $10/MWh.

Under version 4 of the STPIS, the annual performance target is the rolling average of performance history over the three previous calendar years. Thus, the annual performance target is not fixed at the time of the revenue determination but is adjusted each year based on the most recent three years of performance. Actual performance is measured annually and is the rolling average of performance of the two most recent calendar years.

The Framework and Approach Paper explains that:

> A rolling target and actual performance measure provides a tighter incentive to ensure outages on prescribed assets have limited impact on wholesale spot market outcomes. Further, a rolling target ensures the target is relevant to the TNSP's current maintenance and construction activities and limits the incentive for TNSPs to engage in strategic behaviour to influence the outcomes of the scheme.[40]

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

Consequently, in establishing a target for the market impact component, we calculated our average performance over the preceding three calendar years and used this value as the target for the first year of the next regulatory control period. Caps and collars are not required for this component of the STPIS.

13.5 Network capability component

The network capability component provides an incentive of 1.5 per cent of maximum allowable revenue each year, subject to completion of projects that improve the capability of the transmission network at times when it is 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.

The network capability component as set out in version 4 of the STPIS will, in effect, apply to us from 1 July 2014. For the transitional year, the AER has assessed and approved 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 any differences between our proposed revenue and actual revenue approved.

This Revenue Proposal includes our network capability incentive parameter action plan (NCIPAP) as Appendix 21. The action plan:

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

We have consulted with AEMO in developing the action plan.

We have a well-established history of releasing capacity through innovation and we are the Australian leader in the application of dynamic ratings and use of control schemes to optimise network capacity and utilisation.

[40] AER, Framework and approach paper - Transend, January 2014, page 9.

The NCIPAP is based on the continuation of our existing practice, with AEMO-endorsed network capability activities removed from our ex ante operating and capital expenditure forecasts and included in the NCIPAP.

The total value of projects that are funded under the network capability incentive scheme is 1 per cent of the allowed revenue. Therefore, decisions made by the AER in setting the total revenue will affect the value and number of projects that are funded under this incentive scheme.

All projects included under the network capability incentive scheme provide a customer benefit. Therefore, to the extent that a project is not funded under the network capability incentive scheme due only to a forecast lower revenue outcome, the project(s) should be added to the ex ante expenditure allowance.

14 Glossary

Acronym	Description
AEMC	The Australian Energy Markets Commission
AEMO	The Australian Energy Market Operator
AER	The Australian Energy Regulator
AWE	Average weekly earnings
Capex	Capital Expenditure
CAPM	Sharpe-Lintner Capital Asset Pricing Model
CESS	Capital expenditure sharing scheme
CARG	Compound annual growth rate
CPI	Consumer Price Index
COAG	Council of Australian Governments
DNSP	Distribution Network Service Provider
EBSS	Efficiency benefit sharing scheme
ESI	Electricity supply industry
ElectraNet	Owner of electricity transmission networks in South Australia
GWh	Gigawatt hours
IAP2	International Association of Public Participation
kV	kilovolt – 1000 volts
MIC	Market impact component
MAX	Maximum allowable revenue
MD	Maximum demand – usually measured in MW
MW	Megawatt – one million watts
MWh	Megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
The Rules	National Electricity Rules
NCC	Network capability component
NSP	Network Service Provider
NCIPAP	Network capability incentive parameter action plan
NIEIR	The National Institute of Economic and Industry Research
Non-network	Support the business
NTNDP	National Transmission Network Development Plan (AEMO publication)
Opex	Operational Expenditure
PB	Parsons Brinckerhoff
PoE	Probability of Exceedance
PV	Photo-voltaic
PTRM	Post-tax revenue model

Acronym	Description
PWC	PricewaterhouseCoopers
RIN	Regulatory Information Notices
RFM	Roll forward model
TasNetworks	Tasmanian Networks Pty Ltd (created from the merger of Transend Networks and Aurora's distribution business, commences operations from 1 July 2014)
Transend	Transend Networks Pty Ltd, owner of electricity transmission network in Tasmania
TNSP	Transmission network service provider
RAB	Regulatory asset base
STPIS	Service target performance incentive scheme
SCER	Standing Council on Energy and Resources
SP AusNet	Owner of electricity transmission network in Victoria
WACC	weighted average cost of capital (

15 Appendices and references

15.1 Appendices

Appendix 1	Customer survey results
Appendix 2	Stakeholder submissions to our transitional Revenue Proposal
Appendix 3	Transend: Consumer Survey results
Appendix 4	StraightTalk: Consumer engagement outcomes report
Appendix 5	Huegin: Benchmarking of Transend's operating costs
Appendix 6	Huegin: Base year opex efficiency assessment
Appendix 7	Expenditure forecasting methodology
Appendix 8	Certification of reasonableness of key assumptions
Appendix 9	Parsons Brinckerhoff: Review of Transend load forecasting process and methodology
Appendix 10	Evans and Peck: Review of Estimates and Portfolio Risk Calculation
Appendix 11	Independent Economics: Labour cost escalators
Appendix 12	CEG: Escalation factors affecting expenditure forecasts (labour and materials)
Appendix 13	GHD: Tasmanian Rural Land Escalation Updated Report
Appendix 14	Forecast network capital projects 1 July 2014 – 30 June 2019 (>$5m)
Appendix 15	Marsh: Quantification of Self-Insurance costs
Appendix 16	Marsh: Estimation of insurance premiums over the regulatory control period
Appendix 17	Operating expenditure forecasts
Appendix 18	Efficiency Benefit Sharing Scheme 2009–14 outcomes
Appendix 19	SKM: Assessment of Proposed Regulatory Asset Lives
Appendix 20	SFG Consulting: Cost of Equity
Appendix 21	Network Capability Parameter Action Plan
Appendix 22	Capital expenditure 2003–04 to 2018–19
Appendix 23	Proposed pricing methodology
Appendix 24	Proposed negotiating framework
Appendix 25	Jurisdictional network performance requirements
Appendix 26	Grid Vision 2040
Appendix 27	SFG Consulting: Estimate of gamma

15.2 References

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

- 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