Electricity Supply Industry Expert Panel

A Review of the Financial Position of the State Owned Electricity Businesses

December 2011
Contents
GLOSSARY ................................................................................................................................... 4
PART 1 .......................................................................................................................................... 1
Foreword ..................................................................................................................................... 1
Purpose and Approach ........................................................................................................... 2
Qualification............................................................................................................................... 4
Executive Summary ................................................................................................................... 5
How the Proceeds from Electricity Sources Flow Through the SOEB Portfolio .............. 6
Key Sources of Financial Value Within the SOEB Portfolio.................................................. 9
Financial Position of the SOEBs.............................................................................................. 13
Business diversification activities........................................................................................... 18
Future risks and opportunities................................................................................................ 21
1. Structure of the Tasmanian Energy Market ................................................................. 24
2. Financial Flows Through The SOEB Portfolio ................................................................. 25
   2.1.1. Wholesale Energy ............................................................................................. 26
   2.1.2. Transmission use of System Charges .............................................................. 29
   2.2. Significant Intra-SOEB Financial Flows are a Consequence of the Increasing
        Complexity of Hydro Tasmania’s and Aurora Energy’s Business Activities... 29
        2.2.1. Aurora Energy ................................................................................................. 29
        2.2.2. Hydro Tasmania ................................................................................................. 31
3. Cash Generation and Allocation – changes over time ............................................ 34
   3.1. SOEB Perspective - cash generation and utilisation......................................... 35
        3.1.1. Hydro Tasmania ................................................................................................. 35
        3.1.2. Aurora Energy ................................................................................................. 41
        3.1.3. Transend ............................................................................................................. 48
        3.1.4. Summary of SOEB portfolio cash generation and utilisation 2004 to 2010 53
   3.2. Portfolio Perspective of Financing Activities......................................................... 55
3.2.1. Investment – functional and diversified business activities .................. 55
3.2.2. Debt ........................................................................................................ 59
3.2.3. Returns to Shareholders – dividends paid ............................................. 61
3.2.4. Superannuation Defined Benefits Obligations 2010 ............................... 65

4. Financial Risks and Opportunities ................................................................................. 67
   4.1. Hydrological conditions .................................................................................. 67
   4.2. Carbon Pricing .............................................................................................. 69
   4.3. Renewable energy certificates ...................................................................... 70
   4.4. Retail Competition ...................................................................................... 70
   4.5. Expenditure exceeding regulatory allowances ............................................. 70
   4.6. Major financial obligations ........................................................................... 72
      4.6.1. Transend: .............................................................................................. 72
      4.6.2. Aurora Energy: .................................................................................... 72
      4.6.3. Hydro Tasmania: .................................................................................. 72
      4.6.4. Diversification activities and operation in national/international markets 73

PART TWO ......................................................................................................................... 75

5. Hydro Tasmania ........................................................................................................... 76
6. Aurora Energy Pty Ltd ............................................................................................... 92
7. Transend Networks Pty Ltd ...................................................................................... 110
<table>
<thead>
<tr>
<th>TERM</th>
<th>MEANING</th>
</tr>
</thead>
<tbody>
<tr>
<td>AARR</td>
<td>Aggregate Annual Revenue Requirement</td>
</tr>
<tr>
<td>ACCC</td>
<td>Australian Competition and Consumer Commission</td>
</tr>
<tr>
<td>AEATM</td>
<td>Alinta Energy Australia Trading and Marketing</td>
</tr>
<tr>
<td>AEMO</td>
<td>Australian Energy Market Operator</td>
</tr>
<tr>
<td>AER</td>
<td>Australian Energy Regulator</td>
</tr>
<tr>
<td>AETV</td>
<td>Aurora Energy Tamar Valley Pty Ltd</td>
</tr>
<tr>
<td>BBPS</td>
<td>Bell Bay Power Station</td>
</tr>
<tr>
<td>BSA</td>
<td>Basslink Services Agreement</td>
</tr>
<tr>
<td>CLP</td>
<td>China Light and Power</td>
</tr>
<tr>
<td>CY</td>
<td>Calendar Year</td>
</tr>
<tr>
<td>DUOS</td>
<td>Distribution use of System</td>
</tr>
<tr>
<td>EBITDA</td>
<td>Earnings Before Interest Tax and Depreciation</td>
</tr>
<tr>
<td>FRC</td>
<td>Full Retail Contestability</td>
</tr>
<tr>
<td>FTTP</td>
<td>Fibre to the Premises</td>
</tr>
<tr>
<td>FY</td>
<td>Financial Year</td>
</tr>
<tr>
<td>GBE</td>
<td>Government Business Enterprise</td>
</tr>
<tr>
<td>GW</td>
<td>Giga Watt</td>
</tr>
<tr>
<td>GWh</td>
<td>Giga Watt Hours</td>
</tr>
<tr>
<td>HEC</td>
<td>Hydro Electric Corporation / Commission / Department</td>
</tr>
<tr>
<td>ITIE</td>
<td>Income Tax Equivalents</td>
</tr>
<tr>
<td>JV</td>
<td>Joint Venture</td>
</tr>
<tr>
<td>MAR</td>
<td>Maximum Allowable Revenue</td>
</tr>
<tr>
<td>MI</td>
<td>Major Industrial</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>MWh</td>
<td>Megawatt Hour (=1 thousand kWh)</td>
</tr>
<tr>
<td>NBN</td>
<td>National Broadband Network</td>
</tr>
<tr>
<td>NEM</td>
<td>National Electricity Market</td>
</tr>
<tr>
<td>NEMMCO</td>
<td>National Electricity Market Management Company</td>
</tr>
<tr>
<td>PCR</td>
<td>Price Control Regulations</td>
</tr>
<tr>
<td>PD</td>
<td>Price Determination</td>
</tr>
<tr>
<td>TERM</td>
<td>MEANING</td>
</tr>
<tr>
<td>--------</td>
<td>-----------------------------------------------------------</td>
</tr>
<tr>
<td>PTS</td>
<td>Prescribed Transmission Service</td>
</tr>
<tr>
<td>RAB</td>
<td>Regulatory Asset Base</td>
</tr>
<tr>
<td>RECs</td>
<td>Renewable Energy Certificates</td>
</tr>
<tr>
<td>ROA</td>
<td>Return on Allowance</td>
</tr>
<tr>
<td>ROC</td>
<td>Return on Capital</td>
</tr>
<tr>
<td>SOEB</td>
<td>State Owned Electricity Businesses</td>
</tr>
<tr>
<td>TER</td>
<td>Tasmanian Economic Regulator / Tasmanian Energy Regulator</td>
</tr>
<tr>
<td>TESI</td>
<td>Tasmanian Electricity Supply Industry</td>
</tr>
<tr>
<td>TNGP</td>
<td>Transmission Network Service Provider</td>
</tr>
<tr>
<td>ToR</td>
<td>Terms of Reference</td>
</tr>
<tr>
<td>TUOS</td>
<td>Transmission use of System</td>
</tr>
<tr>
<td>TVPS</td>
<td>Tamar Valley Power Station</td>
</tr>
<tr>
<td>WACC</td>
<td>Weighted Average Cost of Capital</td>
</tr>
</tbody>
</table>
PART 1
**Foreword**

In October 2010, the Tasmanian Parliament passed the Electricity Supply Industry Expert Panel Act 2010 to establish an independent expert panel to conduct a review into, and provide guidance to Parliament on, the current position and future development of Tasmania’s electricity industry.

The Panel’s Terms of Reference require it to investigate and report on the financial position of the State-Owned Energy Businesses (SOEBs), Transend, Hydro Tasmania and Aurora Energy. (ToR No.4)

The Panel engaged consultants Ernst & Young to undertake an analysis of the historical and forecast financial performance of the SOEBs. This analysis has informed the development of this Paper and the Panel’s broader work program. The purpose of this Paper is to highlight the:

- sources of financial value and financial flows between the SOEBs and within each business entity;
- relative contributions to business value and Shareholder returns from ‘functional’ (generation, transmission, distribution and retail) business activities; and
- extent to which the value generated from functional business activities have contributed to sustainable capital structures (debt levels), equity returns (dividends and equity transfers) and business growth (diversification).

In addition, the Panel has developed summary papers of the key events which have influenced the financial performance of each of the SOEBs. These have been prepared to provide an information base on which the portfolio analysis has been developed.

John Pierce  
Chairman  
Electricity Supply Industry Expert Panel
Purpose and Approach

The Panel’s review of the financial position of the SOEBs is focused on business activities directly related to the supply of electricity to Tasmanian customers—hydro-generation, transmission, distribution and retail in Tasmania. For the purposes of this Paper these activities are termed functional business activities.

Consistent with its Terms of Reference, the Panel’s review is limited to the financial sustainability of the SOEBs and does not look at wider value considerations of business activities, such as contribution to broader economic or community benefits (beyond direct returns through dividends).

The Panel selected the period 2004 to 2010 for its review as this period spans the key events in the development of the TESI, physical interconnection via Basslink, adoption of National Electricity Market (NEM) arrangements and the phased roll-out of retail contestability to Tasmanian electricity customers. The SOEB entities have commented to the Panel that a historical review of financial performance is not an indicator of future financial performance, citing improved financial outcomes in 2011 resulting from productivity and efficiency measures and new strategic business directions. However at the time of writing, complete actual 2011 data was not available and therefore has not been included.

For Hydro Tasmania and Aurora Energy competition and customer choice for energy gave rise to changes in business risk. Tasmania’s participation in the NEM also provided the stimulus for the pursuit of business opportunities and activities outside Tasmania. As a result, there has been a clear diversification of business activities by Hydro Tasmania and Aurora Energy. The Panel has observed that the primary motivation behind this trend appears to be the mitigation of risk in functional business activities. However, some diversification activities have been pursued as value creating strategies in their own right and are more remotely related to existing functional business activities.

Tasmania’s entry into the NEM has also seen changes to the regulatory framework applying to the transmission and distribution network businesses as it has transitioned from Tasmanian based regulation to the national regulatory framework under the Australian Economic Regulator. Evolution of the regulatory framework has also seen changes in the methodologies applied across regulatory determinations.

In addition to market changes, the review period included a period of extreme hydrological significance, described by Hydro Tasmania as a “1:1000 year event” of low inflows. Water storage levels fell to historic lows of 19 per cent across 2007 and 2008, significantly below Hydro Tasmania’s preferred operating zone of a storage system level between 30 and 50 per cent.

1 As opposed to estimated or forecast data for the 2011 financial year.
During this time Hydro Tasmania was required by its Shareholders to ensure supply. This expectation, coupled with its contract position, required Hydro Tasmania to operate the gas fired Bell Bay Power Station (BBPS) and purchase electricity from the NEM, via Basslink. Both of these options incurred higher costs than Hydro Tasmania’s existing contract arrangements.

The Panel has approached its investigation from both a ‘whole-of-portfolio’ basis (Part 1 of this Paper) and on an individual entity basis (Part 2 of this Paper).

Part 1 of this Paper:

- Provides an overview of the structure of the TESI and describes how the proceeds from electricity sales flow through the SOEB portfolio;
- Identifies the primary sources of underlying profitability – or direct financial value – within the SOEB portfolio, where value is realised and what influences value outcomes (financial performance measured by EBIDTA)²;
- Identifies the major inter-SOEB financial flows and the major intra-SOEB financial flows; and describes how these have been influenced by energy sector reform and diversification of business operations;
- Describes how value translates into ‘free cash’ (measured by cash available from operations) and how this cash is utilised by SOEB entities; and
- Identifies key risks and opportunities to future financial performance.

Part 2 of this Paper:

- Looks at key influences on financial performance for each of the SOEBs in greater detail. In this regard it provides further information underpinning the analysis in Part 1 of the Paper.

² Earnings Before Interest, Depreciation, Tax and Amortisation (EBIDTA).
Qualification

The complexity of the Tasmanian electricity market, and the SOEBs themselves, has increased since 2004. As a consequence, methods of recording and reporting financial information within each business have changed over time. Further, new activities and transactions have commenced and some activities and transactions have ceased. This creates difficulties in analysing changes in financial performance on a consistent basis over time.

The financial information presented in this paper has been obtained from a variety of sources including the audited accounts and other financial information held by the SOEBs, such as management accounts. In developing this Paper, the Panel has requested some information from the SOEBs in forms that are different from the way in which they typically record and review their own information. In some cases, estimates have been required to be established (prepared with the assistance of Ernst & Young). The information in this a paper has been reviewed by the SOEBs where appropriate for factual accuracy. The analysis and conclusions drawn by this Paper are those of the Panel and do not represent the views of the SOEBs.

As such, readers of this Paper should interpret the financial information as illustrative of broad trends, rather than precise and detailed financial results that will always reconcile with published annual report information or information from other sources.

For the purposes of this Paper, Aurora Energy’s principal activities of retail, distribution and energy are discussed as separate business components to enable the reader to gain an understanding of their respective financial performance. This is different to the way in which Aurora Energy structures its business operations, whereby it incorporates retail and energy (including gas) in its Energy Division, while retaining distribution and network services separately in its Distribution Division.

Unless otherwise indicated, all dollar figures in this Paper are expressed on a nominal basis and dates represent the financial year.
Executive Summary

In the simplest terms, the financial performance of the SOEBs is a measure of how much is earned through revenue for services provided offset by how much is spent on the cost of providing those services (operating expenses and capital). The financial position of the SOEBs reflects how what is being earned is utilised by the businesses, including the payment of dividends to Shareholders.

In terms of financial position, from a Shareholder perspective, there is a tension between sustainable capital structures, approving major capital investment (particularly where it relates to business diversification or expansion for growth) and the provision of dividend returns to the community.

From the historical review we can observe how this tension has been resolved through the choices that have been made by the Shareholders; and the financial consequences of those choices. This can provide guidance on future choices around the same inherent tensions.
How the Proceeds from Electricity Sources Flow Through the SOEB Portfolio

Changes in the total revenue earned by the SOEBs over the review period are partly a function of increases in electricity prices paid by Tasmanian customers as well as load growth. It is important to understand that Aurora Energy’s revenue from Tasmanian customers includes pass through costs of supply, such as Renewable Energy Certificates (RECs) and charges applying to distribution and transmission network services, which is revenue earned by its distribution business and Transend. A large portion of Aurora Energy’s cost of supply is the cost of energy, which historically has been reflected as revenue by Hydro Tasmania and now also includes Aurora Energy’s tolling fee for the Tamar Valley Power Station (TVPS). In this sense, prices paid by Tasmanian electricity customers ‘filter through’ the vertical chain of supply as revenue.

Unlike the situation pre-NEM entry, revenue earned from Tasmanian electricity customers is no longer the only source of revenue within the SOEB portfolio. For example, both Hydro Tasmania and Aurora Energy trade wholesale energy in the NEM and have retail customers outside Tasmania. Aurora Energy is also a gas wholesaler and retailer in Tasmania and a gas wholesaler Victoria, and has a tolling arrangement with the Bairnsdale power station for electricity the station produces.

2010 An illustration of revenue flows and cash utilisation

Figure 1 illustrates the two primary financial flows within the SOEB portfolio:

1. How revenue paid by Tasmanian customers to Aurora Energy flows through the SOEB portfolio and is attributed to the components of electricity supply – generation, transmission, distribution and retail; and

2. How total revenue received by SOEB entities, including all revenues arising from the Tasmanian customers (not just those that originate through Aurora Energy’s retail business) and revenues derived from other business activities in Tasmania and elsewhere, is attributed within the business or returned to Shareholders as a dividend.

The internal complexity of Hydro Tasmania and Aurora Energy, and the general complexity of the electricity market, presents challenges in undertaking this type of analysis. Therefore, the Panel reiterates that dollar figures shown in Figure 1 are approximates only and, as all transactions are not represented, will not necessarily be ‘additive’. The intent is to illustrate the broad quantum of financial flows within the SOEB portfolio and between total revenues earned by the SOEB portfolio and uses of cash, including dividend returns to the Tasmanian community.
Figure 1

2010 Revenue to Returns

SOEB Tasmanian Customer Revenue
- Aurora Energy - retail business
  - Tasmanian customer revenue total: $865M
  - Non-contestable: $542M
  - Contestable: $323M
- Aurora Energy - distribution business
  - DUOS/TUOS Total: $223M
  - DUOS $231M
  - TUOS $9M
- Aurora Energy - energy business
  - Energy costs total: $158M
  - TVPS Tolling fee: $62M
  - Hydro Tasmania: $416
- Transend Networks
  - Non-direct connect customers: $93M

Other Revenue
- Retail gas: $6M
- Mainland electricity: $165M
- TUOS Direct connect customers: $676M
- Other Income: $26M
- Settlements: $7M
- Mainland energy: $33M
- Other NiM products: $2M
- Momentum: $114M
- Entura: $49M
- Roaring 40s JV: $-6M

Total Revenue
- $1,197M
- $1,197M
- $1,197M
- $1,197M

EBITDA
- Energy Business: $-10.5M
- Distribution: $165M
- Transmission: $129M
- Hydro Tasmania: $178M
- Aurora Energy: $49M
- Transend Networks: $101M
- Roaring 40s JV: $46M

Net Cash
- $49M
- $101M
- $178M
- $49M

Uses of Cash in 2010
- Aurora Energy
  - Capex: $254M
  - Interest: $55M
  - Dividend Paid: $10M
- Transend Networks
  - Capex: $168M
  - Investment: $66M
  - Dividend Paid: $41M
- Hydro Tasmania
  - Capex: $36M
  - Investment: $60M
  - Dividend Paid: $5M

*This is not an exhaustive account of cash usage. For example, it does not show change in working capital, borrowings, and changes in cash balances between years.

**Dividends relate to payments made in FY10, based on financial performance for FY09.

Combined retail and energy business.
**Revenue flows from Aurora Energy’s Tasmanian customers**

The first column of Figure 1 should be read downward, as it illustrates how revenue from Aurora Energy’s Tasmanian customers flows through the SOEB portfolio.

In 2010, Aurora Energy’s Tasmanian customer revenue was approximately $865 million. Of this $542 million was derived from non-contestable customers and $323 million from contestable customers.

Some $323 million of customer revenue flowed through to Aurora Energy’s distribution business for transmission and distribution costs. Transmission use of system (TUOS) charges of $93 million were a direct pass-through to Transend and distribution use of system charges (DUOS) of $231 million were retained by Aurora Energy’s distribution system.

Aurora Energy’s energy business costs totalled $518 million, of which $82 million was paid to its subsidiary, Aurora Energy Tamar Valley (AETV) under the tolling arrangements for the TVPS. The balance, approximately $416 million, flowed through to Hydro Tasmania for energy purchases.

Figure 2 below illustrates the share of Tasmanian customer revenue attributable to each component of the supply chain, noting that retail will include some pass-through costs, such as RECs, that will flow to third parties.

**Figure 2 - Allocation of Aurora Energy’s Tasmanian customer revenue 2010**

![Pie chart showing the allocation of revenue]

**Source:** Panel analysis

**Note:** This does not reflect the break-up of costs incorporated into non-contestable customer tariffs as shown in Panel publications, as it relates to contestable and non-contestable customer revenue.
**SOEB revenue generation to cash utilisation**

Returning to Figure 1, reading across the page illustrates how total revenue derived from all sources by each SOEB entity translates to earnings after operating expenses (represented by EBITDA), which is then utilised by the business for capital investment, financing costs and dividends paid.

On a cash basis, direct operating costs (payments to suppliers and employees) as a proportion of cash received from customers varied across the SOEB entities, with Aurora Energy 92 per cent, Hydro Tasmania 70 per cent and Transend 33 per cent. These outcomes reflect each entity’s ability to fund capital investment (or business diversification), repayment of borrowings and dividends from cash from operations – or is reflective of need to borrow for these activities. In summary; in 2010:

- **Aurora Energy**’s net cash after operating activities, including payment of finance charges and Income Tax Equivalents (ITEs), was $49 million. Capital investment of $234 million and dividends paid of $10 million were funded from increased debt and retained cash from 2009;

- **Hydro Tasmania**’s net cash after operating activities was $178 million. From this, Hydro Tasmania funded a $95 million capital investment program and completed the Momentum acquisition of $35 million. Hydro Tasmania also prepaid $69 million of debt, improving its capital structure; and

- **Transend**’s net cash after operating activities was $101 million. This was utilised to fund capital investment of $147 million, increasing debt by $30 million.

**Key Sources of Financial Value Within the SOEB Portfolio**

**Across the SOEB portfolio, key sources of financial value relate to hydro-generation, transmission and distribution business activities.** By comparison, gas-fired generation, electricity retailing and diversification activities have contributed only marginally to financial returns.

Energy generation and energy trading is Hydro Tasmania’s main value driver. It generates hydro electricity in Tasmania which it uses to back contract positions with wholesale customers, and retailers in Tasmania and to retail customers, through its subsidiary Momentum in other NEM regions. It also generates value via Basslink arbitrage opportunities and through trading in spot market and contract markets.

**A particular source of value from to Hydro Tasmania is the value from its contracting arrangements with Aurora Energy for supply to non-contestable customer sector.**

---

3 Hydro Tasmania sells electricity to its retail business – Momentum Energy Pty Ltd – which operates on the mainland.
4 Refer Chapter 10 of the Draft Report.
In both the 2007 and 2010 price determinations, the regulated wholesale energy allowance has been higher than the market cost estimate. The contract arrangements struck between Hydro Tasmania and Aurora Energy for the period of the 2007 price determination saw the full value of the wholesale energy allowance captured by Hydro Tasmania.

The latest arrangements for energy to supply non-contestable customers results in a shift in value available under the PCR away from Hydro Tasmania (which with its higher than market value would have been reflected as profit) and to Aurora Energy where it was used to fund the large fixed costs (gas commodity and transport and debt) associated with operating the TVPS. As these fixed costs are paid to third parties, part of the value available under the PCR has been transferred to the private sector and is therefore not available to be returned to the Tasmanian community as a dividend.

During the drought period, Hydro Tasmania’s financial performance was assisted by the price methodology set in the 2007 Price Determination (effective 1 January 2008 to 30 June 2010), which required non-contestable customers to pay a ‘drought premium’ of slightly less than $3/MWh – amounting to $28 million in total.

For contestable customers in the position of renegotiating contracts with Hydro Tasmania during the drought period, market prices reflected the prevailing conditions, meaning that the cost of alternate generation would have been passed through to these customers.

**The value of hydro-generation has also been positively influenced by the Basslink arbitrage opportunity.** This is derived from Hydro Tasmania holding back production of electricity at times of low prices in Victoria, allowing electricity to flow southward as a substitute for on-island generation, and then later producing that same volume and selling it into Victoria at higher value.

**For the regulated network businesses, the largest single driver of value is the return on capital invested in network assets.** Return on capital is determined under the revenue cap regulation process by applying the Weighted Average Cost of Capital (WACC) to the Regulatory Asset Base (RAB).\(^5\)

Over the review period, there has been considerable capital investment by network businesses to replace and refurbish aged assets and to meet customer-driven demand. The opening RAB for Aurora Energy’s distribution network increased by $541 million or 70 per cent from $726 million in 2004 to $1.267 billion in 2010, with WACC increasing from 6.61 per cent to 6.64 per cent between the 2003 and 2007 price determinations. By comparison, the WACC included in Aurora Energy’s proposal for the 2011 price determination is 10.33 per cent which will be applied to

---

\(^5\) The RAB represents the capital investment used to undertake the prescribed network services and is derived from the initial value of the assets plus additional capital expenditure (if approved by the Regulator) after allowing for depreciation.
the opening RAB for each year of the determination.\textsuperscript{6} The opening RAB for the 2011 price determination is estimated by Aurora Energy to be $1.485 billion, $759 million higher than the opening RAB for the previous determination of $726 million.

Similarly, the opening RAB for Transend’s transmission network increased by $524 million or 92 per cent from $570 million in 2004 to $1.094 billion in 2010, with WACC increasing from 8.80 per cent to 10.0 per cent between the 2003 and 2009 price determinations.

This historical expenditure will have ongoing consequences for Tasmanian transmission and distribution prices in the future as the WACC is applied to the RAB (after allowing for depreciation) in future regulatory periods.

Offsetting increases in revenue, operating expenses have also increased over the review period. The Panel observes that there has been a progressive focus by SOEB entities on efficiency gains, in response to a more clearly articulated direction by Shareholders in recent years. While this may improve future financial performance, historical overspending of regulatory allowances by Transend and Aurora Energy’s retail and distribution businesses has contributed to operating expenses over and above those determined through the regulatory process. These have had a direct impact on profit. Recently the SOEBs have adopted a range of measures to improve the efficiency of their operations.

\textbf{Summary of efficiency measures/programs:}

- Hydro Tasmania has had an internal efficiency focus for some time, illustrated by its management of cash through the drought period 2006 to 2009 where it incurred additional costs to source supply from gas fired generation and from the NEM. Hydro Tasmania’s current efficiency strategy is to reduce capital and operating expenditure to generate cash to repay debt to reduce financing costs and achieve a credit rating of BBB+ by 2014; and to finance other investment initiatives. Reflecting the efficiency measures, over the last three years Hydro Tasmania has repaid $69 million in debt and funded the Momentum acquisition of $52 million from internally generated funds.

- Transend has recently implemented an Employee Regulatory Incentive Scheme to incentivise its staff to deliver operating and capital efficiencies, while maintaining service levels. This scheme is funded through the Australian Economic Regulator (AER’s) Capital Expenditure Incentive Scheme which rewards Transend for minimising or deferring capital expenditure. For the first year of the current regulatory period, 2010, Transend’s actual capital expenditure was $28 million below forecast and actual operating expenditure was $3 million below forecast. In part this reflects an increase in the regulatory allowance allowed by

\textsuperscript{6} In its Draft Determination, the AER has not accepted Aurora Energy’s proposed WACC – rather the AER had determined an indicative WACC of 8.08 per cent.
the AER compared to Transend’s previous determination. By comparison, during the previous regulatory period, Transend overspent its capital expenditure allowance by $37 million or 11 per cent and overspent its operating expenditure allowance by $28 million or 15 per cent.

- Aurora Energy is in the progress of implementing efficiency measures to reduce upward pressure on distribution service prices and to position itself competitively in the retail market. Evidence of the effectiveness of these measures will be in future years rather than in data analysed for the review.

Aurora Energy considers that the reductions in its current regulatory proposal for prescribed distribution services are achievable due to the significant investment in the distribution network that has been made in the past. For the first two years of the current regulatory period (2009 and 2010), Aurora Energy overspent its capital expenditure allowance by $29 million or 9 per cent and underspent its operating allowance by $2 million. This compares to the previous regulatory period where Aurora Energy overspent its capital expenditure allowance by $170 million or 80 per cent (noting that $95 million related to customer connections) and overspent its operating expenditure allowance by $16 million or 9 per cent.

There is evidence of historical overspending by Aurora Energy in other parts of its business operations. The development of a new customer billing system, originally budgeted to cost $15 million was completed for $60 million. Of this, $32 million will be directly expensed impacting financial performance (of which $21 million was expensed in 2010 and $11 million was expensed in 2011).

The Tasmanian Economic Regulator (TER) has allowed Aurora Energy an industry benchmarked cost to serve of $95 per customer per annum, compared to Aurora Energy’s submission of $105 per customer per annum. Aurora Energy’s retail cost to serve per customer is impacted by economies of scale and its move into mainland retail sales was driven in part by an effort to spread fixed costs across a larger customer base. This cost is a focus of Aurora Energy’s current efficiency and productivity measures and will need to be reduced if Aurora Energy is to position itself competitively in an open retail market in Tasmania.

The renewed focus on efficiency is expected to improve financial performance. However, this will require ongoing focus by management and Shareholders if it is to be achieved and maintained.
Financial Position of the SOEBs

The Tasmanian Government, on behalf of the Tasmanian community, has a direct interest in the financial sustainability of the SOEB portfolio in three key regards:

- The SOEB entities sustain a financial position to continue the delivery of electricity to Tasmanian customers, including sustainably re-investing in those activities;

- The SOEB entities maintain appropriate capital structures and debt levels. In 2010 the SOEB combined debt comprised 88 per cent of the Tasmanian Government’s total non-financial business debt portfolio. This debt forms part of the total public sector balance sheet which is considered for credit rating purposes and therefore influences the cost of debt to the Tasmanian Government as well as investor confidence in the State; and

- The Tasmanian community benefits from its investment in the SOEBs by way of dividends that should reflect commercial return on its equity investment. These dividends contribute to funding a broad range of policy objectives and this return is core to the public ownership of SOEB entities.

The Panel’s approach to its review of the financial position of the SOEBs is to analyse how net cash from operations (free cash) has been used for capital expenditure and diversification investment, repay debt and return a dividend to Shareholders.

Figure 3 illustrates net cash from operations for each of the SOEBs over the review period.

Figure 3 - SOEB Net cash from operations 2004 to 2010

Source: SOEB annual reports
The extent to which efficiency has been a focus of management and Shareholders will determine whether cash from operations is consistent with that which should be expected given regulatory outcomes or prevailing market conditions.

Each of the SOEB entities has generated sufficient cash to fund operating activities and to have available an amount of ‘free cash’ to utilise for capital investment in functional assets or diversification and growth activities, repay debt or return to Shareholders as equity. Following capital investment for the refurbishment and replacement of assets related to functional business activities, the actual allocation of free cash over the review period indicates a preference by Shareholders for investment in diversified business activities, particularly by Hydro Tasmania, rather than the return of capital to the community by way of dividends (for example through the payment of special dividends).

**Sustainable delivery of core business functions**

The SOEBs generate sufficient cash to continue the delivery of electricity to Tasmanian customers and to sustainably re-invest in those activities.

There has been an increase in the scope and magnitude of financial liabilities which must be met from cash from operations. In 2010, the financial liabilities of the SOEB portfolio included gross debt of $2.5 billion, including an unfunded defined benefits superannuation liability of $450 million. Additionally, the major infrastructure investment decisions of Basslink and the TVPS, together with the commercial decision by Aurora Energy to become a wholesale gas operator, have created fixed financial obligations in the order of $90 million per annum on Hydro Tasmania and Aurora Energy respectively. However, the source of revenue available to service these commitments, and therefore the risk of not being able to do so, is different.

Basslink enables Hydro Tasmania to trade electricity between Tasmania and other NEM jurisdictions to capture the highest value for its water resources. Hydro Tasmania’s ability to generate this value is a function of water availability and the temporal changes in electricity prices that provide arbitrage opportunities.

The Panel’s detailed review of Basslink highlighted that when water is available, Basslink has provided revenues to Hydro Tasmania in excess of the additional costs that it brings to the business. In low inflow periods, Basslink has not provided revenues in excess of its costs, but it has enabled electricity supplies at a lower cost than alternate on-island generation.
Aurora Energy utilises output from the TVPS, by tolling arrangements with its subsidiary AETV, to back approximately one half of its non-contestable customer load. Aurora Energy’s ability to fund the tolling arrangement is based on the current regulatory arrangements for the energy allowance for non-contestable customers and its commercial arrangements with Hydro Tasmania for the balance of energy required for the non-contestable load. These arrangements expire on 30 June 2013. Should different arrangements be applied after that date, this could impact on Aurora Energy’s ability to service these commitments.

**Capital Expenditure and Investment**

Between 2004 and 2010, capital expenditure and equity investment across the SOEB entities totalled $2.6 billion, including $491 million invested in diversification activities. $100 million was invested in business activities outside Tasmania.

Sources of funds for capital expenditure and diversification investment include free cash, debt or equity contributions from Shareholders.

Table 1 shows SOEB capital expenditure on functional business assets and investment in diversification activities between 2004 and 2010.

<table>
<thead>
<tr>
<th>$ million</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro Tasmania Capital Expenditure</td>
<td>135</td>
<td>105</td>
<td>128</td>
<td>54</td>
<td>55</td>
<td>81</td>
<td>96</td>
<td>654</td>
</tr>
<tr>
<td>Hydro Tasmania Investment - R40JV</td>
<td>10</td>
<td>23</td>
<td>10</td>
<td>5</td>
<td></td>
<td></td>
<td></td>
<td>48</td>
</tr>
<tr>
<td>Hydro Tasmania Investment - Momentum</td>
<td>17</td>
<td>35</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>52</td>
</tr>
<tr>
<td>Aurora Energy Capital Expenditure</td>
<td>83</td>
<td>102</td>
<td>134</td>
<td>125</td>
<td>134</td>
<td>168</td>
<td>169</td>
<td>915</td>
</tr>
<tr>
<td>Aurora Energy Investment - TVPS</td>
<td>294</td>
<td>66</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>360</td>
</tr>
<tr>
<td>Aurora Energy Investment - Gas contracts and dispatch rights</td>
<td>15</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>15</td>
</tr>
<tr>
<td>Transend Capital Expenditure</td>
<td>61</td>
<td>74</td>
<td>89</td>
<td>55</td>
<td>64</td>
<td>97</td>
<td>132</td>
<td>572</td>
</tr>
<tr>
<td>Transend Investment - Telco</td>
<td>16</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>16</td>
</tr>
<tr>
<td>Total Capital Expenditure and Equity Investment</td>
<td>279</td>
<td>281</td>
<td>351</td>
<td>244</td>
<td>276</td>
<td>698</td>
<td>503</td>
<td>2 632</td>
</tr>
</tbody>
</table>

Source: Panel analysis
Hydro Tasmania’s primary area of capital expenditure has been on hydro-generation assets, with $407 million spend between 2004 and 2007. In addition to equity contributions to the Roaring 40s joint venture (of which $48 million was provided by the Government) between 2004 and 2006, Hydro Tasmania spent $103 million on renewable developments including wind farm assets, primarily sourced from debt. Hydro Tasmania’s $52 million acquisition of its retail business, Momentum, was made from free cash.

Aurora Energy’s primary area of capital expenditure has been its distribution network, with a total of around $753 million in investment. The second largest spend was $116 million in corporate and shared services – which represented whole-of-entity investment in activities such as IT and the development of its new billing system. Aurora Energy’s capital investment is funded through cash from operations and debt. In 2008, Aurora Energy received an equity contribution of $100 million from its Shareholders to acquire the TVPS.

Transend’s principal area of capital expenditure has been on the transmission network, with $252 million on expended on system augmentation and $274 million on asset renewal. Transend utilises free cash from operations to fund network investment with the balance sourced through increased debt.

**Maintenance of appropriate capital structures and debt levels**

The total SOEB debt position increased by $938 million or 63 per cent from $1.482 billion in 2004 to $2.420 billion in 2010. In general terms, the borrowing capacity of the SOEB portfolio is constrained. Debt levels also impact on credit ratings and consequently the cost of debt through interest charges.

Hydro Tasmania increased its debt in 2005 by $131 million principally for the construction of Woolnorth Studland Bay and Cathedral Rock wind farms. A further increase of $115 million in 2007 provided working capital during the drought period. Repayment of debt is an emerging trend in Hydro Tasmania’s free cash allocation, with debt reduced by $106 million from 2008 to 2010. Hydro Tasmania is targeting a BBB+ credit rating that will require debt to be held at current levels.

Historically, Aurora Energy and Transend’s debt related to capital investment in their respective network businesses. More recently, directions from Shareholders have increased the debt position of both companies.
In 2009, Aurora Energy was required to borrow $260 million to complete the construction of the TVPS. Borrowing to fund the TVPS required the Treasurer to provide a letter of comfort to the Tasmanian Public Finance Corporation on that portion of Aurora Energy’s debt. The TVPS has a highly geared capital structure, impacting on Aurora Energy’s overall credit rating and consequently its cost of debt, including to its distribution business. Any changes in the regulatory framework for non-contestable customers from 30 June 2013 may impact on the ability of Aurora Energy to service this debt. Aurora Energy is currently BBB rated but is targeting BBB+ within a 5 to 10 year time period. A BBB+ rating is consistent with the assumed rating used by the regulator as part of the network pricing determination process. This means that Aurora Energy’s cost of debt relating to its distribution business is higher than the financing costs it receives under its regulatory allowance.

Transend’s debt has increased as a result of the Tasmanian Government’s decision to rebalance equity across the SOEB portfolio via a ‘debt swap’ between Hydro Tasmania and Transend ($220 million) and to withdraw equity ($50 million) in 2008 which was also provided to Hydro Tasmania. Transend is currently ‘A’ rated and has some balance sheet capacity, although this will be reduced if Transend needs to fund from debt the Tasmanian Government’s equity commitment to TasRail of $100 million over the next five years.

**Benefit the Tasmanian community by providing commercial returns on their invested capital**

The Tasmanian community benefits from its investment in the SOEBs through dividends which should reflect a return on its equity investment. These dividends contribute to funding a broad range of government policy objectives and are core to the rationale of ongoing public ownership of the SOEBs.

The payment of dividends to shareholders, and therefore the return to the Tasmanian community from business activities, totalled $309 million over the period 2004 to 2010. This represents, in aggregate, 18 per cent of cash from operations. Of total dividends paid, $52 million, or 17 per cent comprised the Shareholder’s special dividend requirement from Hydro Tasmania. During the first three years of the analysis period, Hydro Tasmania was required to supplement ordinary dividends with special dividends to pay a total dividend of $40 million per annum.

---

7 ‘Equity investment in a government business carries an opportunity cost, being the benefit the Government forgoes from an alternative use of the equity. Accordingly, the Government expects its businesses to achieve returns that are comparable to alternative investments of similar risk, and for dividends to be at an appropriate level to reflect these returns’ (Guidelines for Tasmanian Government Businesses – Dividends – November 2010).
Other than Hydro Tasmania’s special dividend arrangement, the Panel has seen no evidence that successive Tasmanian governments have utilised the SOEBs as quasi tax-raising entities through the extraction of dividends. On the contrary, dividend returns have been continuously low and below the cost of capital for investment of the kind undertaken by the SOEBs. However, in the 2011-12 Budget, the Government announced a preference for improved returns across the SOEB portfolio by increasing the rate of underlying profit to be returned as a dividend from 2011.

**Business diversification activities**

There has been a clear diversification of business activities by Hydro Tasmania and Aurora Energy, away from their respective functional business activities of hydro-generation and distribution and retailing in the Tasmanian market.

The primary motivation for business diversification appears to be mitigating risk in functional business activities - arising in part from the nature of the native Tasmanian market and in part from implications of energy reform. Some diversification activities have been pursued by the entities as value creating strategies in their own right and in some cases the strategic basis for an activity has shifted from a risk mitigating measure to a value creating opportunity over time.

Hydro Tasmania’s initial basis for building wind farms in Tasmania was to secure additional on-island capacity following the end of dam construction. Subsequently, Hydro Tasmania developed wind assets in the national and international markets, as a value strategy not related to energy supply in Tasmania. Hydro Tasmania’s current wind strategy is to secure Renewable Energy Certificates (RECs) to support its retail business growth. Hydro Tasmania’s capital investment in wind assets through the Roaring 40s joint venture is $98 million, which to date has returned a cumulative loss of $11.2 million. In 2010 Hydro Tasmania’s equity share in the Roaring 40s joint venture was $121 million, noting that the joint venture has since been dissolved and Hydro Tasmania has announced its intention to sell 75 per cent of the Woolnorth wind farm assets. Hydro Tasmania’s underlying value in its wind farm investments will be determined through this sale process, rather than on the carrying value of its assets.

---

8 Unlike private shareholders in traded companies, Government shareholders cannot sell shares to access their capital (unless the business is privatised). For Government owned businesses, dividends are the only way in which shareholders can get a return. As such, a Government which is getting little or no dividends is accepting all of the risk and no gain.

9 For example, Hydro Tasmania’s current retail strategy is to provide a path to market for excess generating capacity in Tasmania.
Similarly, following the end of dam construction, Hydro Tasmania’s consulting business, Entura, was retained to provide operation and maintenance services to the existing hydro-generation assets and provide services to the other SOEBs. There has been an ongoing strategy to diversify Entura’s revenue base away from Hydro Tasmania. Entura’s share of revenue sourced from Hydro Tasmania has declined from 68 per cent in 2004 to 39 per cent in 2010, offset by services to external clients, increasingly in the national and international markets. Since 2002, Entura has made an EBITDA contribution of between $1 and $4 million per annum, with a loss of $4 million in 2010 associated with the Global Financial Crisis (GFC).

Hydro Tasmania’s purchase of its retail business, Momentum, is to capture the wholesale and retail value of excess generation capacity in Tasmania following the commissioning of the TVPS and to mitigate against the loss of a large customer. The analysis period reflects the acquisition phase of Momentum. As such, the longer-term outcome of this strategy will be reflected in future year’s performance. Hydro Tasmania’s capital investment in Momentum is $52 million, which to date, has returned a cumulative loss of $15.1 million during its start-up phase. Hydro Tasmania believes that Momentum will deliver strong profit growth in the coming years.

In a similar manner, in response to the introduction of customer contestability, Aurora Energy expanded its retail base into other NEM jurisdictions to spread its largely fixed cost-to-serve expense across a larger customer base. Between 2005 and 2010 Aurora Energy’s cumulative return from mainland electricity retail trading was $3.3 million.

At the direction of its Shareholders, on the basis of energy security, Aurora Energy acquired and completed construction of the gas fired TVPS. This required Aurora Energy to borrow $260 million, which has influenced the overall cost of debt across the business. The Panel has estimated the negative impact on Aurora Energy’s net profit after tax from the operation of the TVPS in 2010 to be $29 million when compared with an assumed situation where it could have sourced its energy requirements from Hydro Tasmania at a price equivalent to the regulated wholesale energy allowance. As noted above, the viability of the TVPS for the period 2011 to 2013 is underpinned by the value of the wholesale energy allowance and Aurora Energy’s contractual arrangements with Hydro Tasmania for the balance of the non-contestable customer load.

Shortly after its sale of the TVPS, Babcock and Brown Power also put up for sale the assets of its business AEATM, which included the gas supply arrangements (commodity and transport) for the TVPS. Aurora Energy made a commercial decision to acquire the AEATM assets for $15 million in order to mitigate gas price risks and to obtain synergies with its NEM retailing operations.
The gas assets acquired through the AEATM purchase included gas commodity and transport arrangements, in addition to those related to the TVPS and tolling arrangements with the Bairnsdale power station in Victoria. The gas arrangements provide Aurora Energy with a growth opportunity in wholesaling gas to major customers in Tasmania and on the mainland and in retailing gas to customers in Tasmania. Aurora Energy returned a $1.8 million loss on wholesale gas trading in 2010.

On a smaller financial scale, Aurora Energy has developed the electrical safety WireAlert product and is the Tasmanian Government’s strategic partner in telecommunications, which includes the rollout of the Australian Government’s National Broadband Network (NBN) project. While these activities are less capital intensive (for example, $8.8m has been invested in the WireAlert product with a cumulative loss of $0.6 million), they consume a significant amount of management and board time that reduces time available to focus on functional business activities.

The Panel has not considered in detail the nature and extent of the risks being mitigated through each of these various diversification activities, whether the activity has been the best way of managing risk, nor whether it has resulted in an overall lower risk position.

These matters are for the Shareholders and the businesses as owners and managers of the businesses respectively. However, irrespective of how these kinds of investments are funded, it is important to remember that the capital has opportunity cost in terms of its ability to support General Government Sector service delivery. In this context, the Panel has questioned whether such investments and activities are appropriate investments for government at all, given that, in making them the Government has also accepted that General Government Services will need to be adjusted in the event that they are not commercially successful.

The Panel has observed the outcomes of these diversification activities and concluded that:

- Diversifications have provided a major focus for (limited) board and senior management resources.
- The Panel has found little evidence in support of the proposition that these business activities have or will generate sufficient improvements in Shareholder value to justify them. Further, there is little evidence that the Tasmanian community, as owner of the businesses, has realised direct value, from these investments though dividends paid.11

---

10 Aurora Energy’s WireAlert product (marketed in Tasmania as Cable Pl) is a safety sensor provided to Tasmanian households in 2009.
11 The Panel believes that this is a key consideration given the difficulties in crystallising the value of capital growth from government-owned businesses.
Through a series of incremental decisions, SOEB business activities have moved away from the primary activity of electricity supply to Tasmanian customers. The extent to which these diversification strategies have changed the risk/return profile in particular of Hydro Tasmania and Aurora Energy is a matter for the Government, as Shareholder, to be aware of and to be satisfied that the resulting risk profiles are consistent with its objectives and expectations for the SOEBs.

There appears to be a lack of clarity around when and how the financial returns from some diversification strategies will be realised by the community. In this regard, a key consideration is whether the financial outcomes of diversification activities reflect the opportunity cost of this capital invested, for example, through higher dividends or the repayment of debt to strengthen the SOEB balance sheet position.

Generally, a consequence of a growth strategy is the medium-term need by the business for capital. This can be in discord with the short-term, year-on-year Shareholder need to withdraw equity through dividends. There is a risk that this tension can compromise the delivery and/or value of the growth strategy.

**Future risks and opportunities**

Although not analysed as part of the Panel’s review, recent results for the 2011 financial year indicate financial performance across the SOEB portfolio is stronger than it has been during the review period. This is due to a number of reasons. Higher than average water inflows means that Hydro Tasmania has inventory to sell rather than using Basslink to back its contract position; the TVPS is underpinned by regulatory arrangements and Aurora Energy’s contract arrangements with Hydro Tasmania; and Transend has benefitted from a materially better outcome under its current price determination that under previous determinations. The 2011 results also reflect the renewed focus on efficiency.

Nonetheless, the energy market is dynamic and there will always be transitory drivers of value up or down in particular years. Similarly, circumstances reflected in the 2011 results may not continue into the future.

In this sense a historical review of longitudinal financial performance is valuable in that it illustrates what decisions have been made and how choices have affected outcomes.
The SOEBs have generated sufficient cash from operations to ensure that the supply of electricity to Tasmanian customers is maintained and reliability improved. In addition, there has been ‘free cash’ generated that has been applied primarily to capital investment and diversification activities. At the same time, returns to Shareholders have been poor. There is a tension between growth (earnings over time) and return of capital now for the benefit of the community. The community has seen limited tangible financial value from diversification initiatives, notwithstanding the considerable investment they have required.

A common theme throughout the Panel’s broader review, and its investigation into the financial position of the SOEBs, is the lack of a clear view on what the Government is seeking to achieve through its ownership of the SOEBs – for example the extent to which it is for the supply of electricity to Tasmanian customers, or it is to pursue Shareholder value through business operations in other NEM jurisdictions and internationally. A key consideration is whether the risk profile of these wider opportunities is consistent with the risk appetite of government and the Tasmanian community relative to its investment in them and the opportunity cost of that investment and, indeed, whether the anticipated returns eventuate.

Value creating strategies require capital investment. As the Panel has observed, in a general sense the SOEB portfolio is currently debt constrained and Hydro Tasmania and Aurora Energy are targeting credit ratings that will require debt to be reduced or maintained. At the same time, the Tasmanian Government has implemented a dividend strategy that delivers better returns to enable provision of key public services. While the Tasmanian Budget is constrained this is likely to remain in place.

A key risk in pursuing non-core value creating strategies is that the associated capital needs exceed SOEB capacity, either through internally generated funds or debt. For example of Hydro Tasmania’s venture into wind asset development could not keep pace with capital requirements and needed to secure an equity contribution from its Shareholders of $50 million.

A key question then is if additional capital is required where is this capital going to be sourced? Or will growth opportunities be forgone due to the lack of available capital, despite the expectation that may have been built around them?

From a Shareholder perspective, there are several key financial risks confronting the SOEB portfolio.

- Aurora Energy’s retail business is financially vulnerable to a loss of market share arising from further retail competition; and the cost of operation of the TVPS, in terms of average cost per megawatt hour of output is higher than both the prevailing market prices in Tasmania and the regulated wholesale energy allowance. This leaves Aurora Energy’s energy business highly vulnerable to changes in the regulatory arrangements and re-negotiation of contract arrangements for the non-contestable beyond 30 June 2013; and to the introduction of further retail competition.
Hydro Tasmania remains vulnerable to hydrological risk, although the nature of this risk has changed over time. Both Hydro Tasmania and Transend are vulnerable to a large industrial load leaving Tasmania, in terms of the opportunity value of stranded energy and stranded network assets respectively.

The financial performance of Aurora Energy and Transend’s network businesses is determined by how aligned actual expenditure compares to determined revenue. The regulatory risk to these businesses arises from changes in the regulatory framework or that the regulatory framework does not deliver revenue outcomes that are consistent with board and management’s expectations of expenditure requirements.¹²

The principal financial opportunity for the SOEB portfolio is the potential increase in value available to Hydro Tasmania from its hydro-generation in light of carbon pricing.¹³ The application of any increase in value remains a key consideration for the Tasmanian Government. A key question for the Tasmanian community is how much of the additional value from hydro-generation resulting from a price on carbon will be allocated to growth strategies or returned to the Tasmanian community in recognition of its historic investment in those assets.

There is a fundamental tension here between certainty and risk which ultimately fall on Government to resolve. Value returned to the community now can be spent on the provision of public services. Value re-invested in growth opportunities with the SOEBs may return greater value to the community at some time in the future, but neither the quantum nor the time frames for that return are certain.

¹² Note the AER’s Draft Determination for Aurora Energy’s distribution business proposes WACC of 8.08 per cent compared to Aurora Energy’s proposes 10.03 per cent; capital expenditure at $536 million compared to Aurora Energy’s proposed $675 million; and operating expenditure of $311 million compared to Aurora Energy’s proposed $340 million.

¹³ this environment will further increase the generation costs of the TVPS relative to hydro-generation, but will also result in higher energy prices overall, which will improve TVPS’s financial position relative to the market.
1. Structure of the Tasmanian Energy Market

Since disaggregation of the Hydro-Electric Corporation (HEC) in 1998, the TESI has experienced major structural, regulatory and investment changes. The Panel’s Discussion Paper ‘The Evolution of Tasmania’s Energy Sector’ provides a detailed discussion of energy sector reform undertaken in Tasmania since 1995. In addition to that paper, the Panel has also previously released the Discussion Paper ‘Tasmania’s Energy Sector - an Overview’ which provides a detailed discussion on the physical structure of, and main participants in, the TESI.

The Tasmanian Government owns the three primary entities in the TESI, Hydro Tasmania, Transend and Aurora Energy, collectively referred to as the SOEBs.

Figure 4 below illustrates the corporate structure of the TESI and summarises the various relationships across the portfolio.

---

14 These papers are available on the Panel’s website at www.electricity.tas.gov.au.
15 Including subsidiary companies and activities undertaken through joint venture arrangements.
2. Financial Flows Through The SOEB Portfolio

There are a number of inter-relationships which govern the functioning of the TESI. These relationships reflect the complexity of financial flows within each SOEB and between the SOEBs.

The diagram below presents a high-level summary of the primary financial flows between the three SOEBs, as well as the intra-entity financial flows among the various business segments within each of the SOEBs.

Figure 5 - 2010 Inter and intra entity financial flows within the SOEB portfolio

Note: Some of the key financial flows have been omitted to preserve commercial confidentiality.

There are two major inter-entity financial flows within the SOEB portfolio, namely:

- wholesale energy contracts between Hydro Tasmania and Aurora Energy for both contestable and non-contestable customers; and
- the pass-through of transmission charges from Transend to Aurora Energy.

Energy sector reform has influenced the complexity of intra-entity financial flows within both Hydro Tasmania and Aurora Energy, as each business has diversified business operations resulting in more vertically integrated entities than those that were in place at disaggregation.
2.1. The Two Major Inter-SOEB Financial Flows Relate to Energy and Transmission

2.1.1. Wholesale Energy

Given Hydro Tasmania’s dominant position in the Tasmanian wholesale energy market, and Aurora Energy’s dominant position as the incumbent retailer, coupled with its direct participation in the wholesale energy market through the TVPS, there are several financial interrelationships between the two SOEBs through the wholesale energy market.

The contractual arrangements between the two entities under which Aurora Energy contracts for wholesale energy to service its contestable and non-contestable load are the primary form of financial interrelationship. The foundation on which these financial relationships are based differ, which is explained below.

**Wholesale contracting for non-contestable customers**

Prior to the commissioning of the TVPS in 2009, Hydro Tasmania provided Aurora Energy’s wholesale energy contracts for its non-contestable customer base. The total value of this relationship was based on the wholesale energy allowance provided to Aurora Energy under the Price Control Regulations\(^\text{16}\) (PCRs). Typically, the contract arrangements struck between Hydro Tasmania and Aurora Energy for these customers saw the full value of the allowance captured by Hydro Tasmania. Aurora Energy did not secure any ‘additional margin’ in excess of the allowed retail margin through ‘savings’ on the wholesale energy cost.

The nature of these arrangements has changed materially. The first significant change was that, following the negotiation of its hedge arrangement with Alinta backed by the TVPS, Aurora Energy no longer sought to contract for the full non-contestable load exclusively with Hydro Tasmania. Following acquisition and completion of the TVPS, Aurora Energy has subsequently has utilised the output of the TVPS, to cover around half of the non-contestable customer load.\(^\text{17}\)

---


The second major change is that Hydro Tasmania is no longer capturing all of the ‘value’ inherent in the wholesale energy allowance for the volume under its contract. Some of this value has been captured by Aurora Energy, which assists it with the financial consequences of owning and operating the TVPS and results in a substantial transfer in value available under the regulatory arrangements from Hydro Tasmania to Aurora Energy, by comparison with earlier arrangements.18

**Contracting for contestable customers**

With Aurora Energy’s commercial decision to utilise the TVPS capacity to part-back its non-contestable customer load requirements, Aurora Energy, like other retailers operating in the Tasmanian market, seeks wholesale contracts with Hydro Tasmania to back offerings to contestable retail customers. Contestable retail contracts will typically reflect the underlying wholesale cost of electricity (i.e. are usually ‘cost plus’). All retailers, including Aurora Energy, may choose to take differing levels of spot market exposure or use different risk mitigation products (e.g. combinations of hedges and caps) to back retail positions. These strategies have differing costs and risk profiles, and could result in a different wholesale energy cost estimate on which retailers could price retail contracts, even if all retailers are faced with a common wholesale energy contract offering from Hydro Tasmania.

The Panel understands that where its retail position is not backed by generation, Aurora Energy seeks to minimise its spot market exposure due to market volatility in Tasmania, so that there is a large degree of financial interconnectedness between Aurora Energy and Hydro Tasmania in relation to contestable customers through wholesale energy contracts for contestable customers.

**Spot Market**

All retailers and generators face a degree of spot market exposure, even in light of a high level of contracting, as end customer loads are variable and difficult to predict. This also applies to the availability of generating plant.19

---

18 The wholesale energy allowance for regulated customers is determined through the Regulator’s price determination. To the extent that the wholesale energy allowance is greater than the prevailing market price for electricity ‘value’ is created. How this value is allocated depends on the contracting arrangements between Aurora Energy and its supplier. Prior to July 2010, the contractual arrangements between Aurora Energy and Hydro Tasmania for backing the regulated customer base consistently allocated all of the value to Hydro Tasmania (i.e. the contact ‘price’ reflected the wholesale energy allowance). Aurora Energy received no additional margin on its retail business for any ‘savings, on the cost of wholesale energy. From July 2010 to July 2012, the contractual arrangements between Aurora Energy and Hydro Tasmania for the cost of wholesale energy supplied to meet the regulated customer load (52 per cent of load) is lower that the wholesale energy allowance, transferring this value to Aurora Energy. Aurora Energy applies this ‘value’ to offset the cost of energy supplied by the TVPS through its tolling arrangements (48 per cent of load) which is higher than the wholesale energy allowance. The changes to the Price Control Regulations in 2010 were made to enable the Treasurer to determine the arrangement between Hydro Tasmania and Aurora Energy should they not be able to reach a commercial arrangement. This regulatory intervention was not utilised as the parties reached a commercial decision.

19 A load following or whole-of-meter swap will provide full cover for a retailer against the spot price, but these are not typically used for the majority of load.
As Hydro Tasmania’s generation business and Aurora Energy’s retail business are on the opposite sides of the buy/sell transaction in the spot market, there can be material value shifts between the businesses arising from spot market outcomes on a half-hourly basis. In circumstances where Aurora Energy has fixed-price supply obligations to retail customers and an exposure to the spot market, spot prices above the assumed rate within the retail contract will shift value away from Aurora Energy and to Hydro Tasmania (assuming it has a similar spot market exposure). Generally, to the extent that Hydro Tasmania is able to capture additional value from spot market activities this will generally see a value shift from wholesale market buyers, including Aurora Energy\(^20\), to Hydro Tasmania.

From an overall SOEB portfolio perspective, improving returns from one part of the portfolio derived through the spot market can be offset by directly poorer returns from another part of the portfolio, noting that respective businesses may have different exposure to the spot market and therefore different risk profiles.\(^21\)

**TVPS**

With the commissioning of the TVPS, there is now an additional financial interconnection between Aurora Energy and Hydro Tasmania. Depending on the contracting and operating profile of the TVPS, Aurora Energy has simultaneous financial interests in both the sell and buy side of the Tasmanian spot market. In some circumstances, this can act as a ‘natural hedge’ by effectively insulating part of Aurora Energy’s exposure to the market by being on the ‘opposite side’. For example, if Hydro Tasmania is able to take advantage of commercial opportunities in the spot market (for example, owing to unexpected demand by customers pushing volumes higher than contracted volumes) to the extent that it is under-contracted, Aurora Energy could be exposed to the spot market. If the TVPS is also operating at that time and is also under-contracted, it would benefit from the higher spot price – offsetting some of the negative impact on the retail business.\(^22\) Similarly, if Aurora Energy is over contracted and spot prices were low it would have a negative impact on its energy business.

\(^{20}\) And also includes other retailers and large customers with spot market exposure.

\(^{21}\) Some value can be lost from the SOEB portfolio to customers from this spot market activity, which is addressed by the Panel in its Draft Report.

\(^{22}\) The impacts are not always neutralising.
2.1.2. Transmission use of System Charges

The second major inter-SOEB financial flow relates to Transend’s TUOS charges. TUOS charges are derived from the following sources:

1. TUOS charges paid by Aurora Energy (and potentially other retailers) to Transend for non-direct connect customers (predominantly residential and business customers). These TUOS charges are passed through to users in the electricity retail price;

2. TUOS charges paid by Aurora Energy (and potentially other retailers) to Transend for direct connect customers (primarily large businesses). These TUOS charges are passed through to users as a separate component of their electricity bill; and

3. Direct connect charges paid by major industrials and generators (Hydro Tasmania and the TVPS) directly to Transend.

The transmission component of electricity charges to customers represents a pass-through cost to Aurora Energy – both its revenues and costs incorporate transmission costs and it receives no value from that proportion of revenue that corresponds to the transmission charges.

2.2. Significant Intra-SOEB Financial Flows are a Consequence of the Increasing Complexity of Hydro Tasmania’s and Aurora Energy’s Business Activities

The current complexity of the financial flows within the SOEBs has been influenced by energy sector reform, particularly Tasmania’s entry into the NEM and more recently, the commissioning of the TVPS.

2.2.1. Aurora Energy

Among the SOEBs, Aurora Energy has the most complex intra-entity financial flows. These are mainly attributable to:

- The pass-through of network charges, (TUOS and DUOS) from its distribution business to its retail business; and

- The acquisition of the TVPS and associated gas supply contracts which have led to the establishment of AETV and the creation of Aurora Energy’s integrated energy business.
**Distribution Business:**

The distribution business, while generating approximately 40 per cent of Aurora Energy’s total revenue, contributes approximately 90 per cent of total earnings margin (EBITDA\(^{23}\)). The distribution business passes through the regulated charges for both the distribution and transmission networks to Aurora Energy’s retail business (and other retailers) for on-charging to customers. The network component (distribution and transmission) of the regulated electricity price has increased significantly during the last decade driven mainly by capital investment and the consequential increase in the value of both the distribution and transmission regulated asset bases.

The balance sheet strength of the distribution business, and the cash flows that it generates, support Aurora Energy’s energy business and its retail business (in a financial, rather than a regulatory sense) and non-core activities. Aurora Energy’s energy business and retail business also benefit from a stronger credit rating than would be achieved on stand-alone basis. Conversely, Aurora Energy’s distribution business is exposed to higher debt costs as a result of the energy business than would be the case on a stand-alone basis.

**Wholesale Energy Business:**

The primary function of the energy business is the wholesale purchase of electricity on behalf of the retail business; and the wholesale purchase and trading of gas for the TVPS operation, the Bairnsdale power station and for resale to large gas customers.

Aurora Energy has implemented two tolling arrangements between the energy business and AETV, the entity which owns the TVPS. These tolling arrangements effectively transfer the rights and obligations associated with the pool income from the generation of TVPS from AETV to the energy business in return for tolling fees to produce and dispatch electricity from the gas provided by the energy business at the discretion of the energy business.

With the Government-directed purchase of the TVPS, Aurora Energy acquired a suite of gas supply contracts to ensure the security of supply of gas to operate the TVPS. Aurora Energy subsequently entered into a separate commercial transaction to acquire a portfolio of gas supply, transport and sales arrangements (including the contracts for the supply of gas to the TVPS) from Babcock and Brown Power (AEATM). With these arrangements Aurora Energy is the principal supplier of gas for industrial and retail purposes in Tasmania (including its own retail gas business and to supply the TVPS). Aurora Energy also wholesales gas in other jurisdictions and has a tolling arrangement with the Bairnsdale power station, including the supply of gas.

---

\(^{23}\) Earnings before interest, depreciation and tax - this is a measure of operating cash flows. Broadly, it provides an indication of profitability before capital financing and income tax considerations.
2.2.2. Hydro Tasmania

Hydro Tasmania’s significant intra-entity flows relate to diversification of business activities on the back of hydro-electricity generation.

Over 2009 and 2010, Hydro Tasmania acquired the retail business, Momentum Pty Ltd (Momentum). Momentum is located in Melbourne with customers in Victoria, New South Wales, Queensland, the ACT and South Australia. Wholesale energy pricing arrangements between Hydro Tasmania and Momentum provide opportunities for Hydro Tasmania to allocate margins and risks between itself and Momentum in relation to electricity and Renewable Energy Certificates (RECs). Hydro Tasmania has advised the Panel that pricing arrangements between its energy business and Momentum are at market rates and consequently do not involve a margin shift from generation to retail. It is less clear the extent to which these arrangements allocate risk between the two entities.

Hydro Tasmania’s consulting business, Entura, provides services to Hydro Tasmania and external entities. The value of internal revenue has been a significant proportion of Entura’s historical revenue, notwithstanding a longstanding objective to increase external revenue.

Over the past decade, there have been substantial flows of funds and physical assets from Hydro Tasmania to the Roaring 40s subsidiary, and the subsequent joint venture with China Light and Power (CLP). Hydro Tasmania has an off-take agreement for energy and RECs with Roaring 40s for the Waterloo wind farm as this comprised part of Hydro Tasmania’s broader portfolio prior to disaggregation of the joint venture.

To illustrate how the financial inter-relationships have changed over time, Table 2 below illustrates a comparison of some of the financial flows within and among the SOEBs in 2004 (pre significant reform in the TESI) and 2010.

---

24 Hydro Tasmania is unable to retail electricity in Tasmania (other than the Bass Strait Islands) due to legislative constraints, which means that Momentum is unable to offer its products to Tasmanian customers.

25 Following the end of development of new major hydro-generation capacity, Hydro Tasmania retained a large engineering workforce formerly referred to as Hydro Consulting and now trading as Entura. Hydro Tasmania does not require the full consulting capacity of Entura to maintain its hydro-generation assets – consulting services between Entura and Hydro Tasmania is projected to decrease.
## Table 2 - Intra and Inter SOEB financial relationships 2004 and 2010

<table>
<thead>
<tr>
<th>Relationships relating to the supply of energy in Tasmania (functional business activities)</th>
<th>2004</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Electricity sources in Tasmania</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity sources in Tasmania</td>
<td>92% (9834 GWh) of total TESI load requirement met by Hydro Tasmania’s dam assets.</td>
<td>76% (8184 GWh) of total TESI load requirement met by Hydro Tasmania’s dam assets.</td>
</tr>
<tr>
<td></td>
<td>7% (796 GWh) of total TESI load requirement met by the BBPS.</td>
<td>10% (1114 GWh) of total TESI load requirement met by the TVPS.</td>
</tr>
<tr>
<td></td>
<td>1% (95 GWh) of total TESI load requirement met by wind.</td>
<td>4% (480 GWh) of total TESI load requirement met by wind.</td>
</tr>
<tr>
<td><strong>Annual value (cost) of energy supplied by Hydro Tasmania to Aurora Energy</strong></td>
<td>$354 million</td>
<td>$416 million</td>
</tr>
<tr>
<td><strong>New cost of energy for Hydro Tasmania - Basslink-related costs</strong></td>
<td>Nil</td>
<td>$84 million</td>
</tr>
<tr>
<td><strong>Substantial value growth is in the distribution business.</strong></td>
<td>$115 million</td>
<td>$165 million</td>
</tr>
<tr>
<td><strong>Distribution EBIDTA ($ value, % of Aurora’s total EBIDTA and RAB value). Note: 2004 RAB includes metering assets whereas the 2010 RAB excludes metering assets.</strong></td>
<td>91%</td>
<td>105%</td>
</tr>
<tr>
<td><strong>Substantial value growth is in the transmission business.</strong></td>
<td>$107 million</td>
<td>$166 million</td>
</tr>
<tr>
<td><strong>Transmission revenue ($ value, % total retail electricity price and RAB value)</strong></td>
<td>15%</td>
<td>15%</td>
</tr>
<tr>
<td><strong>Falling returns to the Government - dividends paid</strong></td>
<td>$66 million</td>
<td>$34 million</td>
</tr>
<tr>
<td><strong>New financial relationships relating to diversification business activities</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydro Tasmania</strong></td>
<td>2004</td>
<td>2010</td>
</tr>
<tr>
<td>Hydro Tasmania’s investment in wind assets - Roaring 40s investment</td>
<td></td>
<td>$48 million (FY07 to FY10 – investment in joint venture)</td>
</tr>
<tr>
<td>Hydro Tasmania’s cumulative returns (loss) from Roaring 40s investment</td>
<td></td>
<td>($11.2 million) (FY06 to FY10)</td>
</tr>
<tr>
<td>Hydro Tasmania’s investment in retail - Momentum acquisition costs</td>
<td></td>
<td>$52 million (FY09 and FY10)</td>
</tr>
<tr>
<td>Hydro Tasmania’s cumulative returns (loss) from Momentum investment</td>
<td></td>
<td>($15.7 million) (FY09 (10 months) and FY10)</td>
</tr>
<tr>
<td>Entura’s share of revenue from Hydro Tasmania</td>
<td>68%</td>
<td>39%</td>
</tr>
<tr>
<td>Aurora Energy</td>
<td>2004</td>
<td>2010</td>
</tr>
<tr>
<td>--------------</td>
<td>------</td>
<td>------</td>
</tr>
<tr>
<td>Aurora Energy’s investment in the TVPS</td>
<td>$360 million (FY09 and FY10)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s impact on NPAT from the TVPS</td>
<td>$29.1 million lower$3 (FY10)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s investment in AEATM (wholesale gas contracts and dispatch rights)</td>
<td>$15 million (FY09)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s returns (loss) from wholesale gas trading</td>
<td>($1.8 million) (FY10)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s cumulative return from mainland electricity retail trading</td>
<td>$3.3 million (FY05 to FY10)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s telecommunications business capital investment</td>
<td>$13.7 million (offset by customer contributions of $3.2 million)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s cumulative return (loss) from telecommunications$4</td>
<td>($4.3 million) (FY07 to FY10)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s investment in Cable PI/WireAlert devices$5</td>
<td>$8.8 million FY10</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s return (loss) from Cable PI/WireAlert$6</td>
<td>($0.6 million) (FY10)</td>
<td></td>
</tr>
</tbody>
</table>

1. 2005 data used as 2004 a half year per the regulatory determination.
3. Estimate based on reversal of tolling fee and AETV net loss before tax, reductions in interest expenses – offset by the purchase of load valued at the wholesale energy allowance.
4. Note that losses in Aurora Energy’s telecommunications business arise from the accounting treatment of the Tasmanian Government’s support of Aurora Energy as its telecommunications strategic partner, which is provided as an equity contribution. Aurora Energy has received equity contributions totalling $7.8 million between 2009 and 2010.
5. $8.8m relating to the cost of supply of WireAlert devices was capitalised into the distribution business in 2010.
6. Segmented data not available for FY09 and operating results to not include an allocation of corporate and shared costs as this information was not provided.
3. Cash Generation and Allocation – changes over time

The purpose of this section of the Paper is to highlight how cash generated within the SOEB entities is used, whether it is for capital investment in assets used to derive income (increasing the equity of the business), to manage debt (capital structures) or returned to Shareholders as dividends.

Two perspectives are considered:

- Section 3.1 – Cash generation and allocation within each SOEB entity. This section considers the broad nature of revenue generated and associated expenditure and how this has trended over time; and how cash derived from operating activities has been used. Net cash from operating activities can be used to invest in existing assets or new business activities, repay debt, or pay dividends.

- Section 3.2 – A portfolio perspective on how capital expenditure and investment expenditure, debt and dividends over time reflect the cash allocation decisions discussed in section 3.1.

The period 2004 to 2010 represents a period of significant change within the TESI and expansion of activities within Hydro Tasmania and Aurora Energy in particular. In addition, Tasmania experienced a major drought event between 2007 and 2009.

It is worth highlighting some of the different circumstances confronting each of the SOEBs over the analysis period, as it provides important context for financial performance and cash utilisation.

- For Hydro Tasmania, the analysis period includes a major drought between 2007 and 2009 combined with high contract cover, which together created very difficult financial circumstances. It also represents a phase of business diversification, particularly outside the Tasmanian market, through investment in wind assets and acquisition of a retail business.

- For Aurora Energy, the analysis period represents a period of significant investment in the distribution network, the phased introduction of retail contestability and the acquisition and operation of the TVPS.

- For Transend, the analysis period represents a period of continued investment in the transmission network, the facilitation of Tasmania’s adoption of NEM arrangements and Basslink connection.
3.1. SOEB Perspective - cash generation and utilisation

3.1.1. Hydro Tasmania

Up until 2005, Hydro Tasmania operated as a hydro-generation business with a focus on sales to Tasmanian customers. With the commissioning of Basslink in 2006, Hydro Tasmania became a trading entity in the NEM, seeking to maximise the value of its energy in the wholesale electricity market. In 2009 and 2010 a change in strategic focus saw Hydro Tasmania acquire Momentum. Hydro Tasmania is now an integrated generator-retailer (‘gentailer’) with its generation and retail activities split between Tasmania and other NEM jurisdictions (i.e. hydro-electricity is generated in Tasmania and sold to wholesale customers in Tasmania and retail customers in other NEM regions).  

Energy generation and trading is Hydro Tasmania’s main value driver. Historically, Hydro Tasmania provided all of Tasmania’s electricity needs. Over the period 2004 to 2010, Hydro Tasmania’s negotiated contractual arrangements relating to the non-contestable load has captured the strongest margins of all customer groups.

Hydro Tasmania’s Financial Performance 2004 to 2010

Figure 6 illustrates Hydro Tasmania’s financial performance between 2004 and 2010.  

Total revenues remained fairly consistent between 2004 and 2008 at between $440 million to $490 million, with significant growth in 2009 (33 per cent) and 2010 (15 per cent). In 2009, electricity revenue, excluding Momentum, increased by $87 million, or 21 per cent from 2008, notwithstanding hydro station output remaining at just over 7000 GWh (7100 GWh in 2008 and 7203 GWh in 2009). Expenses grew on average at a rate of around 18 per cent per annum since 2006, with a decline to around 14 per cent in 2010. This rate of change reflects the change in Hydro Tasmania’s operating environment including the need to purchase gas to supplement hydro storages, the commencement of the Basslink facility fee and the inclusion of network costs associated with Momentum customers (refer Figure 8).

Over the same period EBIDTA declined until 2009 but has not returned to 2004 and 2005 levels.

---

26 Due to Hydro Tasmania’s dominant position in the Tasmanian generation sector, it is precluded by legislation from retailing electricity in Tasmania.

27 Analysis excludes financing and depreciation revenues and costs.
As Figure 7 illustrates, electricity generation and trading is Hydro Tasmania’s primary revenue source. Revenue from electricity is a function of contracted load, actual physical generation and price. The drivers of revenue growth over the analysis period are discussed in Section 5, Part 2 of this Paper. ‘Subsidiary revenue’ in 2009 and 2010 is revenue earned by Momentum.
As illustrated in Figure 8, there was a significant and steady growth in Hydro Tasmania’s expenses from $203 million in 2004 to $491 million in 2010. The purpose of Figure 8, in addition to illustrating the quantum changes in operating expenses, is to show the changes in types of operating expenditure as the market has changed over time. For example, from 2006 Hydro Tasmania had an operating expense associated with Basslink and gas and gas transport costs peaked through the drought period as the BBPS was utilised to maintain supply. The growth in generation, transmission and retail costs in 2010 can be partially attributed to Momentum.

**Figure 8 - Primary contributors to operating expenses 2004 to 2010**

*Source: Hydro Tasmania annual reports*
Hydro Tasmania’s Cash Generation and Utilisation 2004 to 2010

Figure 9 illustrates Hydro Tasmania’s cash from operations over the period 2004 to 2010.

Figure 9 - Hydro Tasmania’s Cash from Operations 2004 to 2010

Source: Hydro Tasmania’s annual reports

In 2004, net cash provided by operating activities was $105 million, which increased over the period to 2006. Reflecting the impact of the drought on Hydro Tasmania’s financial position, net cash provided by operating activities fell by just over $100 million between 2006 and 2007, from $140 million to $37 million. With improved water inflows and storage levels, net cash provided by operating activities increased by $134 million between 2009 and 2010, from $44 million to $178 million.

Between 2004 and 2009, cash receipts from customers ranged between $400 million and $550 million per annum. There is a marked increase in cash receipts in 2010 to $788 million (an increase of $297 million or 60 per cent from 2009), reflecting improved water inflows, storage levels and retail trading. From 2007, cash payments to suppliers and employees increased as a percentage of cash receipts from an historical average of around 55 per cent to between 70 and 80 per cent. There was a step increase in 2008 of $148 million from $305 million in 2007 to $453 million in 2008, reflecting in part Hydro Tasmania’s higher cost of RECs, gas purchases to operate the BBPS through the drought and financial commitments to Basslink.

After operating costs, the two key uses of cash are 1) investing activities, including capital investment in the refurbishment and replacement of primary assets and investment in diversified business activities; and 2) financing activities, including the repayment of debt and returns to Shareholders by way of dividends.
Figure 10, illustrates cash utilised in investing activities over the period 2004 to 2010.

Figure 10 - Cash utilised in investing activities 2004 to 2010

Source: Hydro Tasmania’s annual reports

Over the analysis period, total capital investment was $613 million, or 83 per cent of cash used in investing activities. A more detailed discussion of Hydro Tasmania’s capital investment profile is included at section 3.2.1. Total investment in new business activities (wind and Momentum) was $125 million, or 17 per cent of cash used in investing activities. Hydro Tasmania’s investment in wind activities since 2007, $48 million, was funded by an equity contribution from its Shareholders. Its investment in the acquisition of Momentum, $52 million, was funded from internally generated funds.

Proceeds from other investing activities include proceeds from the sale of property, plant and equipment of $33 million in 2008 which related to the sale of the BBPS to Alinta.

Figure 11 illustrates cash used in financing activities over the period 2004 to 2010.
Excepting 2006, between 2004 and 2007 Hydro Tasmania increased its borrowings, most significantly in 2005 ($131 million, used principally for the construction of the Woolnorth Studland Bay and Cathedral Rock wind farms) and 2007 ($115 million used to provide working capital during the drought). However, Hydro Tasmania has repaid debt in each of the subsequent years. In 2010 this amounted to $69 million. Over the period, Hydro Tasmania decreased its borrowings from $1081 million in 2004 to $893 million in 2010. This was assisted by an equity contribution from Shareholders of $220 million in 2008 by way of transfer of Tascorp loans from Hydro Tasmania to Transend. Other sources of financing included a Shareholder equity contribution of $50 million in 2008 to fund Hydro Tasmania’s ongoing investment in Roaring 40s joint venture (shown in Figure 8 as other operating expenses).

**Summary of Hydro Tasmania cash generation and utilisation**

Hydro Tasmania has maintained a positive cash from operations position throughout the analysis period, including the years in which drought had a significant impact on financial performance where Hydro Tasmania absorbed much of the additional cost of alternate supply (BBPS and from the NEM via Basslink). In this period, Hydro Tasmania adjusted its investment activities by reducing its capital investment program – thereby avoiding additional pressure on debt levels. Hydro Tasmania was also provided dividend relief through changes in its dividend policy agreed to by the Government.

From 2008 to 2010, Hydro Tasmania reduced borrowings by $106 million and funded the acquisition of Momentum, $52 million, from its cash from operations. However, dividends have been nil or minimal during this time, representing only 3 per cent of cash from operations.
3.1.2. Aurora Energy

Up until 2008, Aurora Energy operated primarily as a retailer (in Tasmania and elsewhere in the NEM) and distribution business.28 Subsequent to the acquisition and operation of the TVPS, Aurora Energy is now an integrated generator-retailer (‘gentailer’) and distribution business, as well as a wholesale gas trader.

The regulated part of the distribution business has been Aurora Energy’s main value driver, generating on average 40 per cent of total revenue, but contributing 90 per cent of EBITDA.

Typically, electricity retailing is a high volume/low margin business and is subject to economies of scale.29 Aurora Energy has the financial challenge of spreading its fixed costs across a small (predominantly Tasmanian) customer base.

The introduction of retail competition has resulted in a transfer of load from Aurora Energy to new entrant retailers, which has put downward pressure on Aurora Energy’s retail margins as fixed costs are spread across fewer customers.30 Aurora Energy’s retail business is vulnerable to the loss of further market share, particularly if it is unable to materially reduce retail costs in line with losses in volume.31

While energy revenue has increased due to average price increases across all customer types, particularly non-contestable customers, this higher revenue reflects the pass-through of higher costs rather than material improvements in retail margins. Increases in retail electricity prices that are experienced by customers are not fully captured by Aurora Energy’s retail business. This is because:

- The transmission component, the highest proportional increase over time, represents a pass through cost to Transend;
- The distribution component represents a pass through cost to Aurora Energy’s distribution business; and
- Traditionally, the wholesale energy allowance set the financial parameters for the contract between Hydro Tasmania and Aurora Energy for the non-contestable customer load. The 2010 contract arrangements32 have seen value flow from Hydro Tasmania to Aurora Energy, which has effectively been used by Aurora Energy to fund the tolling arrangements between its energy business and AETV.

---

28 Aurora Energy also had relatively small business activities in telecommunications and gas retailing.
29 The cost of billing and other systems required by electricity retailers are relatively fixed within large bands of customers, although significant step changes can be incurred once certain customer levels are reached (hence the demarcation of TIER 1 and TIER 2 retailers).
30 Aurora Energy estimates that it has around 85 per cent share of contestable customers in Tasmania.
31 Changes to Aurora Energy’s energy business announced in October 2011 indicate that the company is actively addressing these pressures.
32 Hydro Tasmania and Aurora Energy have two contract arrangements, a contract for energy and a drought security option, that combined have the effect of Hydro Tasmania receiving a lower price than the regulated energy allowance, for energy to supply Aurora Energy’s non-contestable load.
In relation to Aurora Energy’s energy business, the average cost of generation (per $/MWh) from the TVPS exceeds the wholesale energy allowance. The viability of the AETV entity which owns the TVPS is sustained by two tolling agreements with Aurora Energy’s energy business. The value provided by the tolling agreements is sufficient to cover the cost of electricity production from the TVPS, pay down debt over the life of the plant and provide a modest rate of return. In 2010, gas commodity and transport costs represented approximately half of the tolling fee revenue.33

Figure 12 illustrates contribution to EBIDTA by Aurora Energy’s business activities.

Figure 12 - Aurora Energy’s EBIDTA Contribution by activity

Source: Aurora Energy

Note: Wholesale includes electricity and gas trading; and AETV EBIDTA is a function of the tolling arrangements between Aurora Energy and AETV.

33 The TVPS cost structure is not competitive in the NEM and while the tolling arrangements cover the power station’s costs, they would not be sustainable at competitive prices in the NEM wholesale market.
Aurora Energy’s Financial Performance 2004 to 2010

Figure 13 illustrates Aurora Energy’s financial performance between 2004 and 2010. Over this period, revenues increased from $643 million in 2004 to $1.173 billion in 2010, an increase of $530 million or 82 per cent. Revenue growth was at a continuous, albeit escalating rate, with a high point in 2010 of 18 per cent from 2009. Expenses increased consistent with revenues from $525 million in 2004 to $1.044 billion in 2010, an increase of $519 million or 99 per cent. The annual rate of increase has also been escalating with a high point in 2010 of 20 per cent.34

Over the same period, EBITDA has remained consistent at, on average, 16 per cent of revenue. The exception was 2010 when EBITDA fell to 11 per cent of revenue as a result of poor performance of the energy business.

Aurora Energy’s revenue comprises revenue from electricity sales from its customers in Tasmania and other NEM jurisdictions; distribution network services, gas wholesale and retail and energy trading from the output of its Tamar Valley and Bainsdale power stations. A portion of revenue earned from electricity sales includes the pass-through of transmission and distribution costs.

34 Aurora Energy has advised the Panel that the 2010 year was not on trend, primarily due to losses in the energy business relating to issues within the Tasmanian wholesale energy market. Losses attributable to the cost of energy account for half of the energy business loss, the other half being attributable to the expensing of $21 million of billing system costs. Improved results for the energy business in 2011 are based on the outcomes of the regulatory process and contracting arrangements with Hydro Tasmania for the non-contestable customer load, which are in place until 30 June 2013. If these arrangements do not continue it is anticipated that energy business results will deteriorate.
For revenue from Tasmanian electricity customers, the pass-through of distribution costs to the distribution business reflects the revenue earned by the distribution business. In addition, the distribution business earns revenue from other Tasmanian retailers. For example, in 2010 the distribution business earned revenue of around $231 million from Aurora Energy and around $10 million from other retail service providers.

**Figure 14 - Primary contributors to functional expenses 2004 to 2010**

![Figure 14 - Primary contributors to functional expenses 2004 to 2010](image)

*Source: Aurora Energy annual reports*

Figure 14 illustrates the primary contributors to functional expenses 2004 to 2010 and Figure 15 provides a further breakdown of energy and transmission costs.

As shown in Figure 14, there was a significant and steady growth in Aurora Energy’s functional expenses from $525 million in 2004 to $1044 million in 2010. Some of these cost increases, such as transmission purchases and RECs are pass-through costs and outside Aurora Energy’s control. For those costs within Aurora Energy’s control, labour costs have increased by $41 million or some 75 per cent between 2004 and 2010. Direct expensing of billing system charges, $21 million, contributed to increased expenses in 2010.

As illustrated in Figure 15 transmission purchases have increased, particularly from 2008, as have energy purchases with energy purchase costs in 2010 reflecting outcomes of operating the TVPS.
**Aurora Energy’s Cash Generation and Utilisation 2004 to 2010**

Figure 16 shows Aurora Energy’s cash from operations over the period 2004 to 2010.

Cash from operations show year-on-year variability and does not ‘track’ the EBITDA profile over the same period. The decline in cash from operations in 2010 reflects the impact of negative returns from the energy business associated with Aurora Energy’s contract position and subsequent fluctuations in the Tasmanian spot market price.
After operating costs, the two key uses of cash are 1) investing activities, capital investment in the refurbishment and replacement of primary assets and investment in diversified business activities; and 2) financing activities, the repayment of debt and returns to Shareholders by way of dividends.

Figure 17 illustrates cash utilised in investing activities over the period 2004 to 2010.

**Figure 17 - Cash utilised in investing activities 2004 to 2010**

Over the analysis period, Aurora Energy’s primary use of cash for investing activities was capital investment in its distribution network and the acquisition and construction of the TVPS in 2009 and 2010. In addition, in 2009, Aurora Energy acquired a suite of gas contracts and dispatch rights from Babcock and Brown. More detailed discussion on Aurora Energy’s capital investment is included at section 7.2.1.
Figure 18 illustrates cash utilised in financing activities over the period 2004 to 2010.

Analysis of cash utilised in financing activities indicates that Aurora Energy increased its borrowings in each year between 2004 and 2010.\textsuperscript{35} The significant increase in borrowings in 2009 relates in part to additional borrowings of $260 million to construct the TVPS. Aurora Energy’s borrowings are also impacted by the timing of AEMO prudential requirements ($100 million in 2009), that required Aurora Energy to deposit cash in a standby facility to ensure sufficient liquidity reserves existed for a potential call on spot market purchases. Cash used for this facility was subsequently used to retire the associated debt in 2010.

Equity issued in 2009 and 2010 reflect the $100 million equity contribution from Government to acquire the TVPS and contributions to support Aurora Energy as the Government’s telecommunications strategic partner.

**Summary of Aurora Energy’s cash generation and utilisation**

In 2004, Aurora Energy was the sole retailer of electricity in Tasmania and, as it remains in 2010, the monopoly distribution services provider. In 2009, as a result of a direction from its Shareholders, Aurora Energy’s business operations further diversified with the ownership and operation of the TVPS. Aurora Energy also made a commercial decision to enter into the wholesale purchase and sale of gas (including the gas supplied to the TVPS) through its acquisition of Babcock and Brown Power’s wholesale gas business. As such, the analysis period, particularly in the latter years, has seen a significant additional complexity in Aurora Energy’s business operations.

\textsuperscript{35} This does not mean that Aurora Energy has not repaid borrowings; rather that drawdown on loans has exceeded repayment of loans in each of the years of the review.
Aurora Energy has maintained positive cash from operations position throughout the analysis period, including 2010 where it saw significant issues in its energy business. However, ‘free cash’ has been variable year-on-year.

Aurora Energy’s capital investment program in its distribution business is driven by the need to upgrade the network and customer generated connections. This capital investment has subsequently driven the distribution business’ regulatory revenue allowance. Throughout the review period Aurora Energy increased borrowings on an annual basis to contribute to its capital investment program. In addition, Aurora Energy was required to borrow an additional $260 million to fund the construction of the TVPS.

Dividend payments have averaged around $10 million per annum – although this has been variable across years, representing, again on average, 15 per cent of cash from operations.

3.1.3. Transend

Over the review period, Transend’s business operations have remained primarily focused on the operation of Tasmania’s transmission network. However, the period has seen the transfer of the system controller function to AEMO in 2006. In addition, at the direction of its Shareholders, Transend resolved a number of complex technical issues to prepare Tasmania for NEM entry and the connection of Basslink. The cost of this work was effectively internally funded\(^{36}\), impacting on financial performance in the early years of this analysis.

Revenue from prescribed transmission services is Transend’s main value driver, contributing on average 90 per cent of revenue. Investment in the transmission network has been funded from cash from operations and increased borrowings. Borrowings have also increased as a result of the Government’s decision to rebalance equity across the portfolio via a debt swap between Hydro Tasmania and Transend ($220 million) and to withdraw equity ($50 million) in 2008 which was also provided to Hydro Tasmania.

Higher incurred operational and capital expenditure spending relative to regulatory allowances has impacted on profitability and contributed to lower returns to Government than would be expected from the return on equity allowance provided for under the regulatory framework.\(^{37}\)

---

\(^{36}\) These costs were not provided for in the regulatory determination and therefore not recouped from customers.

\(^{37}\) Differences in the businesses asset valuation for regulatory and accounting purposes also provides a key driver for this outcome. See Section 2 Part 2 of this Paper.
Transend has advised the Panel that its board made an active decision to spend above the regulatory allowances based on its view of long term benefits to customers and Shareholders and that its Shareholders were informed of this approach. Transend considers that the ACCC’s 2003 pricing determination made unsustainably low expenditure allowances. This issue is discussed in more detail in the Panel’s Paper ‘A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses’

**Transend’s Financial Performance 2004 to 2010**

Figure 19 illustrates Transend’s financial performance between 2004 and 2010. Total revenue in 2004 and 2005 includes the system controller function which was subsequently transferred to AEMO, and is not included in revenue (or expenses) in later years. On average across the analysis period, prescribed revenue accounts for approximately 90 per cent of total revenue and has increased from $86 million in 2004 to $166 million in 2010, an increase of 93 per cent. The total expenses trend has mirrored the total revenue trend across each year. Over the same period, EBITDA has, with the exception of 2006, improved in each year and has remained fairly constant at between 65 per cent and 70 per cent of total revenue.

*Figure 19 - Transend’s Financial Performance 2004 to 2010*

Source: Transend’s annual report

As Figure 19 illustrates, revenue from prescribed transmission services is Transend’s key revenue source. Primary drivers of prescribed transmission revenue over the analysis period are discussed in Section 7 Part 2 of this Paper.
As illustrated in Figure 20, there has been a steady growth in operating and maintenance expenses relating to the transmission network over the review period. In 2004 and 2005 Transend’s expenses included costs of system controller function – as noted above this function transferred to AEMO and is now included in network costs.

Between 2004 and 2006 Transend incurred costs associated with Tasmania’s NEM entry.

Source: Transend’s annual reports

Source: Transend’s annual reports
Transend’s Cash Generation and Utilisation 2004 to 2010

Figure 22 illustrates Transend’s cash from operations over the period 2004 to 2010.

Figure 22 - Transend’s cash from operations 2004 by 2010

Cash from operations shows year on year variability, but overall tracks EBITDA. Following a decline in cash from operations of $61 million in 2009, there has been a significant increase in 2010 of $40 million to $101 million.\(^\text{38}\) 2010 is the first year of Transend’s current regulatory period that saw an opening RAB of $951 million, $123 million higher than the 2009 RAB and an uplift in WACC from 8.8 per cent to 10 per cent.

After operating costs, the two key uses of cash are 1) investing activities, capital investment in the refurbishment and replacement of primary assets and investment in diversified business activities, which in Transend’s case has been very modest; and 2) financing activities, the repayment of debt and returns to Shareholders by way of dividends.

\(^{38}\) Revenue recovered in 2009 was based on the AER’s original decision and prior to the Australian Competition Tribunal’s amended decision released in November 2009. Therefore, 2009 results were based on the AER’s original decision of 8.8 per cent WACC. The Tribunal subsequently amended WACC to 10.0 per cent.
Figure 23 illustrates cash utilised in investing activities over the period 2004 to 2010.

**Figure 23 - Cash utilised in investing activities 2004 to 2010**

Over the analysis period, Transend’s total capital investment was $637 million, or 98 per cent of cash used in investing activities. A more detailed discussion of Transend’s capital investment profile is included at section 3.2.1. Transend’s only investment in new business activities was its purchase of the telecommunications business from Hydro Tasmania in 2009 for $15 million.\(^{39}\)

Figure 24 illustrates cash utilised in financing activities over the period 2004 to 2010. Over this period, on a net basis, Transend has drawn on borrowings in each year. In 2008, return on Shareholder equity represents Transend’s $50 million equity return that was subsequently transferred to Hydro Tasmania for wind asset investment.

---

\(^{39}\) On 1 November 2008, Transend acquired the Communication Services business from Hydro Tasmania to bring-in house communication services required to operate the transmission system. Transend’s telecommunications business also provides services to customers in the TESI, providing the high levels of reliability used for operational purposes such as power station protection, monitoring and control, voice communications and asset management functions. (Transend Annual Report 2009).
Summary of Transend’s cash generation and utilisation

Unlike Hydro Tasmania and Aurora Energy, the scope of Transend’s business operation has remained focused on its functional business activity of owning and operating the transmission network. Notwithstanding this, Transend has managed considerable changes arising from Tasmania’s participation in the NEM and the connection of Basslink.

On an annual basis, cash from operations has been positive with a significant improvement in 2010 - the first year of the AER’s current regulatory determination.

Transend’s capital investment program is driven by the augmentation, renewal and strengthening of the State’s transmission network, which in turn, drives up its regulatory allowances. The capital investment program included a large one-off project in 2009/10, the Waddamana to Lindisfame 220kv line. Throughout the review period Transend has increased borrowings on an annual basis to contribute to its capital investment program. In addition, Transend made a direct return of Shareholder equity of $50 million and an indirect return, of $220 million, by way of a debt swap with Hydro Tasmania in 2008.

Dividends payments have averaged around $15 million per annum, although this has been variable across years, representing, again on average, 22 per cent of cash from operations.

3.1.4. Summary of SOEB portfolio cash generation and utilisation 2004 to 2010

Table 3 illustrates how cash generated has been utilised by the SOEBs over the 2004 to 2010 review period.
### Table 3 - Cash generation and utilisation 2004 to 2010

<table>
<thead>
<tr>
<th>SOEB Entity</th>
<th>Cash Generation</th>
<th>Investing Activities</th>
<th>Cash Utilisation</th>
<th>Dividend Returns</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aurora Energy</td>
<td>Variable. Low of $49 million in 2010 High of $126 million in 2009</td>
<td>Total capital expenditure $876 million or 78 per cent of total expenditure. Total investment (TVPS and gas) expenditure $244 million or 22 per cent of total expenditure. $100 million TVPS investment funded by Shareholder equity.</td>
<td>Substantial increase in debt in 2009 ($337 million) primarily as a result of $260 million borrowings for the construction of the TVPS and $100 million relating to AEMO prudential requirements. Trend through the review period to drawdown on debt. Increase in borrowings from $336 million in 2004 to $1029 million in 2010.</td>
<td>Dividend returns between 2004 and 2010 $81 million.</td>
</tr>
<tr>
<td>Transend</td>
<td>Variable - trend to increased cash returns. Low of $56 million in 2004 High of $101 million in 2010</td>
<td>Total capital expenditure $637 million or 98 per cent of total expenditure. Total investment (telecommunications) $15 million or 2 per cent of total expenditure.</td>
<td>Substantial increase in debt in 2008 ($71 million) and 2009 ($91 million) relating to Shareholder’s equity withdrawal, assumption of debt from Hydro Tasmania and ongoing capex. Drawdown on borrowings variable through the review period reflecting cash available from operations. Increased borrowings from $35 million in 2004 to $518 million in 2010 reflecting establishment with nil debt and subsequent equity withdrawals ($50 million) and debt transfer to Hydro Tasmania ($220 million) in 2008.</td>
<td>Dividend returns between 2004 and 2010 $79 million.</td>
</tr>
</tbody>
</table>

1 Note Hydro Tasmania invested a total of $73m in wind between 2004 and 2008, $48m of which was into the Roaring 40’s JV.
3.2. Portfolio Perspective of Financing Activities

3.2.1. Investment - functional and diversified business activities

Capital expenditure on functional business activities

Over the review period, annual capital expenditure on functional business activities across the SOEB portfolio increased by $118 million from $279 million in 2004 to $397 million in 2010, an increase of 25 per cent. The composition across the businesses is shown in Figure 25.

Figure 25 - Total capital expenditure SOEB portfolio 2004 to 2010

Source: Panel analysis

Note: Hydro Tasmania’s capital expenditure between 2004 and 2006 includes investment in wind assets which has subsequently been included as investment in the Roaring 40s JV.

Aurora Energy was the largest contributor to capital expenditure over the review period with a total of $915 million. On an average basis, Aurora Energy spent $131 million per annum, Hydro Tasmania spent $93 million per annum and Transend spent $82 million per annum. A breakdown of each entity’s capital expenditure is discussed further below.

Investment in diversified business activities

In addition to capital expenditure on functional business activities, across the SOEB entities, between 2004 and 2010, investment in diversified business activities amounted to $475 million, of which $360 million was invested by Aurora Energy on the TVPS at the direction of its Shareholders, Hydro Tasmania invested around $100 million in business activities outside Tasmania; including $48 million wind assets and $52 million on its retail business.
SOEB investment in diversified business activities is illustrated in Figure 26 below.

**Figure 26 - Total investment in diversified business activities SOEB portfolio 2004 to 2010**

The breakdown of each entity’s capital expenditure is discussed further below.

**Figure 27 - Aurora Energy’s Capital Expenditure 2004 to 2010**

Note: Aurora Energy’s capital expenditure profile does not include capital investment in the TVPS of $360 million.
Historically, Aurora Energy’s primary area of capital expenditure has been in its distribution business, with a total of around $753 million invested. Capital expenditure in corporate and shared services shown in 2009 and 2010 includes investment attributable to the development of the new billing system, which is a whole-of-business investment.

The capital invested in the regulated distribution business is relatively low risk, and will earn a regulated rate of return over its economic life. Other capital expenditure has a materially higher risk profile. In the case of the billing system, considerable value has already been written off as an expense.\textsuperscript{40}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{Figure_28.png}
\caption{Hydro Tasmania's Capital Expenditure 2004 to 2010}
\end{figure}

\textsuperscript{40} Of the $60 million expended on the billing system, $32 million has not been capitalised, but has been written off as an expense having a direct impact on the company’s financial performance.
Between 2004 and 2006, $103 million was expended on renewable developments, including wind farm assets. From 2006, following the Roaring 40s joint venture arrangement, investment in wind asset development is recorded as equity to the joint venture. Between 2007 and 2010, Hydro Tasmania contributed $48 million equity to the joint venture.

**Figure 29 - Transend’s Capital Expenditure FY04 to FY10**

Transend’s primary area of capital expenditure is the transmission network. As Figure 29 illustrates, in 2004 capex was predominantly on renewal of assets. However, by 2010 the focus of investment is on development assets. Expenditure in 2009 and 2010 included the Waddamana-Lindisfame 220kV transmission line to secure transmission to Hobart and southern Tasmania, with that project costing approximately $130 million.

**Summary of capital expenditure and investment in business diversification**

Table 4 below sets out the capital expenditure and investment in business diversification activities by each entity over the 2004 to 2010 period. Over this period, a total of $2.6 billion has been invested within the SOEB portfolio, including around $491 million in equity investments to fund business diversification activities.

Hydro Tasmania contributed $48 million of equity to the Roaring 40s JV to fund wind farm development, funded by its Shareholders, sourced from an equity withdrawal from Transend. Hydro Tasmania acquired 100 per cent ownership of Momentum for $52 million from internal funds.

Aurora Energy acquired 100 per cent ownership of the TVPS for $100 million, funded by a direct equity contribution from its Shareholders. Completion of the TVPS cost $260 million and was debt funded by Aurora Energy with the assistance of a Treasurer’s letter of comfort on borrowings. Aurora Energy purchased gas contracts and dispatch rights from Babcock and Brown for $15 million.
Transend acquired Hydro Tasmania’s telecommunications business for $15.8 million.

By comparison, as discussed in the sections below, over the same period net SOEB debt has increased by $938 million and returns to Government through dividends totalled $309 million.

Table 4 - SOEB portfolio capital and investment expenditure 2004 to 2010

<table>
<thead>
<tr>
<th>$ million</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro Tasmania Capex</td>
<td>135</td>
<td>105</td>
<td>128</td>
<td>54</td>
<td>55</td>
<td>81</td>
<td>96</td>
<td>654</td>
</tr>
<tr>
<td>Hydro Tasmania Investment - R40JV</td>
<td>10</td>
<td>23</td>
<td>10</td>
<td>5</td>
<td></td>
<td></td>
<td></td>
<td>48</td>
</tr>
<tr>
<td>Hydro Tasmania Investment - Momentum</td>
<td>17</td>
<td>35</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>52</td>
</tr>
<tr>
<td>Aurora Energy Capex</td>
<td>83</td>
<td>102</td>
<td>134</td>
<td>125</td>
<td>134</td>
<td>168</td>
<td>169</td>
<td>915</td>
</tr>
<tr>
<td>Aurora Energy Investment - TVPS</td>
<td>294</td>
<td>66</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>360</td>
</tr>
<tr>
<td>Aurora Energy Investment - Gas contracts and dispatch rights</td>
<td>15</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>15</td>
</tr>
<tr>
<td>Transend Capex</td>
<td>61</td>
<td>74</td>
<td>89</td>
<td>55</td>
<td>64</td>
<td>97</td>
<td>132</td>
<td>572</td>
</tr>
<tr>
<td>Transend Investment - Telco</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>16</td>
</tr>
<tr>
<td>Total Capex and Equity Investment</td>
<td>279</td>
<td>281</td>
<td>351</td>
<td>244</td>
<td>276</td>
<td>698</td>
<td>503</td>
<td>2632</td>
</tr>
</tbody>
</table>

3.2.2. Debt

The SOEB total debt position has increased by $940 million, or 63 per cent, between 2004 and 2010 ($1.482 billion in 2004 to $2.419 billion in 2010), as shown in Figure 30. The primary drivers of increased debt have been the construction of the TVPS and network investment by Aurora Energy’s distribution business, network investment by Transend and investment in business diversification by Hydro Tasmania.
On disaggregation, Hydro Tasmania retained the dominant share of the former HEC’s debt, which is reflected in its proportion of overall portfolio debt. By comparison, Transend was established in 1998 with nil debt, reflecting its expected need to finance a substantial capital spending program on the transmission network to replace aged assets and improve performance standards.

Although capital investment in the transmission network has required increases in debt over time, Transend has had the requisite balance sheet capacity (the ability to borrow and service additional debt), as the value of its asset base and its revenue has continued to grow.

Historically, Aurora Energy’s debt primarily related to its distribution business for capital investment in the network, for which it receives a return. More recently, the TVPS has impacted Aurora Energy’s debt profile. This is reflected in the increase in debt in 2009 from $555 million to $933 million. Aurora Energy’s prudential requirements caused a temporary fluctuation in debt in 2009 and 2010.

To support the overall debt that would be held by Aurora Energy, Tascorp required a letter of comfort from the Treasurer in respect of the TVPS debt.\textsuperscript{41}

The Tasmanian Government has retained an oversight role in relation to the debt profile of the sector, and has undertaken three Capital Structure Reviews since disaggregation to assess the capital structure position of each entity in the overall SOEB portfolio.

\textsuperscript{41} The Panel understands that these support measures have been used by TASCORP in the case of other businesses when debt has exceeded levels that TASCORP is comfortable with on a stand-alone basis.
In 2008, the SOEB Shareholders approved an equity transfer of $270 million from Transend to Hydro Tasmania, of which $220 million was executed effectively as a ‘debt swap’ between the two entities, and $50 million (also borrowed by Transend) was transferred to Hydro Tasmania, via Government. This is reflected as an increase in Transend’s debt in 2008 and a consequential decrease in Hydro Tasmania’s debt in the same year.

The Government undertook its third capital structure review in 2010 which concluded that, at that time, no equity rebalancing would take place. In the 2011 State Budget, the Government announced a further equity contribution from Transend ($100 million over five years), this time to meet the equity requirements of TasRail to relieve the burden on the Consolidated Fund. Prior to this policy, the Government had intended to recapitalise TasRail by means of direct payments from the State Budget.

While Transend has the balance sheet capacity to borrow in order to fund these Shareholder equity withdrawals, Transend’s increased interest costs on this debt, against which no income is generated, will directly impact financial performance and consequently the dividend returns to Shareholders.

### 3.2.3. Returns to Shareholders - dividends paid

This section considers returns to Shareholders on the basis of dividends paid. The Panel considers that the financial performance of the SOEBs is most appropriately considered on a return on equity basis to provide a competitively neutral comparison with private sector utilities. As such, competitive neutrality payments such as tax equivalent and guarantee fee payments, which do provide cash payments to the Tasmanian Government, are treated as an expense of doing business and not considered a suitable performance indicator. Private sector companies also pay these costs, albeit to other institutional recipients.

Figure 31 below illustrates the total SOEB dividend payments to Shareholders, including contribution by each entity over the period 2004 to 2010.
Over the period 2004 to 2010, total dividend returns to Shareholders from the SOEB portfolio totalled $309 million. Hydro Tasmania was the largest contributor at 48 per cent (or $150 million), with Aurora Energy and Transend each contributing around 25 per cent (Aurora Energy $79 million and Transend $81 million). Hydro Tasmania’s dividend contribution includes special dividends totalling $52 million (comprising $27 million in 2004, $17 million in 2005 and $8 million in 2006) or 17 per cent of the total SOEB portfolio dividend return.

Between 2004 and 2006, total SOEB dividend payments were relatively consistent at around $65 million per annum, largely as a result of the special dividend policy for Hydro Tasmania. However, there has been a significant decline in dividend returns from 2006 ($66 million) following the end of special dividends, declining to a low of $19 million in 2009 and 2010.

Figure 32 below illustrates the total SOEB portfolio dividend payments to Government both as a proportion of total portfolio revenue and portfolio equity over the period 2004 to 2010.
Over the period 2004 to 2010, total dividend returns to Government from the SOEB portfolio, on both a revenue and equity basis, declined, with the most significant decline being the dividend return on equity. This is despite growth in revenue and equity (excepting the 2004 financial year) as illustrated in Figure 33. In the most recent financial period, returns have been at or below 1 per cent for both measures.

Note: The decline in SOEB portfolio equity in 2005 relates to a change in Hydro Tasmania’s equity from $2.056 billion in 2004 to $942 million in 2005. In 2005 there was a fall in Hydro Tasmania’s asset revaluation reserve of $523 million arising from an asset revaluation decrement. In 2006, with the introduction of international accounting standards, the 2005 financial statements were restated in accordance with the new standards – this resulted in a further decline of $19 million arising from an asset impairment loss. In addition, AIFRS required the recognition of additional deferred tax assets and liabilities resulting from adopting a different recognition principle than AGAAP. (Source Hydro Tasmania).
Returns to Government, through dividends paid, reflects the Shareholder’s acceptance of a portion of after tax profit. In setting dividend policy for the SOEBs, the Government balances several key considerations:

- Variability of returns - stability and predictability versus direct links to actual profitability;
- Level of returns - retain capital in the SOEBs to fund growth strategies or return to the community through the Budget; and
- Managing debt levels\(^45\) - retain or withdraw capital in the SOEBs to achieve target capital structures commensurate with each business's risk profile, or accept an alternate credit rating.

For much of the review period, in accordance with the Government’s dividend policy, this was generally a 50 per cent return on after tax profits. However, a reduced or nil dividend has been applied under a range of circumstances. Notably, external events such as the impact of extreme hydrological conditions on Hydro Tasmania are reflected in nil dividends paid in the 2008 and 2009 financial years; and Aurora’s 2010 financial results are reflected in a nil dividend paid in 2011. During the period of special dividends, the Government required a fixed amount of total dividends (ordinary plus special) from Hydro Tasmania which is reflected in the stronger dividend returns for the period 2004 to 2006.

In the 2011-12 Budget, the Government announced a preference for improved dividend returns from its businesses, including those in the SOEB portfolio. For 2011 dividend arrangements for the SOEB’s are:

- Hydro Tasmania’s dividend will increase from a 50 per cent to 70 per cent of underlying profit;\(^46\)
- Aurora Energy’s dividend will increase from a 50 per cent smoothed over five years to a 60 per cent of underlying profit; and
- Transend’s dividend will increase from 50 per cent to 60 per cent of underlying profit.

Both improvements in financial performance and the Government’s preference for improved dividend returns (effective dividends payable in 2012) are illustrated in the following recently announced dividends:

\(^{45}\) Government’s may also make decisions regarding debt allocation between the public trading enterprise sector and the general government sector when considering dividends, but this does not change the overall debt levels in the total Tasmanian Public Sector.

\(^{46}\) In accordance with the Tasmanian Government’s dividend policy, dividends are to be negotiated with reference to after tax profit, although it is recognised that sometimes, reported profit may not be supported by cash flows and it may be appropriate for the dividend to include the adoption of a suitable smoothing arrangement or to include on an underlying profit measure rather than accounting net profit after tax. An underlying profit removes the impact of intermittent non-cash events such as significant asset revaluation or a change in accounting standards artificially increase or decrease operating profits without a supporting movement in cash flows.
In its 2011 annual report, Hydro Tasmania paid a dividend in respect of 2010 of $26 million and announced a dividend of $49 million in respect of the 2011 year (payable in 2012).

In its 2011 annual report, Aurora Energy paid a nil dividend in respect of 2010 and announced a dividend of $11.9 million in respect of the 2011 year (payable in 2012).

In its 2011 annual report, Transend Networks paid a dividend in respect of 2010 of $13 million and announced a dividend of $29 million in respect of the 2011 year (payable in 2012).

3.2.4. Superannuation Defined Benefits Obligations 2010

Each of the SOEBs has employees that are members of the Tasmanian Government’s defined benefit superannuation scheme, reflecting a legacy from the original HEC. The scheme has been closed to new members since 1999. As this liability is unfunded, each business has an obligation to fund the scheme as member’s entitlements fall due. Hydro Tasmania’s liability includes all scheme members retired at disaggregation, regardless of the alignment of employees with the post-disaggregation entities.

Figure 34 below illustrates the increasing net financial liability associated with the defined benefits scheme and the relative contribution of each SOEB. The liability represents the present value of the expected payments to members in the scheme. The three SOEBs are collectively, currently making payments to superannuants of around $25 million per annum.

---

47 Historically, the Defined Benefit Scheme covered all employees of General Government and government instrumentalities, including the HEC.

48 As members retire, the SOEBs are required to fund 75% of the member benefit, with the Retirement Benefit Fund’s plan assets funding the balancing 25%. If members elect to take a lump sum, the SOEB is required to fund 75% of that lump sum at the time it is taken. If members take a pension, the SOEBs are required to fund 75% of the pension on an emerging costs basis.
The Panel’s investigations reveal that the SOEBs do not routinely have actuarial forecasts for the emerging funding requirements beyond the forthcoming year, and for planning purposes typically assume a fixed roll forward of current payments. Given the age profile of the membership in each of the SOEBs, there can be expected to be a large flow of members from the workforce to retirement over the coming five years, which could lead to a significant change in funding requirements.\textsuperscript{49}

\textsuperscript{49} The Panel has been advised that a large portion of the liability relates to past employees that are now 80 years and older. As the liability for these members falls away, it will be replaced by that of current employees.
4. Financial Risks and Opportunities

The SOEB entities, and consequently the Shareholders’ value in the SOEB portfolio, face a number of financial risks with few financial opportunities. These are discussed below.

4.1. Hydrological conditions

In a predominantly hydro-based generation system, hydrological conditions are a major influence on the financial performance of Hydro Tasmania. With the flexibility provided by Basslink, Hydro Tasmania is in a much stronger position to manage the physical (energy) aspects of hydrological risk than in the past and the fundamental nature of the risk has, therefore, changed.

Prior to NEM entry and Basslink, Hydro Tasmania was charged with responsibility for maintaining energy security under the Electricity Supply Industry Act 1995, and Hydro Tasmania was effectively required to meet the full energy requirements of the Tasmanian market.\textsuperscript{50} While this obligation was formally removed with NEM entry, with the sustained period of low inflows into the hydro system, the Government identified energy security as its first priority for Hydro Tasmania until the TVPS was commissioned in October 2009.

Hydro Tasmania’s Ministerial Charter continues to require it to prudently manage its water storages consistent with advised long run energy capability. Hydro Tasmania’s preferred operating zone is a storage system level between 30 and 50 per cent of capacity. The lower level represents an ‘insurance level’ that can be used to generate electricity during some years of drought, while the higher level represents a reasonable buffer that can be used to provide flexibility in trading operations.\textsuperscript{51}

Table 5 below, illustrates water inflow variability between 2004 and 2011, and the impact of water storage levels on Hydro Tasmania’s station output and overall hydro system rating. 2011 water storages reflect improved inflows and Hydro Tasmania’s deferral of generation (‘banking’ water) to maximise business value through the introduction of a price on carbon.

\begin{table}
\centering
\begin{tabular}{|c|c|c|}
\hline
Year & Inflow & Station Output & Overall System Rating \\
\hline
2004 & 220 & 150 & 90 \\
2005 & 280 & 180 & 80 \\
2006 & 300 & 200 & 70 \\
2007 & 240 & 160 & 60 \\
2008 & 260 & 170 & 50 \\
2009 & 320 & 220 & 40 \\
2010 & 280 & 190 & 30 \\
2011 & 340 & 240 & 20 \\
\hline
\end{tabular}
\caption{Water Inflow and Station Output}
\end{table}

\textsuperscript{50} Hydro Tasmania’s obligation to supply was imposed under section 26(1) of the Electricity Supply Industry Act 1995 which was repealed on NEM entry on 29 May 2005.

\textsuperscript{51} Hydro Tasmania’s 2010 Annual Report.
Table 5 - Water inflow variability and system output 2004 to 2011 (as at 30 June)

<table>
<thead>
<tr>
<th></th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro system rating GWh</td>
<td>10 200</td>
<td>10 200</td>
<td>10 200</td>
<td>9 500</td>
<td>9 000</td>
<td>8 700</td>
<td>8 700</td>
<td>8 700</td>
</tr>
<tr>
<td>Yield (inflow) GWh</td>
<td>11 034</td>
<td>7 318</td>
<td>10 923</td>
<td>6 606</td>
<td>7 146</td>
<td>8 419</td>
<td>9 410</td>
<td>10 731</td>
</tr>
<tr>
<td>Hydro station output GWh</td>
<td>9834</td>
<td>9610</td>
<td>9688</td>
<td>8128</td>
<td>7100</td>
<td>7203</td>
<td>8184</td>
<td>9273</td>
</tr>
<tr>
<td>BBPS output GWh</td>
<td>796</td>
<td>934</td>
<td>585</td>
<td>936</td>
<td>1 169</td>
<td>608</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Water storage levels</td>
<td>38.2%</td>
<td>22.7%</td>
<td>30.5%</td>
<td>19.3%</td>
<td>19.1%</td>
<td>27.7%</td>
<td>36.6%</td>
<td>45.9%</td>
</tr>
</tbody>
</table>

Source: Hydro Tasmania

During the drought conditions in 2007 and 2008, Hydro Tasmania’s overall contract position limited its ability to pass through to customers the additional costs associated with operating the BBPS and purchasing electricity from the NEM.\(^{52}\)

However, the methodology used to determine the energy price set in the 2007 Price Determination (effective 1 January 2008 to 30 June 2010), included a drought premium of slightly less than $3/MWh, or an additional 5 per cent to the base estimate allowance determined by independent consultants.\(^{53}\)

In this sense, while Hydro Tasmania predominantly bore the financial risk in backing its contract position from alternative, more expensive on-island generation from the BBPS and from purchases from the market via Basslink, inclusion of a drought premium in the regulated energy allowance for non-contestable customers meant that these customers also carried some of the financial risk. Over the period 2007 to 2010\(^{54}\), this amounted to $28 million paid by non-contestable customers. Additionally, due to the financial impact of the drought, Hydro Tasmania did not pay a dividend to its Shareholders in the 2008 and 2009 financial years, and paid a dividend of only $5 million in 2010.\(^{55}\) Thus, Hydro Tasmania’s Shareholders, and consequently the Tasmanian community, also bore some of the financial risk of the drought through nil or reduced dividend returns.

Hydro Tasmania now has access to flexible options to use its own water to back its contract position or trade through Basslink and effectively purchase from the market. Moreover, with the changes in its regulatory arrangement, Hydro Tasmania has much more commercial flexibility to choose its level of contracting in line with prevailing water availability.

---

\(^{52}\) Spot market prices; however, rose as water value increased and renegotiated contracts were recontracted at higher prices, reflecting water value.

\(^{53}\) The TER’s letter to the Treasurer included at annexure 7 of the Treasury Regulatory Impact Statement available on the TER’s website www.energyregulator.tas.gov.au

\(^{54}\) Based on 8,192,609 MWh to meet the non-contestable customer load during this period.

\(^{55}\) Dividends payable in respect of a financial years operating performance are payable in the following financial year.
From Hydro Tasmania’s perspective, hydrological risk is now primarily a balance between revenue certainty and its own risk appetite for maximising the value of its water, rather than a matter of Tasmania’s energy supply security.

### 4.2. Carbon Pricing

The Australian Government has announced a framework to implement a price on carbon emissions and legislation to implement these arrangements was passed by the House of Representatives on 12 October 2011 and the Senate on 8 November 2011. A price on carbon will increase the relative costs of carbon emitting generators and consequently, the average market price of all electricity.\(^{56}\) As a non-carbon emitting generator, Hydro Tasmania’s cost structure will not be materially impacted by carbon pricing, resulting in a potential value gain as market prices rise.

In the short to medium term, the extent to which Hydro Tasmania can ‘capture’ this value is partially dependent on its contract position and its ability to pass through changes in the market value of electricity as a result of carbon pricing to its customers.

A key consideration for Government and the Tasmanian community is how this additional value is used, particularly the degree to which it is retained within Hydro Tasmania to fund business development and expansion opportunities or returned to taxpayers through dividends for wider use in the Budget process.

Under its current dividend arrangements, Hydro Tasmania is required to return dividends based on 70 per cent of underlying profit, so that a significant portion of any additional revenue will be returned as dividends under that arrangement.

On the other hand, the introduction of a price on carbon will increase the costs of the TVPS, resulting in a deterioration of its competitive position in the Tasmanian market compared to Hydro Tasmania. In the short term, the extent to which a price on carbon impacts on Aurora Energy’s financial position will depend on the extent to which the regulatory framework allows the pass through of these costs to non-contestable customers.\(^{57}\) Carbon pricing will improve the relative competitiveness of gas fired generation compared to coal generation (given its lower carbon intensity). Over the medium term, to the extent that Tasmanian wholesale electricity prices reflect market prices in the NEM, carbon pricing may assist the competitive position of the TVPS. However, without access to the NEM, for example via Basslink IRRs, the TVPS will remain ‘trapped’ in the hydro dominated Tasmanian system.

---

\(^{56}\) See the Panel’s ‘Issues Paper’ available on the Panel’s website [www.electricity.tas.gov.au](http://www.electricity.tas.gov.au)

\(^{57}\) Currently Aurora Energy utilises the TVPS to back its non-contestable customer load. The pass-through of carbon costs is provided for in the current regulatory determination of maximum prices for non-contestable customers.
4.3. Renewable energy certificates

Any improvement in REC prices, for example arising from recent amendments to the Australian Government’s Renewable Energy Target\textsuperscript{58}, will also be a source of value to Hydro Tasmania. In addition, with deferral of generation to capture the benefits of carbon pricing, Hydro Tasmania is likely to see additional REC value arising from increased generation to utilise the stored water, provided the base line threshold is reached.

4.4. Retail Competition

As a relatively small retail business in the context of the NEM, Aurora Energy is already exposed to scale disadvantages. The introduction of full retail contestability (FRC)\textsuperscript{59} in the context of a competitive retail market would be expected to diminish Aurora Energy’s customer base and consequently negatively impact financial performance, as its largely fixed cost base will be spread across fewer customers.

A consequential effect of FRC is a move to a more market-based wholesale energy price. In its submission to the Panel’s Issues Paper, Hydro Tasmania noted “that Tasmanian non-contestable contract prices are higher than those charged for contestable contracts”. The current regulatory arrangements provide ‘headroom’ from which Aurora Energy is able to contract with the TVPS on a basis which allows it to recover its relatively high capital and operating costs.

Reflecting the benefits of competition, the implementation of FRC will result in the transfer of the value inherent in the difference between market prices and the regulated wholesale energy allowance from the SOEB portfolio to Tasmanian electricity customers. A similar outcome could be achieved by more closely aligning the regulated wholesale energy allowance to market prices, noting that this would similarly impact on Aurora Energy’s ability to fund the current cost structure of the TVPS.

4.5. Expenditure exceeding regulatory allowances

For the distribution and transmission network businesses, revenue is primarily determined through the application of the regulatory framework, which provides for a return on assets invested in the network and covers operating costs\textsuperscript{60}.

Actual performance by Aurora Energy and Transend against their respective regulatory allowances is both a potential risk and a potential opportunity.

\textsuperscript{58} To separate the Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES) and provide a more sustainable forward path for LRET to support large scale renewables development.

\textsuperscript{59} A key policy of the Tasmanian Government’s energy market reform since 1997 was the introduction of greater competition in the retail market. At this time the introduction of Full Retail Competition (FRC) is dependent on a public benefit test determining the benefits of FRC will outweigh the implementation costs.

\textsuperscript{60} Refer Sections 2 and 3 of Part 2 of this Paper.
Overspending regulatory allowances within a regulatory period directly impacts on financial performance and consequently returns to Shareholders through dividends. Overspending regulatory operating expense allowances has a direct and equivalent impact on financial performance in the year in which it occurs, while for capital expenditure the impact on financial performance is limited to the additional depreciation and interest charges. Conversely, underspending regulatory allowances, particularly operating expenditure, will positively impact on financial performance in the year in which it occurs.

On a cumulative basis, over the two regulatory periods the 2004 to 2010 review period spans, both Transend and Aurora Energy have overspent their respective regulatory allowances for both capital expenditure and operating expenditure for the network businesses. For the full regulatory period covered by the analysis, both Transend and Aurora Energy overspent their respective capital and operating allowances. However in the initial years of the current regulatory period, both companies have constrained operating expenditure to within the annual allowances. For instance:

- **Aurora Energy overspent its capital expenditure allowance in the 2003 regulatory period by $179 million and to date within the 2007 regulatory period has overspent its capital allowance by $29 million.**

- **Aurora Energy overspent its operating expenditure allowance in the 2003 regulatory period by $16 million and to date within the 2007 regulatory period has underspent its operating allowance by $2 million.**

- Additionally, Aurora Energy’s actual ‘costs to serve’ has consistently exceeded its regulatory allowance.

- **Transend overspent its capital expenditure allowance in the 2003 regulatory period by $37 million and to date within the 2009 regulatory period has underspent its capital allowance by $28 million (largely due to the Waddamana-Lindisfarne project being delivered under budget).**

- **Transend overspent its operating expenditure allowance in the 2003 regulatory period by $28 million and to date within the 2009 regulatory period has underspent its operating expenditure allowance by $3 million.**

---

61 However, provided it is found by the regulator to have been warranted, capital expenditure in excess of the regulatory allowance impacts on customer prices as overspend is included in the opening regulated asset base of the next regulatory period.

62 For drivers of capital expenditure refer Section 2 of Part 2 of this Paper.

63 For drivers of operating expenditure refer Section of Part 2 of this Paper.

64 For drivers of capital expenditure refer Section 3 of Part 2 of this Paper.

65 For drivers of operating expenditure refer Section 3 of Part 2 of this Paper.
As there are adverse consequences for financial performance from consistent overspending in this way, it will be important to ensure in future that the network businesses operated within allowances approved by the regulator. The Panel notes that the Shareholders’ most recent letters of expectation to the Boards of the network businesses have identified this as a requirement.

4.6. Major financial obligations

Each of the SOEBs has major fixed financial obligations in addition to debt and unfunded superannuation liabilities.

4.6.1. Transend:

Following the 2011-12 State Budget, an equity transfer to TasRail totalling $100 million - $20 million per annum for five years - is included in the forward estimates in order to relieve that business’ equity burden on the Consolidated Fund. Based on the analysis of Transend’s use of cash from operations to fund capital expenditure, it is probable that this equity withdrawal will be funded through increased borrowings. This draw on equity is in addition to the Government’s previous decision to rebalance equity across the portfolio via a debt swap from Hydro Tasmania to Transend ($220 million) and to withdraw equity in Transend ($50 million) in 2008 which was also provided to Hydro Tasmania.

Transend’s increased interest costs on this debt, against which no new income is generated, will directly impact financial performance and consequently dividend returns to Shareholders. It will, however, have no impact on electricity prices.

4.6.2. Aurora Energy:

As discussed previously, the TVPS is the most immediate issue in the SOEB portfolio. The TVPS current financial viability is supported by the regulated energy allowance for non-contestable customers and Aurora Energy’s contractual arrangements with Hydro Tasmania. There is no certainty of these arrangements beyond the current regulatory period (ending at 30 June 2013), although the Price Control Regulations provide the Treasurer with the ability to maintain the existing arrangements. The overall debt associated with the TVPS is a key risk should the current contractual and regulatory arrangements not continue beyond the current regulatory period.

Aurora Energy also has large fixed cost financial obligation relating to its commercial gas arrangements.

4.6.3. Hydro Tasmania:

Hydro Tasmania’s ability to fund its Basslink Services Agreement (BSA) relies in part on the arbitrage of energy sales and purchases to other NEM regions. Hydro Tasmania’s ability to generate this arbitrage revenue under the BSA in this manner is influenced by:
the volume of generation in Tasmania, which is a function of water storages;

- electricity price differences between the Tasmanian and Victorian regions; and

- the differences between peak and off-peak prices in Victoria as this drives the value of arbitrage opportunities.

This arbitrage opportunity involves Hydro Tasmania holding back generation of electricity at times of low prices in Victoria, allowing cheap electricity to flow southward as a substitute for on island generation, and then later at times of high Victorian prices generating that same volume and selling it into Victoria, thus achieving higher value from Tasmanian hydro generation. This opportunity is a key component of the Basslink business case.66

4.6.4. Diversification activities and operation in national/international markets

In general terms, the performance to date by the diversified business activities undertaken by Hydro Tasmania and Aurora Energy has meant that those investments have failed to deliver material free cash flows and, consequently, dividend returns to Shareholders.

In terms of capital invested, the largest financial investment within the SOEB portfolio, Hydro Tasmania’s investment in wind assets (of which $96 million67 of direct equity has been expended to date), is yet to return any positive cash flow back to the Tasmanian community. Following the dissolution of the Roaring 40s JV with CLP, Hydro Tasmania has recently announced its intention to sell-down the Woolnorth wind farm assets. It is this process that will determine the level of cash return on Hydro Tasmania’s previous investment. Similarly, Hydro Tasmania’s investment to date in the Musselroe wind farm will not be realised until that project is completed.68

The distribution of returns from Hydro Tasmania should be a matter of fundamental interest for its ultimate Shareholders, the Tasmanian community. This is a potential source of value that can be used to redress structural issues within the TESI, provide a source of funds for public capital spending by the Tasmanian Government in a budget constrained environment or be reinvested by Hydro Tasmania on value creating activities. Hydro Tasmania has announced that the proceeds of the sale of Woolnorth will be utilised to fund its new wind development model with the “divestment of a stake of up to 75 per cent in Woolnorth will assist with the construction of the Musselroe wind farm and progress ongoing wind plans both in Tasmania and on mainland Australia.”69

---

67 Of which $50 million was provided as an equity contribution from the Government.
68 On 6 December 2011 Hydro Tasmania announced that the Musselroe wind farm would proceed with construction expected to be completed by July 2013. Hydro Tasmania is in the process of seeking an equity partner in its Woolnorth wind farm and this partner will also have the opportunity to take an equity position in the Musselroe wind farm.
69 Hydro Tasmania’s 2011 Annual Report.
A clear strategic or policy link to the core purpose of public ownership would provide a more transparent basis for resolving the tensions inherent between investment in business diversification activities and the opportunity cost of that capital that could be invested or utilised elsewhere for the benefit of the community.

Resolution of tensions of this kind would be greatly assisted by the establishment of a well-articulated rationale for public ownership to guide key decisions such as the reinvestment of equity within the portfolio and the split of that investment between functional business activities and diversification activities. This matter is further addressed in the Panel’s Draft Report and in the accompanying Information Paper ‘Governance: Issues and Reform’.
PART TWO
5. Hydro Tasmania

5.1. Scope of business operations

Prior to 1998, the Hydro-Electric Commission (HEC) operated as a statutory monopoly with responsibility for all aspects of the electricity supply industry. The Electricity Companies Act 1997 (Tas) provided for the establishment of State-Owned-Companies (SOC) in respect of transmission, distribution and retailing of electricity in Tasmania. On 1 July 1998, the HEC was structurally disaggregated into three separate businesses: generation and system control (Hydro Tasmania); transmission (Transend) and distribution and retail (Aurora Energy). System control subsequently transferred to Transend on 1 July 2001.

Hydro Tasmania is a wholly owned Government Business Enterprise (GBE), established under the Hydro-Electric Corporation Act 1995 and the Government Business Enterprises Act 1995. Hydro Tasmania is responsible to the Treasurer and its Portfolio Minister, the Minister for Energy.

Hydro Tasmania’s business operations are diverse and cover a range of activities across the electricity supply chain:

- Generation assets are, for the most part, comprised of Tasmania’s hydro-generation system of 30 power stations located across six high-rainfall water catchments formed around natural river systems. Additionally, Hydro-Tasmania owns wind generation assets which currently include wind farms and development sites located in Tasmania, Victoria and New South Wales, but have previously included assets located in South Australia and international markets.

- Hydro Tasmania is an energy trader in the National Electricity Market (NEM) and has customers both in Tasmania and other NEM regions.

- Its retail business, Momentum Energy Pty Ltd (Momentum), is located in Melbourne with customers in Victoria, South Australia, Queensland, the ACT and New South Wales. Hydro Tasmania is currently prevented from retailing electricity in Tasmania (other than the Bass Strait Islands) due to legislative constraints based on competition requirements.

- Hydro Tasmania’s consulting services business, Entura, operates locally, nationally and internationally, providing engineering services to clients in the power, water and environmental services fields; and on a reducing basis to Hydro Tasmania.

---

70 In 1995, the Hydro-Electric Commission was corporatised and was renamed the Hydro-Electric Corporation which currently trades as Hydro Tasmania.
5.2. Key events impacting the financial performance

Figure 35 below illustrates the key events in history of Hydro Tasmania post-disaggregation that have influenced the performance of the business.

Figure 35 - Key events influencing Hydro Tasmania's Financial Performance

The outcome of the Gordon below Franklin debate in the late 1970s and early 1980s effectively signalled the end to the development of new major hydro generation capacity in Tasmania. Around the same time, at the national level, the electricity sector was subject to significant competition reform initiatives. Combined, these led to the Tasmanian Government’s 1997 Energy Strategy\(^\text{72}\) which changed the landscape of the Tasmanian energy sector and has been the primary driver of Hydro Tasmania’s business direction and focus since 1998.

For Hydro Tasmania, the broader market benefits of greater competition and customer choice for energy in Tasmania gave rise to changes in business risk. These new risks come on top of managing hydrological inflows and the possible stranding of energy in a constrained market from the loss of a large industrial load which have been key risks to the business for a long time. Tasmania’s participation in the NEM also provided the stimulus for the pursuit of business opportunities outside Tasmania.

Consequently, Hydro Tasmania’s business strategies between 1998 and 2011 have been based on leveraging advantage (market and knowledge) to manage risk and the pursuit of value creating opportunities in the NEM and internationally.

Following the end of dam construction, Hydro Tasmania’s consulting business, now trading as Entura, was retained to provide operation and maintenance services to the existing hydro-generation assets and provide engineering services to other SOEBs. Subsequently, Hydro Tasmania utilised its engineering capacity for the development of wind farms. Hydro Tasmania has an ongoing strategy to diversify Entura’s revenue base away from Hydro Tasmania including into national and international markets. To this end, in 2011, services provided to Hydro Tasmania comprised 28 per cent of Entura’s total revenue compared to 68 per cent in 2004.

The commissioning of the Tasmanian Natural Gas Pipeline (TNGP) in 2002\(^\text{73}\) resulted in on-island energy and (eventually) electricity generation competition.\(^\text{74}\) Without an alternative market, Hydro Tasmania risked stranded load as a result of a large industrial load leaving the State. This provided the impetus for Hydro Tasmania’s pursuit of the Basslink interconnector. Basslink also provides Hydro Tasmania with an additional source of value through arbitrage.

---


\(^\text{73}\) The Tasmanian Natural Gas Pipeline was underwritten in part the Bell Bay Power Station as a foundation customer-supported by off-take agreements with Hydro Tasmania.

\(^\text{74}\) With the introduction of the TNGP, the Bell Bay Power Station drought support capacity was converted from oil to gas. It was anticipated that Unit 2 would be repowered to a 220MW combined cycle gas turbine and operated competitively in the market. As an alternative Alinta developed a new proposal to construct what is now the Tamar Valley Power Station, owned and operated by Aurora Energy.
Hydro Tasmania’s initial basis for building wind farms in Tasmania (Woolnorth and Studland Bay) was to secure additional on-island generation capacity following the end of dam construction. Subsequently, Hydro Tasmania developed wind assets in the national and international markets (under its joint venture arrangement with CLP) as a value strategy not related to energy supply in Tasmania. Hydro Tasmania’s current wind strategy is secure RECs to support its retail business growth.

With the commissioning of the TVPS in 2009, and to the extent that Aurora Energy utilises the power station to its back non-contestable customer load, Hydro Tasmania has excess capacity in Tasmania, where the predicted load growth is low. This is a similar risk Hydro Tasmania faced with the TNGP and the proposed redevelopment of the BBPS with additional gas generation capacity. Hydro Tasmania’s retail strategy, through its acquisition of Momentum, is to capture the wholesale and retail value of excess generation capacity in Tasmania on the basis that the NEM wholesale energy market liquidity is dominated by a few large integrated rival energy businesses.

That is, Hydro Tasmania has taken the view that there is sufficient market risk to the value of its energy that it needs to secure its own retail load to capture the full value of its energy. On this basis, Momentum is about increasing value to the Shareholder. As previously discussed, the current wind strategy is linked to Momentum’s availability and price risk of securing the necessary RECs for its retail load. In the medium term, Hydro Tasmania has indicated that it is investigating gas generation opportunities on the mainland to back retail sales and to diversify revenue streams.\(^{75}\)

Hydro Tasmania’s current strategy is about building value, a significant move from 2004 where the focus was clearly on providing energy to Tasmanian customers and using Basslink to mitigate the stranding risk of on-island generation. Hydro Tasmania is now seeking to be a material participant in the NEM based on a retail growth strategy of achieving 15,000 GWh of total sales (both to wholesale customers such as Aurora Energy and through Momentum retail sales) by the end of 2014.

In addition to market changes, the review period included a period of extreme hydrological significance, described by Hydro Tasmania as a ‘1:1000 year event’ of low inflows. Water storages fell to historic lows of 19 per cent across 2007 and 2008.

Figure 36 illustrates Hydro Tasmania’s water storages (as at 30 June) compared to Hydro Tasmania’s preferred operating zone is a storage system level between 30 and 50 per cent full.

\(^{75}\) Hydro Tasmania annual report 2011.
Historically, the Tasmanian Government’s highest priority for Hydro Tasmania has been its responsibility for maintaining the reliability of electricity supplies for the Tasmanian customers. Although statutory enactment of this obligation was repealed when Tasmania adopted NEM arrangements in 2005, Hydro Tasmania was only formally released from this priority by its Shareholders when the TVPS was commissioned in October 2009. Combined with additional generation available in Tasmania through the TVPS resulting in loss of market share to Hydro Tasmania, this has provided the opportunity for a more aggressive mainland business plan.

---

76 Hydro Tasmania’s Ministerial Charter still requires it to manage prudently its water storages consistent with advised long run energy capability.
5.3. Summary of Financial Results 2004 to 2010

A summary of Hydro Tasmania’s key financial results for the period 2004 to 2010 are set out in Table 6 below.

Table 6 – Hydro Tasmania’s key financial results 2004 to 2010

<table>
<thead>
<tr>
<th></th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Revenue(^1)</td>
<td>440</td>
<td>462</td>
<td>467</td>
<td>489</td>
<td>466</td>
<td>626</td>
<td>726</td>
</tr>
<tr>
<td>Electricity Revenue(^2)</td>
<td>378</td>
<td>399</td>
<td>406</td>
<td>446</td>
<td>408</td>
<td>553</td>
<td>688</td>
</tr>
<tr>
<td>EBIDTA(^3)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total revenue</td>
<td>237</td>
<td>250</td>
<td>210</td>
<td>180</td>
<td>105</td>
<td>201</td>
<td>236</td>
</tr>
<tr>
<td>EBIDTA/ Total revenue</td>
<td>54%</td>
<td>54%</td>
<td>45%</td>
<td>37%</td>
<td>23%</td>
<td>31%</td>
<td>32%</td>
</tr>
<tr>
<td>Gross Debt(^4)</td>
<td>1,081</td>
<td>1,212</td>
<td>1,077</td>
<td>1,192</td>
<td>971</td>
<td>941</td>
<td>873</td>
</tr>
<tr>
<td>Capital Expenditure</td>
<td>135</td>
<td>105</td>
<td>128</td>
<td>54</td>
<td>55</td>
<td>81</td>
<td>96</td>
</tr>
<tr>
<td>Dividends Paid - ordinary</td>
<td>17</td>
<td>23</td>
<td>32</td>
<td>21</td>
<td>0</td>
<td>0</td>
<td>5</td>
</tr>
<tr>
<td>Dividends Paid - special</td>
<td>27</td>
<td>17</td>
<td>8</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Equity Transfer(^6)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>270</td>
</tr>
</tbody>
</table>

Source: Hydro Tasmania annual reports

\(^1\) Total revenue includes revenue from electricity sales, consulting services, the Bass Strait Islands CSO, Momentum sales revenue and other revenue.

\(^2\) Electricity revenue represents Hydro Tasmania’s revenue from electricity generation and trading.

\(^3\) Includes electricity, RECs, environmental products and ancillary services. Source: Hydro Tasmania annual reports.

\(^4\) EBIDTA in 200, 2008 and 2009 are impacted by reduced generation as a result of the drought and increased costs of sales due to the operation of the Bell Bay Power Station and energy purchases from the NEM to meet contracted load. Source: Panel analysis.

\(^5\) Gross Debt includes amount due to Transend. Source: Hydro Tasmania annual reports.

\(^6\) Dividends paid between 2004 and 2006 reflect a policy of extracting special dividends from Hydro Tasmania, which reflected a withdrawal of equity.

\(^6\) Equity transfer from Transend effectively resulted in a debt swap of $220 million and an equity contribution of $50 million.
Figure 37 illustrates Hydro Tasmania’s electricity sales compared to station output over the period 2004 to 2010.

**Figure 37 - Hydro Tasmania’s electricity sales to Tasmanian customers and station output 2004 to 2010**

Over the review period, electricity sales to Tasmanian customers increased from $356 million in 2004 to $454 million in 2010, an increase of 28 per cent, through a combination of an increase in total demand and price growth (refer section 5.4 below). Over the same period, Hydro Tasmania’s level of generation was strongly influenced by a sustained low inflow period in 2007 and 2008 and the consequential ‘de-rating’ of the hydro system from 10,200 to 9,500, 9,000 and 8,700 GWh progressively.

Largely as a result of drought conditions, EBITDA reduced between 2006 and 2008. During this period, Hydro Tasmania was a net purchaser of energy from the market (via Basslink), although it still achieved revenue in the order of $60 million over this period in arbitrage opportunities.\(^{77}\) The decrease in margin indicates that Hydro Tasmania was unable to pass on to customers the majority of additional costs arising from these conditions. The financial cost was reflected in decreased earnings and consequently lower returns to the Shareholders through dividends.

---

\(^{77}\) Arbitrage refers to the use of Basslink on a balanced trade basis, where electricity is effectively purchased from Victoria at low prices (i.e. water is conserved by Hydro Tasmania) and at a later time is sent from Tasmania when prices are high (that conserved water used). The difference in value between the high and low periods is the arbitrage value of Hydro Tasmania’s generation flexibility.
5.4. Hydro Tasmania’s Role as the Main Source of Generation in the Tasmanian Market

Prior to the existence of large-scale alternative electricity sources (Firstly Basslink in 2006 and then TVPS in 2009) and the introduction of retail contestability, Hydro Tasmania effectively met the full energy requirements of all Tasmanian market participants, broadly defined into three groups, Major Industrial (MI) customers, commercial and industrial customers; and business and residential customers (via its contractual arrangements with Aurora Energy’s retailing business).

With the development of alternative generation, the proportion of total Tasmanian demand met by Hydro Tasmania contracts has decreased over time. However, in 2010, Hydro Tasmania still sold load representing 76 per cent of total demand in the Tasmanian market. With the roll-out of retail contestability, most customer groups have transitioned to being contestable customers (MIs, commercial and industrial customers, and more recently business customers), meaning that Hydro Tasmania’s contractual arrangements have diversified to include new entrant retailers in addition to Aurora Energy.

Figure 38 illustrates changes to the Tasmanian generation profile between 2004 and 2010 – noting that in 2004 gas related to the BBPS and in 2010 gas related to the TVPS
5.4.1. Overall performance of the energy business 2002 to 2010

Hydro Tasmania characterises its energy business as its ‘cash engine’. Key drivers of financial performance have been new market opportunities outside Tasmania facilitated by Basslink, the impact of hydrological conditions and changes in Tasmanian load demand and contract prices across customer groups.

Impact of hydrological risk and Basslink

Tasmania’s adoption of NEM arrangements, facilitated by the Basslink interconnector, resulted in changes to the way Hydro Tasmania manages its energy capability.

The value of hydro-generation has also been positively influenced by the arbitrage opportunity derived from Hydro Tasmania holding back generation of electricity at times of low prices in Victoria, allowing electricity to flow southward as a substitute for on island generation, and then later generating that same volume and selling it into Victoria at higher value. Because Hydro Tasmania is active in both the Tasmanian and Victorian spot markets, the differential between these markets will impact on financial performance.

The margin on energy revenue dipped in 2007 and 2008 as a consequence of extreme hydrological conditions in Tasmania which resulted in reduced hydro-generation capacity. Limited generation volume had the combined effect of requiring Hydro Tasmania to purchase energy from the market to fulfil customer contracts and limited its opportunity to utilise Basslink for arbitrage. Moreover, it did not provide opportunity for generation to support net northward flows and impacted negatively on the production of REC revenue.

The majority of the combined costs of the drought and Basslink imports were not passed onto customers, who had contractual cover that spanned the dry period. The financial cost of these events is therefore reflected in decreased earnings and consequently, through lower dividends paid to the Shareholders over the period 2007 to 2010.

---

78 Hydro Tasmania annual report 2006.
79 The Panel has released a separate paper on the Basslink business case and operational performance.
80 A small number of contestable customers who recontracted towards the end of the drought period did see higher prices as a result of the drought and non-contestable customers paid a $3/MWh drought premium for the period of the 2007 price determination.
81 Note that dividends paid in 2010 were in respect of the 2009 financial year.
**Major Industrial Contract Revenue**

Hydro Tasmania serves Tasmania’s four largest energy demand customers, known as the MI customers.\(^2\) In 2010, MI contracted load comprised approximately 55 per cent of Hydro Tasmania’s total contracted load. Notwithstanding some year-on-year fluctuations during the review period, MI contract load as a proportion of total contracted load has remained relatively consistent at that level. MI customer revenue makes a material contribution to Hydro Tasmania’s revenue at around 40 per cent in 2010.

Throughout the review period, contract prices for MI customers have increased steadily as contracts have been re-negotiated at market prices reflective of those loads, but still remain the lowest of the three customer groupings. Increasing the value achieved from MI customers was an important aspect of Hydro Tasmania’s business case for Basslink as it provided a credible alternative path to market for electricity supplied to MI customers.

Ascribing the commercial value of MI customers to Hydro Tasmania is typically more complicated than for other customers as customer value to Hydro Tasmania is more than the electricity price contained in the electricity supply contracts. The very flat and predictable nature of the MI customers is also a significant factor in pricing.\(^3\)

An important source of value to Hydro Tasmania is MI customer participation in the Basslink load tripping system. This scheme allows Basslink’s southward flows to be operated at higher capacity than otherwise, creating greater arbitrage opportunity for Hydro Tasmania.

The prices paid by MI customers for wholesale energy reflect robust commercial negotiations between Hydro Tasmania and their counterparties, with pricing outcomes representing a tension between what the customers are willing to pay setting the maximum of the ‘bargaining arena’ and the opportunity value of the electricity to Hydro Tasmania setting the lower band. The Panel is satisfied that there are no cross subsidies between regulated customers and MI customers in relation to wholesale energy. Further information on MI customer pricing is contained in the Panel’s Draft Report.

---

\(^2\) The Panel understands that Hydro negotiates directly with these large customers in relation to wholesale contracts, which are then transferred to a retailer to be the counterparty to Hydro. This is different to the arrangements for smaller customers, who generally seek to negotiate contracts with retailers, who separately negotiate wholesale energy contracts to back these retail positions.

\(^3\) The pricing for MI customers is structured differently to that of other customers as the MI customers consume energy in a very even and daily seasonal pattern. The balance of Tasmania’s demand varies drastically so that peak demand can be twice that experienced at low demand periods. Therefore, MI customers utilise assets used to supply them almost 100 per cent of the time, while other demand requires vast volumes of capacity to be available that is only used for short periods.
Non-Contestable Contract Revenue

Non-contestable contract revenue is revenue derived from Aurora Energy in relation to volume contracted to cover Aurora Energy’s regulated customer load requirement (non-contestable customers).

Historically, non-contestable contract revenue has been an important revenue source for Hydro Tasmania’s energy business. For the period of the 2007 price determination (2007 to 2010), the energy price included in the contract arrangements between Hydro Tasmania and Aurora Energy moved in line with the higher energy allowance set in the pricing determination.

Notwithstanding this, Hydro Tasmania’s non-contestable customer contract revenue decreased from $203 million in 2007 to $173 million in 2010. The decline in contract revenue was driven by a 33 per cent reduction in Hydro Tasmania’s contracted load volume for non-contestable customers over that period. This was due to the phased introduction of retail contestability beyond tranche 2 (large industry customers) and by a reduction in load contracted with Aurora Energy to meet its non-contestable customer requirements.

For the period of the 2010 price determination (2010 to 2012), Hydro Tasmania’s non-contestable contract revenue will further decline as a result of both price and load. In 2011, revenue decreased to $99 million (a reduction of $74 million from 2010) and load reduced a further 38 per cent. Aurora Energy’s utilisation of the TVPS to back its non-contestable customer load means that it is only required to source around one half of its non-contestable customer load requirements from Hydro Tasmania. Further, the net effect of the contract arrangements between Hydro Tasmania and Aurora Energy is that the average price per MWh received by Hydro Tasmania is below the wholesale energy cost allowance set in the 2010 price determination.

Because the wholesale energy allowance determined for non-contestable customers has been typically higher than prevailing market prices for contestable and MI customers, energy prices for the non-contestable load are the highest paid in the Tasmanian market and are higher than the average energy price paid by contestable customers.

As a result, Hydro Tasmania earns a higher energy margin on the supply of the non-contestable load than from other customer groups.

---

84 In March 2007, supporting Alinta’s construction of the TVPS, Aurora Energy entered into a long term hedge arrangement to support Aurora Energy’s non-contestable customer load requirements following the commissioning of the power station in 2009. This resulted in Aurora Energy sourcing less of the non-contestable customer load from Hydro Tasmania.

85 Even in a non-regulated environment (i.e. market based pricing), prices paid by non-contestable customers would be expected to be higher for reasons. In particular, the load profile for household customers is very peaky and sensitive to low temperatures requiring capacity to be available that is only used for short periods.
Other Contracts (Contestable Customers)

Beginning on 1 July 2007, retail contestability has been progressively rolled out to eligible customers based on annual power consumption. Contestable customer contract revenue for Hydro Tasmania includes revenue from Aurora Energy and other retailers licensed to operate in the Tasmanian market.

Contestable customer contract revenue has increased steadily from $39 million in 2007 to $93 million in 2010 driven by both an increase in load and average contract price. On average, energy prices to contestable customers are above prices to major industrials and below prices to non-contestable customers.

The pricing framework used by Hydro Tasmania for setting wholesale customer contracts is described more fully in the Panel’s Draft Report. In brief, these prices are set between Hydro Tasmania’s valuation of its water, which is referenced to Victorian contract prices, and its estimate of the LRMC of new entry in Tasmania.

5.5. Diversification of Business Activities86

The increase in the scope of Hydro Tasmania’s operations has resulted in an increase in the financial complexity of the business. With the future retail growth strategy, this is expected to continue. Over the financial review period, the key financial flows have been:

- Internal revenue generated by Entura in relation to work completed for Hydro Tasmania (hydro-generation and wind development). The value of internal revenue has been a significant proportion of Entura’s revenue, particularly through years where external work has been difficult to secure;

- Payments made in relation to Roaring 40s wind farm asset development, and direct cash investment (equity) in the Roaring 40s JV. Hydro Tasmania also has an off-take agreement for energy and RECs on the Waterloo wind farm, previously owned by Roaring 40s; and

- Wholesale energy pricing between Hydro Tasmania and Momentum.

5.5.1. Entura - 2002 to 2010

Entura is Hydro Tasmania’s consulting business that currently provides services to global power, water and environmental markets. Entura operates on a stand-alone basis and has offices in Hobart, Melbourne, Brisbane and New Delhi, India. The Australian operations of Entura are operated as a division rather than a separate legal entity to Hydro Tasmania. Hydro Tasmania Consulting (Holdings) Pty Ltd is a wholly owned subsidiary of Hydro Tasmania established to hold the shareholding of the Indian consulting company.

---

86 Activities considered non-core within the Review financial analysis process may be considered to be core within the SOEBs operations.
Historically, internal revenue, generated through the provision of services to Hydro Tasmania’s generation business, has been a key component of Entura’s total revenue. Internal revenue has decreased from 68 per cent in 2004 to 39 per cent in 2010 and is forecast to decrease further with business expectation that an increasing proportion of revenue is to be sourced from work in the national and international markets.\textsuperscript{87}

Figure 39 illustrates Entura’s revenue by customer segment for the period 2004 to 2010.

Figure 39 - Entura’s revenue by customer segment 2004 to 2010

Since 2002, Entura has made an EBITDA contribution to Hydro Tasmania of between $1 and $4 million per annum up to 2009, with a loss of $4 million recorded in 2010 associated with a substantial downturn in activity across the engineering consulting sector during and after the GFC. In general terms, increased revenues have been offset by increased expenses, particularly labour costs, which are a key driver of earnings. Labour costs rose by 59 per cent between 2004 and 2010. Prima facie, over the review period it appears that Entura’s operating results reflect a reliance, albeit diminishing, on internally generated revenue from Hydro Tasmania as the financial growth opportunities from external sales anticipated at disaggregation have been slow to eventuate.

\textsuperscript{87} Hydro Tasmania has advised that internal revenue has fallen to 28 per cent in 2011.
Over the past five years, there has been an emphasis on moving from an internal service focus to an external focus through diversification of markets (Tasmania, nationally and internationally); and regions (Australia, the Asia Pacific, including Malaysia, India and Papua New Guinea; and Southern Africa).

There has been a clear transition of this segment of Hydro Tasmania’s business operations from engineering services fundamental to the construction and maintenance of electricity infrastructure in Tasmania, to the provision of services predominantly to other market participants in markets unrelated to Hydro Tasmania’s own hydro-generation operations.

While Entura’s financial results have not materially affected Hydro Tasmania’s financial position, there is likely to be significant additional business and financial risk from operating in emerging international markets rather than in the Tasmanian or national market. Beyond standard risks, operating internationally introduces currency risk and insurance risk associated with the local operating and political environment. Entura will also need to compete in a field dominated by a few large global firms.

5.5.2. Roaring 40s (Hydro Tasmania’s Wind Generation Development Vehicle) 2002 to 2010

In response to national policy incentives aimed at growing Australia’s renewables base and to utilise and market its engineering capability, in early 2000 through its subsidiary company Roaring 40s Renewable Energy Pty Ltd (Roaring 40s), Hydro Tasmania commenced the development of a large scale wind farm at Woolnorth.

In 2005, based on Hydro Tasmania’s perceptions of the future opportunities for wind development in Australia, and its desire to grow value in this part of its business, Hydro Tasmania’s wind strategy shifted from direct investment in wind farm assets in Tasmania and Australia, to growth opportunities in the Asia region with a Joint Venture (JV) partner. Hydro Tasmania realised part of its equity in Roaring 40s through a JV arrangement with China Light and Power (CLP) in 2006. The Roaring 40s JV invested in assets both within Australia (on-island and mainland) and internationally (China and India). Following the sale of Roaring 40s JV international assets (China and India) to CLP in 2009, the Roaring 40s JV was dissolved in 2011.

Table 7 below illustrates Hydro Tasmania’s carrying value in the Roaring 40s JV since inception in 2006.

Table 7 - Hydro Tasmania’s Carrying Value in the Roaring 40s JV

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beginning carrying value</td>
<td>85</td>
<td>80</td>
<td>88</td>
<td>108</td>
<td>122</td>
</tr>
<tr>
<td>Equity contribution</td>
<td>-</td>
<td>10</td>
<td>23</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>Share in operating profit (loss)</td>
<td>(5)</td>
<td>(1.9)</td>
<td>(2.7)</td>
<td>4.4</td>
<td>(6)</td>
</tr>
<tr>
<td>End carrying value</td>
<td>80</td>
<td>88</td>
<td>108</td>
<td>122</td>
<td>121</td>
</tr>
</tbody>
</table>

Source: Hydro Tasmania annual report
The Roaring 40s JV has required significant cash investment from Hydro Tasmania to fund capital investment in renewable energy assets. Revenue generated from the wind assets includes generation sales and revenue from the sale of RECs. In 2009, the Roaring 40s JV returned a small profit after tax of $4 million. However, it has returned losses in all other years. Hydro Tasmania has not received any dividend payment from the Roaring 40s JV.

The opening value of Hydro Tasmania’s 50 per cent equity share of the JV in 2006 was $85 million. This increased by $41.8 million or by 52 per cent between 2006 and 2010. However, annual increases in carrying amounts have been driven by annual equity contributions totalling $48 million, offset by share in total operating losses of $11.2 million.

The Roaring 40s JV was disaggregated on 30 June 2011, resulting in the distribution of mainland assets to CLP and the retention of Tasmanian assets, including development sites by Hydro Tasmania. In September 2011, Hydro Tasmania announced the next stage of its wind farm development model, which includes the intention to sell 75 per cent of the Woolnorth wind farm assets and for those funds to be reapplied to further wind developments that accompany Hydro Tasmania’s strategy of retail growth. Hydro Tasmania’s underlying value in its wind farm investments will be determined through any sale process, rather than on the carrying value of its share of the joint venture dissolution.

Hydro Tasmania’s view is that it anticipates a material financial benefit from the sell-down process, which it will apply to develop further wind farms without the need for additional Shareholder equity.

5.5.3. Momentum - 2008 to 2010

Momentum is Hydro Tasmania’s retail arm that offers energy contracts, energy efficiency advice and GreenPower products sourced from wind generation. Momentum is based in Melbourne and specialises in business customers located in Victoria, South Australia, Queensland, the ACT and New South Wales. Momentum does not have a retail licence to operate in the Tasmanian market and is prevented from gaining one due to legislative constraints based on competition requirements.

Hydro Tasmania’s strategy to acquire a retail presence in the NEM was primarily based on defensive positioning, in the context of continuing consolidation in the energy sector; and revenue growth through direct access to customers leveraging Hydro Tasmania’s renewable brand. More recently, with the decrease in non-contestable customer load due to the operation of the TVPS in the Tasmanian market, Hydro Tasmania has ‘excess’ physical generation capacity which is effectively utilised to back Momentum load in the short term.

---

88 Hydro Tasmania’s JV share of the Asia asset sale was $81.8 million ($66 million from China portfolio and $15.5 million from India wind farm) on an investment of $67.8 million. This equity was retained in the JV for investment in renewable energy projects in Australia and not returned to Hydro Tasmania.
Momentum has energy supply agreements with Hydro Tasmania. Hydro Tasmania uses excess load generation/supply in Tasmania to back Momentum through northward capacity on Basslink and through direct participation in the contracts market in other NEM regions.

Hydro Tasmania’s retail strategy is to achieve total sales of 15,000 GWh by growing Momentum’s retail business sales to at least 5000 GWh by 2014, in addition to its Tasmanian-based business. As Momentum’s targeted load growth is realised, this growth is significantly in excess of Hydro Tasmania’s current generation capacity and Hydro Tasmania has noted that “any growth created from new investment will be capital intensive and it will be necessary to explore innovative methods of raising capital”.\(^89\) In its 2011 annual report, Hydro Tasmania has indicated the investigation of gas generation opportunities on the mainland to back retail sales.\(^90\)

Hydro Tasmania purchased an initial 51 per cent share in Momentum in September 2008 for $17 million and the remaining 49 per cent in October 2009 for $35 million (total acquisition cost $52 million).

Since part-acquisition in 2008, Momentum made net losses of $14.3 million in 2009 and $1.4 million in 2010. The Momentum business is emerging from its start-up phase, reflecting underlying business performance which has improved with sales revenue increasing 79 per cent (or $50 million) from $64 million in 2009 to $114 million in 2010 due to a growth in customer numbers. Over the same period, load sold has increased by 81 per cent. Acquisition and marketing costs in obtaining new customers has impacted on profit in the limited trading period since acquisition which is not unexpected.

Hydro Tasmania has advised the Panel of further improvements in business performance in 2011, with sales revenue increasing by 115 per cent (or $131 million) from 2010. In 2011, Momentum made a net profit of $0.8 million. Momentum’s financial performance is included in Hydro Tasmania’s consolidated accounts, meaning that dividends payable in respect of 2011 will include net profit attributable to Momentum.

\(^{89}\) Hydro Tasmania annual report 2010.
\(^{90}\) Hydro Tasmania annual report 2011.
6. Aurora Energy Pty Ltd

6.1. Scope of business operations

Aurora Energy Pty Ltd (Aurora Energy) was formed on 1 July 1998, from the disaggregation of the then Hydro-Electric Commission (now trading as Hydro Tasmania).

Aurora Energy is a wholly owned State-owned Company (SOC), established under the Electricity Companies Act 1997 and is incorporated under the Corporations Act 2001 (C’wth). The Company’s shares are held in trust for the Crown by its Shareholder Ministers, the Minister for Energy and the Treasurer.

Aurora Energy is a vertically integrated energy company with operations in Tasmania and other regions of the NEM. Specifically, Aurora Energy:

- Retails electricity to customers in Tasmania, New South Wales, South Australia, the ACT and Queensland; and gas to customers in Tasmania and Victoria;
- Trades wholesale gas in Tasmania and other jurisdictions;
- Owns and operates the TVPS through its subsidiary company AETV and has dispatch rights over the Bairnsdale power station in Victoria; and
- Owns and operates the electricity distribution network in Tasmania.
6.2. Key events which have influenced financial performance

Figure 40 illustrates the key events in the history of Aurora Energy since disaggregation which have influenced the financial performance of the business.

Since disaggregation, the Tasmanian Economic Regulator has undertaken three regulatory reviews to determine the Aggregate Annual Revenue Requirement (AARR) for distribution services:

- 1999 Distribution Price Determination (1 January 2000 to 31 December 2003)
- 2003 Distribution Price Determination (1 January 2004 to 31 December 2007)
- 2007 Distribution Price Determination (1 January 2008 to 30 June 2012)

Further, Aurora Energy has been subject to a number of regulatory reviews to determine the Maximum Allowable Revenue (MAR) for the retail allowance for non-contestable customers:

- 1999 Retail Price Determination (1 January 2000 to 31 December 2003)
- 2003 Retail Price Determination (1 January 2004 to 30 June 2007)
- 2007 Retail Price Determination (1 July 2007 to 30 June 2010)
- 2009 Retail Price Determination (1 July 2010 to 30 June 2013)
Following Tasmania’s adoption of NEM arrangements in May 2005, the phased roll-out of retail contestability has introduced competition into the retail market, resulting in the transition of contestable customers away from regulated retail tariffs to market-based prices and, for Aurora Energy’s retail business, a loss of market share to new entrant retailers. Aurora Energy estimates that it has retained 85 per cent of the Tasmanian contestable market. To offset this decline Aurora Energy has increased the sale of electricity in other NEM regions.\[^{91}\]

In 2008, Aurora Energy was directed by its Shareholders to acquire, complete construction; and operate the TVPS. The TVPS was commissioned in October 2009 and is currently operated to back around half of Aurora Energy’s non-contestable customer load.

Shortly after the TVPS acquisition, Aurora Energy acquired a suite of wholesale gas arrangements from Babcock and Brown Power, primarily to mitigate the risk of obtaining gas supply for the TVPS from a third party (gas supply to the TVPS formed the nexus of the contracts acquired). Consequently, Aurora Energy has commenced retail and wholesale gas sales, in both the Tasmanian and Victorian markets, and has dispatch rights over the Bairnsdale power station in Victoria.

### 6.3. Summary of financial results 2004 to 2010

A summary of Aurora Energy’s key consolidated financial results for the period 2004 to 2010 are set out in Table 8 below.

#### Table 8 - Aurora’s Key Financial Results 2004 to 2010 - whole of business

<table>
<thead>
<tr>
<th>$ million</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Revenue</strong>¹</td>
<td>643</td>
<td>692</td>
<td>717</td>
<td>790</td>
<td>876</td>
<td>994</td>
<td>1173</td>
</tr>
<tr>
<td><strong>Total Sales Revenue</strong></td>
<td>640</td>
<td>687</td>
<td>716</td>
<td>778</td>
<td>861</td>
<td>971</td>
<td>1150</td>
</tr>
<tr>
<td><strong>EBITDA</strong></td>
<td>118</td>
<td>114</td>
<td>115</td>
<td>116</td>
<td>141</td>
<td>146</td>
<td>128</td>
</tr>
<tr>
<td><strong>EBITDA / Total Revenue</strong></td>
<td>18%</td>
<td>17%</td>
<td>16%</td>
<td>15%</td>
<td>16%</td>
<td>15%</td>
<td>11%</td>
</tr>
<tr>
<td><strong>Debt</strong></td>
<td>366</td>
<td>437</td>
<td>461</td>
<td>505</td>
<td>555</td>
<td>933</td>
<td>1029</td>
</tr>
<tr>
<td><strong>Capital Expenditure</strong></td>
<td>83</td>
<td>102</td>
<td>134</td>
<td>125</td>
<td>134</td>
<td>168</td>
<td>169</td>
</tr>
<tr>
<td><strong>Investment Expenditure- TVPS</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>294</td>
<td>66</td>
<td></td>
</tr>
<tr>
<td><strong>Investment Expenditure- gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>15</td>
</tr>
<tr>
<td><strong>Dividends Paid</strong></td>
<td>14</td>
<td>14</td>
<td>12</td>
<td>10</td>
<td>11</td>
<td>10</td>
<td>10</td>
</tr>
</tbody>
</table>

Source: Aurora Energy annual reports and Panel analysis

¹Total revenue excludes Aurora Energy’s Community Service Agreement as this is a pass through cost and customer contributions.

---

\[^{91}\] Energy retail businesses have scale economies that can result in marked changes in average per customer costs. The Panel understands that Aurora Energy’s strategy of pursuing retail opportunities was to build customer numbers to spread its fixed retail costs (such as IT systems, finance and regulatory functions) and as a risk mitigation measure to preserve scale economies.
Aurora Energy’s returns (measured by EBITDA) have not kept pace with electricity sales trends, primarily due to higher costs across all components of retail pricing and, most significantly, increases in distribution and transmission network costs. Significant increases in transmission costs represent pass-through costs from Transend to Aurora Energy, resulting in a decreased margin as a percentage of sales revenue. EBITDA decline in 2010 is attributable to increased energy costs and the expensing of $21 million billing system costs.92

While generating approximately 40 per cent of total electricity revenue, Aurora Energy’s distribution business has been the main value driver of Aurora Energy’s consolidated business, contributing, on average, approximately 90 per cent of total EBITDA.

Figure 41 below illustrates the historical contribution to EBITDA by business activity.

**Figure 41 - Contribution to EBITDA by business activity 2004 to 2010**

Source: Aurora Energy

Note: Aurora Energy’s wholesale energy business (electricity and gas) did not exist prior to 2009. Network services comprises predominantly contracting activities to Transend and Ezikey is Aurora Energy’s subsidiary company that undertakes its Wirealert development and sales. Wholesale includes electricity and gas trading. AETV EBITDA is a function of the tolling arrangements between Aurora Energy and AETV.

---

92 A discussion on the circumstances influencing Aurora Energy’s energy costs in 2010 is included at Appendix 1.
6.4. Energy Business (retail and wholesale energy)³³

Figure 42 illustrates Aurora Energy’s retail sales by customer segment for the period 2004 to 2010. During this time, Aurora Energy’s retail sales moved from a Tasmanian electricity revenue base in 2004 to a significantly more diversified revenue base in 2010. Although electricity sales to Tasmanian customers remains the dominant sales segment, electricity sales in the national market contributed around 16 per cent of revenue and retail/wholesale gas sales contributed around 4 per cent of revenue in 2010.

Figure 42 - Retail sales by customer segment 2004 to 2010

Aurora Energy’s retail business, similar to its energy business, includes both regulated and non-regulated business activities. Under the Retail Price Determination, Aurora Energy receives a cost to serve allowance for regulated (non-contestable) customers. In the current Pricing Determination, the TER allowed Aurora Energy an industry benchmarked cost to serve of $95 per customer per annum, this compares to Aurora Energy’s submission cost of $105 per customer per annum. Aurora Energy’s retail business is negatively impacted by its actual cost to serve in excess of its regulated allowance.

³³ For the purposes of the presentation of analysis, the Paper separates Aurora Energy’s functional components. This presentation is different to Aurora Energy’s operational divisions where retail, wholesale energy (electricity and gas) and generation are amalgamated under the Energy Division.
In 2009 Aurora Energy commenced the development of a new customer care and billing system. Initial estimated cost of the system was $15 million but the actual cost to complete was $60 million. Of the additional cost, $32 million has been recognised by Aurora Energy as a direct expense in its profit and loss statement, of which $21 million was expensed in 2010 with a direct impact on financial performance.

6.4.1. Energy revenue and retail contestability

As Figure 42 illustrates, Aurora Energy’s Tasmanian electricity revenue has increased from $636 million in 2004 to $864 million in 2010, an increase of $228 million, or 30 per cent. Over the same period, sales in the national market increased from $0.3 million to $185 million. Aurora Energy’s energy business revenue growth in 2010 also includes AETV spot market sales and wholesale gas sales.

For the Tasmanian electricity revenue component of sales, despite revenue increasing, total load sold has decreased as a result of increased competition arising from the phased roll-out of retail contestability. Although revenue, through prices to customers, has increased, this has been largely driven by throughput costs (network, energy and RECs) and has not reflected improved retail margins.

Load

As retail contestability has been rolled-out across business customers, Aurora Energy has realised a decreasing load, primarily in the very large industrial customer market segment (Tranche 1 customers). Figure 43 illustrates Aurora Energy’s Tasmanian load by customer type over the period 2004 to 2010, showing the decline in large industrial customers since 2007 when that customer type became contestable.

For other tranche customers, Figure 43 illustrates that retail contestability has only had a minimal impact on Aurora Energy’s volume, noting that Tranche 5a, which has become contestable from 1 July 2011, and with an estimated 4000 eligible customers, may present a different result in future years.
Figure 43 - Aurora Energy’s Tasmanian load by customer type 2004 to 2010

Source: Panel analysis

Note: The decline in non-contestable business and the growth in contestable business largely reflects the roll-out of retail contestability (change in definition of customer), rather than a fundamental shift in Aurora Energy’s market share.

Retail revenue components

Over the review period, Aurora Energy realised an increase in average revenue per unit of load sold, which was a key driver of total energy business revenue. However, the increase in average revenue (or price to customers) reflects an increase in all components of retail pricing, including network costs and wholesale energy costs. While an increase in distribution network costs has benefited Aurora Energy’s distribution business, revenue growth reflects an increasing component of transmission network costs and wholesale energy costs. These negatively impact Aurora Energy’s margin of revenue over direct costs, as they are a pass-through cost to Transend and Hydro Tasmania respectively. Figure 44 illustrates total electricity sales, total electricity costs and the resulting retail margin (EBITDA) between 2004 and 2010.
6.4.2. Wholesale cost of energy

Increased energy costs have been a key driver in the negative retail margin results, particularly in 2010. In general terms, the financial analysis undertaken for the Panel indicates that Aurora Energy’s reported wholesale energy costs have consistently exceeded the proportion of total revenue allowed in the regulated price determination for non-contestable customers, negatively impacting the profitability of Aurora Energy’s retail business, and subsequently its energy business after its restructure.

The wholesale energy allowance for non-contestable customers is determined under the PCRs. In both the 2007 and 2010 price determinations, the regulated wholesale energy allowance is higher than the market cost estimate. For example, in 2011 the regulated allowance is 11 per cent higher than the market estimate, although it has been considerably higher in the past.

While the process for determining the wholesale energy allowance for regulated customers changed a number of times through the review period, prior to July 2010 the contract arrangements between Aurora Energy and Hydro Tasmania for backing the regulated customer base consistently allocated all of the value to Hydro Tasmania. Aurora Energy received no additional margin on its retail business for any ‘savings’ on the cost of wholesale energy.

---

The energy business outcome in 2010 was directly related to the operation of the TVPS though a combination of ‘take or pay’ gas contracts (which incentivised Aurora Energy to run the TVPS as a base load generator) and the nature of Aurora Energy’s contractual arrangements in place with Hydro Tasmania (refer appendix 1 of this section of the paper).

The impact of higher energy costs for Aurora Energy’s energy business was not directly felt by customers as regulated prices do not allow for changes as a result of differences in costs compared to the allowance. The additional cost of the TVPS was effectively absorbed by Shareholders (the community) through a fall in profitability and reflected in no dividend payable in respect of the 2010 financial year.

6.5. Tamar Valley Power Station

A full account of the TVPS is provided separately in the Draft Report. In brief, the project was advanced by several private sector parties and was to be underpinned by a contract between Alinta and Aurora Energy for a large portion of the output of the facility.95 The project was acquired by Babcock and Brown Power from Alinta in 2008; however due to the deterioration in the global credit market, Babcock and Brown Power found itself unable to complete the project. On the basis of energy supply security, in 2008, the Tasmanian Government directed Aurora Energy to acquire the partially completed TVPS, complete construction and operate it on a commercial basis.

The Government provided Aurora Energy $100 million in equity for the purchase, while completion costs of $260 million were debt funded by Aurora Energy. Gas supply arrangements for the TVPS formed part of the acquisition of the power station. The TVPS was commissioned in October 2009 and the power station is currently operated to back around one half of Aurora Energy’s non-contestable customer load.

In establishing its commercial arrangements for the TVPS, Aurora Energy replaced the hedge arrangement that it had previously established with Alinta (which was subsequently transferred to Babcock and Brown Power) with a tolling fee arrangement between itself and its subsidiary entity AETV, which owns the TVPS. With the acquisition of the TVPS by Aurora Energy, the power station effectively became a ‘merchant’ generator (i.e. exposed to the spot market) as Aurora Energy sat on both sides of the hedge. The tolling fee effectively transfers the rights and obligations associated with the pool income from the generation of TVPS from its holding company, AETV, to Aurora Energy.

95 In preparation for NEM entry, the Tasmanian Government submitted transition arrangements to the ACCC for authorisation under the Trade Practices Act, including a vesting contract between Hydro Tasmania and Aurora Energy for the rollout of retail contestability. In authorising this contract under the ACT, the ACCC included a requirement that from the commencement of Basslink, Aurora Energy was to source at least 10 per cent of its energy for the non-contestable customer load from an entity other than Hydro Tasmania. This provided a regulatory requirement for Aurora Energy to find an alternative supplier of contact cover in Tasmania. See the Panel’s paper ‘The Evolution of Tasmania’s Energy Sector’ available at www.electricity.tas.gov.au
The initial tolling fee in 2010, which was structured to replicate Aurora Energy’s earlier arrangement with Alinta, was insufficient to cover AETV’s operating costs and service its debt. In 2011, the tolling fee was supplemented by a second arrangement, sufficient to provide AETV with cash flows to cover its operating costs and debt obligations. Under these arrangements, AETV is forecasting positive profit before tax and the ability to repay its debt over the life of the TVPS. Importantly, the tolling arrangement effectively transfers all of the wholesale risk associated with TVPS to Aurora Energy’s energy business.

In 2010, gas commodity and transport costs comprised the majority of TVPS cost of generation. The ‘take or pay’ nature of the gas supply contract, which was put in place at the time of acquiring the power station on the basis that it was expected to operate at high capacity factors (and therefore needed a large volume of gas) incentivised Aurora Energy to continue to operate and produce electricity in 2010. However Aurora Energy’s non-contestable load requirements were largely covered by an existing hedge with Hydro Tasmania. This reflected commercial arrangements that were in place prior to the Government’s decision to have Aurora Energy acquire AETV (refer appendix 1 of this section of the paper). This resulted in AETV being exposed to spot market prices that reflected oversupply in Tasmania and resulted in the TVPS generating revenues substantially less than its costs.96

Analysis indicates that the average cost of generating using the TVPS is higher than the wholesale energy allowance and Aurora Energy’s total cost of supply for non-contestable customers is supported by the contractual arrangements with Hydro Tasmania such that Aurora Energy’s weighted average wholesale energy costs are broadly in line with the wholesale energy allowance.

6.6. Distribution Business

Aurora Energy’s distribution business is a regulated monopoly asset owner and electrical service provider, delivering approximately 24,000 km of line to approximately 225,500 domestic and 48,400 business customers. In 2010, the asset base, comprising high and low voltage overhead power lines, underground cables, distribution substations, street lights and poles was worth $1.2 billion.

Costs charged to Aurora Energy’s retail business (and other retailers servicing the contestable market) from the distribution business include charges relating to the distribution and transmission networks (transmission charges are a pass-through from Transend). The discussion in this section relates only to distribution charges.

96 From a commercial perspective, as long as spot prices are higher that the avoidable costs of operating the TVPS, Aurora Energy was better off generating than not, as it provided positive net revenues, given fixed financial obligations in relation to gas supply.
The distribution business has achieved revenue growth each year of the review period, driven by the regulatory pricing determinations. Regulated income in 2004 was $148 million increasing to $240 million in 2010, an increase of 62 per cent. The primary driver of revenue growth has been significant growth in the regulated asset base, primarily driven by capital investment. Notwithstanding revenue growth, Profit Before Tax (PBT) declined in 2006 and 2007, attributable to a decline in customer contributions, increases compared to budget for emergency fault, oil management and vegetation costs and increases in financing costs. Figure 45 illustrates regulated distribution income (DUOS) compared to other income over the 2004 to 2010 period.

Figure 45 - Distribution total income compared to PBT 2002 to 2004

Source: Panel analysis

Note: Other income includes network services and operating net PBT relates to the total distribution business.

Similar to transmission network services, regulated income is determined through a building block approach. Figure 46 illustrates the distribution business' AARR split into its building block components over the three regulatory determinations.

---

97 A more comprehensive discussion of the building block approach to regulated network income is included at Appendix 1 to the discussion on Transend's historical financial performance.
Key drivers of AARR are Return on Captial (ROC) and operating expenditure. These components are discussed in turn below.

### 6.6.1. Return on Capital

As can be seen from Figure 46, ROC is the key driver in the increase in AARR over the current and imminent regulatory control periods. Drivers of ROC are the WACC or return earned by the business, and the RAB on which WACC is applied.

**WACC**

WACC (as determined by the regulator, the AER) increased marginally from 6.61 per cent in the 2003 regulatory period to 6.64 per cent in the 2007 regulatory period. However, WACC is anticipated to increase for the period of the 2011 regulatory period (2013 to 2017). Aurora Energy has proposed a WACC of 10.33 per cent; however the AER in its draft determination has put forward a WACC of 8.08 per cent. The final WACC when determined will be applied to Aurora Energy’s total RAB.

---

98 Under the regulatory framework, WACC for distribution network service providers is determined by the AER. The AER’s WACC determination is based on an assumed capital structure having regard to general market conditions and taking into account bond rates as well as industry specific factors. For example, the current determination assumes a 60:40 debt equity ratio and a credit rating of BBB+. 
Impact of Capital Expenditure on the Regulatory Asset Base

The distribution opening RAB has increased by 59 per cent, from $726 million to $1,157 million between CY2004 and FY2010. The majority of this increase occurred due to increased capital spending during the 2003 regulatory period.

Aurora Energy’s proposal for the 2011 regulatory period (2013 to 2017) has an opening RAB of $1.5 billion. Aurora Energy is proposing capital expenditure totalling $675 million over the five-year regulatory period. The opening RAB for the final year is estimated to be $1.8 million.99

Figure 47 illustrates Aurora Energy’s actual opening RAB and WACC (2013 to 2017 forecast) over the regulatory periods, incorporating annual capex.

Figure 47 - Return on Capital components calendar year 2004 to financial year 2017

Source: Aurora Energy

Capital Expenditure

As discussed above, the impact of capital expenditure is a key driver of revenue through its impact on the regulated asset base. Figure 48 below, illustrates Aurora Energy’s actual capital expenditure compared to the regulatory allowance.

---

99 The AER in its draft determination has put forward the total forecast capital expenditure at $584 million, a reduction of approximately $139 million from Aurora Energy’s proposed capex.
Figure 49 illustrates that on an annual basis, during the 2003 regulatory period and the 2007 regulatory period to date, Aurora Energy’s actual capital expenditure exceeded its allowance in each year.\(^{100}\) However, the over-spend is more pronounced over the 2003 regulatory period, with actual capital expenditure more closely aligned with the determined allowance from the 2007 PD (years to date).

- **2003 PD**
  
  Actual capital expenditure for the 2003 regulatory period was $404 million, $179 million more than the determined allowance of $224 million. This variance was principally driven by customer connections arising from economic and population growth. Actual capital expenditure on customer connections amounted to $130 million, compared to the allowance of $53 million.

- **2007 PD**
  
  For the 2007 regulatory period to date, 1 July 2008 to 30 June 2010, actual capital expenditure of $340 million exceeds the determined allowance of $311 million by $29 million. Similar to the 2003 regulatory period, to date, actual capital expenditure on customer connections exceeds the determined allowance by $33 million. However, actual capex on system capacity is under the allowance by $20 million.

---

\(^{100}\) A more detailed account of the differences between regulatory allowances and actual expenditure can be found in the Panel’s Paper ‘Efficiency and Effectiveness of State Owned Energy Businesses’ available at [www.electricity.tas.gov.au](http://www.electricity.tas.gov.au).
In addition to the impact on ROC\textsuperscript{101}, additional capital expenditure over the determined allowance has increased actual (accounting) depreciation and interest costs, resulting in lower returns than those determined through the regulatory process. This has impacted on returns to Shareholders through dividends.

### 6.6.2. Operating Expenditure

The distribution business’ actual operating expenditure, relative to regulatory allowances, is a key driver of value creation (or erosion).

Figure 50, below, illustrates Aurora Energy’s actual regulatory operating expenditure against the determined allowance over the period 2004 to 2010.

\textsuperscript{101} Capital expenditure in excess of the regulatory allowance, so long as it is subsequently assessed by the regulator as being prudent, is included in the opening regulated asset base (RAB) for the following regulatory period. The WACC is applied to the RAB to determine the capital allowance.
Figure 50 - Annual operating expenditure comparison 2004 to 2010

Figure 51, below, illustrates that actual operating expenditure fluctuates against the allowance.

- On aggregate, actual operating expenditure for the 2003 regulatory period was $204 million, $16 million more than the allowance of $188 million. Actual expenditure on network asset management contributed to this variance, exceeding the allowance by $13 million. However, this was offset on savings on emergency response and repair of $11 million.

- For the 2007 regulatory period to date (1 July 2008 to 30 June 2010) on aggregate actual operating expenditure of $174 million is below the allowance of $176 million by $2 million.

Overall, there has been a relatively minor deterioration in financial value in Aurora Energy’s distribution business over the review period as a result of overspending of operating cost allowances, in the order of four per cent (see Figure 51).

In its 2011 regulatory proposal, Aurora Energy has forecast $340 million of regulatory operating expenditure for the five years of the regulatory period. The AER, in its draft determination has put forward a total forecast operating expenditure of $311 million, a reduction of approximately $29 million from Aurora’s proposal.

Source: Aurora Energy
6.7. Diversified Business Activities

Aurora Energy’s diversified business activities include gas wholesaling and retailing, telecommunications and the development and commercialisation of the household electrical safety device wirealert (marketed as ‘Cable PI’).

6.7.1. Wholesale and retail gas

Subsequent to the purchase of TVPS, in 2009 Aurora Energy made a separate commercial decision to purchase the assets of a wholesale gas trading business, AEATM, from Babcock and Brown Power. Aurora Energy invested $15 million in wholesale gas contracts and dispatch rights, which provide Aurora Energy with gas for wholesale sales to customers in Tasmania and on the mainland, and a tolling arrangement with the Bairnsdale power station in Victoria (giving Aurora Energy mainland generation capacity to back its retail position). These arrangements contain large fixed obligations in relation to both gas commodity (the proportion of gas that is ‘take or pay’) and to gas transportation arrangements. The Panel understands that these were the arrangements that were in place when Aurora Energy acquired the AEATM business. These gas arrangements sit within Aurora Energy’s energy business.

6.7.2. Telecommunications

Aurora Energy’s telecommunications business was established during 2007 and is currently structured into two main streams:

1. A wholesale optical fibre-based telecommunications service provider to the Tasmanian market that competes with the monopoly provider utilising the Basslink cable to connect Tasmania to the national networks; and
2. Aurora Energy is the agent for the NBN project in Tasmania in relation to the roll-out of the Fibre to the Premises (FTTP) network in Tasmania. As an agent, this revenue stream bears less operational risk than the commercial telecommunications operations, and consequently produces marginal returns.

The telecommunications activity also support Aurora Energy’s internal needs for high speed telecommunication links between its distribution assets.

From 2008, the telecommunications activity has derived negative EBITDA returns, partly arising from the accounting treatment\(^{102}\) of funding provided by the Tasmanian Government to support Aurora Energy as the Government’s telecommunications strategic partner. 2010 operating EBIT was negative $0.8 million. However, Aurora Energy received an equity installement from the Tasmanian Government of $4.9 million.

**6.7.3. WireAlert (undertaken through Ezikey subsidiary)**

Historically, WireAlert has not traded as a retail product. The expenditures associated with the provision of the WireAlert device to Tasmanian households (not the historical development costs) have been capitalised in the accounts of Aurora Energy’s distribution business. The total amount capitalised in relation to cost of supply is represented by Aurora Energy as $8.8 million in 2010 and a further $0.3 million in 2011.

On 22 September 2011, Aurora Energy announced its intention to divest the WireAlert business and associated intellectual property in markets outside Tasmania.

Although Aurora Energy has forecast improved results for both the telecommunications and WireAlert activities, analysis of the viability of the assumptions underpinning profit growth has not been undertaken.

\(^{102}\) The Tasmanian Government provides Aurora Energy with an equity contribution to support its role as the Government’s telecommunications strategic partner. Because of the accounting treatment of the Government’s funding (i.e. contributed as equity rather than revenue), Aurora Energy’s results for telecommunications presents as a loss. This impacts overall profitability but is equitable from a cash perspective.
7. Transend Networks Pty Ltd

7.1. Scope of business operations

Transend Networks Pty Ltd (Transend) was formed on 1 July 1998, from the disaggregation of the then Hydro-Electric Commission (now trading as Hydro Tasmania).

Transend is a wholly owned State-owned Company, established under the Electricity Companies Act 1997 and is incorporated under the Corporations Act 2001 (C’wth). The Company’s shares are held in trust for the Crown by its Shareholder Ministers, the Minister for Energy and the Treasurer.

Transend owns and operates the Tasmanian electricity transmission network. Transend transmits electricity from power stations in Tasmania and from the Basslink converter station in George Town to its customers around the State. Under the NEM arrangements, Transend is a registered Transmission Network Service Provider (TNSP). Transend currently has 16 customers, including generators, networks (Aurora Distribution and Basslink) and MIs, all of whom connect directly to the transmission network.

Transend’s core business model is to earn a return on assets invested in the transmission network and to cover its operating costs. This revenue falls into two categories – prescribed revenue, which is revenue determined directly through the application of the regulatory framework for transmission services; and non-prescribed revenue, which is either commercially negotiated revenue sourced from customers that are not determined directly by the regulator or returns from other non-regulated commercial activities (e.g. the provision of contestable transmission services and communication services to third parties).

As a result, Transend’s financial performance is primarily a function of:

1. The level of allowances (capital and operating) determined under the regulatory framework and particularly the WACC that is applied to the RAB; and amendments to the regulatory regime over time (i.e. how Transend manages its participation in the regulatory framework); and

2. The degree to which Transend is able to meet these allowances in operation.

103 Transend Networks has provided the Panel with a summary of arrangements associated with the regulatory regime over the three price determinations discussed in this Paper. This is included at Appendix 2.

104 As noted in its Statement of Approach, it is not the Panel’s intention to revisit specific regulatory decisions. The purpose of this Paper is to understand the impact of under and over spend compared to the regulatory allowance on the financial sustainability of the business.
7.2. Key events which have influenced financial performance

Figure 52 illustrates the key events in the history of Transend since disaggregation which have influenced the financial performance of the business.

**Figure 52 - Key Events Influencing Transend’s Financial Performance**

Transend has been subject to three regulatory reviews to determine Maximum Allowable Revenue (MAR) for Prescribed Transmission Service (PTS) revenue, each undertaken by different regulatory authorities.105

Prior to the commissioning of Basslink, Transend was required by its Shareholders to resolve a number of complex technical issues such as power system security, wholesale energy metering and determining the operational boundaries between Transend and the NEM system operator (at that time the National Electricity Market Management Company (NEMMCO), now the Australian Energy Market Operator (AEMO)). The cost of undertaking this work was outside the regulatory allowance and not recouped from electricity customers and was effectively funded from profits.

---

7.3. **Summary of financial results 2004 to 2010**

A summary of Transend’s key financial results for the period 2004 to 2010 are set out in Table 9.

**Table 9 - Transend's Key Financial Results 2004 to 2010**

<table>
<thead>
<tr>
<th></th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Revenue</strong></td>
<td>97</td>
<td>119</td>
<td>130</td>
<td>127</td>
<td>137</td>
<td>159</td>
<td>183</td>
</tr>
<tr>
<td><strong>Prescribed Revenue</strong></td>
<td>86</td>
<td>108</td>
<td>115</td>
<td>123</td>
<td>130</td>
<td>144</td>
<td>166</td>
</tr>
<tr>
<td><strong>EBITDA(^1)</strong></td>
<td>62</td>
<td>93</td>
<td>82</td>
<td>89</td>
<td>107</td>
<td>127</td>
<td></td>
</tr>
<tr>
<td><strong>Debt</strong></td>
<td>35</td>
<td>53</td>
<td>93</td>
<td>118</td>
<td>409</td>
<td>488</td>
<td>518</td>
</tr>
<tr>
<td><strong>Dividends</strong></td>
<td>8</td>
<td>10</td>
<td>14</td>
<td>19</td>
<td>15</td>
<td>9</td>
<td>4</td>
</tr>
<tr>
<td><strong>Equity Transfer(^2)</strong></td>
<td>2</td>
<td>7</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td>270</td>
</tr>
</tbody>
</table>

Source: Transend annual reports

\(^1\) EBITDA is calculated on a whole-of-business basis (i.e. prescribed and non-prescribed income).

\(^2\) Equity transfer to Hydro Tasmania in 2008 $50 million to develop wind farm asset and $220 million equity was transferred to Hydro Tasmania via increased debt. In the 2011-12 State Budget; the Tasmanian Government announced Transend will meet the equity requirements of TasRail ($20 million per annum over five years) via increased debt.

Electricity transmission levels have remained relatively constant at just over 10,000 GWh over the period 2004 to 2010. However, since the commissioning of Basslink, the operation of the transmission system has changed significantly with substantially different flows within the system as a result of large power flows through the Northern parts of the network and across Basslink.

PTS revenue is Transend’s primary source of income, on average accounting for around 90 percent of Transend’s total revenue for each year throughout the historical period.

Dividends in 2010 were notably lower than historical averages due to the impact of increased depreciation arising from asset revaluations in 2007 and 2008, additional borrowing costs and defined benefit superannuation liabilities.

Table 10 sets out building block components for MAR for the period 2004 to 2010. For simplicity this table does not show the unsmoothed MAR and adjustment lines between the building block components and MAR (smoothed). As such, there is a variance between the cumulative building block components and MAR (smoothed).
Table 10 – Maximum Allowable Revenue Building Block Components 2004 to 2010

<table>
<thead>
<tr>
<th>$ million</th>
<th>H2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Return on Capital</td>
<td>25</td>
<td>55</td>
<td>61</td>
<td>64</td>
<td>71</td>
<td>73</td>
<td>84</td>
</tr>
<tr>
<td>Regulatory Depreciation</td>
<td>8</td>
<td>18</td>
<td>20</td>
<td>22</td>
<td>23</td>
<td>23</td>
<td>26</td>
</tr>
<tr>
<td>Operating Expenditure</td>
<td>16</td>
<td>29</td>
<td>34</td>
<td>33</td>
<td>31</td>
<td>32</td>
<td>51</td>
</tr>
<tr>
<td>Tax Allowance</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>MAR (smoothed)</td>
<td>50</td>
<td>107</td>
<td>118</td>
<td>121</td>
<td>129</td>
<td>137</td>
<td>165</td>
</tr>
<tr>
<td>MAR - actual¹</td>
<td>50</td>
<td>106</td>
<td>118</td>
<td>122</td>
<td>130</td>
<td>142</td>
<td>166</td>
</tr>
</tbody>
</table>

¹After adjusting for actual CPI and pass-through items. Note: In 2010, revenue of $165 million was recovered based on the AER’s original decision. The Australian Competition Tribunal subsequently amended the decision resulting in allowed revenue in 2010 being $177 million. The difference will be recovered over the remaining four years of the regulatory period. The above table reflects the AER’s original decision because revenue recovered in 2010 was on that basis.

Transend’s returns (measured by EBITDA) have not kept pace with MAR trends, primarily due to higher than determined operational expenditure and differences between the regulated asset base and statutory asset base (see below).

Figure 53 illustrates Transend Networks’s MAR building block components for the 2003 regulatory period and the 2009 regulatory period.

Figure 53 - MAR Building Block Components 2003 and 2009 Regulatory Periods

Source: Transend

Note: Figure 53 illustrates the adjustment to return on capital discussed under Table 10.
Figure 53 shows that the single largest driver of Transend’s revenue is the return it is allowed to receive on the regulatory asset base (return on capital). Over the review period, this allowance is typically between 50 and 54 per cent of the total allowance. The operating costs allowance typically comprises between 23 and 28 per cent of the total allowance, and on an annual basis declined through the 2003 regulatory period. Regulatory depreciation, which is linked to the value of the regulatory asset base, has typically accounted for 17 per cent of the total allowance.

Key drivers of the building block component and Transend’s actual performance against the regulatory allowances is discussed in section 16 below.

7.4. Core driver of performance is actual expenditure (capital and operational) against regulated allowances

7.4.1. Operating expenditure for prescribed transmission services

Figure 54 illustrates actual operating expenditure and determined operating expenditure over the 2003 regulatory period (noting that 2004 is a half year); and the first year of the 2009 regulatory period (2010).

Figure 54 - Annual Operating Expenditure Comparison 2004 to 2010

Figure 54 illustrates that on an annual basis, during the review period, Transend’s actual operating expenditure has variously been over and under the annual determined allowance. However, there is a trend of actual operating expenditure exceeding determined operating expenditure and during the 2003 regulatory period, for the over-spend to increase in magnitude.
In those years where actual operating expenditure exceeded the regulatory allowance, the amount of the over-spend negatively impacts on earnings and subsequently returns to Shareholders through dividends. Conversely, in those years where actual operating expenditure was below the regulatory allowance, the amount of the under-spend positively impacted earnings and subsequently returns to Shareholders.

- During the 1999 regulatory period (1 January 2000 to 31 December 2003), Transend’s actual operating expenditure throughout the regulatory period was characterised as being higher than the regulated allowance on an annual basis (noting that over-spend did not occur in every year). In part, this can be attributed to costs associated with preparation for Tasmania’s entry into the NEM, and costs associated with preparing for Basslink connection, neither of which were factored into the 1999 regulatory period (or provided for in the extension to the determination).

- During the five and half year regulatory period from 1 January 2004 to 30 June 2009, actual operating expenditure amounted to $210 million, which was $28 million or 15 per cent higher than the determined operating expenditure of $182 million. This overspend negatively impacted on earnings, particularly in the 2008 and 2009 years, when actual opex amounted to $93 million, which was $23 million or 33 per cent higher than determined opex of $70 million for those years.106

- For the first year of the 2009 regulatory period, 2010, actual operating expenditure of $48 million was $3 million below the forecast operating expenditure of $51 million. Determined operating expenditure is forecast to total $221 million between 2011 and 2014 compared to determined operating expenditure of $154 million in the preceding four year period, (2007 to 2010), an increase of $67 million or 44 per cent.

Figure 55 illustrates a cumulative, rather than annualised, operating expenditure comparison over the 2004 to 2010 period.

---

106 In preparing this paper Transend has advised that the operating expenditure allowance determined under the regulatory framework in the 2003 Price Determination was not sufficient and that the Board made an active decision to spend higher than allowed operating expenditure and that its Shareholders were informed of this. It is Transend’s view that this need was recognised in the 2009 Price Determination where a higher operating expenditure allowance was accepted by the AER.
7.4.2. Capital expenditure for prescribed transmission services

Since Transend’s establishment there has been substantial capital investment in the transmission system to augment and upgrade the network to meet higher load, higher peak demand, service new load centres, meet contemporary standards, replace ageing assets and improve the reliability of the system. This program of work was expected at the disaggregation of the Hydro-Electric Commission.

The transmission system that Transend inherited had been largely constructed between the late 1950s and early 1970 and many key items of the plant were approaching, or had passed, the end of their economic life. In its 1998-99 annual report, Transend noted that the key elements of its plant were older than the industry average, citing transformers with an average age of 33 years compared to the industry average of 25, circuit breakers that were, on average, more than 30 years old compared to the industry average of 22 years and transmission lines that were still in service after more than 80 years of continuous operation. A ten-year capital investment program to upgrade and modernise Tasmania’s electricity transmission system began in 1996. In addition to this program, during 1999 Transend began a comprehensive program aimed at eliminating substandard conductor to ground clearances on a number of transmission lines around the State (in June 1999 1250 substandard spans were identified).
Historical capital expenditure, as illustrated in Figure 56 below, predominantly relates to replacement ($252 million or 44 per cent) and renewal ($274 million or 48 per cent) costs, with significant renewal work occurring between 2004 and 2006, amounting to $147 million of capital investment over that period.

The significant increase in capital expenditure from 2009 (and forecast through the 2009 regulatory period) relates to development (augmentation) and connection-driven investment.

**Figure 56 - Capital expenditure profile 2004 to 2010**

Since the commissioning of Basslink in 2005, the nature of flows through the transmission system have changed substantially, with large power flows through the Northern parts of the network and across Basslink. Transend was the first TNSP in Australia to employ dynamic rating\(^\text{111}\) of its transmission lines, with a view to deferring capital expenditure in light of changing utilisation of the network.

Transend’s annual capital expenditure over the review period is characterised as being generally above the determined allowance, although this varies year-on-year with significant spikes in the last two years of the 2003 regulatory period. Figure 58 illustrates actual capital expenditure and determined capital expenditure over the 2003 regulatory period (noting that 2004 is a half year); and the first year of the 2009 regulatory period (2010).

---

\(^{111}\) Dynamic rating is the continuous monitoring of wind speed and ambient temperature at key locations to recalculate conductor current ratings to maximise the capability of the transmission system.
Figure 57 - Annual Capital Expenditure Comparison 2004 to 2010

Figure 58 - Cumulative Capital Expenditure 2004 to 2010

Note: The basis for the capital expenditure allowance has changed between the 2003 PD and 2009 PD from commissioned to incurred (refer Appendix 2).
During the 2003 regulatory period, actual capital expenditure amounted to $373 million, which was $37 million or 11 per cent higher than the determined capital expenditure of $336 million. Higher than determined capital expenditure spend was predominant in the 2008 and 2009 years when actual capital expenditure amounted to $127 million, which was $43 million or 51 per cent higher than determined capital expenditure of $84 million for those years.

For the first year of the 2009 regulatory period, 2010, actual capital expenditure of $132 million was $28 million below the forecast capital expenditure of $160 million, primarily due to the delivery of the Waddamana-Lindisfame project under budget. For the 2009 regulatory period, determined capital expenditure is $641 million.

7.4.3. The impact of capital expenditure on Return on Capital is a key driver of Maximum Allowable Revenue

ROC is calculated by applying a determined WACC to each year of the determination’s opening RAB. The WACC is the cost of capital based on the return that would be required by investors in a commercial enterprise of a similar nature and with a similar degree of non-diversifiable risk as that faced by a network business. Under the national transmission pricing arrangements, the regulatory-determined WACC is set using the same methodology for each transmission business during a regulatory cycle. The WACC is based on a standardised capital structure so that the actual gearing and equity position of each transmission business is not taken into consideration.

Transend’s ROC component of MAR increased at a relatively steady rate over the 2003 PD regulatory period, with stepped increase at the opening of the 2009 PD regulatory period.

ROC increased significantly in FY10 for two reasons:

1. The opening RAB for the 2009 regulatory period incorporates all capital expenditure incurred in the 2003 regulatory period (including capital expenditure in excess of the regulatory allowance). The RAB for 2010, the first year of the 2009 regulatory period was $951 million, some 15 per cent higher than the RAB for 2009 of $828 million. The RAB for 2010 included work-in-progress of $55 million, reflecting a change to the regulatory framework from as-commissioned capital allowances to as-incurred capital allowances (refer Appendix 2).

---

112 Some parameters used to determine the WACC are locked in under the Rules, however the risk free rate and debt risk premium are determined at the time of the respective decisions. Therefore, the WACC is not necessarily the same for each business during a regulatory cycle.
2. WACC increased from 8.8 per cent in the 2003 regulatory period to 10 per cent in the 2009 regulatory period.\textsuperscript{113} The WACC will apply to the capital expenditure allowance, irrespective of whether that allowance is actually expended. For example, in 2010 capital expenditure allowance was $160 million and actual capital expenditure expended was $132 million. Transend will earn a return on the $28 million unexpended capital expenditure allowance. Similarly, if Transend were to significantly overspend its capital expenditure allowance (as it did in the 2003 regulatory period) it would not earn a rate of return during the regulatory period on that over-spend.

As discussed above, the 2009 regulatory period had a significantly higher capital expenditure allowance\textsuperscript{114} ($641 million) compared to the 2003 allowance ($337 million) and for the first year, 2010, capital expenditure has been underspent by $28 million. If forecast capital expenditure is less than determined for the remainder of the regulatory period, Transend will effectively over-recover ROC, positively impacting profit. Savings will not be passed onto customers through lower prices until the following regulatory period (i.e. from 1 July 2014). These arrangements reflect the current operation of the NEM regulatory framework. Similarly, in periods when Transend has overspent its capital allowance, there has been no immediate impact on customer prices, with the funding cost consequences effectively met through a shortfall in profit and dividends to Government.

7.4.4. Return on Capital (regulatory) Vs Return on Assets (accounting)

There is a significant, and often not well understood, variance between Transend’s ROC for regulatory purposes ROA for statutory or accounting purposes. This can lead to questions such as ‘where is the money going’?

Figure 59 illustrates a comparison of the value of Property, Plant and Equipment (PPE) as presented for accounting purposes\textsuperscript{115} compared to the RAB.

\textsuperscript{113} Transend was one of a number of TNSP providers to appeal the WACC determined through the regulatory process. On appeal, the Australian Competition Tribunal increased the WACC applying to revenue determinations from the 8.8 per cent originally set by the AER to 10.0 per cent. For the 2009 PD.

\textsuperscript{114} Note the capex allowance in the 2003 PD was on an as-commissioned basis. The capex forecast basis changed in the 2009 PD to an as-incurred basis (see Appendix 2).

\textsuperscript{115} Closing PPE value.
Differences in asset values arise because different asset values are used for the regulatory process and for statutory reporting. These differences are driven by a number of factors, including differences in the rate of depreciation (economic versus accounting) and revaluations undertaken for accounting purposes. There was a significant revaluation of assets for accounting purposes in 2007 of $349 million, from $761 million in 2006 to $1.111 billion in 2007.

Asset values in the statutory accounts are based on periodic reviews of the depreciated optimised replacement cost of the whole network, whereas under the regulatory framework a historic cost approach is used. For assets in existence in 2001, asset values are ‘locked in’ based on a depreciated optimised replacement cost determined in that year\(^{116}\) and for subsequent capital investment, assets are depreciated historic cost. Both components are adjusted for inflation.

Values are also impacted by the timing of expenditure; for example, for statutory (accounting) purposes, all expenditure is included in asset values as it is incurred, regardless of whether it was ‘approved’ under the regulatory framework. For regulatory purposes, any under or over spend is adjusted in the RAB before rolling over to the next regulatory period, but not included during the regulatory period. Regulatory financial statements are audited and submitted to the AER each year in which the RAB is calculated based on actual expenditure, disposals and inflation in the relevant years. However, income for the period remains based on the forecast RAB as per the regulatory decision.

---

\(^{116}\) The then Minister’s valuation.
As illustrated in Figure 60, the rate of return on assets for accounting purposes is significantly lower than the regulatory return. In addition to the difference in asset values, additional capital expenditure above the regulatory allowance impacts profit through higher depreciation and interest charges from the year in which it is incurred and commissioned.

Returns are calculated as earnings before interest and tax (EBIT) as a percentage of assets. Statutory returns are based on average assets while regulatory returns are based on the opening asset base for each year in line with the revenue decision methodology.

Comparisons between the returns on statutory and regulated assets do not compare like with like. For example, statutory returns are based on the entire business with (both regulated and non-regulated) and a higher asset valuation, whereas the regulated return as per the regulator’s decision only relates to the regulated assets, using a valuation methodology set out in the National Electricity Rules.

Differences in the returns therefore result from different valuation treatment of the assets and the inclusion of non-regulated assets and expenditure in calculating the statutory returns. The year-on-year return on statutory assets is impacted by asset revaluations. For example, the asset value was re-valued upward in 2007 which resulted a lower return on statutory assets that year. The analysis indicates that Transend’s regulatory returns have generally been consistent with the returns envisaged by regulators.

**Figure 60 - Rate of return on Assets v Return on Capital 2005 to 2010**

Source: Transend

Note: the analysis commences with the 2005 financial year because 2004 spanned two revenue decisions.
In summary, even if Transend was consistently operating in line with its regulatory capital expenditure allowances, its return on assets for accounting purposes would still be lower than the regulatory WACC because of differences in asset valuations for accounting and regulatory purposes.

7.5. Pricing

Some of Transend’s customers (which include Aurora Energy’s distribution business and MI customers) are partially charged for use of system on a locational basis. That means that Aurora Energy’s distribution connection points in the same or similar locations to major industrial connections pay the same or very similar locational prices. However, some of Tasmania’s major population centres, such as Hobart, are more distant from generation and, in general, will face higher locational prices than some of the major industrial connections that are closer to generation.

Aurora Energy’s distribution business is also serviced by more connection assets than the major industrial connections despite direct connect customers accounting for approximately 60 per cent for Tasmania’s electricity demand. Principally, this is because there are almost four times as many distribution connection points compared to direct connection customer points, although some major industrial customers own their connection points and some have negotiated connection charges (and associated non-regulated charges related to assets connecting them to the transmission network), which are not included in the revenue analysis in Figure 61 below.

Under the existing Price Control Regulations, the pricing of network costs (which includes both the transmission and distribution elements), applied by Aurora Energy to a particular class of customer is required to be uniform, regardless of where in Tasmania the customer is supplied with electricity. This means that locational signals included in transmission network costs levied on Aurora Energy by Transend are lost in end customer prices.

Some industrial customers own their own high voltage connection assets and, therefore, avoid connection charges altogether, while others – as a result of having requested changes to their services – pay ‘negotiated’ service connection charges. Once services become ‘negotiated’, they cease to form part of the regulated asset base. While negotiated service charges are not part of the regulated pricing methodology, the NER require that these will be cost reflective. As such, any reduction in the connection charges may reflect reductions in Transend’s costs, for example maintenance savings arising from changes in the agreed level of service. Because negotiated assets sit outside Transend’s RAB, they do not impact on calculations of Transend’s MAR or the connection charges borne by other customers.

Figure 61 illustrates Transend’s revenue by customer type over the period 2006 to 2010. On average, transmission charges per MW/h for direct-connect customers have increased by 35 per cent between 2006 and 2010 and transmission charges for retail customers have risen by 30 per cent.
7.6. Diversified Business Activities

Transend business operations remain closely aligned to its functional business activities.

Transend’s diversified business activities are limited to the purchase of its telecommunications business from Hydro Tasmania on 1 November 2009 for $15.8 million. Transend utilises this business for its own telecommunication needs relating to the operation of the transmission network and also offers telecommunication services to third parties, including the Tasmanian Government’s trunk mobile radio network.
Appendix 1: Summary of the regulatory process as it relates to pricing and profitability.

The economic regulation of Transend’s transmission service is currently the responsibility of the Australian Economic Regulator (AER). The AER undertakes five year reviews of Transend’s network business and determines the allowable revenue that it is permitted to charge, which Transend then translates into network prices in accordance with its approved pricing methodology and the National Electricity Rules (NER).

Transend charges these prices to direct connect customers (generators, Mls and Basslink) and Aurora Energy’s distribution business. Aurora Energy then passes on the Transmission Use of System (TUOS) cost to electricity users as a component of the Distribution Use of System (DUOS). While the AER assesses and approves Transend’s pricing methodologies, it does not approve the actual transmission charges established at particular connection points. Like other TNSPs, it is up to Transend to establish its transmission charges in accordance with its approved pricing methodology and the NER.

Maximum Allowable Revenue - building block approach:

Transend’s MAR is determined by the AER assessing the following building block factors:

1. **Return on capital** is calculated by applying a determined WACC to each year of the regulatory period opening RAB. The opening RAB for one year comprises the opening RAB at the end of the preceding year, adjusting it for inflation; adding any additional capex; and subtracting disposals and regulatory depreciation for the year. The closing RAB for one year then becomes the opening RAB for the following year.

2. **Regulatory depreciation** is based on the concept of ‘economic depreciation, which is essentially a straight-line method of depreciating the regulated asset base from commissioning date over the economic life of the asset, adjusted for inflation.

3. **Operating expense** allowance is determined based on the following criteria: efficient costs of achieving operating expenditure objectives; the costs that a prudent operator in the circumstances of Transend would require to achieve these objectives; and a realistic expectation of the demand forecast and cost inputs in order to achieve opex objectives.

4. **Tax allowance** is calculated based on the determined income tax liability modelled on the tax depreciation and cash flow allowances. The amount of tax payable is determined using 60 per cent benchmark gearing, rather than Transend’s actual gearing and a benchmark income tax rate of 30 per cent. The benchmark value of imputation credits of 50 per cent is applied to the determined income tax payable in order to arrive at the net tax allowance.
### Appendix 2: Summary of regulatory arrangements over time (as provided by Transend)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Merits appeal</strong></td>
<td>OTTER</td>
<td>ACCC</td>
<td>AER</td>
</tr>
<tr>
<td><strong>Regulatory Asset Base</strong></td>
<td>Could be subject to periodic review based on depreciated optimised replacement cost.</td>
<td>Could be subject to periodic review based on depreciated optimised replacement cost.</td>
<td>Locked in and rolled forward based on new additions, disposals, depreciation and CPI.</td>
</tr>
<tr>
<td><strong>WACC</strong></td>
<td>Pre-tax real</td>
<td>Post-tax nominal</td>
<td>Post-tax nominal</td>
</tr>
<tr>
<td><strong>Capex forecast</strong></td>
<td>As-commissioned based on profile of commissioned projects including interest during construction.</td>
<td>As-commissioned based on profile of commissioned projects including finance during construction.</td>
<td>As-incurred based on profile of annual capital spend. Transition to this model required roll-in of work in progress at start of the period.</td>
</tr>
<tr>
<td><strong>Capex incentive</strong></td>
<td>Annual true-up. Pass through of over and unders on an annual basis and consequent annual revenue adjustment (no incentive).</td>
<td>Ex post review. Retain any savings in regulatory period, compensated for any prudent overspend as part of roll-forward of asset base. Depreciation not part of incentive.</td>
<td>Ex ante review. Retain any savings in regulatory period, penalised for overspend compared to revenue allowance. Depreciation and WACC return pat of incentive.</td>
</tr>
<tr>
<td><strong>Capex outcome</strong></td>
<td>Bellow allowance largely reflecting delays in development of jurisdictional planning arrangements to consider and approve augmentation and connection works.</td>
<td>Exceeded allowance in era of high increases in labour, materials and other inputs. AER found capex to be prudent and efficient.</td>
<td>Presently tracking under allowance. Largest capital project (Waddamana-Lindisfarne 220kv transmission line delivered on time and under budget).</td>
</tr>
<tr>
<td><strong>Opex forecast</strong></td>
<td>Ex ante allowance</td>
<td>Ex ante allowance</td>
<td>Ex ante allowance</td>
</tr>
<tr>
<td><strong>Opex incentive</strong></td>
<td>In period only. Retain underspend, penalised for overspend.</td>
<td>In period only. Retain underspend, penalised for overspend. Glide path mechanism for underspend to share benefits between business and customers next period.</td>
<td>In period only. Retain underspend, penalised for overspend. Efficiency benefit sharing scheme to share benefits between business and customers next period.</td>
</tr>
<tr>
<td><strong>Opex outcome</strong></td>
<td>Slight overspend in latter years reflecting growing obligations and preparation for NEM entry.</td>
<td>Overspend in latter years, reflecting increased obligations but reducing allowance.</td>
<td>Presently tracking under allowance.</td>
</tr>
<tr>
<td><strong>Service incentive</strong></td>
<td>No incentive scheme.</td>
<td>Service target performance incentive scheme – up to 1% of annual revenue reward or penalty.</td>
<td>Service target performance incentive scheme – up to 1% of annual revenue reward or penalty. Slight change to component measures. Targets revised upwards based on past improved performance.</td>
</tr>
<tr>
<td><strong>Service outcome</strong></td>
<td>Incentive payment in each year of period for continual improvement.</td>
<td></td>
<td>Incentive payment for first 6 month period.</td>
</tr>
</tbody>
</table>