Electricity Supply Industry Expert Panel

An Independent Assessment of the Tasmanian Electricity Supply Industry
Draft Report

December 2011
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## Glossary

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<tr>
<td>ACCC</td>
<td>Australian Competition and Consumer Commission</td>
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<td>AEATM</td>
<td>Alinta Energy Australia Trading and Marketing</td>
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<td>AEMC</td>
<td>Australian Energy Market Commission</td>
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<td>AEMO</td>
<td>Australian Energy Market Operator</td>
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<td>AER</td>
<td>Australian Energy Regulator</td>
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<td>AETV</td>
<td>Aurora Energy Tamar Valley Pty Ltd</td>
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<td>BBPS</td>
<td>Bell Bay Power Station</td>
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<td>BBP</td>
<td>Babcock and Brown Power</td>
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<td>BDB</td>
<td>Basslink Development Board</td>
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<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
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<td>CSO</td>
<td>Community Service Obligation</td>
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<td>DNSP</td>
<td>Distribution Network Service Provider</td>
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<td>DUOS</td>
<td>Distribution use of System</td>
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<tr>
<td>EBIT</td>
<td>Earnings Before Interest and Tax</td>
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<td>EBITDA</td>
<td>Earnings Before Interest Tax and Depreciation</td>
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<td>ESI Act</td>
<td>Electricity Supply Industry Act 1995</td>
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<td>FCAS</td>
<td>Frequency Control Ancillary Service</td>
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<td>FRC</td>
<td>Full Retail Contestability</td>
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<td>GSP</td>
<td>Gross State Product</td>
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<td>GW</td>
<td>Gigawatt</td>
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<td>GWh</td>
<td>Gigawatt Hours</td>
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<td>HEC</td>
<td>Hydro Electric Corporation / Commission</td>
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<td>ITE</td>
<td>Income Tax Equivalents</td>
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<td>LRMC</td>
<td>Long Run Marginal Cost</td>
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<td>MW</td>
<td>Megawatt</td>
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<tr>
<td>MWh</td>
<td>Megawatt Hour (=1 thousand kWh)</td>
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<td>NBN</td>
<td>National Broadband Network</td>
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<td>NECF</td>
<td>National Energy Customer Framework</td>
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<td>NCP</td>
<td>National Competition Policy</td>
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<td>NEM</td>
<td>National Electricity Market</td>
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<td>TERM</td>
<td>MEANING</td>
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<td>NER</td>
<td>National Electricity Rules</td>
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<td>NPV</td>
<td>Net Present Value</td>
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<td>OECD</td>
<td>Office of the Economic Corporation Development</td>
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<td>OEPC</td>
<td>Office of Energy Planning and Conservation</td>
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<td>OTIER</td>
<td>Office of the Tasmanian Energy Regulator</td>
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<td>PAYG</td>
<td>Pay as you Go</td>
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<tr>
<td>PB</td>
<td>Parson Brinkerhoff</td>
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<tr>
<td>PBT</td>
<td>Profit Before Tax</td>
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<td>PCR</td>
<td>Electricity Supply Industry (Price Control)</td>
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<td>PDI</td>
<td>Price Determination</td>
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<td>PJ</td>
<td>Petajoules</td>
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<td>PTS</td>
<td>Prescribed Transmission Service</td>
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<td>PWC</td>
<td>Price Waterhouse Coopers</td>
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<td>PWM</td>
<td>Prudent Water Management</td>
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<td>RAB</td>
<td>Regulated Asset Base</td>
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<td>RECs</td>
<td>Renewable Energy Certificates</td>
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<td>SOEB</td>
<td>State Owned Electricity Businesses</td>
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<td>SPS</td>
<td>System Protection Scheme</td>
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<tr>
<td>TER</td>
<td>Tasmanian Economic Regulator / Tasmanian Energy Regulator</td>
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<tr>
<td>TESI</td>
<td>Tasmanian Electricity Supply Industry</td>
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<tr>
<td>TNGP</td>
<td>Tasmanian Natural Gas Pipeline</td>
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<td>TUOS</td>
<td>Transmission use of System</td>
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<tr>
<td>TVPS</td>
<td>Tamar Valley Power Station</td>
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<td>WACC</td>
<td>Weighted Average Cost of Capital</td>
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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. Alongside the legislation, the Parliament endorsed the Terms of Reference for the Review.

Candidates for the Expert Panel were identified through the established Government Business Board selection process and approved by Cabinet.

In the broad, the Panel has interpreted the Terms of Reference for its Review as requiring it to investigate and report on:

- How and why the Tasmanian electricity sector is delivering the pricing and other outcomes that are currently being experienced; and how these outcomes compare with elsewhere in Australia; and
- Looking forward, what policy, regulatory, governance and structural reform options could be considered to underpin the efficiency of the sector in the future and how should these be evaluated and prioritised?

This Draft Report contains the Panel’s findings and recommendations for actions to inform the development of an energy strategy. These have been developed on the basis of information made available to the Panel, particularly through its information gathering powers, and also through interactions with stakeholders. Much of the Panel’s thinking has been guided by analysis undertaken by the Secretariat and the Panel’s financial, economic and technical advisors.

The Panel recognises that interested parties may have available supplementary information that it has not taken into consideration in developing its findings and in considering the areas for reform.

As such, the Panel remains open to additional information and evidence being provided to further develop and refine its understanding of the material issues that have given rise to the current position of the Tasmanian energy sector, particularly where there is a connection to the potential reform paths.

The Panel places a particular importance of gathering feedback and input on the reform paths - both the structural reform elements associated with the competitive market segments and in relation to governance. Both are important in shaping the future of the Tasmanian energy sector.

The two key steps for garnering this input are:

- Public hearings, which will be held in Tasmania on 1 and 2 February 2012;
- Written submissions to the Panel by 17 February 2012.
1.1. The Panel Members

John Pierce - Panel Chairman

Mr Pierce was appointed as the chairman of the Australian Energy Market Commission (AEMC) in June 2010. He has previously been the Secretary of the Federal Department of Resources, Energy and Tourism, Secretary of the New South Wales Treasury, and chief economist at Pacific Power.

Dr John Tamblyn

Dr Tamblyn recently retired as the Chairman of the Australian Energy Market Commission. He has had an extensive career in the regulation of public utility services, including positions as Chairman of the Essential Services Commission (Victoria) and Regulator General (Victoria). He has also held senior positions in the Australian Competition and Consumer Commission.

Dr Jerome Fahrer

Dr Fahrer is the head of the Allen Consulting Group’s competition and the regulation and economic evaluation services. He advises businesses and governments on the regulation of energy, water, financial and telecommunications markets. Dr Fahrer is a member of the Appeal Panel Pool of the Essential Services Commission of Victoria.
1.2. Terms of Reference

The Expert Panel shall investigate and report on:

1) The current efficiency and effectiveness of the Tasmanian energy industry with particular reference to the existing regulatory framework and the cost and operation of the energy industry elsewhere in Australia.

2) The primary factors that have driven recent increases in non-contestable electricity prices in Tasmania including the impact of major infrastructure development decisions.

3) The competitiveness of non-contestable electricity prices in Tasmania compared with those in other states.

4) The financial position of the state-owned energy businesses: Transend Networks, Hydro Tasmania and Aurora Energy.

5) The impact of interaction between the three state-owned businesses on the effective operation of the Tasmanian energy industry and Tasmanian energy prices.

6) Having regards to trends in electricity prices and market developments at the national level and Tasmanian-specific circumstances, the implications of Tasmania's market and regulatory arrangements for electricity tariffs over the coming years.

7) Actions that would guide and inform the development of a Tasmanian Energy Strategy particularly in relation to the Government's primary objectives of minimising the impact on the cost of living in Tasmania and ensuring Tasmania's long term energy sustainability and security.

8) The advice that was provided to the State Government by the senior management or Directors of Aurora Energy from 1 October 2009 to 16 June 2010 inclusive.

9) Any other matters that the Expert Panel considers are relevant to the above matters.
2. Executive Summary

The work of the Panel

The Parliament established an Expert Panel to undertake a comprehensive assessment of the Tasmanian Electricity Supply Industry under the provisions of the Electricity Supply Industry Expert Panel Act 2010. This Draft Report describes the state of play in the industry, why it needs further reform and how this reform can take place.

A decade and a half of change: the promise and the disappointment

The modern history of the Tasmanian electricity industry begins with the Gordon-below-Franklin debate of the late 1970s and early 1980s. The outcome of that process triggered a series of reforms, which began in earnest in 1995 with the corporatisation of the Hydro-Electric Commission (HEC). In 1998, the HEC was disaggregated into three separate businesses - Hydro Tasmania for generation, Transend for transmission and Aurora Energy for distribution and retail. These businesses were given commercial structures and objectives.

A key development was the physical connection of Tasmania to the mainland with the opening of Basslink in April 2006. This brought the expectation, or at least the hope that, just like on the mainland, competition would emerge in the generation and retail parts of the industry and led to Tasmania joining the National Electricity Market (NEM).

But competition has not been delivered.

Why competition is lacking and what to do about it

Hydro Tasmania is still the dominant producer and wholesaler of electricity in Tasmania. This dominance, which is equivalent to the absence of any effective wholesale competition, has meant that very little retail competition has developed. While ever Hydro Tasmania remains the dominant wholesaler of electricity, major national retailers will not enter the Tasmanian market and households and small businesses will have no choice but to buy their electricity from Aurora Energy. This situation will not change until and unless structural reforms are made to the wholesale market and subsequently the retail market.

Large retailers that are not currently active in the Tasmanian market have indicated to the Panel that potentially attractive commercial opportunities exist for them in Tasmania. According to these retailers, the key to unlocking greater competition in the Tasmanian retail market is to create competition in electricity wholesaling.
The Panel’s primary concern with the wholesale market is in relation to Hydro Tasmania’s latent market power and the harm this can do to dynamic efficiency – that is the ability of the electricity industry to produce economically efficient outcomes over time, and to respond and adapt to change. It is incontrovertible that Hydro Tasmania possesses significant latent market power. Its periodic signalling of that power through spot and contract market outcomes is a serious barrier to entry into the retail market by efficient, large scale, mainland retailers. This is why the Panel is recommending structural reforms to Tasmania’s electricity supply industry.

Key options for reforms of the wholesale market are:

1. Requiring Hydro Tasmania to conduct a regulator auction of standard contracts to provide retailers with confidence that appropriately priced hedging contracts will be available in the Tasmanian market on an ongoing basis, so that they can build a viable retail business;

2. Creating competition in the trading of energy produced by Hydro Tasmania’s generation assets by establishing independent trading entities to compete in the wholesale market and provide choice in the supply of wholesale contracts; and

3. Increasing competition for Hydro Tasmania by combining the Victorian and Tasmanian NEM regions.

The Panel seeks input from interested parties on these structural reform paths to further understand the practical issues that will require resolution for these reforms to be implemented.

The new sources of supply

The major supply developments in the past decade have been Basslink and Tamar Valley Power Station (TVPS). Envisaged as a means of profitably trading electricity between the mainland and Tasmania, Basslink provides the physical connection to the rest of the NEM. However, because of drought-induced dwindling water storages which constrained Hydro Tasmania’s ability to generate, until quite recently, Basslink was instead used to import electricity for longer periods than it was used for profitable trading. Absent Basslink, the alternative feasible sources of energy to keep the lights on, the fridges cold and the conveyor belts moving would have been much more expensive.

The TVPS, which came to be owned by Aurora Energy at the direction of the Government, after its previous owner Babcock and Brown Power (BBP) went into voluntary administration in March 2009, produces electricity using natural gas sourced from Bass Strait. With over 80 percent of Tasmania’s electricity generating capacity being hydro based, TVPS, together with Basslink, provides some security of supply during droughts.
The TVPS has proven to be a financial burden for Aurora Energy. The current cost structure of the TVPS means that it cannot compete in the market, given current market prices and water levels, and prevailing prices in the remainder of the NEM. The TVPS' commercial viability is underpinned by commercial arrangements between Aurora Energy and Hydro Tasmania that are linked to non-contestable customer arrangements. This is not sustainable. The TVPS needs to be placed on a transparent and commercially sustainable footing.

The prices people pay

The prices paid by residential customers have more than doubled since 2000. Prices paid by small business have not increased as fast, but have grown from a higher base. About half of the increase in prices has been due to costs incurred in running the distribution and transmission networks (the poles and wires), with about 40 percent due to increases in the wholesale price of energy factored into regulated prices.

The Panel has examined the contracts between Hydro Tasmania and the MI customers and has seen no evidence to suggest that they are being subsidised by other electricity users.

Prices are expected to increase into the foreseeable future in every region of the NEM. A major driver of changes in delivered energy costs to Tasmanian customers will be the impacts of carbon pricing. The slowing growth in capital spending of the network business will ease some but not all of the price pressures that have recently been experienced.

Aurora Energy is provided with an allowance to fund its costs of sourcing wholesale electricity for non-contestable customers, which is built into the prices that these customers pay. The application of the regulatory framework for determining that allowance has resulted in prices paid by non-contestable customers that are inconsistent with market trends. These customers pay prices that include the cost of hypothetical new generation capacity, but there will be no need for additional capacity for more than a decade.

For this reason the Panel recommends a refinement to the methodology for calculating the wholesale energy component of regulated prices for non-contestable customers. With new capacity not required until well into the next decade, and given the current relatively high level of water storages and the surplus of capacity and energy relative to demand, such a framework could deliver a reduction in retail electricity prices paid by non-contestable customers between 5 and 10 percent.
Financial performance

Each of the SOEBs generates sufficient cash to fund operating activities and to have available an amount of ‘free cash’ to utilise for capital investment in core business assets or diversification/growth activities, repay debt or return dividends to shareholders/taxpayers.

However, the SOEBs’ financial performance has been relatively weak, particularly with regard to dividends distributed to the Government. Over the period 2004 to 2010, the SOEBs returned $309 million in dividends, representing just 18 per cent of cash from operations.

A feature of the performance by the SOEBs has been the investment in non-core business activities. Since 2004, $100 million has been invested outside Tasmania, which to date has yielded very little financial return. Indeed, one of the reasons that dividends have been so poor has been the retention of capital for investment in these non-core activities. As both the owner of the SOEBs and as a provider of essential public services to the Tasmanian community, the Government faces a critical question: whether the capital employed by the SOEBs in non-core activities would be more usefully employed in the provision of these essential services?

Another notable feature of the SOEBs’ financial performance has been the tendency for Aurora Energy and Transend to overspend regulated allowances for both operating and capital expenditure. Furthermore, Aurora Energy’s retail cost to serve is significantly above its regulated allowance for that function.

Governance changes that drive accountability for performance are starting to emerge which, if sustained, can be expected to improve the financial performance of the SOEBs. In the Panel’s view there is significant scope for improvement.

Governance

Public ownership of the SOEBs, given their dominant role in the Tasmanian Electricity Supply Industry (TESI), affects confidence within the market and more broadly in relation to the underlying drivers of energy policy and regulatory processes.

The central issue in relation to ownership of the SOEBs is what objectives are being sought through public ownership. Clear and unambiguous Shareholder ‘ownership objectives’:

- provide the SOEBs with established parameters within which to operate, particularly with regard to non-commercial activities and investments not directly related to supplying services to the Tasmanian community;

- send a clear message to the community about what government is seeking to achieve through public ownership, including how this is consistent with and contributes to broader strategic policy goals; and
are the ‘foundation stone’ for the accountability and oversight of the SOEBs, particularly given the absence of the normal capital market disciplines.

An important component of the governance framework for state-owned enterprises is for clearly defined ‘business boundaries’. Hydro Tasmania and to a lesser extent, Aurora Energy have invested in business activities which are outside their core function.

Such investments may or may not turn out to be commercially successful and have acceptable level of earnings volatility. However, it may also reasonably be asked whether such investments and activities are appropriate investments for a government-owned business at all, given that in making them government is also accepting that General Government services will need to be adjusted in the event that they are not successful.

Such issues are germane to the scope of the businesses activities that the Government specifies. The businesses need to be as commercially successful as possible within the boundaries set by government, but it is critical that the scope of business activities be precisely defined.

The Tasmanian framework for transparent funding of non-commercial activities by the SOEBs is consistent with good practice and similar to arrangements in other jurisdictions. The Panel has observed examples of where these arrangements have not been implemented, including the practice of accepting a lower rate of return from businesses in exchange for the internal funding of a CSO. This practice runs contrary to the agreed policy of operating government businesses on a fully commercial basis and reduces the businesses’ own retained earnings.

**Reform of the electricity industry: what’s in it for Tasmanians?**

A commercial and regulatory environment which enables competition will allow household and business customers to choose their supplier - and, very importantly, to change their supplier if they are not happy with the service or the price. This will happen if new suppliers who offer a good service can enter the market and win over customers with a better deal. The battle between alternative suppliers for customers should foster an ongoing culture of better service, better products and lower prices. Competition is a process, not an outcome. The beneficiaries at the individual level will be Tasmanian electricity customers. At the macro level, competition in the electricity industry will be an enabler of a more prosperous economy.

Tasmanians are not just consumers of electricity. They also own almost all of the Tasmanian electricity industry. Reforms to governance should give them confidence that their money is being invested wisely, with appropriate controls and accountabilities.
Next steps

This Draft Report contains the Panel’s findings and recommendations for actions that would inform the development of an energy strategy. These have been developed on the basis of information made available to the Panel, through its information gathering powers and interactions with stakeholders. The Panel recognises that interested parties may have available information that it has not taken into consideration thus far, and would welcome its receipt, particularly with regard to its proposed reforms of the wholesale and retail sectors, and of the governance of the SOEBs.

The Panel will be inviting submissions on its Draft Final Report and will also be holding another round of community hearings in relation to its Draft Report on 1st and 2nd February 2012.
3. Key Findings and Recommendations

Key Findings

Competition – the wholesale and retail markets in Tasmania

- Large retailers that are not currently active in Tasmania have indicated that the State presents potentially attractive commercial opportunities.

- Hydro Tasmania possesses and periodically signals significant latent market power through the spot and contract markets. This is a deterrent to entry into the retail market by efficient, large scale, national retailers.

- While ever Hydro Tasmania remains the dominant spot market participant and the principal supplier of contracts, major national retailers will not enter the Tasmanian market and choice for households and small businesses will be stymied. Unlocking greater retail competition in Tasmania, and with it, effective customer choice, hinges on addressing this problem.

- The Panel has identified three reform paths which would create a more competitive environment for spot and contract market trading in the future. They can be represented firstly as a regulatory path, secondly, a means of introducing effective competition within the Tasmanian region and thirdly, as a means of increasing the size of the market available to Tasmanian consumers. These are:
  
  - Reform Path 1: An independent, regular auction of standard contracts from Hydro Tasmania to provide retailers with confidence that appropriately priced hedging contracts will be available in the Tasmanian market on an ongoing basis on reasonable terms;
  
  - Reform Path 2: Creating competition in the trading of energy produced by Hydro Tasmania by establishing independent trading entities while retaining Hydro Tasmania as an integrated generating business; and
  
  - Reform Path 3: Increasing competition for Hydro Tasmania by combining the Victorian and Tasmanian NEM regions.

- On balance, the Panel prefers reform path 2.

- If wholesale market problems are properly addressed, there could be significant benefits in undertaking retail reforms that would deliver new entry in the retail market by making the Tasmanian customer base available through a competitive sale process.

The price-setting framework

- The arrangements for the determination of wholesale energy allowances for non-contestable (regulated) customers should reflect current and prospective supply-demand balances.
The impact of major infrastructure projects

Basslink

- Tasmanian non-contestable customers are not paying for Basslink through their electricity prices.
- Basslink has proven to be an effective and cost efficient means of securing the State’s energy supply during times of drought. It has enabled Tasmanian demand to be met at a materially lower wholesale energy cost than would have been the case under alternative scenarios.
- Since 2006, Basslink’s net overall cost to Hydro Tasmania has been around $134 million. This largely reflects the drought directly following commissioning. With the return to more typical inflows, between 2009 and 2010 Basslink has enabled Hydro Tasmania to generate net returns approaching $30 million.

Tamar Valley Power Station

- The TVPS has proven to be a financial burden for Aurora Energy. The current cost structure of the TVPS means that it cannot compete in the market, given current market prices and water storage levels.
- The TVPS’ viability is underpinned by contractual arrangements between Aurora Energy and Hydro Tasmania that are linked under the Electricity Supply Industry (Price Control) Regulations 2003. The arrangement effectively transfers the shortfall in market value for the TVPS to Hydro Tasmania. This is not sustainable.
- The valuation advice provided to the Government when it decided to buy the partially built power station, indicated a difference between its acquisition and completion costs and its market value under normal hydrological conditions, of around $150 million. The Panel has interpreted this as an energy supply risk ‘insurance premium’.

Governance

- The arrangements that underpin Tasmania’s SOEB governance framework are generally consistent with good practice principles. The evidence supports the Auditor-General’s previous finding that reporting by Aurora Energy to the Shareholders with regard to its financial circumstances between 1 October 2009 and 16 June 2010 was “adequate”.
- There is scope to improve the way the Government, as a Shareholder, communicates its strategic objectives for the SOEBs, particularly with regard to the delivery of non-commercial objectives and the scope of business activities.
- In some instances, the Government’s Community Service Obligation (CSO) policy has not been appropriately implemented, including the practice of accepting a lower rate of return from businesses in exchange for the internal funding of a CSO.
Public accountability of the SOEBs is largely focused on end-of-year performance. There is currently little in the way of ongoing disclosure of performance information.

**Electricity price trends**

- Non-contestable customer prices have more than doubled since 2000.
- About half of the price increase has been due to costs incurred in running the distribution and transmission networks, with about 40 percent driven by the wholesale price of energy.
- Tasmanian price rises have been broadly consistent with increases experienced across Australia. Tasmanian prices continue to be somewhere in the ‘middle of the pack’ when compared with prices in other jurisdictions.
- The Panel has seen no evidence that residential and business customers are subsidising the major industrial customers.
- Electricity prices are expected to increase into the foreseeable future in every region of the National Electricity Market (NEM), including Tasmania, with carbon pricing being a new driver.
- For non-contestable customers, under the current regulatory arrangements, any change in retail prices will be determined by the Tasmanian Economic Regulator (TER) and will not be directly linked to changes in the wholesale market price of electricity in Tasmania but will still reflect the introduction of a price on carbon.

**The performance of the TESI**

- The technical performance, including overall reliability, of the electricity supply industry in Tasmania is generally comparable to that in other states.
- Each of the State Owned Electricity Businesses (SOEBs) generates sufficient cash to fund their operating activities and to have available an amount of ‘free cash’ to utilise for capital investment in core business assets or diversification/growth activities, repay debt or provide a return to shareholders.
- The SOEB’s financial performance has been relatively weak, particularly with regard to returns to the Government. Between 2004 and 2010 the SOEBs returned $309 million in dividends, or just 18 per cent of net cash from operations.
- Poor returns have been partly due to the SOEBs investing in non-core business activities. Between 2004 and 2010, $100 million has been invested outside Tasmania, and, to date, has yielded very little in the way of financial return.
- Until recently Aurora Energy and Transend have regularly overspent their regulated allowances for both operating and capital expenditure. Aurora Energy’s retail cost to serve is also significantly above its regulated allowance.
Key Recommendations

The Panel recommends that:

1. The current regulatory framework for the determination of wholesale energy allowances for non-contestable customers be adjusted in future pricing determinations so that it reflects the prevailing and prospective supply-demand balance.

2. The TVPS be funded transparently and put on a commercially sustainable footing by re-valuing and recapitalising the power station to reflect its current place in the market and the sustainable revenues available to it.

3. Reforms be implemented to address the absence of effective competition under the current structure of the wholesale market.

4. Following implementation of wholesale market reform, full retail contestability, be introduced.

5. The Tasmanian Government commence a scoping study for the sale of Aurora Energy’s retail business to determine an appropriate number of tranches for sale in the market.

6. The Tasmanian Government develops a publicly available Energy Business Ownership Policy that more clearly articulates its overarching, strategic objectives for the SOEBs.

7. SOEB oversight continues to be refined to provide a clear ‘line of sight’ between Shareholder expectations and the requirements of the regulatory framework on the one hand, and Board, management and staff performance on the other.
4. **Structure of the Draft Report**

In its Statement of Approach, the Panel noted that it had interpreted its Terms of Reference (ToR) as requiring it, in broad terms, to investigate and report on:

- How and why the Tasmanian electricity sector is delivering the pricing and other outcomes that are currently being experienced; and how these outcomes compare with elsewhere in Australia; and

- Looking forward, what policy, regulatory, governance and structural reform options could be considered to underpin the efficiency of the sector in the future and how should these be evaluated and prioritised?

Reflecting both the historical and reform-oriented aspects of its Terms of Reference, the Panel has structured the Draft Report into three main sections that investigate, in turn, the Panel’s finding on the past, the present and the future of the Tasmanian Electricity Supply Industry.

**Section 1: The Past** details the Panel’s findings on the key developments and trends in the electricity sector over the past decade. Specifically, the section focuses on:

- explaining the main factors that have been driving Tasmania’s recent pricing trends and how these trends compare with experience of other Australian jurisdictions (ToR 2 and 3);

- the technical and financial performance of Tasmania’s energy businesses (ToR 1, 3 and 5); and

- major investment decisions – namely Basslink and Aurora Energy’s acquisition of the Tamar Valley Power Station – and the outcomes that these projects have delivered relative to expectations, including the impact (if any) on electricity prices and the financial position of the relevant businesses (ToR 2, 4 and 8).

**Section 2: The Present** draws together the key findings from the Panel’s examination of the recent past and lays out the core issues that it believes have the most influence on the outcomes experienced by market participants in the Tasmanian Electricity Supply Industry today. The section examines four key issues:

- the effectiveness of the competitive market architecture at both the wholesale and retail levels;

- the influence of ‘hydrological risk’ and the cost of its mitigation; and

- the structure and operation of the current regulatory framework that determines prices for non-contestable customers.
Section 3: The Future puts forward proposed actions to guide and inform the development of a Tasmanian Energy Strategy (ToR 7). The proposed reforms in Section 3 represent the Panel’s response to the key issues that it identifies in Section 1 and Section 2. In summary, the Panel’s proposed reforms focus on options for the following:

- ensuring that the regulatory framework delivers appropriate price signals to non-contestable customers;
- placing the Tamar Valley Power station on a commercial footing;
- structural reform of the wholesale market in Tasmania;
- developing effective competition in the Tasmanian retail market; and
- strengthening the existing governance framework for the State-owned energy businesses (ToR 8 and 9)

Section 3 also presents the results of the Panel’s modelling of the impacts of its proposed market reforms.

Published in parallel to the Draft Report are five detailed Supporting Volumes that provide further background analysis to the findings presented in the main body of the Report. The Volumes are:

- A Review of the Efficiency and Effectiveness of the State-Owned Energy Businesses;
- A Review of the Financial Position of the State-Owned Energy Businesses;
- Basslink: Decision-Making, Expectations and Outcomes;
- Tamar Valley Power Station: Development, Acquisition and Operation; and
- Governance: Issues and Reforms.

Those wishing to gain a better understanding of the how the Panel has arrived at the views expressed on the topics and issues covered in this draft report would benefit from reading the relevant Supporting Volume(s).

Finally, the Panel has also made available on its website - www.electricity.tas.gov.au - modelling reports by Frontier Economics and the Centre of Policy Studies that detail much of the technical analysis that supports the Panel’s findings and recommendations.
PART 1
THE PAST
5. Tasmanian energy market reforms and developments

The outcome of the ‘Gordon below Franklin’ debate in the late 1970s and early 1980s essentially signalled an end to the development of large scale hydro generation capacity in the State. The Rundle Government’s 1997 Directions Statement – Tasmania’s Future Energy Strategy’ was a turning point in the strategic direction of the Tasmanian energy market. With the end of the development of hydro resources, and the emergence of the NEM reform agenda, the Directions Statement identified the need to re-examine Tasmania’s energy policy, particularly around the availability of new energy options and broader strategic direction of the State.

Since then, successive Tasmanian Government energy reform frameworks have progressed the three primary policy objectives established in the Directions Statement:

1. Securing new sources of supply to meet load growth;
2. Mitigating the State’s exposure to hydrological risk; and
3. Introducing greater competition and customer choice into the Tasmanian energy and electricity market.

Around the same time, at the national level, the electricity sector was subject to two significant competition reform initiatives, the Council of Australian Governments (COAG) electricity reform agenda and the broader National Competition Policy (NCP) reforms. Tasmania was an early participant in both of these reforms.

Implementing this reform program required significant changes to the structure of the market and regulatory frameworks in the Tasmanian Energy Supply Industry (TESI). These are illustrated in Figure 5.1 and described briefly below.

There has been substantial progress in implementing structural reform of the electricity sector, beginning with the corporatisation of the Hydro-Electric Commission (HEC) in 1995, its subsequent separation into generation (Hydro Tasmania), transmission (Transend) and distribution/retail (Aurora Energy) businesses in 1998 and the operation of those businesses under commercial models.

The next major step was the opening up of the Tasmanian generation market to competition and joining of the NEM in 2005, including the phased rollout of retail contestability. Similarly, there has been a progressive transfer of economic regulation of electricity transmission, distribution and retail to independent regulatory bodies.
Key infrastructure developments in the Tasmanian energy market are summarised below:

- New major sources of electricity supply have been delivered, with Basslink entering commercial service in May 2006 and the TVPS was commissioned in October 2009. Tasmania has substantially more electricity generation capability (both energy and capacity) than is currently needed to meet peak demand, and with normal hydrological inflows, no new capacity will be needed until well after 2020.

- In 2002 the Tasmanian Natural Gas Pipeline connected Tasmania to the national gas network in Victoria. A distribution network fronting over 43,000 properties was completed in 2007. However the preliminary expectation to extend this network to front over 100,000 residential properties has not progressed.

- There are currently around 9,000 Tasmanian customers who access the gas network and there is substantial excess capacity available to transmit more gas than is currently being utilised in Tasmania.

- A primary goal of the Tasmanian Government in developing Basslink was reducing exposure to drought conditions in Tasmania. According to Hydro Tasmania, the hydrological circumstances over the first decade of this century reflected 1 in 1,000-year outcomes. Basslink has proved to be effective in maintaining Tasmania’s electricity supply.

- While the supply options anticipated to accompany the introduction of competition in generation and retail sector have been delivered, the competitive dynamic that these additional sources of supply were expected to deliver has not emerged as anticipated.

- There are currently five licensed retailers in Tasmania, but only two – Aurora Energy and ERM Power Retail – are active in the market.

- The Tasmanian Government has deferred the rollout of full retail contestability to small businesses and households.
The Evolution of Tasmania's Energy Sector

Figure 5.1
6. Tasmanian electricity prices

Key Messages

Summary of the outlook for prices

Energy prices:

- Energy prices are expected to increase over the medium term. The average spot price is forecast to reach around $64 MWh ($2012) by 2016, up from its current level of approximately $30 MWh. Carbon pricing will have a marked impact on wholesale prices in Australia, including Tasmania.

- Wholesale contract prices are expected to rise in line with the changes in spot market prices and Victorian contract prices.

- Wholesale energy costs for non-contestable customers are determined through the methodology set out in the Electricity Supply Industry (Price Control) Regulations 2003 (PCR).

Transmission network charges:

- Transmission charges are ‘locked in’ until 2014. By 2014 the average transmission cost will have increased by an estimated 45.6 percent (29.0 percent real) since 2009.

- While capital expenditure on the transmission network is expected to ease, it is the total value of the network that is a key driver of transmission prices. Future determinations of the WACC applied to the value of Transend’s RAB will be a major driver of transmission prices.

Distribution network charges

- The Australian Energy Regulator (AER) is due to publish a new determination relating to Aurora Energy’s distribution business for the period 2013 to 2017 in April 2012.

- Aurora Energy has proposed a real decrease in operating expenditure, as well as an ongoing reduction, in real terms, of its capital expenditure over the coming regulatory period. This would result in its annual revenue requirement increasing by 10 percent in nominal terms over the regulatory period but remaining virtually unchanged in real terms.

Major industrial customer pricing

- The Panel’s view is that Hydro Tasmania has undertaken robust and thorough commercial evaluations of the energy price in its contract negotiations with major industrial customers. The Panel has seen no evidence to suggest non-contestable customer prices subsidise MI customer prices.

- Modelling showed that a significant reduction in MI load in Tasmania would lead to a loss of value to Hydro Tasmania, when compared to current and future MI contract prices.
6.1. Introduction

The Panel’s Terms of Reference require it to investigate and report on the drivers of recent price increases for non-contestable customers (ToR 2) and on the competitiveness of Tasmanian non-contestable electricity prices compared with those in other states (ToR 3). This section of the Draft Report describes how Tasmanian electricity prices have changed since 2000 and what has driven those changes.1 It also compares the competitiveness of Tasmanian electricity prices with those in other regions of the NEM.

During the course of the Panel’s Review, stakeholders have raised Major Industrial (MI) customer pricing from two perspectives. Firstly, stakeholders questioned whether a cross subsidy exists between non-contestable customers and MI customers through the relative pricing of each customer group. Secondly, there was a view that Hydro Tasmania’s financial performance is potentially being constrained by the MI customer load in the context of its opportunity value in the NEM. This section of the Draft Report presents the Panel’s findings on these matters.

6.2. Price changes since 2000

6.2.1. Changes in non-contestable customer electricity prices

In nominal terms, residential customer prices have more than doubled since 2000.2 For example, the variable component of the general light and power tariff has increased by 130 per cent, rising from 10.935 cents per kWh3 in 2000 to 25.132 cents in 2012. Over the same period, the ‘Hydro Heat’ combined hot water and space heating tariff has increased from 7.078 cents per kWh to 15.157 cents per kWh, an increase of 114 per cent.

Prices paid by small business customers have increased to a lesser extent than prices paid by residential customers, with the general low voltage tariff paid by small businesses increasing by 101 per cent, in nominal terms. This is because Aurora has moved to align small business and residential pricing and the prices paid by small business customers began from a higher base in 2000.

Taking into account the 11 per cent rise in non-contestable customer prices from 1 July 2011, since 2000 the price of a single kilowatt hour of electricity has increased, on average, by just over seven per cent each year in nominal terms for residential customers and six per cent for small businesses customers. The respective daily fixed charges have increased at around 3.5 per cent per annum over the same period.

1 This paper provides only a summary of the changes that have occurred in electricity prices and the drivers of those changes. For a more detailed explanation, see Tasmanian Electricity Pricing Trends 2000-2011, published by the Panel and on its website www.electricity.tas.gov.au
2 With the exception of the fixed charges applying to the general light and power tariff, which have increased by just over 50 per cent.
3 Energy Step 2 (500 - 1,500 kWh per quarter)
While non-contestable customer or regulated electricity prices have been rising since 2000, the rate of change has accelerated in recent years, with prices rising by around six percent during 2010, followed by a 15 percent increase through 2011 and an 11 percent increase from 1 July 2011. This upward trend is set to continue, with an increase of around 8.7 percent on 1 July 2012 expected by the TER.4

Figure 6.1 traces the changes in electricity prices for residential and small business customers since 2000 for three key tariffs, including the general light and power tariffs paid by both customer categories, as well as the associated fixed (daily) charges. There was a reduction in prices in 2001, as a result of removal of the five per cent Electricity Entities Levy that the Tasmanian Government had imposed on electricity prices since 1971. Since then clear step increases can be seen, particularly in the cents per kWh energy price applying to residential customers, following retail pricing investigations in 2003, 2007 and 2010.

Figure 6.1 also shows that small business customer prices and residential customer prices have been brought together by Aurora Energy, on the basis that customers with similar supply costs should experience similar tariffs. The per unit rate of energy and the daily fixed charges paid by both types of customer in 2012 are now on par. In 2000, the small business tariff was approximately 15 per cent higher than the corresponding residential tariff, before dipping below the residential rate by nearly 11 per cent in 2004, where it essentially remained until 2010, from which point the two tariffs converged.

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Taking into account underlying inflation, the real increase in electricity prices between 2000 and 2012 has averaged 4.2 percent per annum in the case of general light and power, and 3.6 percent per annum in the case of Hydro Heat.

Figure 6.2 illustrates the changes in non-contestable electricity prices across a select range of tariffs since 2000, and compares them with the growth in wages and increase in the cost of living during the same period. The movements in prices, earnings and wages are presented on an indexed basis, to enable the relative changes to be more readily observed.

Figure 6.2 shows that increases in the per kWh price for residential light and power were broadly aligned with inflation and the growth in earnings observed between 2000 and 2003. Since 2003, the rate of growth in the price of electricity faced by residential customers has substantially outpaced increases in both earnings and prices more generally.
The change in the per unit price of energy paid by small business customers did not keep up with inflation between 2000 and 2008, indicating real per unit price reductions over this period. This trend has been reversed in more recent times with prices increasing at a greater rate than the CPI, albeit at a rate which is consistent with the corresponding changes in energy prices paid by residential customers. On average, the per unit price of energy for small business has risen by three percent per year in real terms since 2000.

Figure 6.2 - Changes in non-contestable electricity prices (nominal), wages and the cost of living

All parts of the supply chain in the electricity sector (generation, transmission, distribution and retail) have contributed to the increases in electricity prices that have occurred since 2000, but not in equal proportions. Table 6.1 presents a breakdown of the ‘building blocks’ that make up the revenue allowance which Aurora Energy is permitted to recover from non-contestable customers through regulated tariffs.5

While the per kW price breakdown is not representative of any particular tariff, being an average taken across the entire volume of energy sold by Aurora Energy to its regulated customer base. The breakdown of electricity prices presented in Table 6.1 is also likely to be instructive, in a general sense, for all but the largest contestable customers that take their supply directly from the transmission network, although the balance between the energy and network costs faced by individual contestable customers can vary on the basis of factors such as the volume of electricity they consume and their peak demand.
Table 6.1 - Components of Aurora Energy's revenue allowance (c/kWh, nominal)

<table>
<thead>
<tr>
<th></th>
<th>2000</th>
<th>2010-11</th>
<th>Nominal change since 2000</th>
<th>Change (%)</th>
<th>Contribution to total change (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wholesale Energy Allowance</td>
<td>3.89</td>
<td>8.26</td>
<td>4.37</td>
<td>112</td>
<td>41</td>
</tr>
<tr>
<td>Transmission Charges</td>
<td>0.89</td>
<td>3.56</td>
<td>2.67</td>
<td>300</td>
<td>25</td>
</tr>
<tr>
<td>Distribution Charges</td>
<td>3.74</td>
<td>6.45</td>
<td>2.72</td>
<td>73</td>
<td>25</td>
</tr>
<tr>
<td>NEM Costs</td>
<td>0.09</td>
<td>0.10</td>
<td>0.02</td>
<td>18</td>
<td>-</td>
</tr>
<tr>
<td>RECs</td>
<td>0.00</td>
<td>0.41</td>
<td>0.41</td>
<td>n/a</td>
<td>4</td>
</tr>
<tr>
<td>Cost To Serve + Retail Margin</td>
<td>1.10</td>
<td>1.65</td>
<td>0.55</td>
<td>50.0</td>
<td>5</td>
</tr>
<tr>
<td>Total</td>
<td>9.70</td>
<td>20.43</td>
<td>10.73</td>
<td>111</td>
<td>100</td>
</tr>
</tbody>
</table>

Source: Data supplied by the Office of the Tasmanian Economic Regulator

The following sections provide and an overview of the main drivers of changing electricity prices shown in Table 6.1.

6.3.1. Wholesale energy allowance

The wholesale energy allowance is the largest of the building blocks that make up retail tariffs for non-contestable customers and the growth in this allowance has had the single biggest impact on prices for non-contestable customers. The TER’s most recent investigation of electricity prices shows the increase in the wholesale energy allowance contributed around 40 percent of the increase in retail prices (at that time) since 2000.6

The methodology for setting the wholesale energy allowances for non-contestable customers is discussed in detail in Chapter 13.

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6 Investigation into Electricity Supply Industry Pricing Policies - Declared Electrical Services Pricing Determination – October 2010, OTTER.
6.3.2. Transmission network charges

Transmission charges have increased at the greatest rate of all of the building block components illustrated in Table 6.1, having grown by 300 per cent, in nominal terms, between 2000 and 2010. Consequently, the contribution of transmission charges to electricity prices has also increased. In 2004 the TER estimated that, for the average customer on a retail tariff, transmission charges made up 12 per cent of their electricity bill. In 2010, transmission charges were estimated by the TER to represent around 17 per cent of retail tariffs, although the TER subsequently revised this estimate to 15 per cent in 2011. This is still higher than in other regions of the NEM where transmission charges represent less than ten per cent of typical electricity bills.\(^7\)

The principal drivers of increased transmission charges are the regulated return that Transend is allowed to receive on its RAB and its operating cost allowance. Over the period 2004 to 2010:

- Transend invested $498 million in capital expenditure, which has contributed to an increase in its RAB of $524 million or 92 per cent, from $570 million in 2004 to $1.094 billion in 2010;\(^8\)

- Transend’s rate of return on its asset base Weighted Average Cost at Capital (WACC) increased from 8.8 per cent for the period of the 2003 regulatory determination (1 January 2004 to 30 June 2009) to 10 per cent for the current regulatory period (1 July 2009 to 30 June 2014; and

- Transend’s annual operating expenditure has increased from $29 million to $48 million.

Tasmania’s experience in this regard is not unique. Transmission charges have contributed to rising electricity prices across Australia. The drivers of transmission costs in Tasmania are discussed in detail in Chapter 7.

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\(^7\) Submission in response to Garnaut Update Paper 8 ‘Transforming the electricity sector’, Grid Australia, 20 April 2011

\(^8\) Capital expenditure for the period of the 2003 Transmission Price Determination (1 January 2004 to 30 June 2009) and the 2009 Price Determination to the most recent audited information available to the Panel for analysis (1 July 2009 to 30 June 2010).
6.3.3. Distribution network charges

The distribution charge building block component contributed to 25 per cent of the increase in Aurora Energy’s revenue allowance illustrated in Table 6.1.

As with transmission charges, the principal drivers of increased distribution costs have been the regulated return that Aurora Energy is allowed to receive on its distribution network RAB and its operating cost allowance. Over the six and a half year period from 1 January 2004 to 30 June 2010:

- Aurora Energy invested $743 million in capital expenditure, which has contributed to an increase in its RAB of $541 million or 75 per cent, from $726 million in 2004 to $1.267 billion in 2010; and
- Aurora Energy’s distribution business annual operating expenditure increased from $46 million to $80 million.

Again, Tasmania’s experience has been shared by other jurisdictions. In New South Wales, for example, from 2011 to 2013 real average network prices are set to rise at or around 16 per cent per annum for two of the three Distribution Network Service Providers (DNSP) and 12 percent for the other. This was acknowledged by the Independent Pricing and Regulatory Tribunal as one of the two factors driving substantial increases in retail electricity prices for all NSW customers, including those on regulated tariffs.

Most DNSPs across the NEM have cited replacement of aging assets and the need to cater for growth in peak demand as drivers of network costs. Both of these factors, to varying degrees apply to Aurora Energy’s distribution capital investment.

6.4. Interstate comparison

While Tasmania’s electricity prices have been increasing rapidly, this is broadly consistent with increases experienced across Australia. Tasmania continues to be somewhere in the ‘middle of the pack’ when compared with other States and Territories.

During public consultation, a number of stakeholders provided anecdotal evidence to the Panel, often based on the experiences of friends or family living elsewhere in Australia, in support of their view that electricity prices are substantially higher in Tasmania. However, care needs to be taken in drawing conclusions from simple direct comparisons of electricity prices and ‘typical’ electricity bills in each state.

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9 Includes customer capital contributions
10 Capital expenditure for the period of the 2003 Transmission Price Determination (1 January 2004 to 30 June 2009) and the 2009 Price Determination to the most recent audited information available to the Panel for analysis (1 July 2009 to 30 June 2010).
This is because average consumption and usage patterns vary markedly between states. Tasmanian’s use more electricity than their interstate counterparts. There are several reasons for this, including climatic differences and the more widespread availability of reticulated natural gas in other states. Because of these reasons, without a comparison of total energy costs involving both gas and electricity in many instances it is difficult to draw meaningful conclusions based on comparisons of electricity prices alone.

To illustrate, the overwhelming majority of Tasmanian residential customers are connected to multiple electricity tariffs, each of which incurs its own supply charge. Interstate customers using both gas and electricity are typically connected to only one electricity ‘tariff’ and comparisons based solely on electricity costs reflect this difference. Ignoring the supply charges associated with the gas connection, not to mention the cost of the gas consumed, creates a skewed result.

The electricity prices offered in different markets also create incentives and disincentives to use electricity for particular applications, and are often driven to a large degree by the operational characteristics of the generation being used to supply a particular market. For example, Aurora Energy’s ‘Hydro Heat’ tariff makes electric home heating a viable option in Tasmania in a way that is not the case in other states. The tariff applying to Hydro Heat is currently just over 15 cents per kWh. This is approximately ten cents per kWh (39.7 per cent) below the per unit price of general light and power in Tasmania. The Hydro Heat price is also typically four to five cents below the lowest residential energy tariffs available in mainland Australia states that do not have time of use restrictions.

Therefore, a comparison of the electricity costs of homes in Tasmania using electric space heating with the costs that would be incurred on a like-for-like basis in another state is of little or no value.

To illustrate the complexities in comparing electricity prices in the different regions of the NEM, an inquiry with one on-line comparison service about the various electricity supply options available in a particular region of Victoria returned nearly 40 alternative plans on offer from eight electricity retailers. A similar inquiry for another region of Victoria returned over fifty different plans from 12 retailers, all with different rates, features and benefits are discussed below:

11 Details of differences in electricity consumption are contained in Chapter X of the Panel’s Discussion Paper Tasmania’s Energy Sector – An Overview, which is available on its website.
12 About six per cent of Tasmanian standard tariff customers take supply under just the Light and Power tariff (Tariff 31), while around 83 per cent take supply under a combination of Light and Power and Hot Water tariffs (Tariff 41 or Tariff 42). Source: Comparison of 2011 Australian Standing Offer Energy Prices, Tasmanian Economic Regulator, August 2011
13 Hydro Heat had its origins in Hydro Tasmania’s desire to utilise water in its run of river generation schemes which was spilling during the wettest months of the year – a ‘problem’ not faced by thermal generators interstate, although Hydro Tasmania’s solution was not dissimilar to the use of off-peak pricing by thermal generators, which also offers lower prices to encourage the use of energy that would otherwise go to waste.
the daily supply charges applying to customers in one of those localities ranged from 64 cents to 87 cents per day (compared to just over 89 cents per day from Aurora Energy);

energy tariffs ranged from 19.4 cents to 27.8 cents per kWh depending on consumption levels (compared to Aurora Energy’s flat rate tariffs of just over 25.1 cents), and went as high as 30 cents per kWh for 100 per cent accredited ‘Greenpower’ energy;

the range of discounts on offer for prompt payment ranged from 3 per cent of the total bill to 20 per cent of the energy tariff, with some suppliers offering multiple discounts;

some plans required the customer to enter into a contract for a set period of time, with the terms on offer ranging from one to three years, while other plans involved no such commitment. Some retailers imposed credit card payment fees; and

the same plan offered by a given retailer can have different pricing in different regions of the same state and even between suburbs in the same city.

For these reasons arriving at meaningful generalisations about relative electricity prices between states for different classes of customer with differing usage profiles is a difficult, if not impossible, process.

Despite these complications, the TER undertakes a six-monthly comparison of the electricity prices paid by non-contestable (residential and small business) and concession customers in Tasmania with electricity prices of equivalent customers interstate. The TER’s report\(^{14}\) is not based on a simplistic comparison of prices, rather it attempts to take into account both fixed and variable charges, as well as consumption, in order to arrive at an effective per kilowatt hour cost as a meaningful basis for comparison, across a range of consumption levels.

TER has chosen the cheapest or most commonly used standing offers\(^{15}\) as being the most representative for customers in particular states. However, interstate customers who are able to exercise choice in competitive retail markets are likely to be able to achieve lower prices than standing offer prices. As noted above due to the complexities involved it would not be feasible to undertake such an analysis on the basis of market offers in those states.

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\(^{14}\) OTTER – ‘Comparison of 2011 Australian Standing Offer Energy Prices’

\(^{15}\) In a competitive market, standing offer prices are offered as a fallback to customers who do not enter into a market contract.
6.4.1. Residential customers

In its Comparison of 2011 Australian Standing Offer Energy Prices, released in August 2011, the TER noted in relation to residential electricity prices that:

- low-consumption electricity customers in Tasmania pay effective per kWh prices that are in the high range of residential electricity prices in Australia;
- effective electricity prices in Tasmania remain in the mid-range for customers with average or high consumption; and
- Tasmanian customers with very high consumption pay prices that are below the national average.

The TER also found that most Tasmanian residential tariffs have higher fixed (daily) charges and lower variable (consumption-related) rates than the standing offers in other markets. This means that for many Tasmanian residential customers, the average incremental cost of energy is lower than in other states, because as consumption increases the fixed costs of supply are spread over a larger volume of energy.

Tasmania’s higher fixed charges have been raised with the Panel as an issue of concern for many Tasmanians seeking to manage their energy costs by minimising their consumption of energy. Given that consumption levels are incidentally higher in Tasmania than is the case interstate, it is arguably preferable that the effective per kWh price of energy in Tasmania reflects the additional costs actually incurred/saved through changes in consumption at the margin.

To summarise, analysis of standing offers by the TER and the Panel’s own research into a limited number of market offers interstate shows that for residential customers in Tasmania:

- fixed supply charges are generally higher than in other states (and most Tasmanian’s incur multiple fixed charges because of their connection to more than one tariff), noting that the daily supply charge associated with the ‘Hydro Heat’ tariff, is substantially lower than the daily supply charges associated with natural gas interstate;
- energy rates in Tasmania are also typically in the mid to upper range of those available elsewhere, with the exception of Hydro Heat; and
- with the advent of retail contestability and multiple distribution networks in other states and territories, Tasmania is one of the last regions in the NEM in which all residential customers pay the same electricity prices regardless of their location.16

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16 This outcome can also be attributed to the Tasmanian Government’s requirement that the pricing applied by Aurora Energy to a particular class of customer be uniform, regardless of where in Tasmania the customer is supplied with electricity.
6.4.2. Concession customers

Approximately one third of Tasmanian residential customers pay less than the full price of electricity as the result of concessions provided by the Tasmanian Government to Health Care Card and Tasmanian Pensioner Concession Card holders. Consequently, the TER also compares electricity pricing outcomes under the range of concession schemes available around Australia.

The Tasmanian Government’s electricity concession is one of the most generous available in Australia, and eligibility for concessions is generally broader in Tasmania than in other states. The concession is a daily fixed discount, which effectively offsets daily fixed charges. As a result, concession customers are able to realise savings in their electricity bill by controlling their consumption directly. The cost of energy for eligible concession customers was assessed by the TER as follows:

- customers with low energy consumption pay prices that are comparable with those available in other states; and

- other customers pay prices in the mid-range of those available in Australia.

The following table summarises the electricity concessions available in each state and territory.

**Table 6.2 Summary of concessions available by state**

<table>
<thead>
<tr>
<th>State/Territory</th>
<th>Concession available</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tasmania</td>
<td>111.70 cents per day, all year round (from 1 July 2011) up to a maximum of $407.71 per annum</td>
</tr>
<tr>
<td>Victoria</td>
<td>17.5 per cent discount all year round (from 1 March 2011)</td>
</tr>
<tr>
<td>New South Wales</td>
<td>$200 Low Income Household Rebate. Rebate paid based on number of days in each billing period (365 days per year)</td>
</tr>
<tr>
<td>ACT</td>
<td>Summer rebate of 27.74 cents per day (Nov – May). Winter rebate of 102 cents per day (June – Oct) up to a maximum of $214.87 per annum</td>
</tr>
<tr>
<td>Queensland</td>
<td>Rebate of $230 per annum</td>
</tr>
<tr>
<td>South Australia</td>
<td>Rebate of $150 per annum</td>
</tr>
<tr>
<td>Western Australia</td>
<td>Rebate on supply charge of 38.23 cents per day</td>
</tr>
<tr>
<td>Northern Territory</td>
<td>$1.179 per day off the fixed charge, 4.7 c/kWh off consumption charges, all year round</td>
</tr>
</tbody>
</table>

Source: OTTER – ‘Comparison of 2011 Australian Standing Offer Energy Prices’

Note: The value of the Tasmanian concession is indexed at the same rate as any increase in regulated electricity prices.
6.4.3. Small business customers

It is difficult to compare prices for business customers because of the different stages of contestability between states, which impacts on the availability of pricing information. In relation to the electricity prices faced by small non-contestable businesses, the TER found that Tasmanian electricity business customers on regulated tariffs pay business rates that are on par with those available in other states.

This assessment was based on a series of ‘standard’ business customers across all states and territories that might generally have similar consumption patterns and usage, regardless of their location. The TER examined the most commonly used general business tariffs offered by a selection of major retailers.

6.5. The outlook for prices

6.5.1. Energy prices

Wholesale energy prices paid by non-contestable customers are determined by the TER in accordance with the Price Control Regulations. The application of the wholesale energy allowance methodology is discussed in Chapter 1. Based on the current price determination, the TER has projected an increase in retail tariffs for non-contestable customers of 8.7 per cent on 1 July 2012. Price predictions beyond that time are difficult to determine until the extent of the carbon pass-through the TER makes under the regulations is known.

Forecast increases in demand across each NEM region and a consequential tightening of the supply demand balance, combined with expected increases in fuel costs are expected to contribute to increased wholesale energy prices across the NEM.

The degree to which this impacts on retail electricity costs will be determined by the nature of contractual arrangements that underpin the wholesale cost of electricity built into those prices.

A major driver of changes in delivered electricity costs to customers will be the impact of the price on carbon. Carbon pricing will increase the costs of thermal generation in the NEM generally, increase the costs of operation of the TVPS and increase the value of hydro-generation.

The Panel has undertaken modelling of the potential impact of a price on carbon on wholesale electricity costs throughout the NEM over the period 2012 to 2016. This analysis suggests that spot market prices in all NEM regions, including Tasmania, will be significantly impacted by carbon. In the case of Tasmania, carbon pricing is forecast to add around 40 per cent on average, to Tasmanian wholesale electricity prices and that increment is the lowest forecast for any region of the NEM. In other NEM regions, the introduction of carbon pricing is estimated to add anything from 43 per cent to 70 per cent to wholesale electricity prices.
Since 2009-10, average wholesale spot price in the Tasmanian region has been below $30 per MWh (measured on an annual basis).\(^{17}\) In both nominal and real terms, recent prices have represented historical lows in the period since Tasmania joined the NEM in 2005. This experience has been repeated in all other NEM regions.

The reduction in prices can be attributed to a number of factors, including the Global Financial Crisis and the consequential reduction in demand across 2009 and 2010. In Tasmania, the increase in rainfall in recent years and a return to normal inflows has alleviated constraints on the hydro-system capacity. Adding further downward pressure on prices, the commissioning of the TVPS in October 2009 has ‘over-supplied’ the Tasmanian market into the foreseeable future, placing downward pressure on Tasmanian spot prices.

The Panel’s modelling is projecting 2012 spot prices that are broadly consistent with current levels (between $20 to $30 per MWh), before increasing to $60 MWh in 2013 reflecting the carbon price impact and higher NEM wholesale prices. The rate of growth is projected to moderate over the following two years, peaking in 2015 and softening again in 2016.

While these increases in the average spot price appear to be substantial, historically low prices in recent times amplify the projected increases. An average spot market price of $40 to $50 MWh in Tasmania would be either consistent with or lower than averages prices in 2007, 2008 and 2009.

In its December 2011 Review of Potential Future Prices, the AEMC considered that the wholesale component of the average residential bill in Tasmania would increase in nominal terms by an average of 5.7 per cent per annum over the period 2011 to 2014 in the absence of carbon pricing, and by 10.3 per cent with carbon pricing.

### 6.5.2. Transmission network charges

Transmission network services are a regulated monopoly and the AER will continue to determine Transend’s maximum allowable revenue for prescribed services. This means that future transmission charges in Tasmania are essentially dependent on the national regulatory framework and the assessments made by the AER.

The current regulatory period, which was set in the 2009 Determination, runs to 30 June 2014. Under the Determination, Transend’s annual revenue is set to increase by 8.4 per cent in 2013 and a further 6.1 per cent in 2014.\(^{18}\) By the end of 2014 the average cost of electricity transmission will have increased by an estimated 45.6 per cent (29.0 per cent in real terms) over the five years from 2010.

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\(^{17}\) Source: Average annual prices (per financial year), Australian Energy Market Operator (AEMO).

The increases in Transend’s annual revenue requirement typically add about one percent per annum to electricity prices for non-contestable customers, which will continue until at least 2014.\textsuperscript{19}

The increase in transmission charges during the current regulatory period is occurring despite Transend’s decreasing expenditure on asset renewal (one of the major drivers of its capital expenditure over the previous decade). To the end of 2010, in real terms\textsuperscript{20} Transend had spent $774 million\textsuperscript{21} on capital expenditure since it was established in 1998. While an easing of asset replacement expenditure may avoid further upward pressure on transmission charges, capital expenditure over the past decade is embedded in Transend’s RAB, and will continue to be recovered in depreciation charges over the operational life of those assets which is typically around 40 years. A regulated rate of return will also be earned on the depreciated value of the RAB.

The future costs of debt and equity incorporated into the return on capital (WACC) applied to Transend’s RAB will also be a major driver of transmission charges in the longer term. This will be influenced by movement in the broader finance market – currently the global financial situation is placing downward pressure on interest rates.

In its December 2011 Review of Potential Future Prices, the AEMC considered that the transmission component of the average residential bill in Tasmania would increase in nominal terms by an average of 7.4 per cent per annum over the period 2011 to 2014.

The AER is currently advocating a change to the National Electricity Rules (NER) under which it determines the revenues of network service providers. On 9 December 2011, the Minister for Resources and Energy, Martin Ferguson AM, MP also announced an inquiry by the Productivity Commission into aspects of national electricity network regulation. Both of these developments are discussed in section 7 of this Chapter.

The loss of a MI load also has the potential to increase transmission charges for all customers, although the impact is difficult to estimate. While the closure of a MI customer is unlikely to result in a significant change in the value of Transend’s regulatory assets, the contribution that the customer had previously made towards the value of the network and the common service assets included in Transend’s RAB would need to be recovered from Transend’s remaining customers.

\textsuperscript{19} Based on the latest estimate by the TER of the contribution that transmission costs make to non-contestable tariffs (15 per cent).

\textsuperscript{20} December 2010 dollars

\textsuperscript{21} Source: Transend
This would be achieved through an adjustment to non-locational Transmission Use of System (TUOS) charges, as occurred following the closure of the Burnie Paper Mill in June 2010. Conversely, the addition of industrial load has the potential to decrease transmission charges for other customers by providing an additional contribution towards the costs of the shared network, assuming the existing network is able to cater for that new load without augmentation.

**6.5.3. Distribution network charges**

Similar to transmission network services, Aurora Energy’s distribution network services are a regulated monopoly. Aurora Energy’s distribution business is currently operating in the final year of the regulatory period covered by a determination made in 2007 by the TER. Responsibility for distribution network economic regulation has transferred to the AER.

The AER is currently in the process of undertaking the distribution determination applying to Aurora Energy from 2013 until 2017. The AER will publish its final decision in April 2012.

Aurora Energy’s approach to its regulatory proposal has adopted customer pricing as the primary driver of future investment decisions, in order to “meet customer needs at the lowest sustainable cost”. Aurora Energy’s stated aim is to deliver more modest price increases than have been experienced elsewhere in Australia in recent years, in the first instance through cost reductions in current service delivery methods, and in the longer term through efficiency gains from changes to the way services are delivered. This is a cultural shift from previous regulatory approaches.

In its submission to the AER, Aurora Energy applied an annual 3 per cent efficiency factor to the labour rates on which its regulatory proposal is based. Aurora Energy estimated this would result in a real reduction in labour rates of more than ten per cent over the duration of the regulatory period. To meet this target, Aurora Energy has started to reduce its workforce in most areas of its business, decreasing the number of staff on a full time equivalent basis by 188 positions (14.7 per cent) in 2011, with a further 40 voluntary redundancies from its distribution business announced in October 2011.

Aurora Energy’s regulatory proposal assumes that the current level of network reliability is acceptable to customers, meaning that expenditure will be required only to meet current standards. On this basis, Aurora Energy proposed a real decrease in operating expenditure of, on average, 2.6 per cent per annum over the regulatory period.
Furthermore, Aurora Energy considers that investment in the network is now “at an appropriate level” and that “consolidation of expenditure can now occur.” Aurora Energy is also seeking to defer further investment in the distribution network through the use of demand management strategies. On this basis, Aurora Energy has also proposed a real reduction in its capital expenditure.\(^{22}\)

The AER has issued its draft determination relating to Aurora Energy’s distribution network. In this determination, the AER has proposed more efficiencies than Aurora Energy had included in its proposal.\(^{23}\) The AER draft determination reduces forecast capital expenditure by $139 million or 21 per cent of Aurora Energy’s proposed capital expenditure; and reduces forecast operating expenditure by $29 million or 8.6 per cent of Aurora Energy’s proposed operating expenditure.

Over 70 per cent of Aurora Energy’s distribution business’ revenue ‘entitlement’ is the return it earns on the RAB. The WACC currently applied to Aurora Energy’s distribution business RAB is 6.64 per cent (pre-tax real). Aurora Energy has proposed a WACC of 10.33 per cent (nominal post tax) in its regulatory submission to the AER. In response, the AER has proposed a WACC of 8.08 per cent\(^ {24}\) (nominal post tax).

Aurora Energy’s regulatory submission includes an annual revenue requirement that, in real terms, would remain virtually unchanged over regulatory period. In nominal terms, after an approximately 14 per cent jump in Aurora Energy’s annual revenue allowance between 2012 and 2013, Aurora Energy’s annual distribution business revenue would increase by ten per cent over the forthcoming five year regulatory period, based on Aurora Energy’s proposals. Based on the AER draft determination, those increases would be removed.

In its December 2011 Review of Potential Future Prices, the AEMC considered that the distribution component of the average residential bill in Tasmania would increase in nominal terms by an average of 6.1 per cent per annum over the period 2011 to 2014.

As noted above, the AEMC’s decision on the AER’s proposal to change the network regulation rules will have a bearing on the level and growth of distribution prices in the future, as will the Productivity Commission’s review into aspects of the national regulatory framework for electricity networks, which was announced by the Minister for Resources and Energy, Martin Ferguson AM, MP on 9 December 2011.

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\(^{22}\) Nonetheless, the value of a distribution network service provider’s regulated asset base is as a key determinant of its regulated revenue entitlement, and Aurora Energy’s capital expenditure over the past decade will continue to feed into future determinations of its allowable revenue for decades to come, until those assets reach the end of their economic life.

\(^{23}\) Draft Distribution Determination Aurora Energy Pty Ltd 2012-2013 to 2016-17, Australian Energy Regulator, November 2011

\(^{24}\) Draft Distribution Determination Aurora Energy Pty Ltd 2012-2013 to 2016-17, Australian Energy Regulator, November 2011
6.5.4. Retail costs to serve and retail margin

For non-contestable customers, Aurora Energy’s retail cost to serve and profit margin are determined by the TER and represent around ten percent of energy prices. For its contestable customers, Aurora Energy determines the price it charges for these services.

**Retail Cost to Serve**

Under the current Pricing Determination for non-contestable customers, the TER has allowed Aurora Energy an industry benchmarked cost to serve of $95 per customer per annum.\(^{25}\) This is higher than the allowances made for retailers in other parts of the NEM, reflecting Aurora Energy’s lack of scale economies, relative to other electricity retailers.

In jurisdictions where full retail contestability has been introduced, the cost to serve that is incorporated into the regulated tariff also includes an allowance for customer acquisition and retention costs.\(^{26}\) In the absence of full retail contestability in Tasmania, this allowance is not included in the calculation of Aurora Energy’s cost to serve. This means that once the cost of customer acquisition and retention is added to the cost of service delivery interstate, the total is frequently higher than Aurora Energy’s cost to serve.

Increased competition in the retail market, particularly the entry of retailers with large customer bases interstate and therefore a lower cost to serve than Aurora Energy, should lower customer prices (although given the proportion of this cost in the overall tariff, this will be small). Aurora Energy has highlighted that retail margins need to be reduced in order to retain market share and this is a focus of its current productivity and efficiency program.

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\(^{25}\) Aurora Energy had proposed a cost to serve of $105 per customer per annum for 2010-11, plus an allowance for Aurora Energy’s relative lack of economies of scale, based on the allowance set in the Australian Capital Territory by the Independent Competition and Regulatory Commission. Investigation of maximum prices for declared retail electrical services on mainland Tasmania – Final Report, Office of the Tasmanian Economic Regulator, October 2010.

\(^{26}\) In its pricing determination for 2010-11, the Queensland Competition Authority allowed for $40.50 per customer in acquisition and retention costs, and the Independent Pricing and Regulatory Tribunal of New South Wales allowed for acquisition costs of $36.80 per customer (expressed in $2009-10). In a submission to the Independent Competition and Regulatory Commission as part of the investigation that informed the ICRC’s determination of electricity prices in the Australian Capital Territory for 2010 to 2012, electricity retailer Actew AGL contended that its cost to serve should include an allowance for customer acquisition costs of $28 per customer, although this was ultimately not accepted by the ICRC.
Retail margin

The retail margin represents the return that an electricity retailer earns on the investment it makes in order to provide retail services.

Under the current Pricing Determination for non-contestable customers, Aurora Energy’s retail margin is currently set at 3.8 per cent per annum of total costs\(^27\) (equivalent to 3.7 per cent on sales). This is lower than the allowances of between four and six per cent made in relation to ‘standing offer’ arrangements in other jurisdictions with fully contestable markets.\(^28\) The lower margin reflects the fact that Aurora Energy is not exposed to customer churn amongst its non-contestable customer base, or the level of volume risk\(^29\) faced by retailers in other regions of the NEM.

It is not expected that future pricing determinations would deviate significantly from the current determination. The exception to this assessment is that, in the event of the introduction of full retail contestability, whereby the TER may need to increase the retail margin included in regulated tariffs in order to create sufficient ‘headroom’ in regulated electricity prices for effective price driven competition.

Using interstate retail margins as a guide, the retail margin built into standing offer prices may increase by 2 per cent for customers who do not enter into market based contracts with an electricity retailer.

In its December 2011 Review of Potential Future Prices, the AEMC considered that the retail component of the average residential bill in Tasmania would increase in nominal terms by an average of 10.5 per cent per annum over the period 2011 to 2014 in the absence of carbon pricing, and by 12.5 per cent with carbon pricing. The AER considered that costs associated with the Renewable Energy Target (RET) / Large-scale Renewable Energy Target (LRET) would increase by an average of 23.6 per cent over the period without carbon pricing, and by 10.6 per cent with carbon pricing. Finally, the AER considered that the costs to customers from the Small-scale Renewable Energy Scheme (SRES) would fall by an annual average of 17.7 per cent without carbon pricing and by 16.8 per cent with carbon pricing.

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\(^{27}\) Investigation of maximum prices for declared retail electrical services on mainland Tasmania – Final Report, Office of the Tasmanian Economic Regulator, October 2010.

\(^{28}\) For the 2009-10 financial year, Aurora Energy was assessed by the AER as having the slimmest profit margin built into its electricity prices amongst the five jurisdictions within the National Electricity Market studied by the AER. The retail margin (as a percentage of sales) applying in the Australian Capital Territory in 2009-10, was 5.0 per cent, increasing to 5.4 per cent in 2010-11. The Queensland Competition Authority provided a retail margin of 5.0 per cent (of total costs) in 2009-10, which it carried forward in its final decision for 2010-11. The Independent Pricing and Regulatory Tribunal of New South Wales set a retail margin of 5.4 per cent for the regulatory period commencing on 1 July 2010, which was slightly higher than the previous allowance of 5.0 per cent.

\(^{29}\) Volume risk refers to the risk of a variation in load from year to year arising from changes in customer behaviour and weather.
6.6. Major industrial customer pricing

Throughout the Panel’s review, MI customer pricing has been raised in two perspectives. Firstly, whether a cross subsidy exists between non-contestable customers and MI customers through the relative pricing of each customer group. Secondly, whether Hydro Tasmania’s financial performance is being constrained by the MI customer load in the context of its opportunity value in the NEM.

In investigating MI customer pricing, the Panel examined Hydro Tasmania’s MI contract portfolio. It has also reviewed, in considerable detail, recent negotiations between Hydro Tasmania and two of its largest electricity customers.

The Panel has found no evidence of cross-subsidisation of MI customers by non-contestable customers. Further, the Panel has found no evidence to suggest that, in contemporary commercial negotiations, Hydro Tasmania accepted lower prices from MI customers in return for whole-of-state benefits. The Panel’s own analysis suggests that prices are broadly consistent with market prices and the prices paid by similar businesses interstate.

In arriving at these conclusions, the Panel has considered two key issues:

- the relative prices paid by large and small electricity customers and the reasons for any differences; and

- the validity of the assertion that Hydro Tasmania could earn more revenue by selling electricity into the NEM instead of supplying MI customers at currently contracted rates.

Following is a discussion of both of these issues and the reasoning behind the conclusions reached by the Panel in relation to MI electricity prices.

6.6.1. Relative pricing

That MI customers have access to lower electricity prices compared households and small businesses is not unique to Tasmania. This pattern of pricing is consistently observed in other regions of the NEM, as well as electricity markets internationally. Variations in electricity prices between different types of customers with differing patterns of consumption are not, in themselves, evidence of cross-subsidisation. Given Tasmania’s history of ‘hydro-industrialisation’, it is perhaps not surprising that some in the community question whether the practice continues to the present day.
There are several reasons why MI customers are able to purchase electricity at lower prices than non-contestable customers. These are not limited to the fact that they use more electricity, although the load they require is certainly a factor in establishing the prices they pay for power.\textsuperscript{30}

One of the key factors is load profile. MI customers typically operate 24 hours per day, seven days per week, and as a result have relatively constant or ‘flat’ load profiles, where their peak level of demand varies very little from their average demand. Households and small businesses use fluctuates markedly during the course of a single day, and exhibits a relatively ‘peaky’ load profile. The non-contestable electricity market also displays marked differences in its consumption depending on the seasons of the year.

As a result, much of the generation capacity needed to service a peaky and variable load profiles stands idle during periods of lower demand. The cost of generation capacity to meet peak demand needs to be recovered during the potentially brief periods when the plant is actually in operation. The generation needed to service a flat industrial load profile, on the other hand, can be run much more consistently through the day and year, spreading the fixed costs of those assets over a much greater volume of electricity and avoiding the inefficiencies inherent in being continually started-up and then taken off line. Flat load profiles are significantly easier and cheaper to supply.

To illustrate this point, Figure 6.3 compares the summer and winter load profiles of the non-contestable electricity market with a hypothetical flat load profile that would result in the same level of consumption over the course of a year. In the example shown, it would be theoretically possible to supply the same total annual volume of electricity to a customer base characterised by the flat load profile with only slightly more than half of the generation capacity needed to supply the non-contestable load profile.

\textsuperscript{30} Industrial customers account for around 60 per cent of Tasmania’s total electricity consumption, with four major industrial customers using around half of the energy supplied by the Tasmanian power system between them.
Because of the amount of energy they consume, MI customers are also able to bypass third parties and purchase electricity directly from the NEM, although those that do typically only source part of their load in this way, with the bulk still being obtained under contract. It is not uncommon for MI customer contracts to contain provisions linking their electricity prices with spot market prices, as well as other price related incentives to reduce their demand at times of higher demand in the market and, therefore, higher prices.

Having secured a lower contract price on the basis of their flat loads and flexibility in their demand, some MI customers then take the risk that they will be able to purchase the additional energy they require direct from the NEM spot market at a price that is the same or lower than their contracted price. If they are unable to do so, they will then resort to curtailing production for a period in order to avoid an unacceptably high energy price. Exposure to spot market prices and the ability to manage the usage of electricity at times of peak demand in return for a lower energy price is not currently available to customers on regulated tariffs.

Another reason that MI customers are able to access lower electricity prices is that they are often supplied with electricity on a ‘take or pay’ basis. In simple terms this means that they pay for a contracted amount of energy, regardless of whether they use it or not. Smaller customers, on the other hand, pay only for the energy they use. The commitments involved with take or pay contracts provide the supplier with greater certainty and less risk, and in return, the industrial customer receives a decrease in the price of their energy - balanced against the risk that they may end up paying for energy which they do not use.
MI customer contracts also tend to be long-term, in order to provide the businesses with certainty that their demand for electricity over time will be met, and certainty about the prices they will face for their energy in the future. This also provides their supplier with greater certainty, which is in turn reflected in the energy price on offer.

Further impetus for a reduction in price is provided by the participation of some MI customers in the System Protection Scheme (SPS) which supports the larger southward capacity of Basslink. Under the SPS, industrial customers commit to shed load instantly in the event of an unplanned outage of Basslink while energy is flowing into Tasmania.

Without the SPS, the southbound capacity of Basslink could not be fully utilised, reducing the trading benefits the link provides to Hydro Tasmania. The interruption of industrial load also ensures the security of the entire Tasmanian electricity grid and continuity of supply for residential and business customers throughout the State.

The flexibility of MI customers to respond quickly to a change in system dynamics is a unique characteristic of the Tasmanian electricity market, and provides benefits for both Hydro Tasmania and industrial customers. This source of value is not present in the case of smaller loads, including the non-contestable load, and the terms under which MIs participate in the SPS have been a factor in the commercial negations between Hydro Tasmania and its MI customers.

Aside from lower energy prices, there are other savings available to MI customers which are not available to smaller customers.

MI customers take their supply of electricity directly from the high voltage transmission network, meaning that they bypass the distribution network, the cost of which accounts for approximately 31 per cent of residential and small business customers’ electricity bills.\(^\text{31}\)

Further, MI customers generally pay lower transmission charges. This is because it costs significantly less to service a flat load profile than it does a relatively peaky load profile, or a load centre with marked differences in seasonal demand, such as a town with a high proportion of holiday accommodation. MI customers are also often located closer to the point of generation than many retail load centres.

Some industrial customers are also able to avoid charges for connecting to the transmission network by virtue of owning and operating their own high voltage connection assets, while others pay reduced connection charges that reflect negotiated changes in the level of service provided to them by Transend.

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\(^{31}\) Electricity Pricing - Information Sheet, Office of the Tasmanian Economic Regulator, Declared Electrical Services Pricing Determination, October 2010, Office of the Tasmanian Economic Regulator
6.6.2. Hydro Tasmania negotiations

The Panel has reviewed the contracts and other documents relevant to the most recent pricing negotiations between Hydro Tasmania and the MI customers. This review has enabled the Panel to compare the outcomes achieved by Hydro Tasmania from those negotiations with MI customer pricing of contracts in the past, as well as expected market prices in the future and the alternative value of the energy if the company in question were to cease production.

The Panel's judgment is that Hydro Tasmania has undertaken robust and thorough commercial negotiations of the energy price in its contract negotiations with MI customers. The analysis undertaken by Hydro Tasmania as part of its negotiation process has taken into consideration:

- both current and possible future market conditions;
- the prices paid for similar types and sizes of load across the Australasian region;
- the value to Hydro Tasmania of the additional Basslink southward capacity provided by the customers' willingness to shed load as part of the SPS; and
- the impact that the prices being considered would have on Hydro Tasmania's ability to meet its own financial targets.

The prices set out in the most recently renegotiated contracts tend to be reflective of the current and expected wholesale energy market conditions over the period of the contract, and are not simply an extension of historical pricing.

In the Panel's opinion MI customers do not receive an 'energy subsidy' to stay in Tasmania. The most recent negotiations between Hydro Tasmania and MI customers gave no consideration to anything other than the commercial benefits that would accrue to each party as a result of the contract. The consideration of wider economic/employment issues associated with retaining these customers in the state did not form part of the negotiations.

This is not to say that the availability of relatively low cost electricity has not been used by successive Tasmanian Governments in the past as a means of exploiting a Tasmanian comparative advantage to promote economic development and growth in the State. However, in the contemporary context, there is no evidence of the Government promoting those outcomes by intervening in the negotiation of MI customer contracts. Furthermore, the transmission costs incurred by MI customers are subject to scrutiny by the AER, which is independent of the Tasmanian Government.
The opportunity value of major industrial electricity sales

One of the matters raised by some stakeholders during public consultation was the concern that Hydro Tasmania’s financial performance is being unduly constrained by its MI customers’ prices. The proposition put forward is that Hydro Tasmania could sell some, or all, of its industrial load into the NEM, via Basslink, at higher prices than Tasmania’s energy intensive users of electricity currently pay.\(^32\)

The Panel has tested this hypothesis, by considering a scenario where 100 MW of industrial load left the State and examining the financial impact that selling that amount of energy into the Victorian region of the NEM would have on Hydro Tasmania. The analysis took into account Tasmanian and Victorian spot price outcomes from the 2010 calendar year, as well as the availability of Basslink and the actual flows of energy across the cable during 2010.

Modelling showed that a significant load reduction in Tasmania would lead to a loss of value to Hydro Tasmania, when compared to current and future MI contract prices.\(^33\) Further, if the amount of lost load was increased, the value lost by Hydro Tasmania would continue to increase. The loss of value was driven by the following factors:

- Basslink’s northward capability is constrained at 500 MW in continuous operation, although the cable can transfer up to 630 MW\(^34\) from Tasmania to Victoria for short periods to meet peaks in Victorian demand. Basslink is already being utilised at its capacity to ‘export’ energy at times of high demand and high prices in Victoria. This means that, were ‘surplus’ energy to become available as the result of a reduction in Tasmanian industrial load, Hydro Tasmania would be unable to achieve additional financial value by selling that energy at times when Victorian prices are high.

- Therefore, the delivery of additional energy across Basslink into Victoria, whether it represented arbitrage or a net export of energy, would occur at more moderate Victorian wholesale prices which, for much of the time, are likely to be similar to the prices currently paid by Tasmania’s MI customers.

- Over time, the substantial shift in the supply/demand balance in the Tasmanian market associated with the loss of industrial load would also be expected to have a negative impact on the value of Hydro Tasmania’s contestable market contracts.

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\(^32\) Refer to ‘Community Hearings – Summary of Proceedings’ on the Panel’s website www.electricity.tas.gov.au.

\(^33\) The Panel considers that disclosure of the methodology used to complete this analysis could give rise to commercial sensitivities and potentially influence future contract negotiations, and on this basis has decided not to publish details of the modelling.

\(^34\) Which translates to 594 MW at the Victorian end of the link, after transmission losses.
While some additional value could possibly be captured by Hydro Tasmania not needing to import the same volume of electricity to enable the same level of exports, the value of the energy sold to MI customers in Tasmania is still higher than the value captured by reducing imports.

Value could also be lost by Hydro Tasmania through a reduction in Basslink’s import capability, because the loss of a significant amount of industrial load would also reduce the scope for industrial load shedding as part of the System Protection Scheme. The reduction in the capacity of Basslink to transfer energy from Victoria to Tasmania would restrict Hydro Tasmania’s ability to withhold production at times of very low Victorian prices, and then sell back a matching volume of energy into the Victorian market during the higher price periods discussed above.

It is also possible that without corresponding growth in demand, the availability of additional energy in the Victorian market from Tasmania may decrease wholesale electricity prices in Victoria, which could further decrease the value that could be achieved through the additional capacity available in Tasmania, although this scenario was not investigated.

In conclusion, the hypothesis that Hydro Tasmania stands to gain from the exit of a MI customer by exporting the lost on-island load to Victoria is not supported by the Panel’s analysis of the evidence.
7. Tasmanian network pricing

**Key Messages**

- Transmission and distribution network charges are major determinants of end-user electricity prices. Higher transmission and distribution network charges have accounted for around half of the increases non-contestable customer prices since 2000.

- The networks are capital intensive businesses and the key driver of their revenue is the value of their RAB, which in part reflects the level of new capital expenditure and asset revaluations.

- Since Transend and Aurora Energy were established in 1998, the replacement of ageing and/or obsolete assets has been a major driver of capital expenditure on both the transmission and distribution networks. This was expected at the time these businesses were founded.

- Network augmentation has tended to focus on alleviating localised constraints rather than upgrades to cope with load growth.

- Growth in the overall demand for electricity has not been the driver of capital expenditure for either business that it has been interstate. Demand for new connections has, however, been a major driver of some of Aurora Energy’s capital expenditure.

- The significant capital expenditure program for both networks is now embedded in the asset bases, and the cost of that investment will continue to be recovered for the duration of the operating life of the assets (typically 40 years).

- Network charges borne by particular groups of customers are essentially cost reflective. The primary exception is the cost-shifting that occurs amongst non-contestable customers as a result of uniform network tariffs within customer classes, regardless of location.

- As a result, residential and small business customers in urban population centres are significantly funding the cost of both the distribution and transmission networks for similar customers located in regional and remote areas of the State.

- Tasmanians are not paying higher transmission prices because of Basslink.
7.1. Introduction

All customers utilise the electricity transmission network, and all but a small number of large, energy-intensive industrial customers also utilise the distribution network. Transmission charges are estimated to represent around 17 per cent of total retail electricity bills for Tasmanian residential and small business customers, compared to distribution network charges, which make up a little over 30 per cent of retail electricity bills.\textsuperscript{35}

Transmission and distribution network costs have long been major determinants of end-user electricity prices. Higher charges in the distribution network have accounted for around 25 per cent of the increases in prices paid by non-contestable customers since 2000. Transmission charges, which have increased at the greatest rate of all of the components in the supply chain, have grown for non-contestable customers by 300 per cent in nominal terms since 2000, accounting for just under 25 per cent of the overall increase in non-contestable electricity tariffs.

Transend and Aurora Energy are subject to independent economic regulation to determine the maximum revenue they are allowed to recover on an annual basis in relation to the provision of network services. Their pricing methodologies are required to comply with Chapter 6A and Chapter 6 of the National Electricity Rules respectively.\textsuperscript{36}

Since the disaggregation of the HEC and the creation of Aurora Energy in 1998, the TER has undertaken three investigations of the issues specific to distribution network pricing, which have served as the basis for the TER’s determinations of the annual revenue requirement for Aurora Energy’s distribution business:

- 1999 Investigation into electricity pricing for the three years from 1 January 2000;
- 2003 Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, covering the period 1 January 2004 to 31 December 2007; and
- 2007 Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, applying from 1 January 2008 to 30 June 2012.

Responsibility for the regulation of Aurora Energy’s distribution services has since been transferred to the AER, which is in the process of determining Aurora Energy’s revenue requirement for the period 1 July 2013 to 30 June 2017.\textsuperscript{37}

\textsuperscript{35} Office of the Tasmanian Economic Regulator
\textsuperscript{36} Economic Regulation of Transmission Services and Economic Regulation of Distribution Services
\textsuperscript{37} A draft decision was issued on 29 November 2011, with the final decision due in April 2012.
Similarly, Transend has been subject to three regulatory reviews to determine the maximum allowable revenue that it is permitted to recover in relation to the provision of regulated transmission services:

- 1999 Investigation into electricity pricing for the three years from 1 January 2000, undertaken by the TER;
- 2003 Tasmanian transmission network revenue cap decision for the period 1 January 2004 to 30 June 2009, undertaken by the ACCC; and
- 2009 Transend transmission determination for the regulatory period 1 July 2009 to 30 June 2014, undertaken by the AER.

Electricity transmission and distribution networks are highly capital intensive businesses and, for both, the key drivers of their allowable revenue are the value of the RAB which reflects increasing levels of capital expenditure and asset revaluations, the economic return allowed on the RAB WACC, and operating costs.

The extent to which Transend and Aurora Energy have operated within their respective regulatory allowances is discussed in the Panel’s Information Papers ‘A Review of the Financial Position of State Owned Electricity Businesses’ and ‘A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses’.

The purpose of this Chapter of the Draft Report is to examine the underlying drivers of the growth in Transend and Aurora Energy’s capital and operating expenditure over the last decade.

7.2. Drivers of transmission network expenditure

7.2.1. Capital expenditure

To illustrate the rate at which Transend’s capital expenditure has grown, and continues to grow, the allowance for capital expenditure in the ACCC’s 2003 revenue cap decision was over 25 per cent higher than Transend’s actual average capital expenditure had been over the five year period covered by the TER’s 1999 determination. For the current five year regulatory period, which runs from 2009 to 2014, Transend’s approved capital expenditure totals $641 million (nominal dollars), an increase of 90 per cent when compared with the capital expenditure allowance of $337 million approved by the ACCC for the preceding five and a half year regulatory period.38

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38 Transend actually spent $440 million on capital works during the previous regulatory period. The capital expenditure allowance approved by the AER for the current period represents a 46 per cent increase on that figure.
Since Transend was established in 1998 there has been substantial capital investment in the transmission system to augment and upgrade the network, to replace ageing assets and improve the reliability of the system, service new load centres and meet contemporary standards. The need for this program of work was highlighted at the time the HEC was disaggregated.

The key drivers of Transend’s capital expenditure are discussed below.

### 7.2.2. Non demand asset replacement

Asset renewal has been a consistent theme in Transend’s capital expenditure proposals and the determinations made by the TER, the ACCC and the AER.

The view that Tasmania’s transmission network was old and in need of substantial replacement was established prior to the disaggregation of the HEC. Consultants engaged by the Tasmanian Government in 1997 to provide financial advice regarding proposed Tasmanian electricity reforms, Credit Suisse First Boston, made the assessment that the State’s transmission network required considerable investment to bring its performance up to the standard that a financially sustainable entity operating on a fully commercially basis would provide.

The transmission system that Transend inherited was largely constructed between the late 1950s and early 1970s, and many elements of the network were older than the industry average and approaching, or in some cases had passed, the end of their economic life. A ten-year capital investment program to upgrade and modernise Tasmania’s electricity transmission system had already begun in 1996. When establishing Transend as a separate State-owned company in 1998, the Tasmanian Government foreshadowed a significant expenditure program over a 10-year period to upgrade and replace ageing network assets. Transend was established without any debt in recognition of the requirement for it to undertake significant borrowing in order to finance the replacement of assets that were nearing the end of their useful lives.

In addition to this asset renewal program, Transend also embarked on a major compliance program in 1999 which was aimed at eliminating substandard conductor-to-ground clearances on its transmission lines, after identifying 1,250 transmission line spans around the State which did not meet clearance requirements.
In its 2003 submission to the ACCC, Transend maintained the position that its transmission assets were some of the oldest in Australia, and nearly half (47 per cent) of Transend’s proposed capital expenditure related to the replacement of assets. This was consistent with the proportion of capital expenditure budgets being allocated to asset replacement by other TNSPs at the time.

Despite Transend’s position, the ACCC observed that “Transend’s network is not significantly older than a number of other TNSPs such as SPI PowerNet and ElectraNet.”

Transend’s capital expenditure proposals, including the company’s plans for expenditure on asset replacement, have been repeatedly subjected to independent regulatory and expert scrutiny, and generally assessed as being justified and reasonable in terms of their cost. Nonetheless, a clear theme emerges from the assessments made by the various regulators involved in setting Transend’s revenue allowances over the past decade that Transend has spent proportionally more on asset replacement than other TNSPs.

7.2.3. Demand driven network augmentation

Investing in the transmission network to meet peak demand is frequently raised by TNSPs in Australia as a primary driver of transmission costs, but State-wide load growth in peak demand has not posed a significant issue in Tasmania.

For example, electricity transmission levels have remained relatively constant at just over 10 000 GWh per annum over the period 2004 to 2010. The operation of the transmission system has changed significantly, however, with the commissioning of Basslink resulting in substantially different flows within the system, due to increased power flows through the Northern parts of the network and across Basslink itself. However, the significant step change in peak demand that this entailed has not required augmentation of the transmission network, as the existing network had the physical capacity to service Basslink in addition to on-island demand.

Nonetheless, Transend’s capital expenditure on augmentation and the total cost of electricity transmission in Tasmania has been increasing, and is expected to continue increasing, at a rate that outstrips the average growth in Tasmania’s peak demand.

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44 The ACCC assumed the TER’s responsibility for regulating Transend’s revenue allowance in 2003, which was subsequently transferred to the AER in 2005.

45 53 per cent of SPI PowerNet’s forecast capital expenditure between 2003 and 2008 was allocated to system asset replacement, although as a percentage of the (opening) value of SPI PowerNet’s RAB, capital expenditure on asset replacement was significantly lower than was the case for Transend. Similarly, Energy Australia initially proposed asset replacement expenditure for the period 2004–05 to 2008–09 which represented 54 per cent of its total capital expenditure plans, although this was subsequently reduced to 44 per cent because the ACCC did not consider that Energy Australia’s entire replacement expenditure proposal was justified.


47 A System Protection Scheme involving load shedding and generation interruption in the event of an unplanned outage of Basslink was developed in order to avoid jeopardising the security of Tasmania’s electricity system.
Transend’s augmentation projects have primarily been aimed at addressing compliance obligations and catering for localised demand growth where connection sites have either needed to be established or modified to meet customer demand. This is not dissimilar to the programme of distribution system augmentation undertaken by Aurora Energy over the same period, which has tended to focus on alleviating localised constraints rather than upgrading the network to cope with load growth in an aggregate sense.

A significant component of Transend’s network augmentation has been the construction of a 220 kV transmission line from Waddamana to Lindisfame on Hobart’s eastern shore. With an estimated project cost during the current regulatory period of $153 million ($2008-09)\(^{48}\), this project alone comprised over half of the capital expenditure on augmentation proposed by Transend between 2009 and 2014, and approximately 17 per cent of total planned capital expenditure.\(^{49}\)

While Transend reference increasing demand across southern Tasmania as a driver for the Waddamana to Lindisfame transmission line, the benefits Transend attributes to the project are that it will provide

“more secure transmission supply to Hobart and southern Tasmania and reinforce the current low capacity supply to Hobart’s eastern shore. It will also reduce our reliance on the Chapel Street substation, as well as reducing the load transferred through the transmission lines connected to Chapel Street substation and through the Chapel Street-Risdon 110kV transmission line.”\(^{50}\)

This suggests that the main rationale for this project has been increasing the security of supply to Hobart and southern Tasmania, rather than the delivery of additional energy. This view is consistent with the ACCC’s assessment\(^{51}\) of Transend’s original proposal for a new transmission line linking Liapootah and Lindisfame, (which later became the Waddamana to Lindisfame project).

Despite aggregate demand growth having a smaller impact on Transend’s capital expenditure than is the case for other transmission businesses, analysis of demand forecasts by Transend has identified a number of areas where connection site and/or transmission line capacity needs to be increased in order to meet customer demand. These include areas on the West Coast (particularly around Rosebery and Savage River), George Town’s industrial precinct, the Fingal Valley (Avoca and St Mary’s), the Launceston/Tamar Valley area, Tasmania’s south-eastern area, Hobart’s southern urban area and the Devonport area.

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\(^{48}\) Revenue Proposal for the period 1 July 2009 to 30 June 2014, Transend
\(^{49}\) Revenue Proposal for the period 1 July 2009 to 30 June 2014, Transend
\(^{51}\) Decision - Tasmanian Transmission Network Revenue Cap 2004–2008/09, ACCC, December 2003
Transend also has a number of connection applications and enquiries for new connections on hand (e.g. new wind farms, new mines, and irrigation schemes) and proposals from direct connect major industrial customers to increase load. If they proceed, these connections will also influence plans for localised augmentations.

7.3. Regulatory impacts

7.3.1. Increase in the economic rate of return

Under the Tasmanian economic regulatory framework that previously applied to electricity transmission (and distribution) there was no process for appealing a determination or final decision made by the TER.

Limited ‘merits review’ of AER decisions by the Australian Competition Tribunal was, however, introduced into National Electricity Law in 2007. While there is no automatic right of review of any of the AER’s decisions, network businesses are able to seek a review by the Tribunal of determinations made by the AER.

In 2009, Transend, along with a number of TNSPs, lodged an appeal with the Tribunal against some aspects of the AER’s revenue determination. The appeal was upheld, resulting in Transend’s WACC increasing from 8.80 per cent to 10.0 per cent, and an increase in Transend’s allowed revenue over the 2009–2014 regulatory period by $80 million (8.3 per cent) to $1.043 billion.

The $80 million increase in Transend’s MAR as a result of the appeal meant that instead of increasing, on average, by 3.5 per cent per annum (real), average transmission charges would increase by 5.2 per cent (real) in each year covered by the determination.

Under the AER’s original determination, when compared to the transmission prices applying in the last year covered by the ACCC’s 2003 decision (2008-09), the average cost of electricity transmission would have increased between by 18.4 per cent (real) by 2014. But following the Tribunal’s ruling, average transmission charges are forecast to increase by 29.0 per cent (real) over the five years from 2010 to 2014.

7.3.2. Revaluation of transmission easements

In making its determination of Transend’s allowable revenues in 2003, the ACCC expressed its concern about the revaluation of Transend’s asset base by the Tasmanian Treasurer – a valuation which the ACCC was required to accept as part of the handover of regulatory responsibilities from state-based to national regulation. The Treasurer’s valuation of Transend’s RAB was $525 million, $72 million (15.9 per cent) higher than the valuations previously used by the TER.52

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The ACCC estimated that the revaluation of Transend’s assets alone would increase Transend’s allowed revenue by approximately $7 million per annum, resulting in higher transmission charges without any corresponding benefit to customers. Such an increase in revenue would, according to the ACCC, translate directly to profits, as Transend had not incurred any additional expenses in order to receive the revenue.

The asset revaluation included an increase in the valuation of transmission easements, mainly notional transaction costs incurred in acquiring easements (accounting for about half of the increase), which the ACCC considered bore little resemblance to the actual costs of acquiring the easements.

**7.4. Operating expenditure**

**7.4.1. Increasing workforce and impact on operational expenses**

Transend was established on 1 July 1998 with 44 staff, allocated across three functional groups - transmission asset management; development and regulation; and administration. At the time, the Tasmanian Government’s intention was that Transend would be sold, so only a small number of core staff, sufficient to run the business in the short term, were transferred from the HEC. In turn, those staff managed a workforce comprised mainly of contractors and outsourced labour.

By the end of 2003, however, with plans to sell the company having been abandoned following the election of the Bacon Government in 1998, Transend’s workforce had increased to 127 personnel. The growth in staff numbers had its origins in the allocation of activities at the time of disaggregation of the HEC. At that time, many of the shared resources and functions that had supported the generation, transmission and distribution businesses within the HEC were retained by either Hydro Tasmania or Aurora Energy. Aurora Energy, for example, retained the field maintenance service, and to this day provides a range of services to Transend under contract, including a 24 hour emergency response service, routine maintenance of Transend assets and the installation of new equipment and execution of minor capital works.

Consequently, in order to operate on a stand-alone basis, Transend decided to replicate many of those resources and functions, which resulted in an increase in its workforce. Separately, the transfer of the system control function from Hydro Tasmania to Transend on 1 July 2000 resulted in 27 staff transferring to Transend.
Between the end of 2003 and the end of 2009, Transend’s workforce more than doubled, growing from 127 to 256. Some of that growth can be attributed to the entry of Tasmania into the NEM in 2005 and the creation of a dedicated group within Transend to address the ongoing evolution of market and regulatory arrangements.53

In response to a submission from the Energy Users Association of Australia, the AER examined Transend’s staff numbers in April 2009 as part of its review of Transend’s revenue proposal for the period July 2009 to June 2014.54 The AER found that the growth which has occurred in Transend’s workforce had been neither imprudent nor inefficient, and noted that caution needed to be exercised when interpreting employee numbers, in that an increase in employee numbers might not result in higher operating costs, because external contractor costs might be correspondingly reduced.

The AER also found that Transend’s staffing levels have only increased marginally, in that the growth has occurred as Transend has evolved from “an organisation that initially relied heavily on out-sourcing of labour to perform key functions to a reliance on a mixture of in-house and out-sourced labour.”

In its May 2008 submission55 to the AER, Transend forecast further additions to its workforce in the regulatory control period spanning 2009 to 2014, to “support the delivery of the capital program by increasing resource levels for the provision of technical advice, contract account management and project support services” along with the in-sourcing of protection and control field-based services. Transend’s workforce is currently made up of around 270 people.

Despite the growth in employee numbers, however, Transend’s labour costs, as a proportion of its prescribed operating expenditure budget have remained consistent over time. The efficiency of Transend’s operations are addressed in Chapter 8.

7.5. **Drivers of distribution network costs and prices**

Higher costs incurred by Aurora Energy in the operation of Tasmania’s electricity distribution network have accounted for around a quarter of the increase in prices paid by non-contestable customers since 2000.

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53 Transend was directed by its Shareholders to “do everything necessary to facilitate Tasmania’s entry to the National Electricity Market and to connect Basslink to the Tasmanian power system” (2005-06 Transend Annual Report).

54 Final Decision – Transend Transmission Determination 2009-10 to 2013-14, Australian Energy Regulator, 28 April 2009

55 Transend Transmission Revenue Proposal for the Regulatory Control Period 1 July 2009 to 30 June 2014
7.5.1. Capital expenditure

The replacement of ageing assets and the need to cater for growth in peak demand have been cited by most DNSPs around the NEM as drivers of network costs and both, to varying degrees, are applicable to Aurora Energy.

Non demand asset replacement

The replacement of ageing and obsolete assets has been a significant driver of distribution network costs for Aurora Energy. Asset replacement has been a recurring theme in Aurora Energy’s proposals to the TER over the past decade, and typically represented around 21 percent of the capital expenditure allowances approved by the regulator during that time.56

For example, in 1999 Aurora Energy proposed a significant increase in capital expenditure to replace ageing assets, with the objective of improving security of the distribution network. In 2003 Aurora Energy’s proposed capital expenditure involved a further step up from historic levels – an average increase of nearly 24 percent per annum above the level of expenditure since 1999 – particularly in relation to expenditure on non demand related asset replacement.57 In 2007, in addition to network upgrades to meet new demand, Aurora Energy again planned a major program of investment to address issues with ageing network assets.

In its 1999 submission58 to the TER regarding the pricing determination that would apply from 1 January 2000, Aurora Energy cited its ageing pole population as the major category of asset in need of replacement, in particular the pressure impregnated poles first installed in the 1960s that were by then beginning to reach the end of their useful (40 year) lives. It was also noted that extensive ‘forced’ replacement of poles occurred following the 1967 bushfires, meaning that a significant portion of Aurora Energy’s poles were projected to reach the end of their operational life over the following ten years and need replacing. Aurora Energy forecast that its pole replacement program would need to be up to four times higher than then current levels in order to achieve this outcome.59

Substandard galvanised iron conductors installed in rural areas60 after the Second World War were also identified as being in need of replacement, as was some of the oil insulated switchgear introduced with underground cables in the 1960s.

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56 Based on information contained in Energy to the people - Aurora Energy Regulatory Proposal 2012-2017
57 The preceding assessments of Aurora Energy’s capital expenditure proposals relative to its pre-1999 and pre-2003 expenditure reflect comments made by the TER as part of the relevant regulatory determinations.
58 Submission to the 1999 Electricity Pricing Investigation, Aurora Energy, May 1999
59 Aurora Energy currently has 220 000 poles in service. Source: Aurora Energy Regulatory Proposal 2012-2017
60 Aurora Energy had approximately 250km of HV lines using galvanised iron conductors.
Having highlighted the need for extensive pole replacement in 1999, Aurora Energy’s December 2002 submission to the TER shows that from 1999-2000 to 2002-03 Aurora Energy spent $48 million on non demand asset replacement, of which $33 million (69 per cent) was spent on pole replacement and staking.

Aurora Energy’s 2002 submission to the TER also canvassed the requirement for non demand related capital expenditure in the future, noting that substantially more expenditure on non demand asset replacement would be needed over the following two decades than had previously been the case. The replacement of overhead structures, including poles and conductors, continued to dominate the business’ capital expenditure requirements in this regard.

For the 2003 regulatory period, Aurora Energy proposed a level of non demand asset replacement that represented, on average, around 21.5 per cent of its total capital expenditure budget.

The TER approved Aurora Energy’s capital expenditure proposals, with only minor revisions made to reflect a reduction in the number of poles that the TER considered needed replacing. Nonetheless, around 70 per cent $44.1 million of the $62.7 million in expenditure on non demand asset replacement approved by the TER was attributed to the replacement of overhead structures, i.e. poles, pole-tops and conductors.

In its 2007 submission to the TER, over 60 per cent of the increase in average annual capital expenditure proposed by Aurora Energy was attributed to non demand asset replacement. Aurora Energy proposed increasing non demand replacement from an average of $15 million per annum over the preceding four years to approximately $30 million per annum in the forthcoming regulatory period. It contended that even that level of expenditure would not be sufficient to prevent continued ageing of the asset base and the emergence of increased risks to reliability. Aurora Energy estimated that expenditure on non demand asset replacement would eventually have to reach $60 million per annum in order for the distribution network to be ‘sustainable’ in terms of its ability to meet acceptable service and safety targets.

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62 Pole replacement and staking alone represented 20 per cent of Aurora Energy’s total expenditure on regulated assets during that period (excluding motor vehicles). In addition, as part of its operations and maintenance expenditure during the same period, Aurora Energy also spent $9.3 million on pole inspection.
63 While this was less, proportionally, than Aurora Energy reported having actually spent in the preceding regulatory period, Aurora Energy noted that expenditure to deal with non demand related replacement could also be found in the proposals put forward in relation to other expenditure categories, such as reliability and performance, and capacity augmentation. Once this was taken into account, Aurora Energy estimated that expenditure on non demand asset replacement would be approximately double the level previously allocated).
In addition to the ongoing replacement of poles, by 2007 Aurora Energy had identified additional assets requiring replacement, including overhead conductors, low voltage circuit breakers containing asbestos, and ground mounted substations dating back to the 1960s.

Information contained in a submission by Aurora Energy to the AER in 2011\(^{64}\) shows that from 2003-04 to 2010-11, even after the substantial increases approved by the TER, Aurora Energy exceeded its cumulative capital expenditure allowances in relation to non demand asset replacement by 20 per cent ($28 million, 2010 dollars).

That over-expenditure is now incorporated into the value of Aurora Energy’s RAB, meaning that the cost of Aurora Energy’s asset replacement program, including the expenditure over and above the allowances approved by the TER, will continue to be recovered from customers for the duration of the operating life of the replacement assets (typically 40 years).

**Localised demand growth**

As noted in a submission to the TER by Aurora Energy in December 2002\(^{65}\), State-wide load growth has not posed a significant issue for Aurora Energy’s distribution business. Growth has been modest over the past decade, with total energy consumption and peak demand actually decreasing in 2009 and 2010 amongst the customers serviced by Aurora Energy’s distribution network.

However, the past decade has seen a ‘shifting’ of load which has placed localised strain on the distribution system. The issues that have contributed to this load shift include the Australian Government’s wood heater buy back scheme, which has had a significant impact on the level of demand in Launceston and its surrounding areas, increased levels of tourism, particularly on the east coast, and the increased consumption of electricity in rural areas as farmers have changed from livestock farming to (irrigated) cropping.

Accordingly, capital expenditure to service growth in demand has focussed on what Aurora Energy describes as growth ‘hot spots’. Load forecasting undertaken by Aurora Energy in 2005 identified 12 specific areas where high customer load growth was expected to result in constraints on Aurora Energy’s ability to supply load at some point in the coming decade. At a higher level, Aurora Energy’s load data shows high customer load growth in the Hobart (eastern and northern suburbs), southern (Kingston), Tamar west (Launceston) and East Coast areas of the State.

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\(^{64}\) Aurora Energy Regulatory Proposal 2012–2017

\(^{65}\) Submission to the Electricity Pricing Investigation, Aurora Energy, December 2002
In some cases, such as the Kingston area, load growth has been the result of high volumes of residential and commercial development, as new subdivisions and housing developments give rise to demand for new connections. Much of that growth was unanticipated, and the demand for new connections, fuelled by the strength of the Tasmanian economy, has been a significant driver of Aurora Energy’s capital expenditure on the distribution network, particularly during the middle part of the past decade.

To illustrate, based on figures contained in a 2011 Aurora Energy submission to the AER, between 2004 and 2008 Aurora Energy incurred capital expenditure to service the new or upgraded connections requested by customers that was more than double (120 per cent) above the estimated expenditure approved by the TER in the two pricing determinations spanning that period. In 2010 dollars terms, that overspend represents an additional $102 million in capital expenditure which, having been assessed by the TER as being prudent, has been added to the value of Aurora Energy’s regulated asset base, where it will continue to influence pricing outcomes for all customers for the duration of the assets’ operating lifecycles.

In addition to the higher than expected expenditure on customer connections, the combination of unexpectedly high economic growth during the middle part of the decade resulted in some significant system capacity-related projects being brought forward, such as two new zone substations for the Hobart region – one at Cambridge with a total cost of $13.1 million and another to be built at Kingston, at an estimated cost of $15 million.

The impact of these localised growth centres on Aurora Energy’s capital expenditure can also be seen in projects such as the Hobart Area Supply Upgrade as well and the Launceston Supply Upgrade.

The upgrade of supply to the Hobart area has already seen upgrades of six existing zone substations from 22kV to 33kV and increases in the capacity of their transformers, and new zone substations planned for Howrah and Rosny. The Waddamana to Lindisfame transmission line, while primarily intended to provide greater security of supply for to Hobart and southern Tasmania, has also been engineered to cater for future load growth, particularly on Hobart’s eastern shore.

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66 And its spending in excess of regulatory allowances
67 ‘Energy to the people’ - Aurora Energy Regulatory Proposal 2012–2017
68 Aurora Energy annual report 2008/2009
69 Aurora Energy annual report 2008/2009
70 West Hobart, East Hobart, Sandy Bay, Derwent Park, Claremont and New Town
In the case of Launceston’s electricity supply, Launceston was previously serviced by only two substations, located at Trevallyn and Norwood, which – as the result of growth in demand – were overloaded, making Launceston vulnerable to transformer failure at either substation. Work undertaken by Transend means that Launceston is now serviced by a ring of new and upgraded substations\(^1\) and Aurora Energy has been required to significantly reconfigure and reinforce its network of higher voltage feeders in order to facilitate the transfer of load between those substations, providing relief for Transend’s overloaded assets at Norwood and Trevallyn and increasing the ability of Launceston’s supply to withstand transmission asset outages.

Aurora Energy’s distribution business has also seen significant increases in the costs of labour and materials associated with capital investment in its network.

### 7.6. Common questions about transmission and distribution network charges

During the course of the Panel’s investigations, stakeholders have raised a range of issues in relation to the drivers of transmission and distribution network charges, the current level of transmission and distribution charges, and the relative charges borne by different categories of customer.

The main themes that emerged during the Panel’s consultation with the wider community were:

- the perception that Tasmanians are paying higher transmission charges because of Basslink;
- a belief that the transmission and distribution network charges borne by particular groups of customers are not entirely cost reflective, resulting in a shifting of costs to other customers; and
- a view that the framework for the economic regulation of network service providers has contributed to rising transmission and distribution charges.

These issues are addressed in the remainder of this Chapter.

#### 7.6.1. The impact of Basslink on transmission prices

Transend was directed by its Shareholder Ministers to “do everything necessary to facilitate Tasmania’s entry to the National Electricity Market and to connect Basslink to the Tasmanian power system”\(^2\) and in 2000-01 the Company established a special project team to handle the issues associated with Basslink and prepare for Tasmania’s entry into the NEM.

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\(^1\) Including new connection points at Hadspen and Mowbray and, soon, St Leonards

\(^2\) Transend Annual Report 2005-06
However, no upgrades of the existing transmission network were undertaken, nor were any new transmission circuits constructed, as the existing network had the physical capacity to service Basslink, in addition to on-island demand. A SPS was developed to enable it to do so without jeopardising the security of the electricity system, along with new connection equipment at Transend’s George Town substation.

The SPS and the Basslink connection equipment at the George Town Substation, which in 2006 had a combined value of $10 million, were paid for by the developers of Basslink, National Grid Australia, and transferred to Transend at no charge. While these assets sit on Transend’s balance sheet, as ‘gifted’ assets – and assets that are also part of a ‘negotiated’ service for a direct connection customer – they are not included in Transend’s RAB.

Consequently, neither the SPS nor the connection assets at the George Town substation are included in the calculation of Transend’s allowable revenue by the AER, meaning that neither direct connect customers, such as the State’s largest industrial sites, nor small non-contestable customers (via Aurora Energy) contribute to the cost of those assets through transmission charges. Moreover, according to Transend, the SPS actually “saved the outlay of hundreds of millions of dollars to build new transmission circuits or reinforce existing infrastructure.”

The original estimate of the cost to Transend of the Basslink/NEM entry project itself was $3.3 million over three years, although the time frame for the project was extended because Basslink was delayed, resulting in the cost of the project being greater for Transend than originally estimated. The costs associated with the Basslink/NEM entry project were not allowed for in the TER’s 1999 decision regarding transmission use of system charges, nor was any allowance made for their retrospective recovery in subsequent regulatory determinations, despite Transend’s submissions to that effect.

As Transend had no other means of recovering those costs, the additional expenditure incurred in relation to Basslink and the funding of its contribution to the Tasmanian Government’s NEM entry initiative had a direct impact on the Company’s earnings, resulting in a $1.2 million reduction in profit before tax in 2001-02 alone.

The ongoing operational costs incurred by Transend in connection with the SPS, and the operational costs associated with the connection assets servicing Basslink, are also excluded from Transend’s revenue cap. Tasmanian customers, whether large or small, are not, therefore, required to make any contribution toward Transend’s costs associated with Basslink, with the cost being recovered from the parties who are the beneficiaries of the trading opportunities the link provides.

73 Transend Annual Report 2005-06
Therefore, Tasmanian customers do not pay higher transmission charges than they would if energy were not being ‘transported’ over the network to a connection with Basslink.

7.6.2. Cost shifting between customer groups

Recovery of transmission services revenue

One of the main issues raised with the Panel in relation to transmission pricing is the issue of cost shifting, both between market segments and within customer categories. On the one hand, some industrial customers have questioned if industry is subsidising the transmission costs of smaller contestable customers and the non-contestable market, while on the other, many within the general public believe the reverse to be the case.

An examination of Transend’s pricing methodology reveals that there is no difference in the methodology used for developing transmission charges for Aurora Energy’s distribution business, which then flow on to residential and small business customers, and the methodology used in relation to direct connect customers, including MI customers. Despite a common methodology, however, the MI customers that are supplied electricity directly from the transmission network do generally pay lower locational transmission charges than Aurora Energy.

The existence of pricing differences is not, of itself, evidence of ‘cross subsidisation’ between customers. In this case, the differences in transmission charges reflect a number of factors, including the fact that Aurora Energy’s distribution network is serviced by more connection assets than the MIs - relative to their respective demands for electricity. At an individual connection point level, Aurora Energy’s connection points are also typically more distant from generation than those servicing MI customers, and many of Aurora Energy’s connection points also have a much lower load factor than those servicing large industrial customers - which continuously take-off a level of energy that closely matches the peak demand nominated in their contracts with Transend.

Some industrial customers are also able to avoid charges for connecting to the transmission network by virtue of owning and operating their own high voltage connection assets, while others pay reduced connection charges that reflect negotiated changes in the level of service provided to them by Transend.

75 This was raised with the Panel during meetings with MI customers.
76 The issue of cross subsidies between small and large customers has been raised in public hearings and in submissions.
Despite Aurora Energy, on average, paying more for transmission services than some of Transend’s largest direct connect customers, the cost differential is less than it might otherwise be because of the scope for non-locational TUoS and Common Transmission Service Charges relating to individual connection points to be calculated on either a capacity or a usage basis. If only capacity-based charges were applied by Transend, Aurora Energy would pay significantly more than it does for transmission services because of its relatively peaky load profile, and the often marked differences in seasonal demand at particular connection points, such as those that service load centres with a high proportion of holiday accommodation.

It is possible that a large direct customer might view this use of ‘optimised’ pricing as an example of heavy industry subsidising smaller contestable customers and the non-contestable market, because it reduces the overall price differential between the transmission charges faced by Aurora Energy and MI customers. Nonetheless, large directly connected customers do pay less for transmission services and there are a number of smaller industrial customers which are charged energy-based Common Transmission Services Charges rather than capacity based prices, just as there are connection points servicing the distribution network for which Aurora Energy’s charges are capacity based.

Despite the focus in the NERs on transmission pricing based on attributable costs, there are a number of circumstances under the NERs in which – at the margins – customers may pay transmission prices that are not entirely cost reflective, or pay for transmission services assets which do not benefit them, either directly or indirectly. For example:

- The ‘stranding’ of transmission assets resulting from the closure of an MI customer with a direct connection to the transmission network would result in customers throughout the State, regardless of their location, paying for those stranded assets for as long as they remain part of Transend’s RAB.

- The requirement under the NERs that the locational TUoS charges applying to a particular connection point must not change by more than 2 percent per annum compared with the load weighted average price for locational TUoS charges in general, can mean that when major new assets are commissioned to service a particular connection point, Transend could conceivably face an under recovery of locational TUoS charges if it were not able to recover any ‘excess’ price increase from the remainder of its customer base.

While these outcomes might be regarded by some as inequitable, they are consistent with the pricing principles for prescribed transmission services set out in the NERs, and in the longer term benefit all consumers by minimising price shocks and providing greater price stability at an individual connection point level. Any pricing outcomes that are not completely cost reflective are also generally transitory in nature, rather than ongoing, and serve to facilitate more gradual paths towards fully cost reflective pricing.
A notable exception to this assessment relates to the recovery of transmission network costs from non-contestable customers, such as residential customers, via retail electricity tariffs. While Transend is required to provide Aurora Energy with (and make public) cost-reflective transmission charges for each connection point servicing Aurora Energy’s distribution network, the mandated use of uniform retail (and distribution) pricing by Aurora Energy means that no locational pricing signals are passed through to the vast majority of customers in Tasmania through retail electricity tariffs.

Consequently, a residential customer in Lenah Valley, for example, makes the same effective contribution to transmission network costs as a customer in Triabunna, despite the fact that the customer in Lenah Valley is serviced by a connection site which incurs significantly lower locational TUoS costs than the connection point serving Triabunna.

Another inconsistency in the recovery of costs from the beneficiaries of transmission services arises in relation to certain assets which primarily exist to provide connection services for a generator, but also supply load to maybe even only one customer, but are deemed to form part of the shared network as a result.

Under the current national transmission arrangements, generators do not pay for the extent to which they utilise the transmission network to ‘move’ their energy, and pay only ‘entry’ connection charges, although inefficiently located generation will incur higher marginal loss factors. That generators pay no Common Service charges or even locational TUoS charges represents a significant financial benefit. However, there are provisions in the NERs that provide network users, including generators such as Hydro Tasmania, with additional financial windfalls, at the expense of other network users.

To illustrate, when Transend adopted the pricing guidelines from the National Electricity Code in 2003, a number of radial transmission lines were identified that were primarily used to connect generators to the transmission network, but which were also required to supply load. Under Transend’s pricing policy at the time (developed in accordance with the NEC and approved by the Regulator), the costs of these assets were allocated to the shared network, meaning that Hydro Tasmania made no contribution toward the cost of those existing transmission lines.

Under the current NERs and Transend’s latest pricing methodology, released in 2009, where assets provide more than one category of prescribed transmission services, any portion of the costs of those assets not allocated to either TUoS or Common Services can be attributed to entry and/or exit services. This means that, in theory, the cost of connecting generation to the transmission network can now include the cost of those radial transmission lines in Tasmania that connect one or more generators - as well as one or more transmission customers, to the extent that those lines relate to the connection of generation.
However, when the changes were made to the NERs that made it possible (from 9 February 2009) for asset-related costs to be allocated to more than one category of prescribed transmission service, transitional provisions introduced at the same time protected certain arrangements applying to existing assets. The transitional provisions ensured that the costs associated with the radial transmission lines in question would continue to be allocated to TUsS services, until such time as the connection agreement between Hydro Tasmania and Transend is amended for the purposes of altering the relevant service, and then only at the request of Hydro Tasmania. It is noted that this is not a unique circumstance, in that the same arrangements also apply to load connection services.

**Recovery of distribution network revenue**

The AER has assumed the responsibility for regulating Aurora Energy’s distribution business and the network pricing that will apply from 1 July 2012 to 30 June 2017. Until then the pricing methodology used by Aurora Energy will continue to be overseen by the TER under the current regulatory determination.

The TER requires the distribution network revenue expected to be recovered from each network tariff customer class to lie on or between an upper bound representing the stand alone cost of serving the customers who belong to that class, and a lower bound representing the avoidable cost of not serving those customers. In practice, this provides for an extremely wide range of ‘acceptable’ outcomes, but as long as the revenue recovered from each customer class falls within this range, ‘cross-subsidisation’ does not exist. This is consistent with the Panel’s view about cross-subsidies.

There are, however, a number of circumstances where the distribution network costs borne by particular groups of customers are not entirely cost reflective, resulting in a shifting of costs to other customers.

**The impact of uniform tariffs**

The most obvious example arises from the requirement under the Price Control Regulations\(^7\) that network tariffs for small customers belonging to a particular class be uniform, regardless of location. Aurora Energy complies with this principle by setting distribution tariffs for each low voltage tariff class which are the same across mainland Tasmania. This is not the case in other states, where multiple distribution networks operate, often servicing multiple retailers, resulting in differential distribution pricing between urban and regional customers, and even between different suburbs within major population centres.

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\(^7\) Electricity Supply Industry (Price Control) Regulations 2003
For Tasmanian customers, the requirement for uniform pricing means that the substantial differences in distribution network costs involved in servicing, for example, residential customers in a low density rural area as opposed to a high density urban population centre, are not reflected in the prices paid by the vast majority of customers. Further, the locational pricing signals built into Transend’s pricing are lost as they are passed through to Aurora Energy’s retail business by its distribution arm and, ultimately, repackaged into the retail tariffs paid by end users. As a result, residential and small business customers in urban population centres are underwriting the cost of both the distribution and transmission networks for similar customers located in regional and remote areas of the State.

The relationship between network costs and regulated tariffs

Even though Aurora Energy’s distribution prices for each tariff class are developed on a ‘per customer’ basis, and reflect factors such as time of use, there is a disconnect between the charges developed by Aurora Energy’s distribution business and the daily fixed charges applied to non-contestable customers by Aurora Energy’s retail business.

This disconnect is, according to Aurora Energy, “largely a matter of history,” but is also due to the fact that the fixed daily charges paid by Aurora Energy’s non-contestable customers currently include the recovery of other elements, such as the cost to serve allowance. The disconnect is not as significant as it once was, however, and is progressively being diminished. Aurora Energy’s Tariff Strategy sets out a number of Retail Tariff Policy Objectives, including the objective that “the strategy will attempt to align (over time) the retail tariffs with the approved network tariffs.”

Aurora Energy has been progressively implementing changes to its distribution prices that are designed to eliminate cost shifting that has historically existed between certain customer groups. Some of those inconsistencies have their origins in long-standing pricing arrangements which, in most cases, pre-date disaggregation. An example of the pricing arrangements which Aurora Energy is looking to phase out are the ‘curtilage’ discounts that, until July 2008, were offered to rural customers with residential dwellings, farm out-buildings and non-irrigation pumps located on the same property that were fed from the same transformer as the residence, but required more than one meter.

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78 A 2007 report by the Joint Working Group advising the Tasmanian Reliability and Network Planning Panel published estimates of the approximate replacement cost of Tasmania’s distribution network for a number of different types of community. Those estimates showed that the capital cost of the distribution network required to service customers in lower density rural areas was over eight times the cost of servicing urban customers.

79 Final Revised Retail Tariff Strategy, Aurora Energy, April 2011

80 ibid
Aurora Energy’s principle of simplifying its tariff structure also requires customers with materially similar load and connection characteristics to be placed on the same network tariff. Again, this is not always the case with interstate distribution network operators, in that differential pricing between residential customers and non-residential customers, who may have similar usage and demand profiles, is not uncommon.

However, on the basis that “it is inequitable that customers with similar supply costs should experience different tariffs”81, the distribution charges relating to small low-voltage business customers82 and residential connections83 have been brought together during the current regulatory period, so that their structure and rates are consistent, with a view to consolidating the two network tariffs in the future.

**Pricing caps for large customers**

There are approximately 20 large customers connected to Aurora Energy’s distribution network that have an individual tariff calculation undertaken for their site, which reflects the transmission charges levied on Aurora Energy by Transend (based on the transmission assets which service those large customers) and the distribution network costs attributable to those customers. The revenue to be recovered from these large customers is removed from the revenue to be recovered from other classes of customers before Aurora Energy develops its pricing regime.

However, Aurora Energy can and, on occasion does, cap the total network charges payable by a particular large customer, in order to address the threat of ‘bypass’ and avoid the potential stranding of the distribution network assets which service that customer. This is an efficient form of pricing. These caps shift some of the distribution network costs attributable to customers with capped network charges back onto other customers, including smaller contestable customers and residential customers. The magnitude of any cost shifting is, however, less than the likely ongoing costs to customers associated with the distribution assets that would be stranded if a large customer elected to bypass the distribution network and take its supply directly from the transmission network. The avoidance of bypass is, therefore, an example of economically efficient pricing and, as such, is permitted by the TER.

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82 General Network – Business (N02)
83 LV General Network – Residential (N01)
The network tariffs applying to different customer groupings are also set to provide pricing signals, for example, shifting demand from peak to off-peak periods. However, the retail tariffs applying to non-contestable customers, including residential customers, currently ‘mask’ any network related pricing signals. Further, the lack of an installed base of interval meters\(^{84}\) in Tasmania means that even if retail electricity prices did reflect time-of-use or demand-based network costs, most small retail customers would be unable to control their own network related costs by modifying their usage of electricity.

Nonetheless, Aurora Energy’s distribution tariffs are being transitioned so that they would be sufficient to send appropriate signals to customers in the event that:

- full retail contestability is to be introduced;
- Aurora Energy’s distribution tariffs were to be passed through to customers without being repackaged into flat tariffs; and
- it becomes possible when allocating TUoS charges to end users/customer classes for Aurora Energy to preserve the pricing signals present in the structure of Transend’s TUoS charges.

**Developer charges - Sharing the cost of upgrading the distribution network**

The cost of augmenting the shared distribution network to cater for general demand growth is shared amongst all customers, as are the costs associated with connecting small customers with ‘standard’ connections, such as residential customers.

In some circumstances, however, the contribution to connection costs included in network tariffs will, over time, fall short of the costs associated with providing new or upgraded connections to individual customers, particularly where a customer is not close to the existing distribution network or the existing network is already fully utilised and augmentation of the network is required in order to service new customer connections.

Under the NERs, Aurora Energy can recover capital contributions, prepayments and/or financial guarantees from customers in relation to the provision of any new assets, including upgrades of the general distribution network, installed as part of a new connection or modification to an existing connection. Capital contributions from customers are effectively a form of network price, which is paid up front rather than over time.

However, the current customer contribution arrangements give rise to cost shifting, which sees all customers funding new customer connections through increased network tariffs, rather than the specific customers that receive the benefit.

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\(^{84}\) meters that can record electricity usage in half hour blocks
As a result, property developers and larger customers have been receiving financial benefits at the expense of other customers connected to the system. Aurora Energy estimates that, over the five years from 2007 to 2011, the under recovery of capital costs associated with extending services to all new connection customers has been in the order of $80 million, resulting in higher retail electricity charges for all households and small businesses.

As a percentage of Aurora Energy’s capital expenditure on customer generated work over the past five years (about $200 million), the value of the dedicated capital works undertaken to connect property developments and larger customers, but funded by the entire customer base, represents about 40 percent of Aurora Energy’s total expenditure on customer driven network infrastructure. A further 20 percent was recovered from the direct beneficiaries of those new connections via capital contributions, with the balance relating to expenditure on the shared network.

Aurora Energy has advised that the recovery of that additional cost translates into an estimated increase in annual costs of about $20 per customer. This additional cost will continue to be borne over the operational life of the assets in question, which is likely to be in the vicinity of 40 years. The cumulative impost is, therefore, much more material, and likely to be higher still, given that the under-recovery of capital contributions has been occurring for much longer than the past five years.

This outcome has led to a number of changes to Aurora Energy’s Customer Capital Contributions Policy to ensure a more equitable outcome for all customers. A number of other external factors have also influenced the changes to the existing policy, including the proposed commencement of the National Energy Customer Framework from 1 July 2012 which will ensure a more consistent approach by distribution companies throughout Australia.85

The masking of connection costs by repackaging them as part of standardised tariffs fails to send appropriate price signals. While requiring a customer to pay all or part of the capital cost of ‘non-standard’ connections may act as a barrier to connection, if the true costs of connection are hidden, cost effective alternatives to connection to the distribution network at that location – such as off-grid generation using renewable sources of energy – may not be considered, particularly in less densely populated areas. This distorts a customer’s decision-making in favour of connection to the electricity grid, leads to lower-cost alternatives not being delivered and places upward pressure on the network prices faced by all customers.86

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85 The Tasmanian Government is yet to announce how and when it will implement the NECF arrangements.
86 For example, the Australian Government’s Solar Credits scheme offers incentives to encourage the installation of small-scale off-grid renewable power generation where the site being supplied is more than a kilometre from the main grid, or would cost in excess of $30 000 to connect to it. There are already many properties in Tasmania where the distribution network has been extended by more than 1km in order to supply electricity, or extended at a cost of more than $30 000, but in the absence of appropriate signals to property owners or developers
7.6.3. The impact of the regulatory framework on network costs

One of the objectives of economic regulation is to prevent monopoly service providers charging customers more than the efficient cost of providing those services and/or providing lower levels of service. In light of recent substantial increases in electricity prices, which have been attributed to rising network costs, and the prospect of further increases, the economic regulation of electricity transmission and distribution networks has been the subject of considerable debate nationally.

While many of the issues involved in that debate are as pertinent to Tasmania as any other jurisdiction, the economic regulation of the electricity networks is outside of the direct control of the Tasmanian Government.

The AER and the Energy Users Rule Change Committee (EURCC) have both proposed changes to the national arrangements for the price regulation of networks to the AEMC, with a view to addressing perceived shortcomings in the current regulatory arrangements.

The AER’s proposals aim to enable a more effective and robust assessment of the efficient costs proposed by electricity network businesses by removing current restrictions on the assessment process required to be followed by the AER. The AER has also proposed changes to the mechanisms for setting the rate of return on investment for electricity networks.

The changes put forward by the AER do not seek to amend the fundamental building block, incentive based regulatory model. Further, despite the AER’s concerns about the current merits review system, the merits review process itself is not the subject of the AER’s attentions, as changes to the merits review mechanism would require legislative amendment.

The AER’s submission to the AEMC does, however, propose:

- removal of the requirement to automatically roll-in capital expenditure above the forecast into the RAB at the beginning of the next regulatory period, with only 60 per cent of any overspend on capital to be added to the asset base in the next regulatory period and the remaining 40 per cent funded by shareholders, with no return on or of capital; and
- a streamlined process for determining the cost of capital.

through the use of cost reflective connection pricing, new uneconomic connections will continue to be added to the network.

88 The relevant legislation requires that a review of the merits review mechanism be undertaken by 2015.
The EURCC has proposed changes to the methodology for the calculation of the regulated return on debt applying to network service providers (NSPs). A feature of the EURCC proposal is that different methodologies would be applied to private and government-owned NSPs.

These proposals are currently under review by the AEMC and are outside the scope of this Review. More information can be obtained from the AEMC website.89

On 9 December 2011 the Minister for Resources and Energy, Martin Ferguson AM, MP announced terms of reference for an inquiry by the Productivity Commission into aspects of national electricity network regulation. The inquiry will examine whether there are any barriers in the existing regulatory framework that prevent greater use of productivity benchmarking by transmission and distribution networks, with a view to delivering more efficient outcomes to consumers. It will also examine whether sufficient transmission network interconnection is being provided to support the efficient operation of the National Electricity Market.

The Productivity Commission’s inquiry is expected to commence in January 2012 and will be required to deliver its final report to the Australian Government within 15 months.

8. The performance of the Tasmanian electricity sector

Under its Terms of Reference, the Panel is required to investigate and report on the performance of the Tasmanian electricity supply industry from two main perspectives:

- The **efficiency and effectiveness** of the industry, with particular reference to the existing regulatory framework and the cost and operation of the energy industry elsewhere in Australia. (ToR 1); and

- The **financial position** of the State-owned energy businesses: Transend Networks, Hydro Tasmania and Aurora Energy (Tor 4)

This Chapter presents the Panel’s key findings from its investigation into the performance of the industry.

The Panel selected the period 2004 to 2010 for its investigation, principally because this period spans the key events in the development of the TESI – physical interconnection via Basslink, adoption of the NEM arrangements and the phased roll-out of retail contestability to Tasmanian electricity customers.

The Panel engaged external expertise to assist with this component of its Review. Consultants Wilson Cook and Ernst & Young provided detailed analysis of the efficiency and effectiveness and financial performance of the TESI respectively.

The Panel’s analysis of **efficiency and effectiveness** considers the technical performance of the Tasmanian electricity sector and the extent to which activities are carried out at least cost.

The Panel’s **financial review** looks at the financial position of the SOEBs from both a ‘whole of portfolio’ and individual business perspective. Analysis is limited to the financial sustainability of the SOEBs only and does not consider wider value considerations of business activities, such as contribution to broader economic or community benefits (beyond direct returns through dividends).

While the Panel examined the SOEBs efficiency and effectiveness and financial performance separately, there are clear overlaps and strong linkages between the two. For example, one of the key reasons that efficiency ‘matters’ in the context of the SOEBs is that it ultimately drives the financial performance of the businesses and their ability to deliver financial returns to the community.

Observed outcomes from this aspect of the Review have also informed the Panel’s views on governance in the TESI, particularly with regard to the effectiveness of Shareholder oversight and SOEB accountability. These matters are discussed further in Chapter 12.
8.1. Efficiency and effectiveness

**Key Messages:**

Efficient SOEBs are important to the Tasmanian community from their perspective as both electricity customers and the ultimate owners of the businesses. Ultimately, efficient operations of the SOEBs will deliver efficient electricity prices and drive financial performance, resulting in appropriate and sustainable returns on the Tasmanian community’s investment in the businesses that are not at the expense of electricity users.

The Panel has found that the effectiveness of the TESI - in other words, its technical performance - is broadly comparable to level experienced in other Australian jurisdictions. In summary:

- The technical performance of Hydro Tasmania’s generating plant currently meets the risk management requirements that arise from its participation in the NEM, particularly its ability to asset-back its trading position.
- The transmission network is performing in line with industry standards and improving by comparison with peer entities.
- Distribution network effectiveness has exhibited mixed performance relative to regulatory benchmarks.
- Customer service at the retail level appears to be relatively stable, and may require additional focus in the event that full retail contestability is introduced.

Benchmarking the efficiency of the TESI - or the extent to which activities are carried out at least cost - is more difficult due to the differences in scale, operating environment and industry structure in other jurisdictions.

The focus on efficiency has varied across the SOEBs. The regulated businesses (transmission, distribution and retail) have regularly overspent their regulatory allowances over the past decade. The preparedness to accept the resulting poor financial performance reflects an insufficient and inconsistent focus by the Boards and the Shareholders on efficient business performance.

Changes in regulatory incentives and governance arrangements to improve efficiency have been implemented recently, with some early positive results.

Optimising business performance within the broad parameters established by the economic regulatory environments remains the domain of management and Boards, with Shareholders providing the ultimate incentives and sanctions for efficiency and effectiveness. Developing and maintaining a culture of maximising efficiency and continual improvement in reducing costs is critical and has not been consistently evident across the portfolio over the review period.
8.1.1. Introduction
This section of the Draft Report sets out the Panel’s findings on the efficiency and effectiveness of the SOEBs over the period 2004 to 2010. It also explains why efficiency and effectiveness are important, particularly in the context of Government ownership of the SOEBs.

The Panel has defined the term ‘efficiency’ as related to all aspects of the business that impact on costs and is a measure of the extent to which activities are carried out at least cost.

The Panel has defined the term ‘effectiveness’ to be the extent to which SOEBs are contributing towards the continuity and quality of electricity supply - or in other words its technical performance. The various functions of the electricity supply chain; generation, transmission, distribution and retail services have specific measures to assess the extent to which individual contributions meet standards necessary to achieve overall performance. The Panel has observed how performance has tracked over time, and how it compares with peers, in order to examine effectiveness.

8.1.2. Why efficiency matters
As noted in the Panel’s Issues Paper, the Panel is of the view that the TESI will make the best contribution to the growth and development of Tasmania, and to the economic welfare of Tasmanians, if it is operated on the most economically efficient basis possible.

Viewed from a customer perspective, the efficiency of the SOEBs is a key driver of electricity prices.

This is particularly the case for the regulated sectors, such as the network businesses, where regulatory frameworks can be effective in protecting customers from the worst aspects of the absence of market forces. However, they are generally less effective in actively driving high levels of productivity.

Once regulatory parameters are set (for example, in the case of network entities, regulated operating cost allowances are set for a 5-year period), the actual performance of the network businesses does not have a bearing on prices to customers, at least in the short term. In this context customers arguably should be at least as focussed on the effectiveness of the regulatory process in ‘allowing’ efficient costs as they are on the performance of the regulated businesses in meeting those allowances.
For those aspects of the TESI that are subject to competitive forces, prices are set independently of the costs of an individual business. However, where competitive forces are relatively weak or the market is illiquid, there is real possibility of customers facing higher costs through inefficiencies.

In Tasmania, customers have seen relatively low levels of competition in the market and as such, Tasmanian customers could be expected to have greater interest in business efficiency than would be the case if high levels of competition existed.

From a shareholder perspective, the efficiency of a business is critical regardless of whether it is regulated or market-based, as efficiency drives the financial performance of the business and the ability of the business to provide shareholder returns and enhance business value.

In the Tasmanian context, where electricity supply businesses are State-owned, Government, Parliament and taxpayers all have an interest in seeing the businesses perform well from both an efficiency and effectiveness point of view.

The key conclusion is that efficiency is of prime importance from two perspectives:

- It can influence the price setting framework depending on the effectiveness of the regulatory framework or the effectiveness of market mechanisms.
- It contributes to the financial stability of the SOEB and drives shareholder value which can be returned to the Tasmanian community through dividends.

The extent to which high productivity is achieved remains one of the primary tasks of management, overseen by the Boards of the SOEBs. Therefore, it remains a priority for Boards to ensure that policies are in place that focus business culture and performance on productivity issues. This Paper explores the extent to which this has been evident in the SOEBs.

There is also a role for shareholders, in the case of the SOEBs, the responsible/shareholding Ministers (the Treasurer and the Minister for Energy) on behalf of the community, to ensure that Boards are clearly focused on achieving high levels of productivity to achieve sustainable financial returns. Through a focus on driving Boards to achieve efficiencies, governments are best placed to achieve other policy objectives, such as minimising pricing pressures on electricity users. The Panel has investigated how the Tasmanian Government, as shareholder, has sought to influence the SOEBs to drive efficiency and effectiveness.

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90 Noting that the Tasmanian community are the ultimate owners of the SOEBs.

91 This is important given the broader economic importance of SOEBs beyond dividend payments to the Budget.
8.1.3. The Panel’s approach

The Panel has taken as a given the outcomes of previous assessments undertaken by expert regulators on efficient costs - and has not sought to reconsider or remake these judgements. The Panel’s focus has been the extent to which the SOEBs have operated within these regulatory determinations as a primary indicator of efficiency. Where efficient benchmarks through regulatory approaches are absent, the Panel has examined cost trends within the SOEBs, and where practicable, peer comparisons, to examine efficiency measures.

8.1.4. Findings in relation to effectiveness

In general terms, the Panel has concluded that the effectiveness, or technical performance, of the electricity supply industry in Tasmania is good and generally comparable to the average effectiveness of the industry in other states. In particular the Panel has concluded that:

- The technical performance of Hydro Tasmania’s generating plant currently meets the requirements of its participation in the NEM, particularly from a risk management perspective (being able to physically back its market positions). Any ongoing significant deterioration of performance could be an indicator that the current asset management strategy was risking long term asset value. Through its annual review and update of its Ten-Year Asset Management Plan, it is important that Hydro Tasmania ensure that the performance of its assets is maintained and improved.

- The transmission network operated by Transend is performing satisfactorily and improving by comparison with peer entities. There remains scope for further improvement, although this is an economic question of the cost of further capital investment required to increase reliability levels.

- Aurora Energy’s distribution network effectiveness is currently adequate and while community based targets for improvements are in place it remains to be seen if this approach results in average performance improvements. The declining trend in service levels for urban areas is a matter that needs to be addressed to ensure that improvements in rural performance are not delivered at the cost of effectiveness for the majority of customers.

Aurora Energy’s retail’s performance in terms of customer service measures appears to be relatively stable, and may require additional focus in the event that full retail contestability is introduced.

8.1.5. Findings in relation to efficiency

The Panel’s assessment of efficiency is less clear cut. The benchmarking of operating expenditure, and particularly capital expenditure, is more problematic than benchmarking technical performance, due to the differences in scale, operating environment and industry structure.
In relation to Hydro Tasmania, there has been a sustained focus on reducing operating costs, with three efficiency programs implemented over the past eight years, the latest of which aims to reduce operating expenses to around 80 per cent of current levels.

A primary driver for improvements in efficiency within Hydro Tasmania has been the scarcity of capital to fund capital investment and growth strategies, which was compounded by the drought in 2007 and 2008. Capital constraints have also incentivised Hydro Tasmania to achieve more efficient delivery of major capital projects.

Transend’s operating costs are higher than its peers (in part reflecting scale dis-economies) and have grown at a higher rate over the period 2004-05 to 2008-09. Transend made a considered decision to spend above the regulatory allowances, based on its view that the regulatory determination was unsustainable. Over that period, Transend’s operating costs were $28 million, or 16 per cent higher than its allowance.

Transend’s performance relative to its operating allowances has improved with its 2009 regulatory determination, which saw a 40 per cent increase in its operating cost allowance. Transend has operated within the allowance for the past two years.

In relation to capital spending, Transend’s capital program exceeded its regulatory capital allowance by around 10 per cent over the period 2005 to 2009. The AER subsequently undertook a detailed ex-post review of capital projects over that period and found that the capital expenditure was prudent.

Aurora Energy’s distribution business has also had a history of overspending regulatory allowances, but to a smaller degree than Transend. Over the period 2004 to 2010, the distribution business overspent its operating allowances by a nominal $14 million, which represents four per cent of total allowed expenditure, with a key driver of this being emergency repair and response costs. Aurora Energy’s regulatory proposal that is currently being considered by the AER indicates that the business is seeking to deliver real operating cost decreases over the period 2012-13 to 2016-17. Significant changes are emerging within the distribution business that indicates there is a commitment to deliver on the productivity savings that underpin the regulatory proposal. The AER’s draft determination was released in November 2011, and the AER has proposed to reduce the proposed level of operating expenditure by $36.5 million (nominal) over the forthcoming regulatory period.

In relation to capital spending, Aurora Energy’s distribution business has consistently exceeded its regulated allowance, spending $208 million above its total allowance of $535 million over the period 2004-2010. Around half of the additional spending was a result of customer-driven capacity developments.
Aurora Energy’s retail business has been unable to operate within its regulatory operating allowance with respect to the non-contestable customer base. The Panel understands that in the competitive contestable market, there have been strong pressures on retail margins to maintain market share. Aurora Energy has developed a strategy to reduced costs in line with regulated cost-to-serve levels, and the first phases of that strategy have been implemented.

The major capital expenditure program related to the retail business over the review period was the customer information and billing system project. This project was highly complex, under-scoped and poorly managed, particularly in the period before January 2010. Because of the large differences between the eventual costs of the system and allowance permitted under the regulatory arrangements and as a result of capitalisation tests under the accounting standards, the project has had a large negative financial consequences for the business, with around $32 million in project costs being written off.

Overall, taking previous detailed regulatory determinations as the benchmark for efficiency, the Panel has not been able to conclude that regulated aspects of the SOEBs have been operating efficiently over the review period.

The financial consequences of this have primarily been borne by taxpayers as owners of the businesses through lower returns, rather than by electricity customers through higher prices. This is further discussed in the Panel’s Information Paper “A Review of the Financial Position of the State Owned Electricity Businesses”. Where subsequent regulatory determinations have been undertaken to reconsider efficient costs and allowances ‘reset’ at higher levels, there have been price impacts on electricity customers, but only to the extent that regulators have determined costs to be efficient.

The approach taken within the SOEBs towards efficiency and effectiveness is, in the Panel’s view, the fundamental driver of performance. It shapes the way in which the regulated businesses approach and operate within the regulatory framework and, together with competitive forces, drives performance for the market-facing SOEBs.

There has been a mix of approaches across the portfolio in relation to driving efficiency over the past decade, and the focus on efficiency has varied within parts of the businesses.

The apparent willingness of the regulated businesses to regularly overspend regulatory allowances and preparedness by Boards and the Shareholders to accept the financial consequences of this through poor financial performance and lower returns to the Budget has not created an environment where there is a consistent focus on driving business performance.

The Panel notes that more recent changes in regulatory incentives and governance arrangements have sought to address this to some extent.
The nature of the cultural change currently evident within Aurora Energy provides an
indication of the preferred approach to business management, with a strong focus
on efficiency. While that has arguably been available across the portfolio, until
recently it has not been a strong focus, at least not uniformly. It is notable that in
Aurora Energy’s case, the driver for improved efficiencies has not been prompted by
the economic regulatory framework. Rather it has been prompted by a
combination of personnel change, technological change and a change in the
strategic direction of the company.

The Panel has sought to determine why such initiatives have not been a consistent
and prominent feature of business activity in the past. The Panel has concluded
that:

- The process by which businesses are licensed by the TER, and which is aimed in
  part to promote efficiency in the electricity supply industry, does not of itself
  require efficiency improvement programs to be implemented or provide a
  particular focus for Boards or management to drive business performance.

- Revisions to the regulatory framework in 2008 and 2009 provide more comfort
  that regulatory allowances permit network businesses to recover their efficient
  costs, and provide stronger incentives to outperform expenditure and service
  targets.

- While Ministerial Charters and Letters of Expectation have contained broad
  expectations that SOEB Boards will conduct their businesses efficiently, they are
  pitched sufficiently broadly that specific expectations are not established.

- Annual Shareholder letters associated with the development of corporate plans
  have required businesses to operate efficiently and, more recently, formalised
  expectations for the businesses to instigate and report on specific programs.

- Although businesses have tended to respond positively to these specific requests,
  there does not appear to have been a process developed for reporting the
  details of the program, or programs, so developed or of the success or otherwise
  of the programs.

The extent to which Boards have taken responsibility for initiating efficiency or
productivity improvements, rather than executive management, is difficult to
determine given the generally cooperative approach to strategic planning
undertaken by the businesses. It is the Panel’s view that it is important for Boards to
take the primary role in ensuring an efficiency focus is initiated and appropriately
measured.

Of particular importance in driving business technical and financial performance is
the establishment of accountability and incentive frameworks that provide a ‘clear
line of sight’ between Shareholder expectations and the regulatory framework on
the one hand, and Board, management and staff performance on the other.
The Panel has not reviewed in detail the effectiveness of the performance monitoring frameworks employed in the different parts of each of the SOEBs, but notes that these do variously exist. The Panel’s view is that it is important that these frameworks are regularly and independently (of management) reviewed by either Boards or Shareholders to ensure that there remains strong alignment between the incentives faced by individual employees, management and the Board in driving outcomes that are consistent with regulatory requirements and Shareholder expectations.

The Panel considers that Shareholders could have been more active in driving accountability for efficiency and effectiveness over the past decade. The Panel has been left with the impression that until recently, there has been a relatively low level of engagement between Shareholders and the businesses in efficiency-related matters and that Shareholders have taken the view that the economic regulatory environment and independent regulators will provide the dominant drivers for SOEBs efficiency and effectiveness.

The regulatory framework can, at best, provide a level of assurance that businesses not exposed to competitive disciplines are not able to routinely operate at generally inefficient levels.

Optimising business performance within the broad parameters established by the economic regulatory environments remains the domain of management and Boards, with Shareholders providing the ultimate incentives and sanctions for efficiency and effectiveness. Developing and maintaining a focus on maximising efficiency and continual improvement in reducing costs is critical and has not been consistently evident across the portfolio over the review period.

The Panel notes that in relatively recent times, this has become more of a focus in the broad corporate governance arrangements between Boards and Shareholders in the SOEBs, and highlights this as a key area of governance reform for the SOEBs.

Finally, in any business, an important challenge for management is resolving the tension between meeting performance standards on the one-hand and managing costs and the consequences for prices. Similarly, there are tensions between investment in asset replacement and renewal and higher maintenance costs. The tension is evident in the SOEBs.

In the case of Hydro Tasmania, decisions have been made within the business to defer capital expenditure on maintaining core hydro generation assets to provide financial headroom for other investment activities. A key judgement that has been made by Hydro Tasmania’s Board and management is that the proceeds from the reinvestment of these funds into other activities will offset the short-term negative impacts from this strategy, and that expected improved financial outcomes will enable Hydro Tasmania to ‘catch-up’ the deferred expenditure. Hydro Tasmania considers this strategy to be prudent, particularly given the strategy is reviewed annually, with the potential to increase investment if funds are available (as has occurred).
Closely examining the risks and returns from capital spending and the appropriateness of potential maintenance expenditure are characteristics of a well performing businesses - they are consistent with an approach focused on efficiency and effectiveness. A key issue that arises from Hydro Tasmania’s asset management strategy is that its success is dependent on growth in future revenue streams that have significant accompanying risks. Those future revenue streams also have alternative uses, both within the business and from a shareholder perspective.

Decisions around capital expenditure, particularly where it relates to core assets versus diversification and growth strategies, are one of the inherent reconciliations that need to be made in providing scope to the SOEBs in planning business strategy and performance. Having a very clear understanding of the purpose of the SOEBs and what government is seeking to achieve through its ownership of them is a key foundation in resolving these tensions. This is addressed further in Chapter 22.
8.2. Financial position of the SOEBs

**Key Messages:**

The main sources of financial value in the SOEB portfolio are hydro-generation and the transmission and distribution network asset bases. Electricity retailing generates relatively little financial value by comparison and involves considerable risk.

Under prevailing market conditions, the revenue available in the market is insufficient to meet the TVPS operating costs.

The SOEBs each generate sufficient cash to fund their operating activities and have available an amount of ‘free cash’, which they spend on capital investment in core business assets or business growth, use to repay debt or return to their Shareholders as dividends.

Given their monopoly or near-monopoly positions in their respective markets, the SOEBs should be capable of delivering a rate of return to their Shareholders that private sector investors would expect, commensurate with the risks of each enterprise, without impacting on the ability to manage other capital needs.

Dividend returns have been low and below the cost of capital investment of the kind undertaken by the SOEBs. This is a result of the following key drivers:

- relatively weak profit performance;
- the need for reinvestment in core business activities to rebuild the asset base and improve reliability standards (particularly in the network businesses), which has led to decisions to reinvest returns within the SOEBs;
- the pursuit by Hydro Tasmania and to a lesser extent Aurora Energy, supported by the Government, of diversification/growth activities, which has required the application of capital, rather than a return to the community by way of dividends; and
- the 2007 to 2009 drought.

$491 million of equity has been invested in diversification activities, of which $100 million was for business activities outside Tasmania. To date, the Tasmanian community has not earned a financial return on those activities commensurate with its equity investment. Diversification activities have provided a major focus for limited Board and senior management resources.

The Panel has concluded that there is significant scope to improve the SOEBs’ financial performance. Results indicate a need to improve the accountability of Boards and management to the Shareholders with regard to financial performance. Changes in SOEB governance and oversight arrangements are starting to emerge that, if sustained, can be expected to improve performance over time.
### 8.2.1. Introduction

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.

### 8.2.2. 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 in 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, present challenges in undertaking this type of analysis. Therefore, the Panel reiterates that dollar figures shown in Figure 8.1 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 SEOB portfolio and between total revenues earned by the SOEB portfolio and uses of cash, including dividend returns to the Tasmanian community.
Figure 8.1

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: $323M
  - DUOS $231M
  - TUOS $92M

- Aurora Energy - energy business
  - Energy costs total: $518M
  - TVPS Tolling Fee: $82M
  - Hydro Tasmania $416

Transend Networks
- Non-direct connect customers: $93M

Hydro Tasmania (Energy)
- Total energy revenue: $416M

Other Revenue
- Retail gas: $6M
- Mainland electricity: $165M

Total Revenue: $1,197M

EBITDA
- Energy Business: $-10.5M
- Distribution: $165M

Net Cash
- Aurora Energy
  - Capex: $254M
  - Interest: $55M
  - Dividend Paid: $10M

- Transend Networks
  - Capex: $168M
  - Investment: $66M
  - Interest: $23M
  - Dividend Paid: $4M

- Hydro Tasmania
  - Capex: $36M
  - Investment: $40M
  - Interest: $63M
  - Dividend Paid: $5M

Uses of Cash in 2010

Total EBITDA: $522M
Total Dividends: $19M

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*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 8.1 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 business.

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 8.2 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 8.2 - Allocation of Aurora Energy’s Tasmanian customer revenue 2010

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

Returning to Figure 8.2, 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.

For further information on SOEB revenue generation and cash utilisation refer to Section 3 of the Panel’s Information Paper ‘A Review of the Financial Position of the State Owned Electricity Businesses’.

8.2.3. 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.

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92 Hydro Tasmania sells electricity to its retail business - Momentum Energy Pty Ltd - which operates on the mainland.
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.\footnote{Refer Chapter 10 of the Draft Report.}

In both the 2007 and 2010 price determinations, the regulated wholesale energy allowance is 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 away from Hydro Tasmania (which would have been reflected as profit) 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 Price Control Regulations (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, which required non-contestable customers to pay a ‘drought premium’ of slightly less than $3/MWh – amounting to $26 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.\footnote{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.} 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).\footnote{Refer Chapter 10 of the Draft Report.}
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 75 per cent from $726 million in 2004 to $1.267 billion in 2010, with WACC increasing from 6.61 percent to 6.64 percent 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 percent which will be applied to the opening RAB for each year of the determination. 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.

For further information on major financial flows within the SOEB portfolio refer to Section 2.1 of the Panel’s Information Paper ‘A Review of the Financial Position of the State Owned Electricity Businesses’.

This historical capital expenditure will continue to be reflected in 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 has observed 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.

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95 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.
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 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.

8.2.4. 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 percent 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 8.3 illustrates net cash from operations for each of the SOEBs over the review period.
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 regions of the NEM 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 8.1 shows SOEB capital expenditure on functional business assets and investment in diversification activities between 2004 and 2010.

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96 For further information on SOEB capital expenditure and investment refer Section 3.2.1 of the Panel’s Information Paper ‘A Review of the Financial Position of the State Owned Electricity Businesses’.
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 percent 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.

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97 For further information on SOEB capital structures and debt levels refer Section 3.2.2 of the Panel’s Information Paper ‘A Review of the Financial Position of the State Owned Electricity Businesses’. 
Benefit the Tasmanian community by providing commercial returns on their invested capital\(^98\)

The Tasmanian community benefits from its investment in the SOEBs through dividends which should reflect a return on its equity investment.\(^99\) 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.

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.\(^100\) 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.

8.2.5. 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.

\(^98\) For further information on SOEB dividend returns refer Section 3.2.3 of the Panel’s Information Paper ‘A Review of the Financial Position of the State Owned Electricity Businesses’.

\(^99\) ‘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).

\(^100\) 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.
The primary motivation for business diversification appears to be mitigating risk in functional business activities\textsuperscript{101} – 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.

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 declined from 68 per cent in 2004 to 39 per cent in 2010, partially offset by services to external clients, increasingly in national and international markets. Since 2002, Entura has made an EBIDTA contribution of between $1 and $4 million per annum, with a loss of $4 million in 2010 attributed by Hydro Tasmania to 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.

\textsuperscript{101} For example, Hydro Tasmania’s current retail strategy is to provide a path to market for excess generating capacity in Tasmania.
In a similar manner, in response to the introduction of customer contestability, Aurora Energy expanded its retail base into other parts of the NEM 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.

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102 Aurora Energy’s WireAlert product (marketed in Tasmania as Cable PI) is a safety sensor provided to Tasmanian households in 2009.
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, or whether they have 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. These issues are discussed in more detail in Chapter 12.

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.\(^{103}\)
- 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.

\(^{103}\) The Panel believes that this is a key consideration given the difficulties in crystallising the value of capital growth from government-owned businesses.
8.2.6. 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 more favourable regulatory arrangements and Aurora Energy’s contract arrangements with Hydro Tasmania; and Transend have 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 regions 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.

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104 For further information on future risks and opportunities refer Section 4 of the Panel’s Information Paper ‘A Review of the Financial Position of the State Owned Electricity Businesses’. 
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 strategy 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, 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.105

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105 Note the AER’s Draft Determination for Aurora Energy’s distribution business proposes WACC of 8.08 percent compared to Aurora Energy’s proposes 10.03 percent; 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.
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. 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.

8.2.7. Conclusion

The Panel has found that each of the SOEBs generates sufficient cash to fund operating activities and to have available an amount of ‘free cash’ to utilise for capital investment in core business assets or diversification/growth activities, repay debt or return to shareholders as equity.

Dividend payments, particularly in more recent years, can at best be described as mediocre. This has been result of three key drivers:

- relatively weak profit performance despite the near monopoly positions of Hydro Tasmania and Aurora Energy’s retail businesses in the competitive market and the regulated monopoly networks of Transend and Aurora Energy’s distribution businesses;
- the need for re-investment in core business activities to rebuild the business’ asset base and improve reliability standards (particularly in the network businesses), which has let to decisions to reinvest returns within the SOEBs; and
- the desire by Hydro Tasmania and to a lesser extent Aurora Energy; supported by the Government, to pursue diversification/growth activities, which have required the application of capital, rather than a return of dividends to the community.

The Panel’s opinion is that there is significant scope to improve the SOEB’s financial outcomes through improved accountability of Boards and management on financial performance by shareholders.

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106 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.
In addition, the Panel notes the portfolio effects of the TVPS acquisition that are not immediately observable and which need to be addressed to halt the current negative impact on the financial performance of Aurora Energy and Hydro Tasmania. These are:

1. There is insufficient revenue in the market to meet the TVPS cost of production

Under current market conditions, the TVPS is not delivering any value because its cost per MWh of production exceeds the market price for electricity. Aurora Energy effectively backs the higher value non-contestable customer load with the power station. However, because the TVPS' cost per MWh of production also exceeds the regulated wholesale energy allowance, this strategy does not provide sufficient revenue to sustain the TVPS' financial viability.

The effect of the Tasmanian Government's amendments to the Price Control Regulations in 2010 is to ensure that the cost to Aurora Energy to supply the non-contestable customer load is not more than it is permitted to charge those customers for supply. As such, given Aurora Energy's decision to utilise the TVPS to back around half of the non-contestable customer load, the contractual arrangements between Aurora Energy and Hydro Tasmania for the other half of the load must effectively 'balance' Aurora Energy's cost of energy associated with the TVPS by being lower than the wholesale energy allowance by the same amount. In prior regulatory periods, the contractual arrangements between Hydro Tasmania and Aurora Energy for the non-contestable customer load have seen the full value of the regulated energy allowance accrue to Hydro Tasmania.

2. The debt associated with the TVPS has increased Aurora Energy's total cost of debt

The TVPS project is highly geared, meaning that is funded by proportionally more debt than equity than is generally anticipated. In order to complete the construction of the TVPS, Aurora Energy was required to borrow around $260 million from Tascorp, which in turn required a letter of comfort from the Treasurer for this amount.

The impact of this additional debt on Aurora Energy's credit rating increases its cost of debt across its entire business. 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 for its distribution business is higher than that provided for in its regulatory allowance, having a negative financial impact on returns from that business segment. Similarly, the higher cost of debt will impact the competitiveness of Aurora Energy's retail business.

The overall effect is that while the TVPS is receiving revenue sufficient to cover its costs - and therefore operates commercially, the consequences of its operation in the SOEB broader portfolio are less well defined.
9. Major infrastructure projects

The Panel’s Terms of Reference require it to investigate and report on major infrastructure development decisions affecting the electricity sector and the impact that those decisions have had on Tasmanian electricity prices (ToR 2).

This Chapter examines in detail the two main electricity infrastructure projects delivered in Tasmania over the past decade, namely:

- Basslink, the undersea cable linking the Tasmanian and Victorian electricity grids; and
- The gas-fired TVPS.

The initial development of both the Basslink and TVPS projects were key components of successive Tasmanian Governments’ broader energy strategy, underpinned by the three core objectives of securing new sources of energy to meet load growth, mitigating the State’s exposure to energy supply risk by reducing reliance on on-island hydro generation and increasing competition in the market.

Since their completion, both projects have heralded significant changes to the Tasmanian electricity sector, in terms of providing new sources of electricity and changing the State’s energy risk profile.

However, the circumstances in which the projects were realised differ in a number of ways, occurring within fundamentally different contexts and in response to markedly different policy imperatives.

The development of Basslink was a long-term, pro-active strategic development based on a range of clear commercial and policy objectives. Hydro Tasmania entered into the Basslink arrangements on commercial grounds. While the Basslink business case evolved over the course of its development, the fundamental commercial and operational aspects of the project that had been envisaged at the outset were delivered.

The TVPS, on the other hand, was not delivered as originally intended. Aurora Energy’s acquisition, completion and operation of the TVPS was not in response to a commercial opportunity, but was undertaken as an energy supply security measure, at the direction of the Government and in the context of a unique set of unforeseen hydrological and global financial circumstances.

Instead of a new private sector entity competing in the generation sector, as had been planned, the State has retained control of all of Tasmania’s significant on-island generation capacity. As a result, the TVPS is yet to deliver the original objective of gas-fired generation delivering effective competition in the wholesale market in Tasmania.
Detailed analysis of the two projects since commissioning also reveals their different impacts on the financial performance of Hydro Tasmania and Aurora Energy respectively, and, ultimately, on Tasmanian electricity prices. While both have failed to deliver net commercial value since entering commercial operations, the outlook of each is quite different.

The outcomes for Basslink in relation to Hydro Tasmania reflect hydrological circumstance. With a return to more typical hydrological circumstances, Hydro Tasmania has been able to more than cover its Basslink-related costs from Basslink-related revenues. While not providing a source of revenue to meet Basslink-related costs, the costs avoided from having Basslink in place have also been large, such that when these are added to the trading performance of the link, its financial benefits to Hydro Tasmania since commissioning are estimated to be at least in the order of $70 million. Leaving aside the energy supply security benefits provided by Basslink, Hydro Tasmania’s Basslink-related revenues have fallen short of its Basslink-related costs by around $135 million since the link entered commercial operations.

Conversely, the TVPS has had a significant negative financial impact on Aurora Energy. Market revenue has not been sufficient to support the commercially sustainable operation the TVPS. Subsequent actions taken by the Government to support the viability of the TVPS, post-acquisition, have seen a number of changes to the power station’s commercial and operational arrangements.

This Chapter examines the Basslink and TVPS projects from the point of initial development through to their commissioning and present-day operation. It describes the processes, decisions and expectations of the State Government and the SOEBs in relation to both projects and examines the extent to which the outcomes achieved to date have been consistent with these expectations.

The investigation into Basslink and TVPS has been extensive. The Panel engaged in discussions with a range of stakeholders, including senior representatives, both past and present, from the SOEBs and the Government. The Panel used its information gathering powers to access a range of documents pertaining to the development of both projects, including Cabinet materials, SOEB Board papers and meeting minutes, independent advice obtained by the Government and various other relevant commercial and legal materials.

Therefore, this Chapter necessarily represents a summary of key analysis and findings only. A more detailed account of the Panel’s review of both Basslink and TVPS can be found in the Panel’s Information Papers Basslink: Decision Making, Expectations and Outcomes and Tamar Valley Power Station: Development, Acquisition and Operation.

The Chapter also includes a brief summary of the Tasmanian natural gas roll-out and a discussion of potential efficiency benefits of gas as a complementary alternative to electricity.
9.1. Basslink

Key Messages:

- Hydro Tasmania entered into the Basslink arrangements on commercial grounds. The final November 2002 Basslink business case showed that the project could be expected to produce an estimated Net Present Value (NPV) to Hydro Tasmania of around $260 million ($2002).

- To date, Basslink’s financial performance has not fulfilled expectations relative to the final business case. This is largely a reflection of low inflows to the hydro system since commissioning, which has seen Basslink utilised predominantly as an electricity supply option and reduced its availability for trading between Tasmanian and Victoria.

- The return to more typical hydrological inflows in recent years has resulted in financial outcomes for Hydro Tasmania from Basslink that have been more consistent with the business case expectations.

- Basslink has proven to be an effective and cost efficient means of managing hydrological risk. The Panel’s analysis shows that Basslink has enabled Tasmania’s demand for electricity to be met at a materially lower wholesale energy cost than would have been the case under alternative scenarios evaluated by the Panel.

- With typical hydrological inflows, Hydro Tasmania has been able to more than meet its Basslink-related costs from opportunities that Basslink brings for trading electricity between Tasmania and Victoria and from improved hydrological management. Where hydrological circumstances have not enable trading opportunities to the same extent, Hydro Tasmania has not been able to generate revenues greater than Basslink-related costs and this has impacted on Hydro Tasmania’s profit performance.

- Having examined the detailed financial performance of Basslink, as well as transmission network pricing in Tasmania, and having regard to the way in which prices for regulated customers are set, the Panel has concluded that Tasmanian regulated customers are not paying for Basslink through their electricity prices.
9.1.1. Introduction

The economic and technical feasibility of a submarine cable across Bass Strait had been considered numerous times by the Hydro-Electric Commission since the 1950s. The end of large scale hydro electric development in Tasmania and the need to secure the State’s next electricity supply option led the Rundle Government to announce plans to proceed with the development of an interconnector linking the Tasmanian and Victorian electricity grids. The long-standing issue of energy supply risk management was also a key motivation for pursuing interconnection, which would also be required if Tasmania were ever to participate in the nascent National Electricity Market.

Interconnection was only one of a number of major electricity sector reforms announced by the Rundle Government, which included the disaggregation of the Hydro-Electric Corporation’s generation, transmission and distribution/retail functions into separate businesses. Basslink’s status as a key component of the Government’s reform agenda was recognised in the declaration of Basslink as a Project of State Significance.

Having instigated a competitive selection process to find a private sector party to develop and operate the link, Premier Rundle called an election, which resulted in a change of government in 2008. The incoming Bacon Government endorsed the development of an undersea interconnector, and the process that had been set in motion to find a private sector developer for Basslink continued.

The new government revised the previous government’s goals and strategic objectives for Basslink to the following:

- improve the security of electricity supply and reduce the exposure to drought conditions in Tasmania;
- provide Tasmania with access to electricity prices determined competitively in the NEM;
- provide a means by which electricity generated in Tasmania can be sold into the NEM and provide a new source of peak generating capacity in the NEM;
- ensure that, through a competitive selection process, the cost of Basslink to users is minimised; and
- ensure that the returns to the State from the State Owned Electricity Businesses are maximised.
9.1.2. Security of electricity supply

Many within the community appear to hold the view that Basslink was proposed on the basis that it was predominantly, or solely, intended to be used to enable the sale of electricity from Tasmania to Victoria. However, it is clear from the Government’s strategic objectives (see above) that, from the outset, the link was intended to be used as a net supply option for Tasmania in times of low hydrological inflows (drought), as well as net exports in times of high inflows.

As a result of markedly below average inflows into Hydro Tasmania’s water storages in the years immediately prior to and following Basslink commencing commercial operation, Basslink has thus far been used as a net supply option for Tasmania. 2011 was the first year in which north-bound flows of electricity over Basslink exceed southward flows, reflecting a return to more typical rainfall totals in recent years.

In its own evaluation of Basslink’s performance, Hydro Tasmania looks beyond the direct costs and benefits identified in the business case for interconnection, and compares the outcomes made possible by Basslink with the hypothetical outcomes that might have been realised had Hydro Tasmania been required to supply Tasmania’s electricity needs over the past five if Basslink had not been built.

Hydro Tasmania assumes that in the absence of Basslink, the shortfall in the capacity of its hydro generation schemes to meet Tasmania’s demand for electricity would have been met using a combination of new natural gas fired generation – owned and operated by Hydro Tasmania – and, in times of extremely low inflows into Hydro Tasmania’s storages, negotiated load shedding by major industrial customers.

Taking into account the additional costs of additional on-island generation and buying back load from major industry, and comparing them with the costs associated with Basslink, Hydro Tasmania estimates that Basslink has enabled it to avoid costs in excess of $300 million since the link commenced commercial operations.

The Panel has developed its own estimates of the alternative supply costs that may have arisen in the absence of Basslink. Like Hydro Tasmania, the Panel considered that the use of natural gas fired generation to meet the shortfall in the capacity of hydro-generation to meet on-island demand was the most plausible alternative to Basslink. The Panel also considered a second scenario involving the use of large-scale wind generation to meet the State’s electricity needs.

The Panel has estimated that when compared with its gas scenario, Basslink has resulted in lower wholesale energy costs for Tasmania of around $200 million over the period 2007 to 2011, and approximately $350 million when compared with a hypothetical wind scenario.
On this basis, Basslink has enabled Tasmania’s demand for electricity to be met – without any demand side management – at a materially lower wholesale energy cost than would have been the case under either of the two alternative scenarios evaluated. If not for Basslink, the prolonged dry period experienced by Tasmania in the middle of the previous decade would have had severe negative financial consequences for Hydro Tasmania, along with potentially undesirable consequences for customers, to the extent that the higher wholesale energy costs would have been passed on.

Having enabled ‘the lights to be kept on’ during a period of extremely low inflows, inflows of energy into Tasmania at times of low prices in the Victorian market, even after the return to more typical rainfall sequences, have enabled Hydro Tasmania to rebuild its storages to their current levels, which at the time of writing were just under 60 per cent of capacity.

Basslink has, therefore, proven to be a physically effective and cost effective means of managing hydrological risk for Hydro Tasmania, and energy supply security risk for the State. Further, the bi-directional functionality that enables the State to both access interstate generators as well as send energy generated in Tasmania interstate means that Basslink is more flexible as a means of managing hydrological risk than the addition of gas-fired thermal generation.

However, as a monopole cable, Basslink provides inherently less security of supply than would a bipole cable. Consequently, while Basslink effectively underpinned Tasmania’s security of supply during the second half of the 1990s, Tasmania’s reliance on the cable as a source of supply during that period highlighted for Government the potential risks were the cable to fail.

It is apparent from the Government’s decision to direct Aurora Energy to purchase the partially completed Tamar Valley Power Station in 2008 that the Government considered that Basslink did not adequately ‘drought proof’ Tasmania.

9.1.3. The Basslink decision making process

The decision-making process that led Hydro Tasmania, as a State-owned business, to commit to Basslink, as well as the cost of the link and its financial impact on Hydro Tasmania has been the subject of debate for a considerable period.

The Government established the Basslink Development Board (BDB) to identify a preferred developer through a competitive process. A process that commenced with 14 expressions of interest was reduced to two competing bids in November 1999 - Australian Energy International (Basslink) Consortium (AEI) and National Grid International Ltd (NGIL). Each was asked to finalise its project development arrangements with the State, as well as any commercial and other arrangements required with Tasmania’s SOEBs (principally Hydro Tasmania), with a view to the BDB evaluating their final proposals in February 2000. The BDB’s evaluation of the NGIL and AEI proposals, based solely on the BDB’s selection criteria and weightings, determined the NGIL proposal to meet the selection criteria to a higher standard than AEI’s proposal.
Hydro Tasmania examined the business case for interconnection repeatedly. The business case for Basslink was also regularly reviewed by the Board of Hydro Tasmania, independently of Hydro Tasmania’s management, and the project was subject to scrutiny by the State Government, through the use of independent expert advisers on multiple occasions, in the wider context of energy reform.

As a result, the business case for Basslink evolved significantly during the project’s development, and the early iterations considered by Hydro Tasmania were markedly different from the business case that underpinned the final decision to proceed with Basslink.

As the opportunities associated with interconnection became better understood by Hydro Tasmania, the business was able to identify and quantify a variety of additional commercial benefits which had not been part of the original business case. At the same time, however, the projected cost of constructing Basslink also increased, from approximately $500 million to almost $875 million - much of the increase driven by the outcomes of the joint Commonwealth, Victorian and Tasmanian environmental assessment process.

Those investigations repeatedly showed Basslink to be a positive commercial proposition for Hydro Tasmania’s business, even with the significant increase which occurred in the project’s cost. Basslink’s ability to add value to Hydro Tasmania’s business was also assessed as being robust to the likely range of sensitivities which reflected the key risks to the business case, and had both positive and negative impacts on the net value of the link to Hydro Tasmania.

The final November 2002 business case showed that, if the base-case’s assumptions held, the Basslink project would produce an estimated Net Present Value (NPV) to Hydro Tasmania of around $260 million ($2002), with a benefit/cost ratio of 1.44:1.107 This is illustrated in Figure 9.1.

107 These are estimates developed by the Panel on the basis of cash flow projections for the first 20 years of Basslink’s operation provided to the Hydro Tasmania board in December 2002.
Accordingly, the Hydro Tasmania Board made a commercial decision that, having regard to the risks and returns associated with the project, it was in the best interests of Hydro Tasmania to proceed with the development of Basslink.

The consultants engaged by the Department of Treasury and Finance to consider the range of risks associated with the Basslink project from the State’s perspective also highlighted that without Basslink, and in the face of new on-island gas-fired generation, the outlook over the following ten years was for a decline in Hydro Tasmania’s returns to Government.
9.1.4. Basslink’s financial performance

The Panel has how Hydro Tasmania’s financial performance has been affected by Basslink compared with its expectations regarding the commerciality of the project.

Since it entered commercial operations, Basslink’s financial performance for Hydro Tasmania has not fulfilled the expectations contained in the final business case. This is largely a reflection of hydrological factors.

The hydrological risk benefits of Basslink have come at a cost to Basslink’s commercial performance for Hydro Tasmania. Leaving aside the contribution Basslink has made to managing hydrological risk, and taking into account only the direct realised benefits attributable to Basslink, Hydro Tasmania’s overall Basslink-related costs have been around $135 million ($ nominal) greater than the actual revenue benefits that Basslink has generated since it began delivering energy in April 2006. This is illustrated in Figure 9.2

Figure 9.2 - Benefits of Basslink to Hydro Tasmania, 2006-07 to 2010-11 compared with business case, % of Basslink-related costs

Source: Hydro Tasmania
Notes: Quantums are not shown on the chart in monetary terms as the information is commercial-in-confidence. ‘Victorian Contract’ benefits have been captured in the arbitrage value, whereas these were separately identified in the business case (and in Figure 1). The benefits are expressed as a proportion of the Basslink-related costs in each case and, as such, are not directly comparable. For example, in the business case, arbitrage benefits coupled with Victorian contract value was expect to be broadly similar to the Basslink-related costs, whereas, in the first 5 years, these benefits were equivalent to around 60% of costs.
Hydrological issues were consistently recognised as one of the key risks in the Basslink business case. Variations in the yield from Hydro Tasmania’s water catchments were expected, along with the impact that this would have on a number of components of Basslink’s trading value, particularly the opportunity for net ‘exports’ of electricity energy and for the creation of additional yield from the hydro system and the consequent Renewable Energy Certificates.

In this sense, the low hydrological inflow sequences that occurred prior to and immediately after Basslink’s commissioning reflect the anticipated variability in the value created for Hydro Tasmania by Basslink. The return to more typical hydrological inflows in recent years has resulted in financial outcomes for Hydro Tasmania associated with Basslink that have been more consistent with the expectations in the final business case, while at the same time the imperative to use Basslink to manage hydrological risk has diminished.

Illustrating the importance of hydrology in driving these outcomes, in 2009-10 and 2010-11, with inflows at more typical levels, the direct realised revenues associated with Basslink have been around $25 million in excess of Hydro Tasmania’s overall Basslink-related costs.

When the indirect benefits of Basslink as a net supply option during times of drought are added to the trading performance of the link, the financial benefits of Basslink to Hydro Tasmania in the first five years of its operation are positive, despite the underperformance of the trading outcomes, relative to the business case.

This analysis also does not consider yet-to-be-realised financial benefits that Basslink is likely to deliver, such as the ability of Hydro Tasmania to build storages in order to capitalise on the introduction of carbon pricing in the future, or any assessment of the impact that Basslink has had on the wider Tasmanian economy.\(^{108}\)

### 9.1.5. The cost of Basslink to non-contestable customers

A number of stakeholders have asserted that regulated customers are effectively underwriting the cost of Basslink. The evidence that has been analysed by the Panel indicates that this is not the case.

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\(^{108}\) Hydro Tasmania contends that the security of supply provided by Basslink has provided a number of large energy intensive businesses with the confidence to invest in upgrades of their Tasmanian production facilities and enter into new long term contracts.
Under the Basslink Services Agreement, Hydro Tasmania is responsible for meeting the cost of Basslink, which it does through a combination of payments, including the Basslink Facility Fee (BFF), which paid to the owner and operator of the link. In return for the BFF, Hydro Tasmania receives the market revenues that accrue to Basslink.\(^\text{109}\)

Having Basslink in place presents Hydro Tasmania with a range of revenue generating opportunities which, in turn, provide a source of funding toward the cost of the link, as well as potential sources of profit.

None of those revenue streams draws on customers in the Tasmanian non-contestable electricity market. For example, the value of the opportunities provided by Basslink to Hydro Tasmania from arbitrage\(^\text{110}\) is derived from interstate customers and not on-island demand, and net exports of energy by Hydro Tasmania into the NEM involve the earning of income from interstate customers.

As noted in Chapter 7, no upgrades of the existing transmission network were undertaken to accommodate Basslink, as the existing network had the physical capacity to service Basslink in addition to on-island demand. A System Protection Scheme (SPS) was developed to enable it to do so without jeopardising the security of the electricity system, along with new connection equipment at Transend’s George Town substation, but both the SPS and the Basslink connection equipment at the George Town Substation were paid for by the developers of Basslink, and transferred to Transend at no charge.

The values of those assets are not included in Transend’s RAB and have no impact on the calculation of Transend’s allowable revenue by the AER. This means that neither direct connect customers, such as the State’s largest industrial sites, nor small non-contestable customers (via Aurora Energy) contribute to the cost of those assets through transmission charges.

The electricity prices and fixed charges paid by non-contestable customers through their regulated tariffs, which are set by the TER, also have no reference to Basslink in their derivation.

In conclusion, having examined the detailed financial performance of Basslink from Hydro Tasmania’s perspective, as well as transmission network pricing in Tasmania, and having regard to the way in which prices for non-contestable customers are set, the Panel concludes that non-contestable customers are not paying for Basslink through their electricity prices.

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\(^{109}\) Which are the price differences between Tasmania and Victoria multiplied by the volume of electricity transported across.

\(^{110}\) Arbitrage involves Hydro Tasmania withholding the production of hydro electricity at times when Victorian prices are low, with the result that some of Tasmania’s demand is met by the flow of electricity into Tasmania from Victoria, and then increasing production in order to export a matching volume of electricity from Tasmania at times of high Victorian prices.
9.2. Tamar Valley Power Station

**Key Messages:**

- The Government’s decision to direct Aurora Energy to acquire the partly-built TVPS reflected an unwillingness to accept a low probability, but high consequence risk of having insufficient energy to meet on-island demand in the event of continued low inflows combined with the inability to source sufficient capacity from Basslink and thermal generation.

- The valuation advice provided to the Government when it decided to buy the power station shows that the difference between TVPS’ acquisition and completion costs and its estimated enterprise value from market trading at the time it was acquired was around $150 million. The Panel has interpreted this as an energy supply risk ‘insurance premium’ of around $150 million.

- The commissioning of the TVPS in October 2009 achieved the objective of securing on-island gas-fired generation in Tasmania.

- However, ownership of the TVPS by Aurora Energy, and its use to back non-contestable customer load, does not deliver the original policy objective of delivering effective competition in the Tasmanian wholesale market.

- Further, the TVPS’ entry has resulted in more available energy than is required to meet demand, at least until 2027. Tasmanian spot prices have been low since the TVPS came online. This has had a direct impact on the TVPS’ financial viability, as has the somewhat volatile nature of the wholesale market.

- The TVPS’ viability is currently underpinned by a commercial deal between Aurora Energy and Hydro Tasmania that is linked to non-contestable customer arrangements. The arrangement effectively transfers the shortfall in market value for the TVPS to Hydro Tasmania.

- The financial position of the TVPS in the context of prevailing market conditions is a key issue that needs to be resolved as part of the Tasmanian
9.2.1. Introduction

Securing a large gas-fired power station in the State to provide alternative supply and a source of competition in the wholesale energy market has been a key energy policy objective of successive Tasmanian Governments since the 1997 Directions Statement. The objective was closely linked to the introduction of natural gas to Tasmania, with a power station providing a foundation customer of the Tasmanian Natural Gas Pipeline (TNGP). 111

The commissioning of the TVPS in October 2009 partly achieved this objective. However, ownership of the TVPS by Aurora Energy, and its use to back non-contestable customer load, does not deliver the original objective of effective competition in the Tasmanian wholesale market for new entrant retailers to back retail contracts with contestable customers. 112

The TVPS’ entry has resulted in more available energy 113 and capacity than is required to meet demand, at least until well into the next decade. Reflecting market conditions in Tasmania and the NEM more broadly, Tasmanian spot prices have been low, relative to historic norms, since the TVPS came online. This has had a direct impact on the TVPS’ financial viability, as has the volatile nature of the wholesale market.

A key change with the Government’s decision to acquire the TVPS via Aurora Energy on the grounds of energy security is that the financial consequences of these risks are now borne by Tasmania’s public sector, rather than the private sector, as was anticipated early in the reform process.

Wholesale market revenue has not been sufficient to support the commercially sustainable operation the TVPS, which placed Aurora Energy in stressed financial circumstances during 2009-10.

The combination of the wholesale energy allowance that is provided to Aurora Energy for non-contestable customers, coupled with the contractual arrangements it has with Hydro Tasmania to partly back non-contestable customer load 114 provide Aurora Energy with sufficient financial ‘headroom’ to cover the full costs of operating the TVPS to back the balance of its non-contestable customer load.

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111 Initially, this was achieved with the conversion of the Bell Bay Power Station to natural gas in 2003.
112 Arguably it does deliver this benefit to Aurora Energy, although the cost structure of the TVPS relative to prevailing market conditions means that it is not a commercially attractive option.
113 Noting that, in Tasmania, this is a function of hydrology.
114 Hydro Tasmania currently backs around half of the non-contestable customer load.
Having on-island thermal generation provides supply security for the market in light of the hydrological risk inherent in Hydro Tasmania’s generation system. It was on this basis that Government made the decision to acquire and complete the TVPS when the private sector developer, Babcock and Brown Power (BBP), indicated to the Government that it would not complete the project.

At the time that decision was taken, water storages were at near record lows, existing, aged on-island thermal generation was experiencing reliability difficulties, and Tasmania was effectively reliant on Basslink to meet electricity demand.

All Tasmanian customers benefit from having higher supply reliability through the TVPS being available for generation in the event of severe drought. The key issue is predicting the frequency and nature of those conditions, and the willingness of market participants to contract to manage those risks in periods of normal and above normal hydrology.

Currently, the shortfall in market value for the TVPS is effectively transferred to Hydro Tasmania. This is unlikely to be a sustainable approach under typical inflows and storages conditions (in terms of Hydro Tasmania’s willingness to contract with thermal generation to manage hydrological risk) and these arrangements will not be robust with a move to market-based arrangements for all customers. The financial position of the TVPS in the context of prevailing market conditions is a key issue that needs to be resolved as part of the Tasmanian Government’s future Energy Strategy.

This Chapter summarises the Panel’s findings in relation to the TVPS project. A Supporting Paper Tamar Valley Power Station: Development, Acquisition and Operation115, provides, in significantly more detail, the following:

- The development of the project through its initial conception to its acquisition by the State and its subsequent commissioning and operation in the market;
- the commercial aspects of the TVPS project, including a comparison of initial expectations of the TVPS project with the outcomes that have been observed since its commissioning; and
- An explanation of the evolution of the TVPS operating model including how and why the power station’s fundamental value proposition changed from the initial commercial arrangement between Alinta and Aurora Energy to the model that was put in place following acquisition by the State.

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115 Can be found on the Panel’s website: www.electricity.tas.gov.au
The Panel’s key findings are outlined below.

**9.2.2. The development of gas-fired generation in Tasmania**

The acquisition, completion and operation of the TVPS by Aurora Energy was the outcome of a chain of energy policy and market developments over the preceding decade. These included Tasmania’s entry into the NEM, the Basslink and Tasmanian Natural Gas Pipeline (TNGP) connections and the management of hydrological risk in order to ensure reliable electricity supplies during periods of low inflows and storage levels.

The Tasmanian Government’s early reform of the State’s energy market included the separation of the Bell Bay Power Station (BBPS) from Hydro Tasmania into an independent generating business. The TNGP development agreement provided for the establishment of a joint venture between Duke Energy and Hydro Tasmania to convert the existing units to gas and to repower the station to a 220 MW combined cycle gas turbine operating in competition with Hydro Tasmania in the wholesale market in Tasmania.

A commercial agreement for the development of the joint venture was not concluded. In April 2004, Alinta acquired Duke Energy’s assets, including the TNGP and interests in the BBPS. As an alternative to the joint venture, Alinta developed a proposal to construct a new power station, the TVPS, with a 203 MW combined cycle gas turbine on a site adjacent to the BBPS on a stand-alone basis.

The TVPS project was announced in October 2006 following agreement to a 25-year energy contract between Alinta and Aurora Energy. These arrangements were consistent with the ACCC’s requirement that Aurora Energy would source between ten and 25 per cent of the load required to support non-contestable customers from a party other than Hydro Tasmania.

Alinta subsequently acquired from Hydro Tasmania the BBPS site and three 40 MW FT8 gas-fired turbines, which had been acquired by Hydro Tasmania as generation support during times of low inflows ahead of Basslink commissioning. Alinta granted a licence to Hydro Tasmania for it to continue to operate the Bell Bay 1 and 2 gas-fired units until the new combined cycle turbine was commissioned. A key component of the sale agreement was Hydro Tasmania’s release from its gas Pipeline Capacity Agreement liability with Alinta\(^\text{116}\), which had been entered into by Hydro Tasmania\(^\text{117}\) and was valued by Hydro Tasmania at approximately $90 million.

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\(^{116}\) Which was originally negotiated with Duke as a foundation for the Tasmanian Natural Gas Project.

\(^{117}\) The Agreement provided for the transport of gas for the BBPS power station in the first instance, and would have underpinned gas transport requirements for the proposed Joint Venture.
In August 2007, Alinta began construction of the TVPS. Shortly after, the project was acquired by Babcock and Brown as an element of its acquisition of Alinta. As part of the broader distribution of Alinta’s assets, Babcock and Brown allocated the TVPS to BBP, and the natural gas transmission assets to Babcock and Brown Infrastructure. This decoupled key financial value aspects of the TVPS development.

Due to a range of factors, in June 2008 BBP reached the point where it could no longer complete the project and elected to pursue a divestment strategy. BBP sought to sell the development to the market.

The Tasmanian Government initially attempted to facilitate BBP’s sale of the TVPS to a third party operator. The Government’s efforts focused on resolving technical issues relating to the connection of the station to the State’s transmission network. This was likely to impact on the successful divestment of the power station to another private operator in the short term.

However, BBP was unable to complete a market sale on terms acceptable to it and within its desired timeframes. BBP then approached the Government with a proposal for acquisition within an extremely compressed timeframe.

9.2.3. Acquisition and completion of the TVPS by the Tasmanian Government

Threats to timely completion of the TVPS came at the same time as near-record low hydrological inflows and storage levels, which in the event that the drought continued and both the Basslink and the BBPS were unavailable, had increased the risk of potential energy shortfalls in the autumn of 2009.

Based on its assessment of supply risk, the Government determined that it would direct Aurora Energy to purchase and complete the project.

The Government undertook a rapid due diligence process, which examined technical, legal and commercial aspects of transaction.

The Government agreed to an acquisition price for the partially-completed project of $100 million. Funding was made available to Aurora Energy through an equity contribution, with Aurora Energy assuming responsibility for what was estimated at the time to be $260 million in project completion costs, funded by debt. The transaction, and equity funding, was approved by the Tasmanian Parliament and the sale was completed on 15 September 2008.
A key aspect of the acquisition was the negotiation of gas supply (commodity and transportation) arrangements. At the time of the acquisition, there were no gas contracts in place for the TVPS. Aurora Energy and the Government were concerned that negotiating a gas supply contract with Babcock and Brown after the completion of the acquisition would result in a materially worse negotiation position than putting those arrangements in place as a part of the acquisition.

Accordingly, Babcock and Brown ‘carved out’ gas supply arrangements for the TVPS on terms consistent with a wider package of gas commodity and transportation agreements that were in place in a related Babcock and Brown entity. The nature of the gas arrangements (volume and conditions) was consistent with the use of gas implied under BBP’s operating model for the TVPS.

9.2.4. Post-Acquisition commercial and operational arrangements

Aurora Energy completed construction of the power station on time, and around $20 million under the anticipated budget. Given the complexity of the internal and external challenges Aurora Energy faced in delivering the project, this represents a highly successful outcome.

However, by October 2009 when the TVPS was commissioned, hydrological conditions had improved such that the risk of supply shortfalls was significantly reduced - although water storages remained just under 30 per cent. The operation of the TVPS enabled Hydro Tasmania to rebuild water storages at a faster rate than otherwise would have been the case.

The power station’s unsustainale financial position was realised in early 2009 (pre-commissioning) when Aurora Energy established a baseline budget for the subsidiary created to own and operate the TVPS, Aurora Energy Tamar Valley (AETV).

Aurora Energy’s modelling indicated that a fair market value of the TVPS was around $220 million and that without increases in expected revenue, and reductions in operating costs, the asset value of TVPS could face a large ‘write down’ in Aurora Energy’s accounts at the end of the 2009 financial year.

118 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. (source: Hydro Tasmania 2010 annual report)
In response, Aurora Energy restructured its energy business to improve efficiency and implemented a tolling agreement\textsuperscript{119} which replaced the Alinta contract and provided the same value to AETV. The consequence of this restructuring was that value implications of changes in market conditions that relate to the operation of the TVPS would be observed in the parent Aurora Energy’s energy business, and AETV would be financially ‘whole’.

The initial tolling fee did not provide sufficient cash flow for AETV to operate the TVPS and manage the debt incurred in completing the power station. Aurora Energy’s Board approved an additional fixed tolling fee on the expectation that the 2010 Pricing Determination would allow for an increase in the wholesale energy component of regulated tariffs paid by non-contestable customers over the period 1 July 2011 to 30 June 2013.

This was based on the assumption that the cost allowance methodology used in the 2007 Determination would again be used in 2010. In July 2009, the then Treasurer provided assurances to Aurora Energy consistent with this expectation, advising that the Tasmanian Energy Regulator (TER) would be instructed to apply a long-run marginal cost (LRMC) methodology to the wholesale energy allowance for non-contestable customers, which would set the allowance based on industry benchmark costs for ‘new entrant’ gas-fired generation.

Aurora Energy’s Board decided that impairment at the end of 2008-09 was not required, based in part on increase in the tolling agreement paid by Aurora Energy to AETV and also because the station had not yet been fully commissioned and therefore had no actual substantive operating period in which to assess its cost and revenue base could be confirmed to inform that decision.

A number of issues during the 2010 financial year contributed to a worsening of the Aurora Energy’s energy business financial position:

- the cashflows from Aurora Energy to AETV under the tolling agreement were insufficient to meet the costs in operating the TVPS, resulting in AETV generating losses;
- early in the first half of year, Aurora Energy was using the TVPS as a physical hedge to back part of its non-contestable customer load, and had some exposure to the spot market for TVPS output, which impacted on the revenues available to Aurora Energy to fund the tolling fee;

\textsuperscript{119} The tolling arrangement effectively transferred the rights and obligations associated with the pool income from the generation of TVPS from AETV to Aurora Energy in return for a tolling fee to effectively convert gas into electricity as directed by Aurora Energy. The tolling fee has fixed and per unit charges, to incentivise AETV to operate the TVPS efficiently.
• From January 2010, Aurora Energy became over contracted and faced larger wholesale market price risk from the TVPS. Tasmanian spot prices reflected Hydro Tasmania bidding to match its level of contract cover, and TVPS bidding to utilise its gas contracts, with consequential sustained reductions, relative to historic levels\textsuperscript{120}; and

• On a per unit basis, the 2009-10 wholesale energy allowance factored into non-contestable tariffs and, therefore, Aurora Energy’s revenues were below TVPS operating costs, requiring additional revenue to support its costs.

Aurora Energy’s energy business again faced significant write-down in value at the end of the 2010 financial year. Aurora Energy briefed its Shareholder Ministers in January 2010 and again (with detailed supporting figures) in April 2010, on its adverse financial position and requested significant and immediate assistance.\textsuperscript{121}

Amendments to the Price Control Regulations, passed by the Parliament in June 2010, have the effect of supporting AETV’s viability in two key respects.

Firstly, the Regulations specified that the TER apply a long run marginal cost (LRMC) methodology for determining the wholesale energy allowance for non-contestable customers, which had the effect of delivering an allowance at levels that were broadly consistent with the costs of the TVPS. This removed the risk that the TER would set an allowance that did not place a high weighting on benchmark costs of generation from the TVPS\textsuperscript{122} - for example, by placing a high weighting on prevailing market prices. Consequently, the ‘blanket’ five per cent cap for all non-contestable customers announced during the 2010 State Election campaign was not progressed, instead being replaced by a one-off increase to the electricity concession.

\textsuperscript{120} In calendar 2008 and 2009, average annual Tasmanian spot prices were around $50/MWh, and 20 per cent or more above the average annual Victorian price. Coincident with the commissioning of the TVPS and a change in the non-contestable contract cover provided by Hydro Tasmania, annual average spot prices fell by around 40 per cent, and remained below Victorian average annual spot prices. Average quarterly Tasmanian spot prices showed substantial variation, which was also coincident with timing issues associated with the TVPS (commissioning and outages).

\textsuperscript{121} The key areas in which Aurora Energy sought Government assistance was in: rebalancing the debt levels within the Company; arrangements in relation to the setting of non-contestable customer prices and in delivering pricing outcomes from Hydro Tasmania consistent with those determinations having regard to Aurora Energy’s overall costs; and pursuing reform of the wholesale market in Tasmania.

\textsuperscript{122} Basing the wholesale energy allowance on LRMC is not the same as basing the allowance on actual costs of the TVPS, but by using relevant benchmarks, the costs do broadly align.
Secondly, the Regulations gave the Treasurer power to ensure that any commercial arrangements between Hydro Tasmanian and Aurora Energy in relation to non-contestable customers did not place Aurora Energy in a position of having overall higher energy costs (from all sources) than its revenue provided for under the regulatory allowance. These regulations empowered the Treasurer to impose a contract between the parties consistent with this outcome, in the event that a commercial agreement could not be reached. In the event, this power was not required to be exercised as the parties came to commercial arrangements that satisfied the overall cost test in the Regulations.

9.2.5. Economic and commercial considerations

The original BBP-Aurora Energy contract

BBP’s commercial arrangements with Aurora Energy provided some flexibility for Aurora Energy to change the balance of nominated contracts on an annual basis, after an initial five-year period. This would have enabled Aurora Energy to optimise its wholesale energy position in light of prevailing market dynamics.

Any change in Aurora Energy’s nominated hedge levels with BBP could change the operation of the TVPS and the level of gas it required. Under the BBP contract, this risk was BBP’s to manage and it would appear that, given its position in the national electricity and gas markets, BBP considered it was able to manage these risks.

While the Aurora Energy contract was a key underpinning source of revenue, BBP was proceeding on the basis of being wholly reliant on the contract to cover the costs of TVPS. It expected that spot market revenues and wider gas trading arrangement would also provide key sources of revenues or risk mitigation.123

The TVPS under Aurora Energy ownership

Aurora Energy’s risk position fundamentally changed once it became the owner of the TVPS. Aurora Energy also lost access to a hedge contract with a price below existing Hydro Tasmania contracts, and moved to a situation where it instead had all the costs of the TVPS, which turned out to be above its previous hedge costs. This has been a major driver of the financial implications of the TVPS for Aurora Energy. These are summarised in Table 9.1 and discussed in more detail below.

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123 The Panel has reviewed the BBP’s financial model for the TVPS, which indicates that BBP was anticipating generating value over and above the commercial arrangement with Aurora Energy through the Tasmanian spot market.
### Table 9.2 - Aurora Energy’s risk position pre and post TVPS acquisition

<table>
<thead>
<tr>
<th>Risk</th>
<th>With hedges for TVPS</th>
<th>As owner of TVPS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Construction Risk</strong></td>
<td>Nil – BBP risk</td>
<td>Aurora Energy risk - managed through construction contracts and owners arrangements</td>
</tr>
<tr>
<td><strong>Operations and maintenance</strong></td>
<td>Nil – BBP risk</td>
<td>Aurora Energy risk - managed through internal resourcing</td>
</tr>
<tr>
<td><strong>Dispatch risk</strong></td>
<td>Nil – BBP risk</td>
<td>TVPS as a ‘physical’ hedge against spot prices requires gives rise to dispatch risk</td>
</tr>
<tr>
<td><strong>BBP contracts</strong></td>
<td>Contracts provide risk management for 203MW of generation to back contestable and non-contestable load</td>
<td>Contracts ineffective as on both sides of the transaction. TVPS becomes a merchant plant for Aurora Energy, highly exposed to the spot market</td>
</tr>
<tr>
<td><strong>Tas spot price firm</strong></td>
<td>BBP contract ‘in the money’, mark-to-market gain in Aurora Energy’s accounts (unrealised)</td>
<td>Spot market revenues increase, improving TVPS profitability (realised)</td>
</tr>
<tr>
<td><strong>Tas spot price softens</strong></td>
<td>BBP contract ‘out of the money’, mark-to-market gain in Aurora Energy’s accounts (unrealised)</td>
<td>Spot market revenues decrease, weakening TVPS profitability (realised)</td>
</tr>
<tr>
<td><strong>Spot market opportunities</strong></td>
<td>No exposure - BBP risk and return</td>
<td>Risk and return on Aurora Energy’s account</td>
</tr>
<tr>
<td><strong>Hydro Tasmania exercises options to vary load under its contract with Aurora Energy for non-contestable customers</strong></td>
<td>Aurora Energy has market risk, capped at the value of the BBP contract price</td>
<td>Aurora Energy has market risk, capped at value of TVPS operating costs (substantially higher than BBP contract price)</td>
</tr>
<tr>
<td><strong>Gas supply</strong></td>
<td>Nil – BBP risk</td>
<td>Aurora Energy risk - managed through gas contracts</td>
</tr>
<tr>
<td><strong>Gas volume</strong></td>
<td>Nil – BBP risk</td>
<td>Take-or-pay gas commitments result in large financial risk if required gas volumes change.</td>
</tr>
<tr>
<td><strong>Gas price increases</strong></td>
<td>Pass-through at time of price reset.</td>
<td>Direct financial exposure for TVPS</td>
</tr>
</tbody>
</table>

Three key changes related to:

1) **The internalisation of the contractual arrangements that were in place between the TVPS and Aurora Energy**

With Aurora Energy’s acquisition of the TVPS, the value to Aurora Energy of the risk management advantages inherent in the previous contract arrangement were nullified, as Aurora Energy now sat on both sides of the transaction.\(^{124}\)

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\(^{124}\) The purpose of a hedge contract is to ensure that a generator and a retailer see and agreed price for a volume of electricity. The result of being on both sides of the contract is that Aurora Energy compensates itself for ‘overs’ and ‘unders’ between the hedge price and the market price, meaning that it always sees the market price.
In the absence of another third party being willing to take a longer-term position in contracting with the TVPS, this effectively turned the TVPS into a merchant plant, with its value being dependent on the outcomes in the Tasmanian spot market. This had negative consequential impacts on the value of the power station.

Based on financial due diligence undertaken for the Government during the acquisition process, the estimated value of the TVPS under separate ownership with the Aurora Energy contract in place was between $330 million and $415 million. By comparison, the estimated value with Aurora Energy owning and operating the TVPS as a merchant plant was around $200 million. At that time, the estimated cost to Aurora Energy to acquire and complete construction was $350 million.

Neither the valuation advice, nor work within government on the acquisition, addressed the mechanisms through which the additional ‘hydrological risk premium’ could be raised and secured by Aurora Energy so that the value of the TVPS in its accounts could have corresponded to the combination of its merchant value and the assigned hydrological risk value.

2) The risks facing Aurora Energy arising from contractual arrangements that it had in place with Hydro Tasmania in relation to the non-contestable customer load

With the Alinta contract negotiated and expected to come into effect on 1 April 2009, Aurora Energy negotiated two fixed-volume profile hedges with Hydro Tasmania to back the non-contestable load for the periods 1 April 2009 (the expected commissioning date of the TVPS) to 31 December 2009 and from 1 January 2010 to 30 June 2010. Under each contract, Hydro Tasmania had the option to elect to reduce the notional quantity by either 75 MW or 150 MW.

The combined effect of the contractual arrangements with Hydro Tasmania and the BBP contract (previously the Alinta contract) exposed Aurora Energy to the risk that it would be over-contracted and therefore exposed to spot prices. Aurora Energy has explained to the Panel that it had an expectation that, given the terms contained in the BBP contract and its expectation of spot prices, it would be able to utilise the BBP contract to back contestable customer contracts.

However, when it became the owner of the TVPS, Aurora Energy took on higher costs than under the previous hedge arrangements and was now directly exposed to spot market prices to generate revenues to cover these costs. More importantly, the take-or-pay gas contracts reflected an expectation at the time of acquisition of the power station running at a high level of capacity. Aurora Energy was left exposed to spot market for the output of TVPS when Hydro Tasmania exercised its right to supply the full non-contestable load. Consequently, Aurora Energy was obliged to run the TVPS to minimise losses on its take or pay gas contract.
This risk was not proactively managed and the financial consequences were left to unfold as Hydro Tasmania exercised its commercial rights. This resulted in Aurora Energy being over-contracted and exposed to the prevailing spot market prices for output of the TVPS, particularly given its take or pay gas exposures - spot revenues were commercially superior to paying for unused gas and achieving no revenues.125

The financial consequences of the operation of the TVPS in the wholesale market in Tasmania were significant. At the end of the 2010 financial year, earnings before interest and tax (EBIT) for Aurora Energy’s energy business were $50 million below budget, at minus $31 million.126 The financial impact on Aurora Energy during 2009-10 is discussed in more detail in Section 3 of the Panel’s Information Paper Tamar Valley Power Station: Development, Acquisition and Operation.

The financial issues identified by Aurora Energy in the 2010 financial year, particularly its ability to meet its cash costs and service debt (and the implications for the book the value of the TVPS) have been addressed in the medium term through the regulatory arrangements put in place by the Tasmanian Government in relation to the 2010 Price Determination for non-contestable customers and the contractual arrangements between Aurora Energy and Hydro Tasmania for the supply of the non-contestable load, as noted above.

These arrangements provide revenue certainty for the wholesale energy allowance which more closely reflects the cost of production from the TVPS and enable Aurora Energy to access contractual arrangements for the balance of the non-contestable load with Hydro Tasmania at a cost less than the wholesale energy allowance, such that its average contract costs are in line with the allowance. By utilising the TVPS to back non-contestable load and securing a lower price from Hydro Tasmania, Aurora Energy is able to cover the costs, and therefore preserve the value, of the TVPS. This arrangement is vulnerable to a change in regulatory arrangements at the end of the current Price Determination period.

3) Aurora Energy’s financial exposure arising from all the operating costs of the TVPS, including gas contracts and the debt associated with the acquisition and completion of the power station.

The gas commitments put in place at the time of acquisition were consistent with the operating regime anticipated for the TVPS in the BBP. While the Government and Aurora Energy’s decision to ‘lock in’ a gas supply regime at the time of acquisition arguably optimised the timing of gas negotiations and removed the risk of a weak bargaining position, the strategy had two other material consequences:

125 Lower spot prices did not present an opportunity for improved margins in Aurora Energy’s retail business as given the risks of keeping a spot price exposure in Tasmania, very high levels of contract cover are maintained.

126 There were other contributors to this overall outcome, including the performance of Aurora Energy’s national retailing activities.
it placed Aurora Energy, in the position of having a long-term large take or pay gas exposure\(^{127}\), which has had significant implications for the financial consequences of the operation of the TVPS; and

- it provided a stronger underpinning of Babcock and Brown’s Tasmanian gas pipeline business.

Aurora Energy also had to manage the significant debt attached to the acquisition and completion of the TVPS, including the cost of servicing this debt and the impact on its credit rating.

### 9.2.6. The future of the TVPS

The financial performance of the TVPS is driven by a combination of:

- its costs, relative to prevailing wholesale market prices; and

- its inability to vary production due to take or pay gas supply contract arrangements.

The current regulatory arrangements provide Aurora Energy with access to a customer group that is required to pay a wholesale energy allowance more in line with the TVPS costs, as opposed to currently prevailing market prices, which reflect the current supply/demand balance, strong storage levels and modest Victorian (and wider NEM) wholesale prices. The financial difficulties currently facing the TVPS reflect contemporary market circumstances. If Tasmania’s average wholesale prices increase, for example through a tightening of the supply/demand balance, the market value of the TVPS should rise. Changes in hydrological conditions will be a major driver of the Tasmanian spot market over time and the TVPS’ value as a hydrological risk management tool will be able to be captured by higher spot and contract prices at times of low storages.

The introduction of carbon pricing will have two opposing financial consequences for the TVPS:

- It will increase its costs of production, as it emits carbon dioxide and so will have to purchase carbon emission permits; and

- Tasmanian market prices will increase as the Victorian price of electricity will rise with a price on carbon emissions.

Across the NEM, the commercial position of gas generators will improve relative to coal fired electricity, given the former’s relatively lower carbon intensity. The extent to which carbon pricing will provide a commercial benefit to the TVPS will depend on the degree to which Tasmanian market prices rise in parallel with Victorian market prices.

\(^{127}\) Noting that it is not uncommon for CCGT plants to have take or pay gas supply contracts.
The second key influence on financial performance of the TVPS in the longer term is the renegotiation of gas supply arrangements, which remain in place until 2017. Unlike the situation at acquisition, Aurora Energy may consider the potential operating profile of the TVPS given the market settings that will exist in 2016-2017 and to secure gas supply arrangements that are consistent with that profile. This remains an issue for Aurora Energy’s future performance.

More immediately the Government needs to consider alternatives that more transparently manage the difference between the cost structure of the TVPS and its sources of revenue.

The Panel has put forward alternative options in Chapter 16 of this Draft Report.
9.3. Natural gas

The Panel’s Terms of Reference require it to report on the current efficiency and effectiveness of the Tasmanian energy industry and to report on actions that would guide and inform the development of a Tasmanian Energy Strategy.

The introduction of natural gas to Tasmania was a key initiative identified to deliver the Tasmanian Government’s 1997 Directions Statement. Specifically, the Tasmanian Natural Gas Project and Basslink were considered to be the only two options for significant new energy supply.

Consistent with the national electricity market reforms, Tasmania was an early signatory to the national gas reform arrangements. In order to comply with the National Gas Pipeline Access Agreement, which applied a uniform national framework to access gas transmission pipelines between and within jurisdictions, in late 2000/early 2001 the Tasmanian Government introduced a suite of legislation to establish to provide for the introduction of gas to the State.128

In 1997, the Tasmanian Government conducted an Expression of Interest process for the development of a natural gas supply to Tasmania and subsequently in May 1998, announced the selection of Duke Energy as the preferred developer of natural gas supply to Tasmania.

In 2001, the Tasmanian Government entered into a Development Agreement with Duke Energy to supply natural gas from Victoria to Tasmania. The Tasmanian Natural Gas Pipeline (TNGP)129 was commissioned in December 2002.

In addition to the gas transmission project, the Tasmanian Government facilitated the development of gas distribution and retailing in Tasmania. Following a tender process, in December 2002, the Government announced PowerCo Ltd as its strategic alliance partner for the gas distribution network.

The Tasmanian Government entered two development agreements with PowerCo Ltd for the construction and operation of the gas distribution networks.

- Stage 1 – the development of the backbone network fronting 23 foundation customers. The Tasmanian Government committed $9.2 million in total towards development costs.

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128 This legislation included the Gas Act 2000, the Gas Pipeline Act 2000 and the Gas Pipelines Access (Tasmania) Act 2000. Additionally, in June 2001, the Government Prices Oversight Commission was appointed as the Tasmanian Gas Regulator.

129 The TNGP is a combination of sub-sea, 305 km connecting Longford in Victoria and Five Mile Bluff in Tasmania, and onshore, 430km running from Five Mile Bluff to Port Latta in the north-west and Bridgewater in the south, gas transmission pipeline.
Stage 2A - the rollout of the distribution network to from 38,709 properties in the areas of Hobart, Launceston, Devonport and Burnie. The Tasmanian Government committed $46 million towards development costs.

A proposed Stage 2B to extend the distribution network to front 100,000 residential properties was not progressed by the Tasmanian Government.

The introduction of natural gas to Tasmania required considerable capital investment. The TNGP was funded by Duke Energy at an estimated cost of $440 million (in 2002 dollars). The estimated total capital cost of the distribution network was $230 million\(^\text{130}\), of which $55 million was provided by the Tasmanian Government.

Natural gas has provided some Tasmanian industry, businesses and residents with an alternative to electricity, coal and other energy options. It has also provided a new energy source for electricity generation (initially the conversion of the BBPS and currently the TVPS).

There are opportunities for gas to play a more integrated role in an efficient and effective Tasmanian energy industry. The TNGP has the capacity to convey 47 petajoules (PJ) of natural gas per annum but currently delivers only around 16 PJ per annum\(^\text{131}\). The distribution network fronts 43,400 properties but, of those, only approximately 9,000 are currently connected.

TasGas Networks, the current operator of the gas distribution network has indicated its interest in extending the network.\(^\text{132}\) It has, however, concluded that extending the distribution network is not economically feasible for the company without further Government funding. TasGas considers the key efficiency benefits of gas to be:

1. **Reticulated natural gas offers energy efficiency gains when compared to the use of gas to generate electricity.**

   Distributed end-use consumption of natural gas, for applications like space heating, is more energy efficient than using natural gas to remotely generate electricity in order for that electricity to be applied to the same end use.

\(^{130}\) TasGas Networks.

\(^{131}\) TasGas Networks

\(^{132}\) Further, the five year exclusive franchise for the distribution of natural gas in Tasmania (originally granted to the network’s developer) has expired opening the way for other interested parties in the State.
2. The availability of natural gas presents opportunities for network displacement and electricity generation.

The availability of natural gas creates opportunities for the connection of embedded generators to the distribution network within load centres, including co-generation.\textsuperscript{133} This has the potential to avoid or, at least delay, further capital intensive investment in upgraded electricity transmission and distribution infrastructure, thus mitigating one of the major drivers of increased electricity prices over the past decade.

TasGas Networks has put forward a number of proposals for changes to the planning framework with a view to enabling more economically efficient transmission and distribution networks to be developed in the future. Those proposals essentially seek to better integrate the consideration of natural gas into network planning in Tasmania.

In this regard it is important that the network planning and funding framework for Tasmania properly consider the potential of embedded generation fired by natural gas to displace network investment.

In its submissions and representations to the Panel, TasGas Networks has contended that this cannot be accomplished by electricity businesses, which are both the system planners and the infrastructure suppliers. TasGas argues that that there are incentives that currently exist within the national regulatory framework for network service providers to spend more than is necessary and efficient. Professor Ross Garnaut\textsuperscript{134} has also called for transmission ownership to be separated from the planning function at the national level.

With natural gas now available in Tasmania, it is important that future energy strategies fully consider natural gas as a complementary alternative to electricity, particularly in the context of avoiding over investment in networks and providing a mechanism to deliver the most efficient means of meeting emerging energy needs in the most cost-effective manner.

\textsuperscript{133} Cogeneration is the simultaneous production of electricity and heat using a single fuel, such as natural gas, where the heat produced from the electricity generating process is captured and used to produce steam. The steam is then used as a heat source for industrial or domestic purposes, and can be used in steam turbines to generate additional electricity using combined cycle power generation technology. Cogeneration provides greater efficiencies than traditional generation methods as it harnesses heat that would otherwise be wasted, and carbon dioxide emissions can be substantially reduced.

\textsuperscript{134} Update Paper 8 - Transforming the Electricity Sector, Garnaut Climate Change Review, 2011. Professor Ross Garnaut is the head of the Climate Change Review commissioned by the Australian Government,
PART 2

THE PRESENT
10. Energy policy objectives

10.1. Key issues

10.1.1. Policy objectives

Successive Tasmanian Governments have placed a high emphasis on the price and reliability of electricity to the State’s economy. ‘Hydro-industrialisation’ was a cornerstone of the State’s energy strategy in the middle part of the last century. Until the last decade, Tasmania has utilised hydro-electricity as its electricity generation source. In this context, hydrological risk equated to energy supply security risk. The economic consequences of potential electricity shortages for the State and its subsequent effects for investor confidence has been a long-term driver of the governments support for additional capacity in Tasmania.

More recently, with sharp and sustained increases in electricity prices, a greater focus has been placed on them and their consequence for the cost of living and the competitiveness of the Tasmanian economy. This is evident in the Panel’s Terms of Reference, particularly Terms of Reference 7 – which request the Panel to report on “actions that would guide and inform the development of a Tasmanian Energy Strategy particularly in relation to the Government’s primary objectives of minimising the impact on the cost of living in Tasmania and ensuring Tasmania’s long term energy sustainability and security” (emphasis added).

The Tasmanian Government is also the owner of the SOEBs, which constitute the majority of the TESI. SOEB ownership gives rise to the Government’s broader interest in the TESI beyond ensuring energy supply and security. The Government and the community more generally have a fiscal interest in financial performance of the SOEBs as they provide a source of funding for the delivery of core government services. It also utilises its ownership to deliver broader non-financial outcomes through the SOEBs. The achievement of broader social and economic policy objectives is intrinsically linked to, and can impact on, outcomes in the electricity sector – for example the impact of electricity prices on the cost of living.

The Panel has developed a framework against which key issues raised throughout its Review have been considered. This Framework is illustrated in Figure 10.1 and is discussed below.
Figure 10.1 – TESI Policy Framework

Panel’s Energy Supply Industry Objective

“To promote a secure, reliable, efficient and sustainable electricity supply industry providing electricity services at efficient prices to Tasmanian households and businesses over the long term.”

Energy Supply Industry Desired Outcomes

1. An energy sector that is safe:
   - An industry that is safe for those who work in it and for the general community.
2. Energy supply that is reliable and secure:
   - There is sufficient supply (installed capacity and energy availability) to meet current and forecast demand.
   - An energy sector that provides the right energy source to meet energy needs within an efficient framework.
   - Network investment that is appropriate to ensure sustainability and reliability of supply.
   - The system is managed to withstand shock.
   - Hydrological risk is appropriately managed.
3. An energy supply industry that is sustainable:
   - Environmental factors are appropriately managed (e.g., water resources and carbon emissions).
   - Energy supply industry participants are financially sustainable now and into the future.
   - Providers of capital investment achieve appropriate returns.
4. An efficiently operating energy sector:
   - Electricity generated by least-cost means at all times.
   - Short-term generator efficiency and availability.
   - New sources of supply are triggered at the appropriate time.
   - Network services are delivered at least cost.
   - Retail functions are delivered efficiently.
   - Risks are appropriately allocated.
5. A transparent and appropriate governance structure that manages energy supply risk.
6. Prices that reflect objectives above:
   - Efficient prices – prices that support a sustainable industry (no more, no less).
   - Pricing structures that send correct economic signals.
   - Price movements that are predictable, that can be planned for and managed.

Public Ownership of Electricity Assets

Electricity Assets Entity Structure:
- Single Hydro Generation
- Structure of Network Utilities
- Structure of Distribution Retail Entity

Regulatory Framework:
- Determining appropriate and equitable levels of risk, incentives to manage risk, and risk for customers.

Long Term Commercial Arrangements:
- Bilateral power purchase agreements.
- Gas Contracted Power.

Tasmanian Electricity Retail Design Principle:
- Market-based 80% of load.

Hydrological Variability:
- Hydro system energy constrained.

National Energy Policy Framework:
- Strategic carbon target.

National Electricity Market Rules (AEMC):

National Regulatory Framework (AEMC):
- Australian Energy Regulator.

Renewable Energy Target Policy and Carbon Pricing Scheme (AEMC):
- Australian Government.

OBSERVED OUTCOMES

Influences

BROADER DESIRED OUTCOMES LINKED TO ENERGY POLICY OUTCOMES – ADDITIONAL LENSES THROUGH WHICH GOVERNMENT AND THE COMMUNITY VIEW OUTCOMES

Electricity Price Outcomes:
- Affordability
- Maintain economic competitive advantage

SCER Return to Budget:
- Levels, stability and risk

SCER Objectives:
- Core versus non-core business
- Development of non-core operational function in Tasmanian market versus operation in other NEA jurisdictions

Development of Renewable Energy Resources:
- Tasmanian Climate Change Targets
- Alternative transport options - electric vehicles

National Market Related
- National Market Related
- National Market Related
- National Market Related

Yes
- Non-energy supply industry policy intervention

No
- Yes

Are observed outcomes consistent with Broader Desired Outcomes?

Adjust internal influences or seek to change external influences.

Are observed outcomes consistent with Energy Supply Industry Desired Outcomes?

Yes
- No

Are observed outcomes consistent with Energy Supply Industry Desired Outcomes?

No
- Yes

Are observed outcomes consistent with Energy Supply Industry Desired Outcomes?

Yes
- No

Are observed outcomes consistent with Energy Supply Industry Desired Outcomes?
10.1.2. The Tasmanian energy supply industry

The Panel is of the view that the electricity industry will make the best contribution to the growth and development of Tasmania and to the economic welfare of Tasmanians if it is operated on the most economically efficient basis possible. The policy framework is fundamentally based on the importance of establishing and maintaining the market architecture that will provide the incentives for an economically efficient electricity market.

The Tasmanian energy supply industry policy framework is illustrated in the left hand column of Figure 10.1 and should be read downwards. The framework is centred on the achievement of the Energy Supply Industry Policy Objective:

‘To promote a safe, secure, reliable, efficient and sustainable electricity supply industry, capable of providing electricity services at efficient prices to Tasmanian households and businesses, over the long term’

Six Energy Policy Outcomes deliver the Policy Objective, and the performance of the TESI needs to be measured against these. These Outcomes are:

1. An energy sector that is safe.
2. Energy supply that is reliable and secure.
3. An energy supply industry that is sustainable.
4. An efficiently operating energy sector.
5. A transparent and appropriate governance structure that manages energy supply risk.
6. Prices that reflect the above objectives.

The TESI sits within a broader national energy policy framework and within the Tasmanian Government’s jurisdictional energy regulatory framework and ownership policy for the SOEBs. These will influence whether the Energy Policy Outcomes are delivered in the Tasmanian market. The Panel’s Policy Framework identifies the following Energy Policy Influences:

- Influences which are in the Tasmanian Governments control relate to the ownership and structure of the SOEBs (ie governance); and the Tasmanian regulatory framework including network performance standards and the existing limitations on Hydro Tasmania’s Basslink bidding.
- There are also a number of Tasmanian jurisdictional specific influences. These are the long term commercial arrangements relating to Basslink and Aurora Energy’s gas supply, the Tasmanian electricity demand profile which is dominated by a few large industrial loads; and hydrological variability.
NEM related influences include the National Energy Policy Framework (administered through the Ministerial Council for Energy), the NEM Rules and the National regulatory framework.

National policy influences include the Australian Government’s Renewable Energy Target Policy and Carbon Pricing Scheme.

The Tasmanian Government has broader policy objectives that are linked to the Energy Policy Outcomes. This establishes an additional lens through which the Government and the Tasmanian community view the Energy Policy Outcomes. Broader policy objectives include electricity affordability, SOEB dividend returns to the State Budget, the development of renewable energy resources and Tasmanian climate change targets.

The Energy Policy Framework establishes a way to measure and manage the desired Energy Policy Outcomes such that the Energy Policy Objective is met.

The Framework should be read from left to right. If observed outcomes are inconsistent with desired outcomes, the appropriate action is to identify the influence that creates the disparity. The Tasmanian Government would then change what is in its control or seek to change external influences to maintain the Energy Policy Outcomes as its highest order priority.

Financial outcomes from the operation of the SOEBs and their implications for public sector finances should flow from and complement economically efficient electricity market outcomes. This will ensure that they are sustainable and do not come ‘at the expense of’ electricity users.

Clear ownership objectives need to be developed and updated by successive Tasmanian governments. The inter-relation ship between these, and broader social and economic objectives, with the ESI Policy Objective are key components of future energy strategies for Tasmania.

10.1.3. Reviewing the TESI against the energy supply industry objectives

Table 10.1 highlights the major conclusions regarding the extent to which the Electricity Supply Industry Objectives are currently being achieved in Tasmania. Table 10.2 provides a more detailed summary of the Panel’s assessment. It draws on the discussion in the previous Chapters and the balance of this Chapter provides the detailed assessment of the key issues arising from ‘gaps’ between objectives and observed outcomes.
Table 10.1: Major conclusions on the achievement of the electricity supply industry objectives

<table>
<thead>
<tr>
<th>Objective</th>
<th>Observation</th>
</tr>
</thead>
<tbody>
<tr>
<td>An energy sector that is safe.</td>
<td>Outside scope of Review</td>
</tr>
<tr>
<td>Energy supply that is reliable and secure</td>
<td>Performance generally consistent with objective. Energy supply security now addressed, but funding is the key issue.</td>
</tr>
</tbody>
</table>
| An energy supply industry that is sustainable | Financial sustainability of TVPS in the current market environment is a key area for reform. Otherwise financial position of the SOEBs sustainable.  
Key issues are the ability of the businesses to manage costs and deliver a return to the community from available revenues and the use of capital for business diversifications. |
| An efficiently operating energy sector        | ▪ There has been a mixed focus on operating efficiencies across the SOEBs.  
▪ The architecture underpinning the wholesale market in Tasmania has significant shortcomings that impact on dynamic efficiency in the market-based sectors.  
▪ This is a key area for reform. |
| A transparent and appropriate governance structure that manages energy supply risk | Several layers of oversight at State level and interconnection with AEMO processes. No significant changes required. |
| Prices that reflect the above objectives      | ▪ Regulated wholesale energy allowance sending inappropriate pricing signals to non-contestable customers. This is a priority for reform.  
▪ Wholesale market spot pricing mostly consistent with efficient outcomes, but transitory market power evident.  
▪ No evidence of sustained market power in wholesale contract market pricing. This is as a result of internal restraint from Hydro Tasmania, rather than external influences. Provides a substantial barrier for participation in the wholesale market.  
▪ This is a key area for reform. |
### Table 10.2 - Review of energy market outcomes energy policy objectives

<table>
<thead>
<tr>
<th>TESI Objective</th>
<th>×</th>
<th>✓</th>
<th>Where in Architecture</th>
<th>Observed Outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>An energy sector that is safe.</td>
<td></td>
<td></td>
<td>SOEBs and Workplace Standards Tasmania.</td>
<td>Outside scope of Review.</td>
</tr>
<tr>
<td>Energy supply that is reliable and secure.</td>
<td></td>
<td>✓</td>
<td>NEM Framework – role of the market in allocating resources and informing investment decisions.</td>
<td>Tasmanian Government has continued to make investment decisions, with a primary focus on energy supply security management. Tasmania has excess capacity to meet current and forecast demand. Transend Annual Planning Report and AEMO Statement of Opportunities indicate additional capacity is not required until at least 2027.</td>
</tr>
<tr>
<td>There is sufficient supply (installed capacity and energy availability) to meet current and forecast demand.</td>
<td>✓</td>
<td></td>
<td>NEM Framework – role of the market in allocating resources and informing investment decisions.</td>
<td>The TVPS CCGT base load displaces lower cost hydro-generation with lower cost. Displaced hydro-generation is traded in the NEM. Hydro Tasmania internal controls rather than the wholesale market architecture drives market outcomes. Impacts on new entry and the costs of that entry (not an immediate issue given supply/demand balance) Hydro Tasmania’s ability to set energy and FCAS prices in Tasmania impacts on Basslink flows.</td>
</tr>
<tr>
<td>An energy sector that provides the right energy source to meet energy needs within an efficient framework.</td>
<td></td>
<td>×</td>
<td>NEM Framework – role of the market in allocating resources and informing investment decisions.</td>
<td></td>
</tr>
<tr>
<td>TESI Objective</td>
<td>Where in Architecture</td>
<td>Observed Outcome</td>
<td></td>
<td></td>
</tr>
<tr>
<td>--------------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------</td>
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<td></td>
<td></td>
</tr>
</tbody>
</table>
| **Network investment that is appropriate to ensure sustainability and reliability of supply.** | The Australian Energy Regulator (AER) is responsible for the economic regulation of the transmission and distribution networks.  
The AER sets allowance for capital and operating expenditure for price determination period.  
Tasmanian and nationally based standards for performance. | Over the last 10 years, distribution customers are experiencing fewer interruptions and the average duration of interruptions has decreased slightly.  
The trends show a deteriorating performance in the CBD and urban categories but generally improving performance in the rural category. Improvements in rural areas may be at the expense of the deterioration in performance in urban areas.  
Over the last 10 years there has been an upward trend in transmission circuit availability and a relatively steady trend in system minutes off supply. |
| **The system is managed to withstand shock.**                                      | NEM standards for contingency planning in networks and generation planning  
Hydro Tasmania’s prudent water management requirements under Tasmanian legislative arrangements. | Managing energy supply security risk has been a major focus for Government over the past decade. This has delivered a decoupling of energy supply security risk and hydrological risk.  
Load shedding was avoided during a “1 in 1000 year” drought.  
TESI has sufficient capacity in generation and networks. Water storage levels currently exceed the upper limits of Hydro Tasmania’s prudent operating zone. |
<table>
<thead>
<tr>
<th>TESI Objective</th>
<th>×</th>
<th>Where in Architecture</th>
<th>Observed Outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Hydrological risk is appropriately managed.</strong></td>
<td>✓</td>
<td>Hydro Tasmania’s prudent water management requirements under Tasmanian legislative arrangements.</td>
<td>Managing hydrological risk is about managing water storages in response to particular inflows by utilising other energy sources.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Previously closely linked with energy supply security - hydro-generation represents 81 percent of installed native capacity.</td>
<td>Hydro Tasmania utilises Basslink and, more recently, the TVPS to manage hydrological risk.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Following the development of alternative energy sources, hydrological risk is no longer a supply risk, but a financial risk for Hydro Tasmania of meeting its contracted load and for revenue more broadly.</td>
<td>Hydro Tasmania is highly focused on managing hydrological risk, as it drives financial performance.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>During prolonged periods of below average rainfall there may reach a point when hydrological risk becomes a security of supply risk.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>An energy sector that is sustainable.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Environmental factors are appropriately managed (e.g. water and carbon emissions).</strong></td>
</tr>
<tr>
<td><strong>Energy supply industry participants are financially sustainable now and into the future.</strong></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>TESI Objective</td>
</tr>
<tr>
<td>----------------</td>
</tr>
<tr>
<td>Providers of capital investment achieved appropriate returns.</td>
</tr>
</tbody>
</table>

4. An efficiently operating energy sector.

<p>| Electricity generated by least cost means. | NEM Framework – competitive pressures on generator bidding delivers least cost supply. | Hydro Tasmania bidding generally reflects efficient costs (opportunity value of water), but there are transitory periods of strategic bidding and capacity withholding. TVPS OCGT operating at higher levels that resource costs would imply. Reflects commercial reality of gas contracts. |</p>
<table>
<thead>
<tr>
<th>TESI Objective</th>
<th>✓</th>
<th>Where in Architecture</th>
<th>Observed Outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short-term generator efficiency and availability.</td>
<td>✓</td>
<td>Market dynamics, including spot market incentive and the incentives for availability from contracting</td>
<td>No significant issues identified</td>
</tr>
<tr>
<td>New sources of supply triggered at the appropriate time.</td>
<td>✓</td>
<td>Wholesale market architecture provides pricing signals and an environment for new entry at appropriate time. AEMO planning and market advice that identifies opportunities</td>
<td>Wholesale market architecture likely to be a barrier to entry (dynamic inefficiencies), but not a medium term issue given current supply/demand balance.</td>
</tr>
<tr>
<td>Network services are delivered at least cost.</td>
<td>✓</td>
<td>National framework for the economic regulation of the networks under the National Rules, administered by the AER.</td>
<td>Historical overspending regulatory allowances by Transend and Aurora Energy’s distribution businesses has contributed to operating expenses over and above those determined through the regulatory process and increases in the regulatory asset base greater than anticipated through the regulatory process. This has primarily been at the expense of shareholders, rather than electricity users through higher electricity prices.</td>
</tr>
<tr>
<td>Retail functions are delivered efficiently.</td>
<td>✓</td>
<td>NEM - competition drives retail performance. The Tasmanian Government has implemented the phased introduction of customer contestability. The Tasmanian economic regulatory framework for regulating retail prices.</td>
<td>Only 2 retailers actively participating in the contestable market. Evidence of effective competition on retail services, but major driver of retail value through wholesale risk management not as evident in Tasmania as elsewhere in the NEM. Aurora Energy is the only retailer participating in tranche 5a. Aurora Energy’s retail cost is higher than its regulated allowance.</td>
</tr>
<tr>
<td>TESI Objective</td>
<td>Where in Architecture</td>
<td>Observed Outcome</td>
<td></td>
</tr>
<tr>
<td>----------------</td>
<td>-----------------------</td>
<td>------------------</td>
<td></td>
</tr>
<tr>
<td>Risks are appropriately allocated.</td>
<td>Market framework and negotiation provides commercial tension for risks to be managed by parties best able to manage them (least cost).</td>
<td>Lack of competitive tension in wholesale contract market leads to lack of transparency in relation to risk management. Lack of choice sees Hydro Tasmania able to determine risk allocation and premiums.</td>
<td></td>
</tr>
</tbody>
</table>

5. A transparent and appropriate governance structure that manages energy supply risk.

NEM Rules - responsibility for oversight of the market to ensure capacity adequacy is a function of the market manager AEMO.

At the State level, under the Energy Coordination and Planning Act 1995, the Director of Energy Planning is the statutory officer with responsibility for providing advice to the Minister for Energy and under section 67(3) of the Electricity Supply Industry Act 1995 to provide advice in relation to the making of emergency restriction orders as a result of the depletion of water supplies available for hydro-generation.

Several layers of oversight at State level and interconnection with AEMO processes.

Default NEM arrangements and mechanisms for delivering ensuring supply not been tested. The Government’s concerns regarding the economic consequences of supply restrictions prompted it to act to ensure delivery of TVPS.
<table>
<thead>
<tr>
<th>TESI Objective</th>
<th>Where in Architecture</th>
<th>Observed Outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>6. Prices that reflect above objectives.</td>
<td></td>
<td>Regulated wholesale energy allowance sending inappropriate pricing signals to non-contestable customers.</td>
</tr>
<tr>
<td>Efficient prices - prices that support a sustainable industry (no more, no less).</td>
<td>Contestable customers - market competition.</td>
<td>Wholesale market spot pricing mostly consistent with efficient outcomes, but transitory market power evident.</td>
</tr>
<tr>
<td></td>
<td>Non-contestable customers - Tasmanian regulatory framework (price determinations)</td>
<td>No evidence of sustained market power in wholesale contract market pricing. This is as a result of internal restraint from Hydro Tasmania, rather than external influences. Provides a substantial barrier for participation in the wholesale market.</td>
</tr>
<tr>
<td></td>
<td>Networks - regulatory determinations under national framework.</td>
<td></td>
</tr>
<tr>
<td>Pricing structures that send correct economic signals.</td>
<td>NEM Framework - market prices signal supply / demand balance and need for new entry generation or energy availability.</td>
<td>Regulated wholesale energy allowance sending inappropriate pricing signals to non-contestable customers.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Contestable customers are responding to pricing signals in network tariffs. Signals in network pricing not reflected in retail prices for non-contestable customers.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tasmanian spot prices spike at times of low demand and high availability, providing signals to curtail energy use when there is no underlying economic driver.</td>
</tr>
<tr>
<td>TESI Objective</td>
<td>Where in Architecture</td>
<td>Observed Outcome</td>
</tr>
<tr>
<td>-------------------------------------------------</td>
<td>-----------------------------------------------------------</td>
<td>-----------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Price movements that are predictable, that can</td>
<td>Wholesale risk management products</td>
<td>Changes in marginal loss factors not predictable (depends on hydrology in</td>
</tr>
<tr>
<td>be planned for and managed.</td>
<td>Regulatory arrangements for non-</td>
<td>previous year) and this creates price shocks for large customers.</td>
</tr>
<tr>
<td></td>
<td>contestable customer pricing</td>
<td>Changes in water availability drives changes in wholesale energy costs (innate</td>
</tr>
<tr>
<td></td>
<td></td>
<td>feature of Tasmania).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Retail price path is typically smoothed by TER.</td>
</tr>
</tbody>
</table>
11. Effectiveness of the current competitive architecture

11.1. Overview

A key objective of energy policy is to ensure that end-customers face efficient cost-reflective prices. The main way of achieving this outcome in Australia and many other jurisdictions has been to undertake structural separation of vertically-integrated energy businesses in order to enable competition to drive efficient outcomes in those elements of the supply chain that are potentially contestable, and to regulate the remaining ‘natural monopoly’ elements. This gives rise to the NEM model of competitive wholesale and retail markets, and the economic regulation of networks.

The NEM model, which Tasmania committed to in the late 1990s, is based on competition at the wholesale level between generators offering to supply power to retailers and competition at the retail level between retailers offering to supply power to end customers.

A fundamental precondition for effective competition in a market is scope for a number of actual and potential buyers and sellers between whom trade can occur. As noted by the United States Attorney-General’s National Committee to Study the Antitrust Law in its report of 1955:

> The basic characteristic of effective competition in the economic sense is that no one seller, and no group of sellers acting in concert, has the power to choose its level of profits by giving less and charging more. Where there is workable competition, rival sellers, whether existing competitors or new or potential entrants into the field, would keep this power in check by offering or threatening to offer effective inducements...\(^{135}\)

The wholesale and retail electricity markets in Tasmania are not vigorously competitive. Under the current structure of the wholesale market, Hydro Tasmania has the ability to profitably influence the Tasmanian spot price in a far wider range of scenarios than generators elsewhere in the NEM. Though this ability is not often exercised, its presence alone creates risks and costs for other market participants. In particular, as the principal supplier of wholesale risk management products in Tasmania, Hydro Tasmania has a high degree of discretion regarding the extent to which these products are offered to the market and their terms and conditions, including price.

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This state of affairs at the wholesale level leads many potential market participants to conclude that entering the Tasmanian retail market is highly risky and commercially unattractive relative to opportunities available elsewhere. As a result, retail customers do not have effective choice between suppliers. Consequently, lack of competition at the wholesale level begets lack of competition at the retail level.

This was a common theme in discussions the Panel held with national retailers, and was highlighted in Alinta’s submission on the Issues Paper:

Alinta Energy has a commitment to growth in its retail business across the National Electricity Market. As part of this strategy Alinta Energy has commenced signing up new customers in South Australia and commenced registering customer interest in New South Wales, Victoria and Queensland. Unfortunately, given the Tasmanian market’s out-workings, pursuing a Tasmanian strategy is seen as a second order issue in the absence of structural reform. Alinta submission, p 2. (emphasis added).

The Panel has engaged with nationally-based retailers that do not currently participate in the Tasmanian retail market. These business have indicated that they see the Tasmanian retail market as a potentially attractive opportunity, and the main barrier (other than that full retail contestability has not yet been declared) is their perceptions of wholesale market risk.

The Panel is of the view that for the retail market to deliver choice to Tasmanian end customers, retailers serving those customers need to have confidence that the wholesale markets risks that they face in doing so are manageable. The Panel contends that this is the key to unlocking greater participation and choice in the Tasmanian retail market.

The remainder of this Chapter explains how the Panel has come to this view.
11.2. **Expectations under the NEM entry framework**

When the Tasmanian Government made the decision to join the NEM, it had a range of expectations regarding the options that would emerge for choice in the market—both for retailers and for customers, as summarised in Table 11.1. As Table 11.1 shows, however, the range of options has not developed as anticipated.

**Table 11.1 - Expectations of choice at NEM entry**

<table>
<thead>
<tr>
<th>Retailers would have all of these options</th>
<th>Delivered by current architecture?</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contracting with Hydro Tasmania</td>
<td>✅</td>
<td>Dominant provider of contract cover in Tasmania.</td>
</tr>
<tr>
<td>Contracting with gas-fired generation</td>
<td>✗</td>
<td>TVPS owned by Aurora Energy, which uses it as a physical hedge. Could offer some competitive tension for Aurora Energy’s dealings with Hydro Tasmania.</td>
</tr>
<tr>
<td>Contracting with interstate generators across Basslink through the IRR auction</td>
<td>✗</td>
<td>IRR auction framework failed. Hydro Tasmania uses Basslink IRRs to support MI contract prices at NEM competitive levels.</td>
</tr>
<tr>
<td>Viable spot market trading opportunities – delivered by spot market competition between Hydro Tasmanian, gas generation and new-entrant wind generation,</td>
<td>✗</td>
<td>Hydro Tasmania’s demonstrated ability to capture spot market opportunities, which increases risk in relying on the spot market. Evidence shows that some participants have ruled out spot market exposure as being too risky.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Customers would have all of these Options</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>A competitive choice of retailers</td>
<td>✗</td>
<td>Lack of competition in the wholesale market has resulted in a lack of entry of new retailers.</td>
</tr>
<tr>
<td>Large customers choice in energy source – electricity or gas</td>
<td>✅</td>
<td>Most of the largest gas loads have gas connections and substitution and cogeneration increasingly taking place.</td>
</tr>
<tr>
<td>Small customers choice in energy source – electricity or gas</td>
<td>✗</td>
<td>Roll-out 60 percent smaller than anticipated, and around 20 percent of passed premises have elected to connect.</td>
</tr>
</tbody>
</table>

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136 Confidential submissions to the Panel.
Through submissions on the Panel’s Issues Paper, a number of stakeholders expressed the view that the current market architecture in Tasmania will not allow the development of sufficient competition to achieve the Government’s objectives.

For example, Aurora Energy cited the current wholesale market arrangements as “unsustainable”. Aurora Energy has provided the Panel with a detailed confidential paper discussing its concerns with the efficiency and effectiveness of the wholesale market in Tasmania. In its submission, Aurora Energy contended that:

Reforms to the wholesale market has [sic] the greatest potential to increase incentives for efficient operation which would positively impact on customer electricity prices. Benefits that may accrue from full retail competition are also heavily dependent of reforms to the wholesale market. P1.

Loy Yang’s submission made the following point:

... Hydro Tasmania’s dominance disincentives entry into the Tasmanian region. Clearly, IRRs can not be used effectively to manage risk in Tasmania for generators based in other regions wishing to enter that market. Hence, we agree with the view that Hydro Tasmania’s ownership of the vast bulk of supply ensures that “all roads lead to Hydro Tasmania” when any party seeks to take a position in the market. Furthermore, that Hydro Tasmania has a dominant price setting position given its monopoly makes it difficult to conceive how a private sector participant could risk entering that market for a sustained period. p. 6

Finally, the Australian Energy Regulator commented that:

wholesale market outcomes in Tasmania do not reflect efficient supply costs...The AER is also of the view that the significant inefficiencies and risks in the wholesale energy market in Tasmania are hindering the development of retail competition. p. 2

In contrast, other stakeholders expressed the view that, despite the lack of trading options, the market is operating well. For example, in its submission on the Issues Paper, Hydro Tasmania contended that:

Both the spot and contract elements of the NEM wholesale market are operating efficiently and effectively in Tasmania. p4.

The wholesale energy market is delivering least cost and cost effective outcomes, evidenced by comparison of Tasmanian wholesale prices against prices in other NEM regions. p5.

The market is effective because any retailer or wholesale customer who wishes to obtain a contract can secure one and the volume and profile of the contract will correspond to the retailer’s or customer’s request. p18.

ERM’s comments supported Hydro Tasmania’s view:

ERM has not seen the structure of the Tasmanian market as a barrier to entry for retailers and generally believes the market is operating efficiently. p1.
The following sub-sections develop the Panel’s framework for assessing the performance of the Tasmanian wholesale and retail markets before going on to examine the available evidence and discuss the Panel’s analysis.

**11.3. Framework for assessing market performance**

As noted above, a key driver for the introduction of the NEM reforms in Tasmania was to promote cost-reflective pricing to end customers. Cost-reflective prices help to maximise overall economic welfare and are one outcome of competitive markets.

Economists often assess market performance by reference to outcomes under the theoretical model of perfect competition. Under perfect competition, the market consists of a large number of small firms that are identical and produce a homogeneous product. All firms can be described as pure price takers, because no individual firm has any ‘market power’ – that is, the ability to increase its profits by restricting its output and increasing its price, or to ‘give less and take more’. Due to the assumption of free entry and exit, there is always another identical firm able to supply customers for the prevailing market price. Under perfect competition, firms make only the minimum level of profits needed to stay in business, known as ‘normal profits’, and prices reflect the lowest sustainable costs of supply.

The characteristics of real world markets differ from those under perfect competition to varying degrees. For example, firms are not identical and products are not homogeneous. Under real world conditions, many firms may have some ability to profitably increase the prices they receive, at least for a time. This can be described as transient market power.

However, an important finding in both economic theory and competition law is that the ability of a firm to increase prices above cost is of less concern if this ability is only temporary or transient in nature. In the words of Kaysen and Turner:

> A firm possesses market power when it can behave persistently in a manner different from the behaviour that a competitive market would enforce on a firm facing otherwise similar cost and demand conditions.137 [emphasis added]

This is recognised in Queensland Wire, where the High Court defined market power as:

> ... the ability of a firm to raise prices above the supply cost without rivals taking away customers in due time, supply cost being the minimum cost an efficient firm would incur in producing the product...138 [emphasis added].

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Therefore, so long as the relevant market in which the firm operates is ‘workably competitive’, the responses of actual and potential rivals will ensure that no firm can make supernormal profits on a sustained basis. Such firms will not have sustained market power.

Whether a market is workably competitive – and hence is likely to promote efficient cost-reflective pricing outcomes in the long term – depends in large part of the structure of the market. Market structure reflects a range of factors. These include:

- Market concentration – the number and size distribution of participants.
- Height of barriers to entry and exit.
- Scope for actual or potential import competition.
- Existence and closeness of substitutes for the product in question – more and closer substitutes will tend to reduce the market power of sellers.
- Responsiveness of demand to price increases.
- Dynamic characteristics such as the speed of technological change.

These are the factors are applied in the Competition and Consumer Act when assessing mergers.139

If a firm has market power, the next question is whether the firm chooses to exercise that market power. Ordinarily, economists assume that firms have a straightforward objective of profit-maximisation. Therefore, a firm with market power would expect to choose to exercise that power in order to increase its profits. However, in real-world conditions, firms with market power may choose not to exercise that power, at least not explicitly. This may be because they are inhibited by the explicit or implicit threat of government or regulatory intervention or because they prefer an ‘easy life’ making a certain level of profits rather than potentially earning higher profits but facing more risks to their position from competitors. Market power that is voluntarily not exercised can be described as latent market power. While the presence of latent market power may not have as immediate a detrimental impact on economic welfare as the explicit exercise of market power, latent market power is likely to harm welfare in the longer term by deterring efficient new entry.

A key task for the Panel in assessing the performance of the wholesale market in particular is to establish whether the architecture of the wholesale market in Tasmania gives rise to Hydro Tasmania, as the predominant generator, having market power and the extent to which this power is transient, sustained or latent.

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139 Competition and Consumer Act 2010 (Cth), ss.50(3).
11.4. Structure of the Tasmanian wholesale and retail markets

11.4.1. Wholesale market

Since 2005, Tasmania has been part of the NEM wholesale market arrangements. Tasmania is interconnected to mainland NEM regions through Basslink. In the NEM, wholesale trading of electricity occurs through the spot market operated by the Australian Energy Market Operator (AEMO) as well as through over-the-counter (OTC) and exchange-traded financial contracts entered into by various counterparties that are settled against spot market outcomes.

This section discusses the key structural features of the wholesale market in Tasmania.

Market concentration in Tasmania

Despite the opportunity for some imports of electricity, there is no question that given its absolute size relative to other supply options, Hydro Tasmania is almost always required to generate to meet demand in Tasmania. In other words, Hydro Tasmania is ‘pivotal’ in the wholesale market in Tasmania, as demonstrated in Figure 11.1.

The supply lines in Figure 11.1 show the residual capacity available from sources other than the named supplier. A supplier is pivotal if a supply line is below the demand curve. The Figure shows that Hydro Tasmania is pivotal in most trading intervals in capacity terms (i.e. the solid blue line is below the demand curve almost all of the time) and in all intervals if Basslink is considered as part of Hydro Tasmania’s wider portfolio. Conversely, the orange line shows that Tasmanian demand could be met at all times without the TVPS operational. That is, TVPS is never pivotal.

Figure 11.1 - Tasmanian residual demand curve

Source: Aurora Energy confidential submission
This means that at virtually all times, some level of output from Hydro Tasmania is required to meet demand. This provides the opportunity for Hydro Tasmania to almost always be the ‘marginal’ generator in the spot market. That is, the generator whose output equates supply with demand and sets the Tasmanian spot price. However, as seen below, Hydro Tasmania does not always bid in such a way as to be the marginal bidder.

Hydro Tasmania’s ability to set the spot price – in addition to their domination of the contract market - means that retailers are put in a position where they must choose between entering into hedge contract arrangements with Hydro Tasmania or be left exposed to a spot market price that Hydro Tasmania controls.

**Scope for inter-regional trading**

One of the key potential wholesale contracting options anticipated at NEM entry was interregional contracting across Basslink. Basslink has an import capacity of up to approximately 480MW. The idea was that by providing Tasmanian retailers/customers with access to the Basslink IRRs, Tasmanian participants would find it more attractive to contract with generators in Victoria (in particular). This is because the IRRs would enable Tasmanian participants to hedge interregional price basis risk arising on contracts with Victorian generators settled at the Victorian regional reference price. In principle, with access to an appropriate number of IRRs, a Tasmanian retailer would effectively end up paying a similar wholesale price as a retailer operating in Victoria.

As noted in a submission from Rio Tinto Alcan generators are, of their own accord, typically unwilling to enter derivative contracts settled at ‘foreign’ regional reference prices:

> Our experience is that, throughout the NEM, generators have a preference for hedge contracts referencing the NEM price in their own region, to avoid inter-regional basis risk. If such contracts cannot be sourced, generators have the choice to take pool exposure; that is, they do not need to have contracts in order to earn revenue. Therefore, the incentives for generators to contract inter-regionally are not high for the NEM generally. **The size and structure of the Tasmanian electricity industry does not provide any improved incentive and indeed the converse is more likely.**

Under the present arrangements, the Basslink IRRs accrue in the first instance to Basslink as a market network service provider and are transferred to Hydro Tasmania in return for the payment by Hydro Tasmania to Basslink of the Basslink Facility Fee. Therefore, IRRs are not available to other participants to underpin inter-regional wholesale trading.

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140 IRRs are the differences between Victoria and Tasmania spot prices multiplied by the volume of electricity transmitted across Basslink. When Basslink is constrained, differences will emerge in the spot prices in the two regions (because of the constraint). For example, if the price in Victoria is $20/MWh and the price in Tasmania is $30/MWh, the IRR would be $10, multiplied by the volume of electricity transmitted by Basslink.
Following discussions with the ACCC, the Tasmanian Government agreed to implement an auction arrangement that was intended to make the southward IRRs available for underpinning wholesale contracts across regions. However, the auction arrangements were subsequently withdrawn because of a lack of market interest in acquiring the IRRs.

Part of the reason for this lack of interest could have been related to a view that IRRs would not provide a sufficiently reliable or ‘firm’ hedge for inter-regional price variations. IRRs can only be firm if Basslink flows in the direction of higher prices at its full capacity. To the extent Basslink flows at less than full capacity during periods of inter-regional price variation\(^\text{141}\), or worse, flows in a counter-price direction, IRRs would be non-firm.

Hydro Tasmania has provided the Panel with analysis that demonstrates that the IRRs are an ineffective interregional risk management tool.\(^\text{142}\) Further, it is clear to the Panel that given its position in both the energy market and the market for ancillary services, Hydro Tasmania has the ability, the incentive and a track record of using its bidding behaviour to drive the direction of flows on Basslink and the extent to which the interconnector is constrained.\(^\text{143}\) This would be unlikely to inspire confidence amongst other participants regarding the firmness of IRRs as a basis for entering contracts with participants on the mainland.

**Conclusion**

The discussion in this section indicates that it is highly likely from a structural perspective, prima facie, that Hydro Tasmania has a high degree of market power in the wholesale market in Tasmania:

- Hydro Tasmania has a dominant position/market share in the Tasmanian region, controlling over 80 per cent of on-island capacity and holding a pivotal position;
- Hydro Tasmania can and does control Basslink flows through bidding in the energy and FACS markets;
- Hydro Tasmania is almost always the marginal bidder in Tasmania and can choose to set the spot price; and
- Given the lack of alternative providers of contract cover in Tasmania, Hydro Tasmania is also dominant in the contacting market, giving it leverage over contract prices/terms and the flexibility to vary its contract cover/spot exposure positions if it chooses.

\(^{141}\) For example, if Basslink was unavailable because of an unplanned outage.

\(^{142}\) For example, they are non-firm and their cost/value contains risk mitigation elements that are not relevant in providing risk mitigation against the Tasmanian spot price, so are not cost effective.

\(^{143}\) This ability is not absolute, as Hydro Tasmania has no control over prices in Victoria, which is the other principal driver of Basslink flows. Moreover, it is not costless for Hydro Tasmania to achieve the outcomes that it seeks to achieve over Basslink.
The real issue for the Panel in determining the need for further wholesale market reforms in Tasmania is to understand the manner and extent to which Hydro Tasmania exercises or does not exercise its market power and the nature of external constraints on it doing so.

11.4.2. Retail market

Currently, there are five electricity suppliers licensed to retail in Tasmania - AGL Sales Pty Limited, Aurora Energy, Country Energy, ERM Power Retail and TRUenergy. However, aside from the incumbent retailer, Aurora Energy, there is only one other active retailer in the Tasmanian contestable market - ERM Power Retailing. Aurora Energy estimates that it has retained around 85 per cent market share of the contestable market, and it has a legislative monopoly for non-contestable customers. A key question for the Panel is exploring the extent to which a more competitive wholesale market could create the conditions for a more competitive retail market. As noted above, many stakeholders consider that greater retail entry will not occur without a less concentrated generator sector.

11.5. Assessment of wholesale market competition

11.5.1. Background

Aurora Energy provided data to the Panel (shown in Table 11.2 below) concerning the frequency and severity of high-price events in Tasmania. The Panel considers that the data provides useful background to its analysis of Hydro Tasmania’s market power.

The data from Aurora Energy demonstrates that the number of high priced events in Tasmania (defined as spot market prices above $300/MWh) is not remarkably different to that in other NEM jurisdictions. However, what does stand out is the number of events that occur in off-peak periods, when the system is not under stress.

### Table 11.2 - Events where regional spot price has exceeded $300/MWh, July 2005-May 2011

<table>
<thead>
<tr>
<th></th>
<th>VIC</th>
<th>TAS</th>
<th>SA</th>
<th>QLD</th>
<th>NSW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of events</td>
<td>108</td>
<td>160</td>
<td>152</td>
<td>171</td>
<td>138</td>
</tr>
<tr>
<td>Number of peak events (7am - 10pm)</td>
<td>102</td>
<td>133</td>
<td>145</td>
<td>165</td>
<td>131</td>
</tr>
<tr>
<td>Number of off-peak events (10pm - 7am)</td>
<td>6</td>
<td>27</td>
<td>7</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td>Duration of events (half hours)</td>
<td>2.89</td>
<td>1.56</td>
<td>2.80</td>
<td>2.16</td>
<td>3.62</td>
</tr>
<tr>
<td>Magnitude (Average event price)</td>
<td>2277</td>
<td>2158</td>
<td>3898</td>
<td>2375</td>
<td>2152</td>
</tr>
<tr>
<td>Average Load Factor</td>
<td>0.62</td>
<td>0.67</td>
<td>0.50</td>
<td>.070</td>
<td>0.65</td>
</tr>
</tbody>
</table>

Source: Aurora Energy confidential submission on the Issues Paper
It its submission on the Issues Paper, Aurora Energy cited analysis undertaken by Deloitte on its behalf, which concluded:

For a system with relatively benign demand volatility and significant hydro energy storage, Tasmanian pool prices have been remarkable volatile. Inter-year pool price standard deviation shows an average base load customer in Tasmania is exposed to a 50-70 percent higher price volatility compared to Victoria, Queensland and New South Wales. Yet, there is no clear relationship between demand, capacity availability or energy in storage to price volatility in Tasmania.

11.5.2. Market power classifications

As noted above, based on the structure of the wholesale market in Tasmania, Hydro Tasmania does have market power. Nevertheless, in determining whether and what kind of further reforms are appropriate, the Panel needs to understand:

- The manner in which Hydro Tasmania exercises its market power – that is, whether Hydro Tasmania exercises only transient market power or sustained market power; and
- The extent to which Hydro Tasmania chooses not to exercise its market power – that is, the extent to which Hydro Tasmania’s market power is latent.

While these terms were introduced above, it is worthwhile developing their meaning further in the specific context of the wholesale electricity market operating in Tasmania.

Transient market power

Transient market power is the ability of a firm to profitably influence the price it receives for a limited period of time, but not more generally, because of short term market circumstances. Transient market power may arise even in a workably competitive market. As noted above, by itself, transient market power is unlikely to lead to substantial detriment to overall economic welfare.

For the purposes of the Panel’s analysis, the exercise of transient market power has been defined as bidding behaviour in the spot market that does not reflect economic costs and results in a higher wholesale spot price than would otherwise be the case for a relatively short period of time.

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144 For example, if electricity demand were to reach unusually high levels, there may be only one generator with capacity able to be dispatched to meet that level of demand, and it would have the capacity to set price at its level of choosing. In both economic theory and competition law, transitory market power is typically less of a concern than sustained market power as the efficiency losses are typically small. This is particularly the case in the electricity market, where demand is highly unresponsive to price in the very short term.
In the context of examining Hydro Tasmania’s bidding behaviour, the Panel has interpreted ‘economic costs’ to mean Hydro Tasmania’s opportunity cost of water. This is because, unlike coal or gas-fired generators, Hydro Tasmania does not have a readily observable short run marginal cost function for its 29 power stations. For a hydro generator, the tangible variable costs of production are relatively small, and the primary ‘economic’ cost is the opportunity value of water — the future value foregone by using water today. In the case of hydro generation that has limited or no water storage capability, the opportunity value of water is very low because there is limited or no ability to utilise that water in the future — it is essentially a ‘use it or lose it’ resource and the value of the electricity that can be generated is the value that is prevailing in the market at that time. Conversely, where a generator is able to store water for a long period of time, the opportunity value of water may be much greater, as it could be used when spot prices are high.

To avoid the concept of the opportunity cost of water from becoming circular, it has been defined as “opportunity cost under conditions of least-cost dispatch”. That is, Hydro Tasmania’s opportunity cost of water is determined by assuming that Hydro Tasmania would offer its output into the market at a zero price at such times and in such quantities that the overall cost of meeting load is minimised. Another way of expressing this is that the opportunity cost of water is derived by assuming pure price-taking behaviour by Hydro Tasmania and all other NEM participants.

The derivation of Hydro Tasmania’s opportunity cost of water is discussed in more detail below. For the purposes of assessing the incidence of transient market power, the Panel focussed on instances where Hydro Tasmania’s bidding behaviour was clearly inconsistent with any potential feasible estimate of its water value.

**Sustained market power**

Sustained market power is the ability of a firm to withhold capacity from the market and profitably drive prices higher than economic costs for a sustained period. In a workably competitive market, prices in excess of economic costs yield economic profits, which serve to attract new entrants. The entry of new participants continues until economic profits are competed away. Therefore, sustained market power in a market only arises where potential new entrants face barriers to entry.

For the purposes of the Panel’s analysis, the exercise of sustained market power has been defined as either bidding or contracting behaviour that does not reflect economic costs and that results in average wholesale prices that are in excess of the economic costs (rather than its commercial or operational costs) of serving load on a long term basis.

Strictly speaking, Hydro Tasmania’s economic costs in a long term sense include not only the opportunity cost of water, but also the recovery of its water infrastructure costs (e.g. dams, pipes). However, the Panel has assumed that, given their age, the cost of Hydro Tasmania’s assets have already been recovered and so the economic costs of its output are limited to the value of its water.
Latent market power

By definition, latent market power cannot be easily observed. However, its existence can be inferred from surrounding circumstances. One example is where a generator is theoretically able to increase the spot price through its bidding behaviour, but cannot do so profitably because it is highly contracted. This means that a higher spot price will simply cause the generator to make larger difference payments to its counterparties, offsetting the benefit of higher spot prices to the generator.145 Under these circumstances, the generator has no incentive to exploit its ability to increase spot prices, at least until its contracts ‘roll off’ and it is potentially uncontracted. Another situation where latent market power can arise is where firms are inhibited from exercising their market power on a routine basis by sporadic threats of government or regulatory intervention.

The Issues Paper noted that the existence of latent market power is potentially more problematic than the explicit exercise of market power. This is because the impacts of latent market power are less readily observable and while it may do little harm in the short term, in the longer term it could materially deter efficient new entry and investment.

In particular, latent market power can ham the long term development of competition in the wholesale and retail markets. The presence of a generator with latent market power may act as a disincentive to investment by large consumers, retailers or even other generators. This may occur as follows:

- Consumers and retailers may be concerned that if they invest in a market in which generators have latent market power, generators will exercise that power once the consumer or retailer enters and its investments are sunk.

- Potential new entrant generators may be concerned about the prospect that incumbent generators will act to suppress prices in order to destroy the value of the new entrant’s planned or sunk investment in a new power station in order to deter further entry.

Whether potential new entrants’ concerns are real or perceived matters little, to the extent those concerns deter entry into the market, it will result in long term damage to the market’s competitive processes. The implication of this is that this is likely to require continued government investment in general, as it is required.

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145 This only applies in the case of swap contracts.
11.5.3. Assessment methodology

To assess the extent and nature of Hydro Tasmania’s market power and its effect on wholesale market performance, the Panel has undertaken three broad forms of analysis. The Panel has:

- Reviewed Hydro Tasmania’s actual bidding behaviour and market outcomes – to inform the Panel whether Hydro Tasmania has exercised transient or sustained market power (see below);
- Reviewed Hydro Tasmania’s contracting behaviour and the relationship between Hydro Tasmania’s costs and its average contract strike prices – to inform the Panel whether Hydro Tasmania has exercised sustained market power; and
- Commissioned modelling of strategic behaviour in the Wholesale market in Tasmania to examine the extent to which Hydro Tasmania could exercise its market power if it chose to do so – to inform the Panel whether Hydro Tasmania has latent market power.

The Panel’s assessment of Hydro Tasmania’s bidding behaviour has in turn been in two parts:

- First, the Panel has focussed on instances of high spot prices in Tasmania and their relationship to Hydro Tasmania’s bidding behaviour – this has been done to inform the extent to which Hydro Tasmania has exercised transient market power; and
- Second, the Panel has considered longer term evidence comparing Hydro Tasmania’s bidding behaviour with average spot prices and its own opportunity costs of water – this has been done to inform the extent to which Hydro Tasmania has exercised transient market power.

11.5.4. Hydro Tasmania’s bidding behaviour

Relationship with high spot prices - Transient market power

The Panel examined the structure of Hydro Tasmania’s bids, the marginal bid at which Hydro Tasmania is dispatched and the Tasmanian spot price. Each of these is shown from 2007 to 2011 at the end of this Chapter.

The Panel has also reviewed price spikes that have occurred in Tasmania to determine whether they can be attributed to Hydro Tasmania bidding inconsistently with its (competitive) opportunity costs.

146 The Panel engaged Frontier Economics to assist in this analysis. The Panel has published a modelling report from Frontier as a supporting document to the Draft Report. It explains in detail the results of the historic analysis, the modelling methodology and modelling results.
The Panel’s primary conclusions of this historical review are:

- for the vast majority of the time, Hydro Tasmania bidding and Tasmanian spot prices remained at moderate levels;

- where high price events occurred in Tasmania over this period, they were most typically associated with high price bidding by Hydro Tasmania;

- patterns of bidding by Hydro Tasmania have varied between years:
  
  a. high-priced bidding was relatively frequent in 2007 and 2008, which appears to be linked to hydrological circumstances, but did not result high spot prices; whereas
  
  b. in later years high-priced bidding was more limited (eg. June 2009, March 2010 and August 2010), and there was a stronger correlation with high priced outcomes.

Both public and confidential submissions to the Panel have highlighted these patterns of bidding as evidence of market power problems in the Tasmanian region. For example, the AER submission on the Issues Paper provided a detailed analysis of the events in June 2009 that led to high-priced spot market outcomes. These involved Hydro Tasmania withdrawing non-scheduled generation and rebidding its scheduled capacity at much higher price bands. This flowed through to Tasmanian spot prices given the absence of competing bids at that part of the merit order.147

The Panel sought an explanation of Hydro Tasmania’s bidding behaviour at the times where the Tasmanian price was $5000/MWh or more. In its response, Hydro Tasmania explained that on each occasion:

  its contract position was such (or was believed to be such) that its sold Tasmanian contract position was less than its dispatched generation. On each occasion, the shortfall in the contract position was the result of customers (or retailers) choosing not to contract with Hydro Tasmania and not any failure or refusal by Hydro Tasmania to contract with customers.

The information provided to the Panel, and indeed on Hydro Tasmania’s admission, makes it apparent that Hydro Tasmania specifically targets short term opportunities to maximise revenue if it believes they exist. This reflects typical market behaviour that could be expected of any market participant in a position equivalent to Hydro Tasmania’s. The issue is not that such opportunities are pursued by Hydro Tasmania. Rather, the issue is whether the underlying architecture of the wholesale market in Tasmania creates too many of these opportunities and under too wide a variety of market conditions.

147 The AER observed that Hydro Tasmania has employed the same strategy on most occasions where the spot price has exceeded $5000/MWh in Tasmania, and at other times of high price outcomes.
To illustrate the market dynamics during periods of both high price bids and high spot prices, Figure 11.2 shows four series of half-hourly data in four separate panels:

- Hydro Tasmania bidding, disaggregated to show volumes (in MW) bid in various price bands.

- Aurora Energy’s bidding for the Tamar Valley CCGT, disaggregated to show volumes (in MW) bid in various price bands. This provides an indication of the availability of the Tamar Valley CCGT plant during periods of high price bidding by Hydro Tasmania.

- The Tasmanian regional reference price (in $/MWh).

- The Tasmanian scheduled demand (in MW). This provides an indication of the level of demand during high price events in Tasmania.

In each of the price panels, the red dots indicate half-hours during which the Tasmanian regional reference price was higher than $1,000/MWh.

A number of things stand out from Figure 11.2.

First, the extended periods of high price bidding by Hydro Tasmania in June 2009 and May 2010 coincide almost exactly with periods during which the TVPS’ CCGT plant was unavailable. Immediately before and after TVPS’ unavailability, Hydro Tasmania bid the majority of its capacity at prices below $100/MWh. For extended periods during Tamar Valley’s unavailability, however, Hydro Tasmania bid the majority of its capacity at prices in excess of $9,000/MWh.

Second, the high price events that occurred during these four months did not necessarily coincide with high demand periods. In fact, the red dots in the time series for Tasmanian scheduled demand show that high price events driven by Hydro Tasmania’s bidding occurred even at very low demand levels.148 Ordinarily, it would be expected that high price events would occur at or near daily maximum demand – where the generating system is under stress and there is insufficient capacity available to meet demand.

Finally, even with the TVPS fully available, high price events are not necessarily confined to high demand periods. This can be seen in August 2010 and November 2010, during which time the TVPS was fully available and high price events occurred at moderate levels of demand.

148 Indeed, in some instances, high price events occurred at or near daily minimum demand.
Figure 11.2 - Hydro Tasmania bidding, Tamar Valley bidding, Tasmanian spot price and Tasmanian demand

Source: AEMO data, Frontier Economics
The Panel has examined how Hydro Tasmania’s bidding behaviour and Tasmanian spot prices change with a loss in supply alternatives. The results are shown in Figure 11.3. Hydro Tasmania’s bidding patterns do not materially change when there is an outage on Basslink (August 2008 and April 2010). However, Hydro Tasmania’s behaviour does change when the TVPS is out of service (June 2009 and May 2010).

This suggests that the drivers of bidding behaviour are not primarily the supply demand balance in Tasmania. Rather, the drivers are Hydro Tasmania’s contract position and its exposure to the spot market. In simple terms, when Hydro Tasmania is not contracted, it can (and does, by its own admission) drive up spot prices with its bidding behaviour.

Figure 11.3 - Hydro Tasmania bidding with loss of alternative supply options, 2009

Source Frontier Economics
Figure 11.4 – Hydro Tasmania bidding with loss of alternative supply options, 2010

Taken as a whole, the analysis of historical spot market outcomes shows that prices remained at moderate levels for the vast majority of the time over the period from 2008 to 2011. However, there were a limited number of instances during this period when Hydro Tasmania’s bidding behaviour resulted in high spot price events.

The historic review of Hydro Tasmania’s bidding indicates that Hydro Tasmania is highly sophisticated in the way in which it chooses to influence Tasmanian spot market prices. For example:

- there is clear evidence\(^{149}\) to show that Hydro Tasmania has used its discretion over dispatch of its non-scheduled generation to assist in influencing the spot price;
- Hydro Tasmania has taken advantage of a tighter demand-supply balance in Tasmania when the TVPS is not in service, whereas it does not appear to have behaved in the same way when Basslink has been on planned outages - this suggests strategic behaviour driven by contract positions.

\(^{149}\) The evidence has been presented to the Panel confidentially by Aurora Energy, the AER submission to the Issues Paper and the Panel’s own analysis.
Given that instances of transient market power leading to high spot price events in Tasmania appear to have been limited, they are unlikely to have created substantial productive efficiency losses. Hydro Tasmania’s bidding behaviour is likely to have led to some instances in which higher cost plant has operated instead of Hydro Tasmania’s plant, but the costs associated with this would have been relatively minor.

Of greater concern is the wide range of conditions under which Hydro Tasmania has been able to exercise transient market power through its bidding behaviour in the period under examination. Transient market power is typically a function of specific and atypical market conditions. However, participants in Tasmania know that Hydro Tasmania can vary the spot price under a wide range of conditions – such as during low demand periods and even when TVPS and Basslink are available. For the most part, Hydro Tasmania’s contract position materially reduces the incentives for it to exercise market power, but its contract levels are ultimately a matter of choice. This suggests that Hydro Tasmania may be able to drive up the spot price through its bidding behaviour far more often than it has done so to date. This is indicative of Hydro Tasmania having significant latent market power.

The implications of Hydro Tasmania having significant latent market power are discussed below.

**Relationship with economic costs and average spot prices - Sustained market power**

The above analysis was limited to the relationship between Hydro Tasmania’s bidding behaviour and particular high-priced events. To assess whether Hydro Tasmania has exercised market power on a sustained basis, the Panel has reviewed Hydro Tasmania’s bidding behaviour over a longer continuous timeframe to understand how it relates to its (competitive) opportunity cost of water and Tasmanian wholesale prices.

To the extent that Hydro Tasmania’s bids have exceeded its opportunity cost of water on an ongoing basis and led to average wholesale prices in excess of the costs of serving load, Hydro Tasmania has exercised sustained market power. Such behaviour would go beyond transient market power and represent an ongoing ability to price without being constrained by competitors.
Spot market outcomes

A starting point for the analysis of the exercise of sustained market power in the spot market is a comparison of average Tasmanian spot price outcomes with prices in other jurisdictions. This is done in Figure 11.5. This shows that spot prices in Tasmania have generally been within the range of spot prices in other jurisdictions, other than in 2008-09 which coincided with low storage levels and inflows in Tasmania. More recently, as inflows have increased, and the TVPS has been operating at high capacity factors, spot prices in Tasmania have fallen significantly, and have been among the lowest in the NEM.

Figure 11.5: Average annual prices spot prices

Source: Frontier Economics, AEMO data

The differences between Tasmanian spot market prices and those in other regions are sometimes cited as evidence that there are no issues with market power in the Wholesale market in Tasmania.

For example, in its submission on the Issues Paper, Hydro Tasmania contends that:

The wholesale energy market is delivering least cost and cost effective outcomes, evidenced by comparison of Tasmanian wholesale prices against prices in other NEM regions. P5.

It also reflects Hydro Tasmania’s bidding behaviour in June 2009. The events were unprecedented in Tasmania, with spot energy prices exceeding $5 000/MWh on 13 occasions. For the first time ever administered prices were applied in Tasmania.
Comparison of Hydro Tasmania bids to opportunity cost of water

While there will be typically be a clear relationship between Tasmanian and Victorian spot prices due to interconnection, the Panel is not persuaded by price comparisons alone that there is no sustained market power in Tasmania. This is because the test of whether market power has been exercised on a sustained basis fundamentally depends on whether Hydro Tasmania’s bidding and contracting behaviour is inconsistent with the opportunity cost of its water in a competitive market.\textsuperscript{151} If Hydro Tasmania’s assessed opportunity cost of water is significantly lower than the economic costs of serving load on the mainland, then average Tasmanian spot prices should be below average Victorian spot prices.

Figure Z shows the modelled opportunity cost of water for 2006 through to 2011. The opportunity cost of water is calculated under two cases: one with medium inflows and one with low inflows. With medium inflows, Hydro Tasmania’s opportunity cost of water is between $20/MWh and $30/MWh. With low inflows, Hydro Tasmania’s opportunity cost of water is initially between $50/MWh and $60/MWh. This subsequently drops to the same level as the medium inflow case, as new investment occurs in response to the assumed low inflows. The difference between these cases reflects the fact that under the low inflow case, Hydro Tasmania has lower levels of efficient dispatch and when Hydro Tasmania does dispatch, it displaces more expensive plant (until an investment response occurs).

Figure 11.6 also shows Hydro Tasmania’s actual marginal dispatch price for each quarter for 2005-06 through to 2010-11. The pink line shows the median quarterly marginal dispatch price and the 25 percent to 75 percent range of quarterly marginal dispatch prices are both shown by the light blue bars. The green line shows the Tasmanian regional reference price.

\begin{footnotesize}
\textsuperscript{151} The opportunity value of water is not readily observable, and given that it is forward looking, is open to judgement. The Panel has reviewed in detail the process by which Hydro Tasmania internally calculates water value, at the whole of system level and for individual storages. The Panel has not sought to recreate or back-cast those values for the purposes of this analysis. Rather, the approach was to develop a reasonable estimate of what water values would have been and then comparing those estimates with observed bids and market prices. This is explained more fully in the Frontier Modelling Report.
\end{footnotesize}
Comparing Hydro Tasmania’s opportunity cost of water with Hydro Tasmania’s marginal dispatch price suggests that in the main, Hydro Tasmania’s bidding has been reasonably consistent with estimates of its opportunity cost of water:

- During 2006-07 and 2007-08, when inflows were low and storage levels were falling, Hydro Tasmania’s marginal dispatch price steadily increased from around the level of the estimated opportunity cost for the medium inflow case to around the level of the estimated opportunity cost for the low inflow case. This is consistent with what would have been expected of a firm bidding, on average, competitively.

- As inflows increased over 2008-09, the marginal dispatch price steadily decreased back to around the level of the estimated opportunity cost for the medium inflow case. During 2009-10 and 2010-11, Hydro Tasmania’s marginal dispatch prices remained, on average, at around the level of the estimated opportunity cost for the medium inflow case.

Figure 11.6 does shows there is variation across quarters, with median marginal dispatch prices sometimes above and sometimes below the estimate of water value. However, marginal dispatch prices do not exceed the estimated water value on a sustained basis, and on an annual average basis there is a high degree of consistency between marginal dispatch prices and the estimated value of water.
Conclusion

The analysis in this section shows that Hydro Tasmania has, on average, bid in a way that would be expected of a firm in a workably competitive market. While the detailed analysis of half-hourly bidding over the period 2007-08 to 2010-11 indicates a number of instances when Hydro Tasmania’s bidding behaviour resulted in high spot price events, there is no evidence that Hydro Tasmania exercised sustained market power in the spot market during this period.

11.5.5. Hydro Tasmania’s contracting behaviour

Although it does not appear that Hydro Tasmania has exercised sustained market power through its spot market bidding, it may have done so through its contracting activities.

However, identifying market power in contract trading is less straightforward than the equivalent assessment in the spot market. Some of the reasons for this are:

- Spot market dispatch occurs on a 5-minute basis, so non-price-taking behaviour is relatively easy to identify as any bidding that departs from economic costs. By contrast, derivative contracts are typically struck for much longer periods of time, over which the economic costs of supply are more difficult to ascertain.

- The strike price of a forward contract typically incorporates a positive premium over the expected future spot price to reflect the unobservable value of the ‘insurance’ provided by the seller of the hedge (e.g. a generator) to the buyer of the hedge (e.g. a retailer).

- Hydro Tasmania’s contract book comprises a range of contracts that were negotiated at various points in time. At the time of entering into each of these contracts, expectations regarding future market outcomes would have varied, and so Hydro Tasmania’s opportunity cost of water calculated at those various points in time would also have varied.

- In entering into these contracts, Hydro Tasmania takes on hydrological risk, and depending on storage levels, that level of risk can vary at each point contracts are negotiated, which would legitimately impact on the contract price.

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152 Hydro Tasmania’s contract portfolio is highly commercially sensitive. This limits the degree to which the Panel is able to present this evidence publicly.
Comparing contract prices that reflect these different expectations with an opportunity cost of water calculated on the basis of current forward-looking expectations of market conditions is not a like-for-like comparison. In this context, comparing contract strike prices in Hydro Tasmania’s portfolio with forward-looking water values is, at best, indicative of whether Hydro Tasmania’s contract prices reflect economic costs. However, this was the only option available to the Panel to test for sustained market power in contract trading.

The approach taken by the Panel was to first calculate the volume-weighted strike price of Hydro Tasmania’s firm swap contracts. Once this was established, it was compared to projections of Hydro Tasmania’s opportunity cost of water as determined over the period from 2011-12 to 2015-16 using the same methodology as for the spot price analysis.

The comparison of Hydro Tasmania’s opportunity cost of water with its volume-weighted average contract price showed that Hydro Tasmania’s average contract prices tend to be somewhat higher than its opportunity cost of water. This becomes more apparent towards the end of the period, in 2014-15 and 2015-16. However, given the risk associated with forward contracting for an energy-constrained hydro generator and the premium that is typically associated with this, there is no clear basis for concluding that these average contract prices indicate that Hydro Tasmania has exercised sustained market power across its overall contract book.

11.5.6. Strategic modelling of latent market power

The analysis of Hydro Tasmania’s historical bidding patterns above showed that while Hydro Tasmania has not engaged in strategic bidding on a regular basis, it has often done so when demand has been relatively low and/or TVPS has been out of service. At these times, Aurora Energy is more likely exposed to spot market prices. This approach to the exercise of transient market power signals to market participants that Hydro Tasmania has significant latent market power that it can use if it chooses to.

Because latent market power cannot be observed retrospectively, the Panel’s approach to analysing Hydro Tasmania’s latent market power involved utilising a forward-looking market modelling approach. The purpose of this exercise was to examine the potential strategic behaviour that Hydro Tasmania could employ to maximise its commercial position, overlaying the constraints that the current market architecture imposes on such behaviour.153

153 One example is the demand side response from large customers that have shown the ability to respond to market outcomes by varying load. Another is the operation of the TVPS.
Methodology

The Panel engaged Frontier Economics to undertake a forward-looking analysis over the period 2011-12 to 2015-16 to examine the likely and potential exercise of market power in the wholesale market in Tasmania. The key to this exercise was the use of Frontier Economics’ models of the electricity market that examine the outcomes from strategic market behaviour. This type of modelling is well suited to identifying latent market power because it does not rely on using past patterns of bidding in any way to determine rational and stable patterns of bidding. Instead it relies on working out the bidding that delivers the maximum sustainable profit.154

A key determinant of the outcomes from strategic behaviour modelling is the level of financial hedging of major NEM participants. In the absence of such contracts, generators would be more likely to have the ability and incentive to profitably bid up spot prices by strategic withdrawal of capacity.155

The assessment considered three scenarios:

- A base case where Hydro Tasmania is able to strategically withdraw capacity to seek higher profits. A key aspect of the base case is that Hydro Tasmania is assumed to hold a relatively large quantity of hedging contracts, which broadly represents its current level of contract cover;

- A competitive case, where the model requires Hydro Tasmania to bid at the estimated opportunity value of water; and

- A case that removes the constraints arising from a high level of contract cover, which acts as a reference point to assess the extent of Hydro Tasmania’s latent market power.156

The modelling allowed for demand side response from major industrial customers to shed load in response to high spot price outcomes, as has been observed in Tasmania. It also provided for the influence of the TVPS in the Wholesale market in Tasmania (operating under its current gas contracts) and for the influence of competitive market influences in Victoria through Basslink.

154 Details of the modelling approach are contained in the Frontier Modelling Report.

155 The fact that the historic analysis has not demonstrated Hydro Tasmania bidding up spot prices on a sustained basis does not mean that it is unable to do so. Rather, with a different contract position or a different motivation, Hydro Tasmania’s bidding incentives may be significantly different.

156 Currently, there are no formal or informal constraints imposed on Hydro Tasmania in relation to the level of contract cover that it establishes with market participants in Tasmania. There are strong commercial drivers for it to maintain a level of contract cover (eg. sensible risk limits imposed by the Board), and given the nature of the Tasmania demand side, particularly the MI customer segment, it is implausible to consider a scenario where it completely withdraws from the contract market. It is not possible for the Panel to form a sound judgement on a realistic “minimum” contract level that Hydro Tasmania could commercially decide to take. Nonetheless, it is clear that with its pivotal position in the wholesale market in Tasmania that Hydro Tasmania does not need to maintain a high degree of contract cover to manage unpredictability in the Tasmanian spot price.
Results

The modelling results showed that the projected price outcomes for the Tasmanian spot market are almost identical in the base case and competitive case. The conclusion from the modelling is that with a high level of contracting, Hydro Tasmania’s incentives to engage in strategic behaviour in the spot market by withdrawing capacity are very low.

This is demonstrated in Figure 11.7, which shows the simplified load duration curve (the grey line) generated by the model and identifies the modelled spot price outcomes (the dots), with the colour of the dot indicating the average spot price at each level of demand. The size of the dot reflects the size of the capacity withdrawal that the model predicts would maximise Hydro Tasmania’s profits.

Figure 11.7 Base Case – Hydro Tasmania Strategic Behaviour, 2012-13

Figure 11.7 demonstrates that with the assumed high level of contract cover, the opportunities for Hydro Tasmania to strategically withdraw capacity to profitably drive up spot market prices are minimal. The modelled price outcomes show spot prices always below $50MW/h and the outcomes that maximise Hydro Tasmania’s profitability do not involve any strategic withdrawal or re-pricing of capacity. This is because Hydro Tasmania’s spot market exposures are highly limited. Where spot opportunities do arise, these need to be greater than the output of non-Hydro Tasmanian generation, and there is the potential for demand side response from major industrial customers. This forward-looking modelling of potential behaviour is consistent with the findings of the historic review discussed above.
To examine the influence of contracting position on these outcomes, the same strategic modelling approach was implemented with the assumption that Hydro Tasmania has not entered any contracts. All other modelling assumptions, including the operation of Basslink and the TVPS and the demand side response observed from major customers in light of high spot prices, were held constant.

**Figure 11.8 - Removal of contract constraints - Hydro Tasmania Strategic Behaviour 2012-13**

Figure 11.8 demonstrates that compared with the base case, there is a significant increase in both the regularity and extent of strategic withholding, as well as the average prices found at each level of demand. The modelled price outcomes show the Tasmanian spot price is always above $100MWh and routinely at the level detailed by Hydro Tasmania (in the model, this is the market price cap used to maximise profits).

**Interpretation**

What the modelling clearly demonstrates is that the competitive outcomes observed in the base case were very much the result of the assumed contract levels and without these contracts in place; Hydro Tasmania would have had the clear incentive and ability to withhold capacity to increase the price under most demand conditions. This would occur despite the presence of the other generation plant in Tasmania, the capacity of Basslink to import electricity from Victoria and the demand side to reduce load in response to market prices.
Hydro Tasmania has argued\textsuperscript{157} that there is a range of constraints on its ability to act unconstrained in the Wholesale market in Tasmania. The constraints it cites include:

- the threat of new entrant generation;
- the need to manage hydrological risk;
- the behaviour in spot dispatch of Victorian generators, other Tasmanian generators and major industrial customers;
- the delivery risk associated with being able to back a contract, including the risks associated with the availability of Basslink; and
- the need to secure sustainable future revenues through longer term contracts.

Of these potential constraints, it is the level of Hydro Tasmania's contracting that is the principal constraint on Hydro Tasmania's wholesale market behaviour. Being highly contracted minimises its exposure to the spot market and is the primary influencing factor that drives bidding outcomes and market prices towards efficient levels.

Other constraints do exist and have the effect of potentially reducing the gains available from strategic behaviour,\textsuperscript{158} but they are of a secondary importance. This is demonstrated by the modelling, which shows that the influence 'must run' Hydro Tasmanian generation, other Tasmanian generators, Victorian generators through Basslink and the demand side response of major industrial customers is insufficient to moderate the commercial drivers for strategic behaviour.

Given the current supply/demand balance and the timing of new entry from an energy supply perspective, coupled with the large wholesale market risk potentially faced by a new entrant generator without a portfolio, the threat of new entry is not a material constraint for Hydro Tasmania.

\textsuperscript{157} Hydro Tasmania submission on the Issues Paper, p.20.

\textsuperscript{158} For example, a response from an MI customer that has the ability to rapidly decrease load if spot market price spike may decrease, or potentially nullify a transient market opportunity. Hydro Tasmania has provided the Panel with examples of occasions when it targeted opportunistic spot market opportunities and found that as a result of a demand side response, the commercial value of that opportunity was significantly eroded. The Panel does not consider this type of market response a mitigant for sustained market power, in the same way that Hydro Tasmania's contract position is.
The outcomes described in Figure 11.8 do not represent a likely market outcome. It is extremely unlikely that Hydro Tasmania would completely unwind its contract position, or drive up spot prices for the majority of the year. What the modelling does show very clearly is the incentives that Hydro Tasmania would face in the absence of contracting. The analysis indicates that, if Hydro Tasmania is not contracted, it is routinely in a position to (and would have the incentive to) drive up (or down) spot prices, even if demand was low. This is consistent with the historical analysis, which demonstrated that Hydro Tasmania’s bidding behaviour has led to high prices even when demand is low.

It is important to note that, presently, Hydro Tasmania has a very high degree of discretion over the quantity and characteristics of contracts it negotiates. If Hydro Tasmania wished to reduce their contract cover to increase the profitability of raising the spot price, it could easily do so.

In summary, the residual demand curve analysis, market modelling, observation of Hydro Tasmania’s intermittent bidding of high prices (including at times of low demand) and submissions from a range of other market participants provide evidentiary support for the proposition that Hydro Tasmania possesses substantial latent market power which, in the absence of structural reform, will be sustained over the longer term due to significant entry barriers.

**Implications of latent market power:**

**For contracting and new retailer entry**

The strategic modelling analysis showed that there is a very wide range of market conditions (particularly levels of demand and competing supply) under which Hydro Tasmania would be in a position to exercise market power if it were exposed to the spot market. Figure W demonstrates that even at Tasmanian demand levels a little over 1100 MW, an uncontracted Hydro Tasmania could push the spot price towards the market price cap to maximise profitability. This is consistent with Hydro Tasmania’s status as a pivotal generator in Tasmania at virtually all times – a pivotal generator is always able to be marginal and set the spot price. It also tallies with the empirical evidence of Hydro Tasmania’s historical bidding behaviour, which shows that Hydro Tasmania can choose to withhold its capacity and push up the Tasmanian spot price to extreme levels under a wide variety of market conditions and even if TVPS and Basslink are in service.

The only significant constraint on Hydro Tasmania’s strategic bidding (in the sense that the incentive reduced) is the volume of hedge contracts it has entered. However, Hydro Tasmania ultimately chooses its contract position and can change it as it wishes. For example, Hydro Tasmania could unilaterally choose not to renegotiate expiring contracts that are rolling off.

Retailers and major energy users cannot reliably forecast Hydro Tasmania’s contract position, and certainly cannot forecast Hydro Tasmania’s contract position for the
entire life of their investments. Any customer or retailer that has made or is considering making an investment in the market will be concerned with the potential market outcomes if Hydro Tasmania chooses to reduce its contract levels and increase the frequency of its strategic bidding behaviour. Thus, the uncertainty created by the presence of latent market power will increase the risk of customer and retailer investments.

The key implication of Hydro Tasmania’s latent market power is that retailers will either:

- feel compelled to enter derivative contracts with Hydro Tasmania at whatever price is nominated by Hydro Tasmania in order to avoid the risk of being left exposed to high spot prices at virtually any and all times; or

- avoid entering the market altogether to avoid facing the risk of having being ‘held to ransom’ when contracts come to an end and need to be renegotiated.

This is has been a key theme that has been raised in discussions between national retailers and the Panel. The same theme is observed in the Alinta submission on the Issues Paper:

Alinta Energy agrees that in most circumstances Hydro Tasmania is able to set the regional price, although market outcomes do not necessarily demonstrate such behaviour. Nevertheless, this does not negate the existence of market power and that at times the exercise of this power could have significant cost implication for market participants. As such, the threat of misuse of market power to damage third parties can be as powerful a tool to deter new entry and to compel existing participants to take specific actions as misuse of market power itself.

We share the view that the Tasmanian spot market outcomes present a major risk for potential market participants. Potential retailers, including Alinta Energy and generators seeking to enter into wholesale contracts with large-scale customers, would not be able to effectively hedge this risk.

We understand the Panel’s view that this spot market risk in Tasmania is likely to incentivise participants to enter into contracts. We also note Hydro Tasmania’s puts forth its willingness to contract with “all comers” as evidence that retailers and contestable customers in Tasmania have access to efficiently priced electricity.

However, our view is that the current arrangements ensure very limited entry into Tasmania by new participants, no entry by mass market retailers, limited market liquidity, and that existing participants have access to limited products; the oft cited “all roads lead to Hydro Tasmania” dilemma which cannot ensure efficient outcomes.

In the Panel’s view, Hydro Tasmania’s latent market power, and its periodic signalling of that power through spot and contract market outcomes, is a serious barrier to entry into the retail market by efficient, large scale, mainland retailers.
For new generation entry

In relation to the generation sector, as new investment in capacity will not be required for 10 years or more, the market conditions, price signals and available technologies nearer to that time will influence those new capacity decisions rather than those that apply now or in the next few years.

Nonetheless, it is arguable that relevant structural reforms would assist in ensuring that when those important future capacity investment decisions need to be made, they will not be distorted by latent market power considerations. Hydro Tasmania may merely signal its ongoing market power now, but when the supply/demand balance begins to tighten, it could exercise its market power to pre-empt new entry and future rivalry in various ways. For example it could invest early in new capacity, making independent entry risky and uneconomic. Alternatively, it could eliminate any investor in new capacity post-entry by reducing prices for a sustained period making the new sunk investment uneconomic. As its capacity to act in these ways would be recognised by potential entrants, new entry would remain highly risky and so unlikely and the risk of sub-optimal future investment by the unconstrained incumbent would remain a high risk. Hence the case for structural reform to allow efficient market signals to guide those future investment decisions.

11.5.7. Conclusion of wholesale market assessment

The Panel’s analysis and submissions from interested parties lead it to conclude that Hydro Tasmania has substantial market power in the wholesale market in Tasmania. However, most of the time, that market power has not been exercised and remains latent.

Where Hydro Tasmania’s contract position and market circumstances present the opportunity, Hydro Tasmania engages in strategic bidding to influence Tasmanian spot market prices. Hydro Tasmania has explained this in its responses to the Panel’s information requests. But the nature of its contract position historically has meant that these opportunities are not routine and when they do occur, they are transitory.

The exercise of market power by Hydro Tasmania in its contract trading is more difficult to discern. A review of Hydro Tasmania’s current contract book is not indicative of sustained market power being exercised in that part of the wholesale market. There are fewer external limitations on it doing so and, particularly given the lack of transparency on contracting outcomes (by comparison with the spot market) and the difficulty in establishing a reliable benchmark. This is critical, given the importance generally in the NEM and particularly so in Tasmania, given the spot market risks and the absence of alternative contracting parties.

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159 Given the very low level of tangible marginal costs for a hydro generator, this could be a particular concern.
Together, this suggests that the wholesale market in Tasmania has not suffered significant productive and allocative efficiency losses to date due to Hydro Tasmania’s exercise of market power.

The Panel’s primary concern with the wholesale market is in relation to Hydro Tasmania’s latent market power and the harm this can do to dynamic efficiency – that is, the ability of the electricity industry to produce economically efficient outcomes over time, and to respond and adapt to change.

The Panel is concerned that Hydro Tasmania’s latent market power has and continues to act as a barrier to new retail and large customer entry and may deter new entry in generation at such a time that new generation in Tasmania becomes necessary. The Panel considers that Hydro Tasmania’s demonstration of its market power – particularly at times when TVPS is out of service and when demand is relatively low – can and does send a very clear signal to actual and potential participants about the potential for adverse outcomes under a wide variety of conditions if they behave in ways that diverge from Hydro Tasmania’s commercial interests. This greatly increases the riskiness of investments.

Market participants are highly unlikely to make investment decisions that involve material sunk costs if the viability of those investments depends on the maintenance of internally-imposed constraints on the behaviour of the dominant generator, such as choosing to be highly contracted, or not exploiting all of the market opportunities that present.

To the extent that otherwise-promising investments are not undertaken due to the risks and costs arising from Hydro Tasmania’s latent market power, the dynamic efficiency of the market will be compromised. Ultimately, this will manifest itself as foregone consumer welfare, either through higher wholesale and retail prices (due to the non-entry of new retailers or generators) or by the abandonment of profitable load projects. In either case, the outcomes would be contrary to the National Electricity Objective and to Tasmanians’ long-term economic interests.
Capturing dynamic efficiencies is a key driver for implementing the reform measures proposed by the Panel. As noted by the Productivity Commission\textsuperscript{160}:

Establishing competition in any market should not be regarded as an end in itself. However, competition does serve as a mechanism for achieving allocative, productive and dynamic efficiency gains, and economic growth. For example, competition can provide a strong incentive for service providers to:

- seek out cost efficiencies and minimise costs, putting downward pressure on prices;
- innovate, providing consumers with a wider range of goods and services;
- undertake efficient investment; and
- improve the quality of services provided to customers.

For these reasons, the Panel considers that the primary focus of future wholesale market reforms should be on creating viable contracting options for retailers within the Tasmanian region. More contracting options will reduce the risks faced by new retailer and large customer entrants when they make their investments. This is because new entrants will not be reliant on Hydro Tasmania to not exercise its discretion to reduce its contract levels and increase the frequency of its strategic bidding. More contracting options will also directly reduce Hydro Tasmania’s market power, including its latent market power. This will increase the confidence of new generation investors, when the time comes that new generation investment is required. More details of the Panel’s reform proposals are contained in chapter XX.

\textbf{11.6. Assessment of retail market competition}

As noted above, there are five electricity suppliers licensed to retail in Tasmania – AGL Sales Pty Limited, Aurora Energy, Country Energy, ERM Power Retail and TRUenergy. However, only Aurora Energy and ERM Power Retailing are active in the contestable market, with Aurora Energy having about around and 85 per cent market share of the contestable market. Aurora Energy also has a legislative monopoly for non-contestable customers.

This section discusses:

- the scope of and barriers to retailer participation in the contestable segment of the market;
- market outcomes for contestable customers; and
- decision-making around FRC.

\textsuperscript{160} Source: Australia’s Urban Water Sector, Productivity Commission, 2011, Volume 1, Chapter 12, p333.
While the Panel’s Terms of Reference do not explicitly extend to examining the experience of contestable customers or the extension of contestability to the domestic sector, the Panel believes that these issues are central to address Terms of Reference 7 – actions that would guide and inform the development of a Tasmanian energy strategy.

11.6.1. Retailer entry into Tasmania

Latent market power in the wholesale market

As noted above, one of the Panel’s key concerns is how Hydro Tasmania’s latent market power can serve to deter the entry of new retailers into the Tasmanian contestable market, as well as deter the entry of new customers themselves. As noted above, many stakeholders believe that greater retail entry will not occur without a less concentrated generator sector.

The Panel considers that mainland retailers are likely to have lower cost structures than the incumbent retail monopoly, Aurora Energy. This is because Aurora Energy lacks the scale and risk management opportunities of the mainland retailers. Therefore, to the extent that market power (whether exercised or latent) at the wholesale level deters mainland retailers from entering Tasmania, contestable customers are likely to miss out on lower cost and more competitively priced retail services that are potentially better tailored to consumer preferences.

The deterrence of new retail entry into Tasmania due to Hydro Tasmania’s latent market power is probably the most significant source of future dynamic inefficiency that would occur if the architecture of the wholesale market in Tasmania is not addressed.

Other factors influencing retailer participation in the Tasmanian market

To further inform its understanding of level of participation by retail service providers in the Tasmanian market, the Panel met with a range of major retail service providers operating across other NEM jurisdictions.

Size and characteristics of the market

While the relatively small size of the Tasmanian electricity market and the high proportion of electricity customers on government benefits have been touted as a deterrent to entry, this was not borne out in the Panel’s discussions with retailers. Neither the size of the Tasmanian retail market nor the level of concessions or income support was viewed as making Tasmania an unattractive prospect.

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161 The Tasmanian Government also formally referred to the Panel the Tasmanian Liberal Opposition’s draft bill for the immediate introduction of full-retail contestability, tabled in the Parliament on 13 April 2011.
The size of the Tasmanian market is comparable to other market segments that are attractive to retailers to grow market share. For example, the Tasmanian residential customer market is comparable to a regional centre on the mainland. The market size and its relative physical ‘isolation’ from other NEM regions could be potentially attractive, particularly to trial innovative products and services. Further, Tasmanian customers have higher electricity consumption (partially due to a lack of competing fuel resources such as the penetration of gas into the residential market) potentially making the load attractive as the acquisition price per customer is fixed and retailers earn a mark-up on the energy price.

However, one observation made to the Panel was that, given the size of the Tasmanian market, there is room for only a limited number of retail service providers. Potential entrants need to be confident about obtaining sufficient market share to make it worth their while to enter the retail market. The risk of not obtaining sufficient scale is compounded by the risk that a single retailer might be able to acquire a dominant market share.

**Barriers to entry in existing ownership and regulatory arrangements**

Rather than the size and nature of the customer base, particular market and regulatory arrangements were identified as creating greater risk in the Tasmanian market than exists in other potential markets. A common observation was that the Tasmanian Government needs to establish pro-active market and regulatory conditions for retail competition reform. In particular, this meant that government ownership of all major Tasmanian electricity supply industry market participants needed to be opened up as in other jurisdictions. As things are, there is a perceived risk that SOEBs can price below market (or even cost) to drive market share rather than to derive commercial financial outcomes for shareholders.

Importantly, the incumbent retailer, Aurora Energy, is not widely seen to hold a significantly dominant position to the extent that would deter other retailers entering the market. However, it is necessary to ensure that appropriate ring-fencing exists between Aurora Retail and Aurora Distribution to ensure equality in treatment. An example of a possible issue in this regard was that advice to customers on their contestability status in tranches 1 – 4 was issued by Aurora Energy’s retail/energy business. This was rectified through amendments to the Electricity Supply Industry (Contestable Customer) Regulations 2005 in 2011 requiring that customer contestability notification are issued by Aurora Energy’s distribution business – which took effect for the notification of tranche 5a customers. Potentially, Aurora Energy needs separate brand differentiation between its distribution and retail/energy businesses.
Transparency in regulatory pricing arrangements are critically important for the new entry of private capital into the market with the introduction of FRC and the attendant ‘fall back’ contract arrangements. New entrant retailers will be potentially exposed if in the future there is a ‘squeeze’ between wholesale market prices (hence the need for diversity) and any regulatory arrangements that may impose price caps on retail prices.

The Panel has observed not infrequent changes in Tasmanian regulatory arrangements that determined delivered electricity prices over the past decade. Ensuring that retailers have confidence in the regulatory regime, based on observed outcomes in the determination of wholesale energy prices, such that retailers will not be left squeezed between the market on one hand and regulated maximum prices on the other hand. There needs to be certainty in regulated fall-back tariff and market based prices to create ‘headroom’ for competition.

From a retailer’s perspective, greater consistency of regulatory arrangements with Victoria was seen to be a way in which the Tasmanian Government could facilitate market participation by retail service providers.

For example, an observation made is that obtaining a retail licence is time consuming and that a retailer who was licensed in other NEM jurisdictions should be able to obtain a licence in Tasmania with less process burden than is currently the case. Similarly, consistent application of the National Energy Customer Framework (NECF) with minimal derogations was seen as supporting new entry. The Panel notes that while consistency of arrangements may facilitate business operations of retail service providers, regulation must be appropriate to the circumstances and needs of each jurisdiction (where legitimate and genuine reasons exist for non-standard arrangements) to ensure that appropriate outcomes are achieved.

A key consideration for potential and new entrant retailers is an environment that will facilitate customer choice between retailers. Providing mechanisms for businesses to compete could be a proactive strategy to increase the likelihood of competition being successful.

Specifically, Tasmania is seen as a market – a question being ‘why and how will Tasmanian customers be attracted to new market entrants?’ Choice requires an awareness of electricity prices and retail options.

- New entrant retailers do not have market information as to which customers have become contestable in order to seek them out. Customers are more difficult to assess as tranches become smaller.162

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162 For tranches 1 to 4, notification of contestability was delivered by Aurora Retail, which may have provided a competitive advantage. This was rectified through regulation for tranche 5a where notification of contestability was delivered by Aurora Distribution.
▪ Conversely, customers need to be aware of alternative retailers. Brand recognition of existing market participants has been assisted by information and links on the OTTER website and energy consultants.

▪ The ease of accessing customer information – i.e. half hour data usage, from Aurora Energy in order to enable pricing proposals to be developed has proven difficult at times.

Retail margins

The retail margin is intended to compensate the retailer for its investment in the business and the risks it assumes in providing those retail services.\(^{163}\)

Advice from non-participating large and smaller scale retailers indicates that the prevailing view is that the cost of retail operations in Tasmania would not be materially higher than elsewhere in the NEM. However, competition to acquire customers may see margins squeezed until a customer base is established.

In determining Aurora Energy’s retail margin, the TER looked at allowances made in other jurisdictions in the context of standing offers in fully contestable markets where retailers are subject to significant energy price and volume risks. The effect of the Price Control Regulations is to remove the energy price risk for Aurora Energy in supplying non-contestable customers. Further, as Aurora Energy is not exposed to customer churn for its non-contestable customer base, volume risk also remains low. Consequently, Aurora Energy’s retail margin is set at 3.8 per cent per annum which is somewhat lower than allowances made in other jurisdictions under fully contestable market conditions.\(^{164}\)

On this basis, it is expected (paradoxically) that the retail margin component of the cost of electricity would increase with retail competition. However, combined the cost to serve and retail margin comprise only eight per cent of the current average tariff price, meaning that any uplift in the retail margin component is unlikely to have a material impact on prices.

11.6.2. Market outcomes for contestable customers

The key policy intent of the introduction of competition in the retail market was to provide greater customer choice for retail services and to encourage competition on the basis of price. In its Issues Paper, the Panel has previously observed that the contestability timetable in Tasmania has largely been achieved with tranche 1 to 4 customers – or equivalent to around 80 per cent of the market in terms of energy use. However, in terms of customer numbers the majority of customers remain non-contestable (households and small businesses).

\(^{163}\) The retail margin is set to recover return on capital invested, financing expenses, depreciation charges and risk associated with bad debts, energy purchase risk and volume risk.

\(^{164}\) The TER notes that retail margins are set somewhere between four and six per cent in relation to standing offer arrangements.
Price

The Panel understands that large industrial customers (who account for approximately 50 per cent of Tasmania’s energy load), directly negotiate wholesale energy contracts arrangements with Hydro Tasmania which are then transferred to the customer’s retailer of choice. In this sense the retail arrangements are developed after the wholesale arrangements, with the retailer taking no part in the former. On this basis, it is anticipated that retail competition has had very little impact on customer prices for this customer group.

By comparison, for commercial/industrial contestable customers, customers tend to seek competing offers from retailers rather than negotiating direct wholesale energy arrangements with generators.

Currently, the two retailers active in the tranche 3 and 4 markets are Aurora Energy and ERM Power. In its submission to the Panel, ERM Power indicates that it has encountered no wholesale energy market issues in Tasmania; however, its key consideration is that ‘derivative pricing provided by Hydro Tasmania enables us to compete on a level playing field’. In this regard, the ability to secure energy on a comparable price basis as the incumbent retailer, Aurora Energy, rather than competition within the wholesale energy market itself, appears to be a primary consideration.165

This is supported by Hobart City Council’s (HCC) submission to the Panel dated 10 August 200 that notes that ‘in tender submissions received pricing has been reasonably close on each occasion.’

In its submission to the Panel’s Issues Paper, Hydro Tasmania notes ‘that Tasmanian non-contestable contract prices are higher than those charged under contestable contracts’. Further, Hydro Tasmania observes that this is the case because ‘the Tasmanian regulatory framework has mandated that the current wholesale energy component of non-contestable customer contracts be calculated using long run marginal costs (LRMC)’166 Hydro Tasmania contends that ‘average annual spot prices in NEM regions is not close to LRMC, and Hydro Tasmania’s experience of OTC hedges are also not close to LRMC’. On this basis, the primary driver of price decreases in the tranche 3 and 4 markets is more likely to be the outcome of energy market prices being below the regulated wholesale energy allowance, rather than the effect of competition.

165 On this basis, wholesale energy prices able to be offered by retailers will be based on their ability to manage risk in the Tasmanian wholesale energy market, rather than competition within the wholesale energy market.

166 Note: The regulatory framework does not, in fact, mandate that LRMC is the basis for calculating the cost of energy – rather it establishes the wholesale energy allowance able to be recovered by Aurora from non-contestable customers on this basis. The basis of pricing of energy contracts is a commercial matter between Aurora and its supplier (whether that be Hydro Tasmania or AETV). However, historically the regulated wholesale energy allowance has been used as the basis of energy contracts between Aurora and Hydro – although as the Panel notes in its Issues Paper, this has changed under the current contracting arrangements.
However, the HCC also notes that terms and conditions do appear to be a point of difference and that pricing has been somewhat more predictable for contestable sites given that contract rates can be obtained for two or three year durations. Conversely, HCC notes that, at the same time, there have been some significant increases for non-contestable sites in recent years. This indicates that while retail competition may not drive competition around the price of energy, energy prices are somewhat more predictable, and lower, under market arrangements than under the regulatory framework.

**Choice of retail services**

Consistent with the policy basis for retail market reform, choice of retail services including service standards, energy use information and customer service responsiveness have also been drivers of customer choice and are viewed as benefits of market reform.

In its submission, NEM Power has identified factors other than price that are included in customers’ decision-making processes. These include brand and the overall customer offering including contract terms and conditions. This is consistent with HCC submission to the Panel which noted that the primary differential between tenders has not been price but terms and conditions. As examples, the HCC cites improved availability of detailed site usage information through web portals, which has assisted it in analysing usage for potential savings and identifying issues such as lights being left on during daylight hours when they were not required. This, and the provision of information comparing tariff options has provided the opportunity to reduce costs through actions such as the transfer of load from peak to off-peak when there is the opportunity to do so. In addition, through agreement with its retailer, HCC can share savings during periods of high spot prices through load shedding.

The Panel’s observations are that retail competition has delivered some of the anticipated benefits – particularly through demand side measures made possible by time of use metering and customer/product information. However, the Panel anticipates that the full benefits of FRC will not be realised until there is greater transparency and flexibility within the wholesale energy market that, through retail market competition, is passed through to customers via lower energy prices.

**11.6.3. Full retail competition**

The Panel has previously released a paper ‘The evolution of Tasmania’s energy sector’[^167], which sets out the background to the roll-out of retail contestability in Tasmania.

Unlike previous tranches of contestable customers, a Tasmanian Government policy decision was to provide tranche 5a customers with the option to enter into an electricity supply contract (market contract) or to stay on their current tariff under the regulated standing offer contract (regulated contract).

On this basis, tranche 5a customers are known as Standing Offer Contestable Customers (SOCCs). SOCCs have the option of remaining on a regulated contract, moving to a market contract with Aurora or another retailer or moving back to a regulated contract after being on a market contract.

Customers who are not yet contestable continue to be supplied by Aurora Energy either through the regulated tariff or through Aurora PAYG.

On the basis that Aurora Energy retains its effective monopoly position to tranche 5a customers (which appears largely to be the case to date), retail contestability to these customers has the effect of deregulation rather than competition. That is, customers can choose a contract based on the market price of energy or a contract based on the regulated wholesale energy allowance. Under a market based contract, the primary customer benefit is the energy price Aurora Energy can source in the Tasmanian market and chooses to pass through to customers. Where the market price offered to customers is below the wholesale energy allowance this represents a shift in value from the SOEB portfolio (through the loss of value captured under the wholesale energy allowance) to customers.

Public benefit test

In September 2007, in accordance with its energy policy position, the Tasmanian Government requested the TER to prepare a special report on the impact of full retail contestability on residential and small business customers in Tasmania. The TER reported in 2008.168

In summary, the TER found that the overall societal benefits of FRC exceeded the societal costs169 and recommended the progressive implementation of FRC. The TER also proposed that the Government should take appropriate steps to ensure that the governance of the wholesale electricity market is conducive to the development of competition, so as to maximise the benefit of FRC. The Panel has reached the same conclusion, as discussed above.

The TER also noted that in addition to societal benefits: ‘FRC would bring the TESI arrangements into line with arrangements in other states, progress economic reform in Tasmania consistent with national Competition Policy Agreements and allow for the future development of the TESI through the operation of an open market.’

169 Societal benefits (not quantified by the TER) include a customer’s choice of retailer and increased competition in the electricity generating sector. Societal costs (quantified) predominantly related to the required changes to the distribution network and regulatory system to accommodate FRC.
Notwithstanding the outcome of the Public Benefit Test recommending the progression toward full implementation of FRC by 1 July 2010, the Tasmanian Government has not yet committed to FRC. Rather it has restated its position to continue under a regulated structure, primarily on the basis of the additional costs to the distribution network required to enable multiple retailers and customer churn.

Quantification of the costs of FRC

System implementation costs, primarily IT systems that Aurora Energy’s distribution business must install to enable multiple retailers and customer churn between retailers, is the key cost of FRC.

Based on information provided by Aurora Energy, the TER estimated that the (then) net present value of the incremental societal costs was $70.6 million over the seven year implementation period. The TER’s report notes that its own advisers estimated the net present value of the same costs to be $49.5 million, although this could be further reduced by around $9.7 million if it is assumed that meter reading requirements in Tasmania are aligned to standard practice in other states. On this basis, the TER assessed the costs of FRC to be in the range of $37.7 million to $70.6 million over seven years (or $5.4 million to $10.1 million per year).

On a per customer basis, the TER quantified FRC costs to be $20 to $35 per customer per year.\textsuperscript{170} The TER’s report notes that only the prudent and efficient incremental costs of FRC facilitation (subject to the TER’s assessment of the investment) would be passed through to customers via distribution charges. The TER considered that the societal cost of implementing FRC ‘is modest in comparison to the value of the sector, with current sales of approximately $500 million per annum’.\textsuperscript{171}

The Tasmanian Government’s hesitation towards the implementation of FRC appears to be on the basis that the full benefits of retail competition would not be realised under the current operation of the Tasmanian energy market, while customers would bear the burden of the implementation cost.\textsuperscript{172}

As discussed above, the Panel agrees that without reform of the wholesale market in Tasmania, it is far from clear that new entry would arise in the Tasmanian retail sector and the benefits of customer choice and competition would be delivered to offset the costs of implementing FRC.

\textsuperscript{170} The TER further noted that ‘customers who remain on a regulated standing offer contract could pay $50 to $80 per customer per year above franchise tariffs, inclusive of the system costs ... and assuming that the energy costs assessed for standing offer contracts are the same as the energy cost which would be assessed in setting maximum prices for retail tariffs’.

\textsuperscript{171} They are also not large in relation to other large capital expenditures made within the sector, such as Aurora Energy’s customer information and billing system, and Hydro Tasmania’s costs of acquiring Momentum.

\textsuperscript{172} Mercury article January 29 2011 quotes the Premier ‘Our residential customers are protected from competition from interstate because we are not convinced at this point that it would be to the benefit of residential customers’ and ‘We are yet to be convinced that the energy market is operating in such a way that the benefits of full retail contestability will outweigh the significant costs that will likely be incurred in moving to this level of competition’.
In its submission to the Panel’s Issues Paper, Aurora Energy advises that it is currently working to update the expected system costs associated with a move to FRC in order to assist the Panel with its consideration of this issue. At the time of writing this information is not yet available from Aurora Energy.

11.6.4. Conclusion of retail market assessment

In progressing the energy reform agenda over the past decade, a key objective has been to provide competition and customer choice in the retail market, which needs to be underpinned by effective competition in the wholesale market.

The evidence provided to the Panel during the Review indicates that this objective is deliverable, provided that the perceived barriers to entry are adequately addressed.

The principal issue is to address wholesale market risks in Tasmania. The issue is not that the current outcomes are creating inefficient outcomes today, in terms of spot prices or productive inefficiencies. Rather, the current architecture is creating dynamic inefficiencies by deterring entry into the retail market, and in time, most likely in the generation sector.

Reform of the wholesale market in Tasmania in a way that adequately addresses the perceptions of risk for market participants is the key to unlocking greater participation in the Tasmanian retail market. Reform of some elements of the retail framework will also decrease barriers to entry and encourage the participation of new large scale retailers in Tasmania.
12. Hydrological risk management

**Key Messages:**

Hydrological risk is not the same as energy supply risk, although the two are linked. Only in the most extreme cases does hydrological risk result in a risk to physical, on-island supply.

When hydro-generation was the only source of firm supply in Tasmania and there was a close supply/demand balance, the two risks were effectively the same. However, the link between hydrological risk and Tasmania’s energy supply security has moderated since Tasmania’s connection to the Victorian grid via Basslink and the commissioning of the TVPS, which have seen a decrease in the reliance on hydro generation to meet Tasmanian demand.

Prior to 2005, Hydro Tasmania was legislatively responsible for energy security in Tasmania and provided physical insurance to its hydro system through the BBPS. With Tasmania joining the NEM, energy security risk transferred to the market.

Despite the market-based arrangements in the NEM, the Government has taken on ultimate responsibility for ensuring reliability of supply in Tasmania, based on a wider consideration of the economic harm that may be done to the State in the event of supply restrictions or shortages. In 2008, the Government acted to acquire the TVPS on these grounds.

Further, Hydro Tasmania was only formally ‘released’ by the Government in 2009 from its obligation to ensure continuity of supply, following the commissioning of the TVPS.

As owners of the hydro system, it is Hydro Tasmania that bears hydrological risk first and foremost as a commercial risk, linked to its ability to back its contracted load with available energy. While the cost of this risk is, in part, passed back to customers through an insurance ‘premium’ in prices, the costs of the risks being realised are borne by Hydro Tasmania. Volume risk has been passed back to customers in terms of potential loss of load, but this has been rare and limited to the major loads.

Hydro Tasmania has hydrological risk ‘insurance’ available to it through its access to financial contracting arrangements with Basslink and contracting arrangements with Aurora Energy for the non-contestable customer load that allows it to reduce load when certain low inflow ‘triggers’ are met.

The TVPS contributes further hydrological risk mitigation for Hydro Tasmania and to the State terms of energy security (in the event of extreme drought and/or Basslink failure). The key issue is how the costs associated with providing these benefits are funded over time, in the situation where the timing and level of those benefits are unpredictable.
Introduction

Since the mid-1990s successive Tasmanian Governments have sought to address Tasmania’s exposure to low inflows to the hydro system, in recognition of the importance of energy supply security to the State’s economy. Managing ‘hydrological risk’ has been a key driver of Tasmanian energy policy settings and has influenced major investment decision-making, including, most recently, the State’s acquisition of the Tamar Valley Power Station in 2008.

The purpose of this Section is to briefly examine the concept of ‘hydrological risk’. Specifically, it seeks to answer the following questions:

- What is hydrological risk and how does it manifest itself in Tasmania?
- Who is responsible and how is it managed?
- What is the relationship between hydrological risk and energy supply security?
- and

- How has the nature of this relationship changed as the Tasmanian energy market has evolved?

12.1. What is hydrological risk?

The ability of a hydro system to generate electricity is constrained by the availability of water, which means that they are energy constrained. In thermal-based systems, fuel is typically plentiful, and as such, energy production is typically constrained by the level of installed capacity. Mainland Australian States are capacity constrained, and the Tasmanian system is energy constrained.

In simple terms, therefore, **hydrological risk is the risk that the hydro-generation system will not be able to meet residual demand in the medium to long term due to an extended period of lower-than-expected inflows.**

Hydrological risk is not the same as energy supply risk, although the two are linked. This is particularly true in Tasmania, where hydro generation accounts for 81 per cent of total installed capacity. This means that the physical consequences of hydrological risk, at their most extreme, can extend to there being insufficient energy to meet on-island demand.

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173 Under some circumstances, thermal systems can become energy constrained, for example the disruption of fuel supplies or lack of cooling water.

174 Hydrological risk is not the risk of non-supply due to short term events, like the loss of major equipment, although such events can impact on the management of hydrological risk.
12.1.1. **The impact of hydrological risk on hydro-generation capacity**

Hydrological risk is realised as a consequence of sustained annual inflows below Tasmanian demand, or that portion of it that cannot be supplies from non-hydro sources.

Hydro Tasmania’s current installed hydro-generation capacity is 2281 MW. Figure 12.1 depicts the development of other non-Hydro Tasmanian generation capacity over time to match the longer-term energy requirements of Tasmanian customers. The large increases in storage capacity illustrated in Figure 12.1 also reflect the development of storages to help manage inflow variability.

**Figure 12.1 - Long System Development Overview 1955-2010**

Source: Hydro Tasmania

Note: Full storage capacity is the notional output that could be produced if the storages were 100% full and run until empty, with no inflows.

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175 The intersection of the hydro system rating and the State’s total demand in the late 1990s drove the Government’s need to consider the next energy source, and led to the pursuit of both Basslink and the introduction of natural gas to Tasmania.

176 The step changes in the storage capacity of the hydro system in 1978 represents Lake Gordon coming on line and in 1982 the subsequent raising of Great Lake.
Hydro Tasmania models inflow variability as an energy yield (measured in GWh per calendar year). Figure 12.2 shows historical annual inflow variability, which has fluctuated between lows in the order of 6 000 GWh up to peaks of 14 000 GWh. Long term average inflows have reduced considerably over the past 40 years.\(^\text{177}\)

**Figure 12.2 - Long Term Historical System Inflows as modelled by Hydro Tasmania**

In recent years, Hydro Tasmania has progressively revised down its expected long term inflows, reflecting historical trends. Statistically significant changes to inflows following the years 1975 and 1996 have resulted in Hydro Tasmania’s expected inflows dropping from 10 200 GWh over the longer term, to 9 500 GWh in 2007, and 9 000 GWh in 2008. Since 2009, the system has been rated at 8 700 GWh.

Table 12.1 further 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, the operation of non-Hydro Tasmanian generation, low NEM spot prices, and Hydro Tasmania’s commercial decision to build storages by deferring generation to capture value opportunities following the introduction of the Commonwealth’s carbon tax.

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\(^{177}\) It should be noted that Figure [y] shows modelled output, which is based on having today’s hydro system in place over the entire 1924-2010 period.
Table 12.1 - 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>9000</td>
<td>8700</td>
<td>8700</td>
<td>8700</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>
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<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

Figure 12.3 illustrates the impact of the reduced hydro-system inflow between 2007 and 2009 on hydro-generation compared to the Tasmanian system load (demand).

12.2. Physical management

In times of low inflows, system storages are drawn down to meet demand. As storages reduce, more expensive non-hydrological sources are utilised to meet demand.
The general procedure followed to physically manage hydrological risk comprises a number of steps, undertaken in the following order:\textsuperscript{178}:

\begin{itemize}
  \item[a)] use storages initially to balance variations in inflows to meet supply needs – this provides a large degree of protection for the system;
  \item[b)] start to operate the next least expensive non-hydro energy source to reduce the demand on the storages;
  \item[c)] if storage continues to fall, introduce the next source of supply or demand reduction to further ease the demand on storages;
  \item[d)] continue this process of introducing more and more expensive options until storages recover; and
  \item[e)] as storage recover, stop using the most expensive options for energy supply first until storage are recovered and no other supply options are required.
\end{itemize}

Since 2001, Hydro Tasmania’s Ministerial Charter has required it to demonstrate the prudent management of its water storages. On the joining the NEM, Hydro Tasmania’s Prudent Water Management (PWM) obligation became the basis on which to advise the Government of emerging issues in the hydro system.\textsuperscript{179}

Hydro Tasmania’s PWM policy (see Figure 12.4) uses a series of ‘triggers’ to highlight the increasing risk to security of supply, based on risk levels associated with water levels and potential contingency events, which include a major Basslink outage or major hydro-plant failure. Under the PWM policy, storage management rules are designed to manage storages through low inflow periods.

The PWM defines a preferred seasonal minimum operating level\textsuperscript{180} and then medium, high and extreme risk zones. These risk zones indicate an increasing risk of supply failure, with the extreme case having both a higher probability of load curtailment as well as significant environmental consequences.

\footnotesize
\textsuperscript{178} The mechanisms to implement/action these broad steps are different now than prior to interconnection, but the core concepts remain.

\textsuperscript{179} The Electricity Supply Industry Regulations 2008 requires, as part of Hydro Tasmania’s generating licence, the amount of energy in storage in each headwater storage (expressed both in GWh and as a percentage of maximum storage capacity) to be published on a weekly basis.

\textsuperscript{180} Minimum of 30% full by 30th June, Hydro Tasmania Annual Report 2011.
For example, the medium risk storage level starts 12 per cent below the preferred operating level and this “storage buffer” allows the management of low inflows and major infrastructure outages. Below the medium risk storage level is additional buffer storage, but there is an increasing risk of supply shortfall. The high risk level is built around having sufficient capacity to meet demand in the event of a two-month outage of Basslink or loss of all thermal support\footnote{Currently the Tamar Valley Power Station} and being able to maintain storages above the extreme risk zone, assuming very low inflow scenarios.

Given the large amount of run-of-river generation in Hydro Tasmania’s system, Hydro Tasmania is not just energy constrained by hydrology, but also capacity constrained. Short periods of very low inflows could result in capacity shortfalls, regardless of the energy available in the major storages. Hydro Tasmania has a process in place to manage capacity across its storages.

Hydro Tasmania also defines a ‘shortfall index’ based on the number of days that load can be met in circumstances that:

- Basslink is not available;
- There is no generation from wind or thermal production; and
- Inflows are very low.

As this index falls, various actions\footnote{Reschedule outages, etc} are undertaken to address the commensurate increase in risk, including communication with stakeholders\footnote{Including AEMO and the Tasmanian Jurisdictional Co-ordinator through WSAC} to allow external responses, if required. An index of 60 days or greater indicates no material issues with meeting demand.
The Tasmanian Government has established an advisory committee\textsuperscript{184} to inform the Jurisdictional Co-ordinator\textsuperscript{185}, and subsequently the Minister for Energy, on emerging hydrological issues and course of action required to address them.\textsuperscript{186} AEMO is also a part of this process to ensure that it is suitably informed and can manage any security of supply issue.

12.2.1. Physical management of risk – pre-Basslink

As the hydro-system has developed over time, Hydro Tasmania’s ability to physically manage hydrological risk has been continually improved. Prior to the connection of Basslink, key measures included:

- The development of large, long-term storages, such as Great Lake and Lake Gordon\textsuperscript{187}, to store during high inflow periods and use this water during dry periods;
- The incremental increase in the capacity of existing power stations; and

\textsuperscript{184} Water Shortage Advisory Committee (WSAC) which reports to Committee to Coordinate the Response to Energy Supply Emergencies (CCRESE) chaired by the Jurisdictional Coordinator

\textsuperscript{185} Director of Energy, Department of Infrastructure, Energy and Resources

\textsuperscript{186} For example, rotational load shedding in the extreme situation

\textsuperscript{187} As shown in Figure 12.4
The commissioning of the Bell Bay Power Station (BBPS) between 1971 and 1974, its subsequent conversion to gas in 2003 and the installation of additional capacity in 2006 in the form of three 35MW gas turbines.

However, even with thermal support from the BBPS, if low inflows persisted for long enough, supply security could still be at risk. In this event, Hydro Tasmania would pursue further risk management measures to enable a further reduction in hydro-generation and allow storages to be run down at a slower rate. The key measure, implemented in both 2002 and 2005 was to enter into commercial arrangements to ‘buy back’ energy from major industrial customers. Customers who participated in load curtailment were compensated for any lost production. Hydro Tasmania has also implemented a cloud seeding program over the winter months, which is seen by it to be a cost-efficient means on improving yields in the major storages.

The rotational load shedding of all customers is only considered as a ‘last resort’ would to avert a total loss of electricity supply due to insufficient water in storage.

This application of the general principles discussed above, pre-Basslink, is depicted in Figure 12.5.

**Figure 12.5 - The application of the principles for managing hydrological risk pre-Basslink**

12.2.2. **Physical management of risk - post-Basslink**

The connection of Basslink and Tasmania joining the NEM has further improved the flexibility of mechanisms to manage hydrological risk and its costs. The ‘physical escalation’ approach described above continues to apply in the NEM context but there have been a number of significant changes.

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188 Prices for this service could exceed $200/MWh.
In the NEM, the key driver becomes market price signals that encourage alternative generation to operate, physically facilitated by Basslink. Changes in inflows and storage levels impact on the value of water in storage, and this translates to changes in Hydro Tasmania’s bidding and contract pricing decisions. As storages fall, the value of water will increase (assuming other variables are constant)\(^{189}\) and this will encourage either more southward flows on Basslink (expected to be more periods when the Victorian price is lower than generation bids in Tasmania) and/or, in the current market, more output from the TVPS.

If storages continue to decline below Hydro Tasmania’s desired level, noting its PWM obligations, the value of water increases and Hydro Tasmania’s bidding similarly increases. This would encourage more TVPS operations using the high cost peaking plant. As more of these alternatives operate in the Tasmanian region, less hydro-generation is required and the storage decline moderates. In theory this will continue until Basslink is importing all the time and the TVPS is operating continuously.\(^{190}\)

The principles of hydrological risk management in the current market structure is illustrated in Figure 12.6.

**Figure 12.6 - The application of the principles for managing hydrological risk, post-Basslink**

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\(^{189}\) As storage levels fall, the marginal opportunity value of water will increase due to the scarcity of the water.

\(^{190}\) The existence of Basslink and market pricing signals through the NEM enables Hydro Tasmania to more effectively manage water levels, as it can make incremental decisions over time to adjust storage levels, whereas thermal controls were much more binary - Bell Bay was either ‘off’ or called into duty for blocks of time.
12.2.3. Financial management

Prior to Basslink, the obligation to supply Tasmanian customers rested solely on Hydro Tasmania, which meant hydrological risk was Hydro Tasmania’s to manage. This risk manifested as additional cost borne by Hydro Tasmania. Only in the most extreme cases did hydrological risk result in a risk to physical, on-island supply. As noted above, where this risk materialised, it was shared by large industrial customers through load-shedding arrangements.

Under the current market framework, however, the financial consequences of hydrological risk are shared between Hydro Tasmania and the market.

Hydro Tasmania manages the financial effects of hydrological risk by pricing energy according to current or expected inflows and storages. In calculating water value - and subsequently spot and contract prices\textsuperscript{191} - Hydro Tasmania considers the likelihood of numerous inflow scenarios to obtain the expected value for an expected water storage target. Inherently, this water value will have some value attributable to the likelihood of lower-than-expected inflows.

Pre-Basslink, the higher costs associated with operating the BBPS and the cost of load buy-back were probabilistically weighted and factored into the prices Hydro Tasmania charged.\textsuperscript{192} In this sense, while the financial effects of hydrological risk were borne by Hydro Tasmania, it received financial compensation for carrying that risk, much like an insurance company.

All customers can expect to pay some premium to Hydro Tasmania to manage its hydrological risk, although this premium is unlikely to be sufficient to cover the additional costs to support its contracts during low inflow periods.\textsuperscript{193} This premium is also likely to be higher for longer term contracting, as the risk of low inflows and low storages will increase. Another key determinant is the starting position of storages.

\textsuperscript{191} Note the Hydro Tasmania policy is to set contract prices at Victorian contract prices, adjusted for water value. In times of low storages, water value is more likely to set the contract price.


\textsuperscript{193} The costs of drought support will be probability weighted based on the likelihood a drought will occur in the period being considered. In reality if the drought does occur then the actual costs will be incurred rather than the small proportion included in the water value calculation.
Customers not under contract with Hydro Tasmania can expect to pay higher prices when storages are low because of the higher opportunity value for water that comes from the need to use more expensive sources of generation. Similarly, if customers are contracting during or immediately after low inflow periods, the cost of hydrological risk will be passed through to these customers in terms of higher prices. This provides a price signal that will drive market behaviour to reflect the prevailing energy/demand balance.

However, should water storages continue to fall, Hydro Tasmania will become further exposed to the financial consequences of hydrological risk. This is because Hydro Tasmania’s output will be reduced and it will become more exposed to the market in order to back its contracts. If wholesale market prices are high, Hydro Tasmania’s financial performance will decline, assuming that it is not able to pass these costs back to its contracted customers under existing contracts. As discussed above, this risk will be factored into contract prices.

As Hydro Tasmania no longer has a direct obligation to ensure supply to Tasmanian customers, it may seek to manage the financial consequences of hydrological risk in a number of ways. It may:

- reduce the volume of energy for which it has contracted. As storages fall below the preferred storage levels, the volume limits of forward contracts start to reduce for the immediate 12 to 36 month period. This aligns to the expectation that with lower storages the use of hydro generation will be reduced and encourage higher cost generation to meet market demand.

  If Hydro Tasmania withdraws contracts, counterparties will see the financial consequences of hydrological risk through the need to seek contracts with other suppliers or be exposed to higher spot market prices. In this context, the financial consequences of hydrological risk falls to Hydro Tasmania to the extent of its contract cover, and to market participants who are exposed to the spot market, or are in the process of recontracting.

- offer contracts at sufficiently high prices to be able to back them through market purchases.

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194 This occurred for contracts negotiated during the 2007 to 2009 drought period, where higher prices were apparent in the market. This will provide a price signal that will drive market behaviour to reflect the prevailing energy/demand balance. As a consequence (as well as uncertainties around the future of a price on carbon), one counterparty decided to delay negotiations for a longer-term contract in the expectation that with time, storages and inflows would return to more normal levels and prices drop.

195 Assuming Hydro Tasmania is highly contracted.

196 Tasmanian prices would be expected to be relatively higher if Hydro Tasmania through lack of water is required to reduce production. If Victorian prices are also relatively high, these prices will be factored into the Tasmanian price through Basslink southward flows.

197 Similarly, if inflows are plentiful and the opportunity value of water falls, customers will not see the ‘value’ from falling electricity prices, given the prices locked into contracts. Like any form of insurance, Hydro Tasmania keeps the upside from risk not materialising, and carries the cost if the risk does arise.

198 Hydro Tasmania has a stated policy to offer contracts.
Hydro Tasmania’s contractual arrangements with Aurora Energy for the supply of energy for non-contestable customers include such a provision. In this case, the volume that Hydro Tasmania is required to supply is reduced based on a storage level ‘trigger’ and the preceding 12 monthly inflows.

Similarly, a counterparty interested in a long-term contract may wish to take on ‘hydrological risk’ by negotiating a clause to adjust price or volume in case of drought, in exchange for a lower price. This kind of hydrological clause has been included in the non-contestable load contract between Aurora Energy and Hydro Tasmania.

In summary, both Hydro Tasmania and its customers use pricing and contract terms to manage hydrological risk. Customers will face some ‘insurance’ cost in the prices they pay under their contracts. However, if a low-inflow event occurs during a contract period, it is Hydro Tasmania, and not contracted customers, who will bear the financial consequences. If a customer is uncontracted during a low inflow period they will bear the higher price in the market.

Hydro Tasmania has hydrological risk ‘insurance’ available to it through its access to Basslink and contracting arrangements with Aurora Energy for the non-contestable customer load that allows it to reduce load when certain low inflow ‘triggers’ are met.

### 12.3. Responsibility for energy supply security

In the event of extreme and prolonged low inflows, hydrological risk can be manifested as energy security supply risk in the Tasmanian market. When hydro-generation was the only source of firm supply in Tasmania and there was a close supply/demand balance, the two risks were effectively the same. However, the direct link between hydrological risk and Tasmania’s energy supply security was moderated with the commissioning of BBPS in the 1970s. More recently, Tasmania’s connection to Victoria via Basslink and the commissioning of the TVPS have seen a decrease in the reliance on hydro generation to meet Tasmanian demand. There is now separation of hydrological risk and Tasmania’s energy supply security risk.

Prior to Tasmania joining the NEM in 2005, the Electricity Supply Industry Act 1995 (ESI Act) specified that, under its licence, Hydro Tasmania’s was responsible for meeting the State’s electricity needs solely from its capacity.
With the joining of the NEM in May 2005, the licensing obligation imposed on Hydro Tasmania under the ESI Act was repealed, along with the legislative responsibility for ensuring supply. As noted above, joining the NEM saw a market-based mechanism implemented to signal and deliver capacity increments, rather than having a physical planning arrangement through Hydro Tasmania or by the Tasmanian Government.199

The NEM Rules allocate the responsibility for ensuring capacity adequacy to the market manager - the Australian Energy Market Operator (AEMO).200 While reserve trader arrangements have been procured on several occasions in the NEM environment, they have not been tested in the Tasmanian context, particularly in light of the potential consequences of hydrological risk.201

In this context, the Tasmanian Government replaced Hydro Tasmania's legislative responsibility with a formal expectation communicated through corporate planning process its expectation that Hydro Tasmania would continue to play a central role in maintaining the security of supply, particularly in light of the dry conditions being experienced in the lead up to, and after Basslink commissioning. Hydro Tasmania was only formally 'released' from this obligation in 2009 with the commissioning of the TVPS.

Ultimately, the Tasmanian Government has taken on responsibility for ensuring energy security in Tasmania. This is reflected by its decision to acquire the TVPS on energy security grounds. In its 2010 Ministerial Statement on Energy, the Government stated that:

“Power rationing, a dire situation which is not uncommon on the global stage, had never been experienced in Tasmania. This Government has taken on responsibility in the past and will continue to take responsibility in the future to ensure that the lights indeed stay on”.203

199 The Director of Energy Planning is the statutory officer with responsibility under the Energy Coordination and Planning Act 1995 for providing advice to the Minister for Energy on energy supply and security issues.


201 While AEMO took an active role in monitoring the supply situation during the 2008 to 2009 drought period, it did not put in place reserve trading arrangements for Tasmania.

202 This expectation was removed following the commissioning of the Tamar Valley Power Station in October 2009.

203 Ministerial Statement 16 June 2010 (Hansard).
12.4. The impact of the Tamar Valley Power Station on hydrological risk

As discussed in this Chapter, hydrological risk is a commercial risk faced by Hydro Tasmania and is managed physically through its PWM system and NEM dispatch of Basslink southward flows and TVPS and financially through its contracting position in the market.

In the months leading up to the State’s acquisition of the TVPS, Hydro Tasmania had identified the risk of continued low inflows and the possibility of unplanned Basslink outages as a risk to its ability to meet the Government’s expectation that Hydro Tasmania would maintain reliability of energy supplies.

AEMO has advised the Panel that it was keeping a close watch on the hydrological in Tasmania in the lead-up to the TVPS acquisition decision, but had not reached the view that reserve trader arrangements or other market interventions were required to ensure energy needs could be met.

The Tasmanian Government assessed the prevailing hydrological conditions, combined with Basslink as a single point contingency and the emerging problems with the reliability of the Bell Bay Power Station, as collectively posing enough of a risk to energy security that Government intervention - in this case acquisition of a partly-built power station - was required on the grounds of potential damage to the State’s economy and reputation.

As events transpired, Hydro Tasmania was able to manage continued energy supply through the combination of the hydro-system (with improved inflows) and Basslink. By the time the TVPS was commissioned, the severity of the drought had reduced and inflows and storages had returned to more comfortable levels, noting that the TVPS enabled Hydro Tasmania to rebuild water storages when inflows increased more quickly than it otherwise would have been able to.

12.4.1. What is TVPS’ value in the current market?

Hydro Tasmania’s current contractual arrangements with Aurora Energy provide cover against rising spot prices in the event of low inflows. Under these arrangements, TVPS effectively provides Hydro Tasmania with hydrological risk insurance, in return for an option fee. Hydro Tasmania now has hydrological risk insurance both through Basslink and through the TVPS, although it is no longer responsible for energy supply security in the State.

It is unclear whether Hydro Tasmania will continue to see the current level of value in hydrological risk management from on-island thermal generation, given Basslink and the current level of water in storage.
High capacity base load generation from the TVPS in the context of the current supply/demand balance is contributing to reduced market prices. As such, parties contracting in the market are likely to be experiencing a benefit through their prices, as well as the lower likelihood of power constraints. These customers are not directly contributing to the costs of either, as the TVPS is effectively funded through a combination of option payments discussed above, and through non-contestable customer prices.

The TVPS does provide improved energy supply reliability. However, its ability to capture a premium from the market will depend on prevailing inflows and storage levels and Basslink availability. It is difficult to see how the TVPS can recoup its costs from the market when hydrological risk is low, given prevailing market prices.
13. Non-contestable customer pricing - wholesale energy allowances

**Key Messages**

- The tariffs paid by non-contestable customers include an allowance for the wholesale cost to Aurora Energy of procuring energy from the wholesale market.
- The allowance is determined by the Tasmanian Economic Regulator under regulations. They have been changed on several occasions.
- As a result of the way in which the framework has been applied, the energy cost included in non-contestable customer prices has increased while the wholesale market price of electricity has decreased.
- The resulting divergence in non-contestable customers is a result of the application of the current methodology not taking account of the underlying supply/demand balance in Tasmania.
- The Panel recommends the ongoing use of benchmarks linked to the LRMC of electricity generation that take into account the supply/demand balance, the timing of the need for new generation and hydrological conditions.
13.1. Introduction

Aurora Energy’s residential and small businesses customer tariffs reflect the costs involved with the entire electricity supply chain, from generation through to the transmission and distribution networks, as well as retail functions such as metering, billing and customer service.

The contribution that each of these costs make to the tariffs paid by non-contestable customers is determined through economic regulation, involving the Australian Energy Regulator (AER) in the case of the transmission and distribution networks, and the Tasmanian Economic Regulator (TER) in the case of the retail functions and the cost of energy.

This Chapter examines the way in which Aurora Energy’s cost of energy allowance has been determined in the recent past, looks at the implications that this has for non-contestable customer prices, and puts forward an alternative basis for setting the cost of energy built into regulated electricity tariffs in the future.

13.2. Paying for the energy in regulated electricity prices

The wholesale cost of energy represents approximately 40 per cent of the overall delivered price of electricity for non-contestable customers. It is the growth in this cost over the past decade that, of the four elements that make up the cost of delivered energy, has had the biggest impact on the prices paid by non-contestable customers.

The cost of energy included in regulated retail tariffs is based on an ‘allowance’, that is set by the TER on a per megawatt hour (MWh) basis. Unlike the transmission and distribution network costs that are set by the AER and ‘passed-through’ from Transend and Aurora Energy’s distribution business to customers, Aurora Energy’s retail business is responsible for purchasing energy to supply non-contestable customers. As energy purchase costs vary over time, Aurora Energy’s profitability is partly a function of the cost it incurs in purchasing wholesale energy, relative to the allowance.

The TER’s objective in setting an energy cost allowance is the same as the objective guiding the setting of the other components of regulated retail tariffs; to allow for the costs that an efficient service provider – in this case an Aurora Energy – would incur in delivering energy to customers on regulated tariffs. However, meeting this objective can be a difficult task.

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Transmission and distribution network costs, combined, account for just under 50 per cent of the delivered cost of energy for non-contestable customers. The allowance for retail costs, which includes an allowance for a retail profit margin, represents approximately 8 per cent of the average retail tariff meaning that changes in retail costs exert only a relatively minor influence on electricity prices.
This is because the wholesale market price for energy and, therefore, retailers’ energy costs can vary significantly, and not always predictably, depending on the season, the time of day, and the characteristics of the customer load a retailer is serving.\textsuperscript{205} Even though retailers enter into financial contracts with generators to manage those spot market risks and provide greater certainty for their businesses, the prices they pay for electricity under these contracts also change over time as market dynamics evolve.

Given that regulated tariffs are typically set for periods of three years, setting the energy cost allowance based on spot market outcomes, or predicted market outcomes, is almost certain to either provide a windfall or impose a penalty on Aurora Energy.

Accordingly, when setting energy cost allowances, economic regulators have traditionally sought to ensure that the allowance provided to retailers does not place them in a position where they are unable to recover their actual costs from regulated customers. While it is usual for an allowance to be set with some reference to market prices, allowances still need to cater for a reasonable degree of price volatility.

Like other economic regulators in Australia, the TER has needed to balance a number of competing considerations when setting the energy cost allowance, and regulated electricity prices in general. As noted by the TER:

\begin{quote}
"The Regulator considers that customers have a preference for price stability and certainty over the regulatory period, but also do not want to pay at any time more than the efficient cost to supply. Retailers, while also preferring price stability and certainty, do not want to be held to a rigid fixed price in an environment of escalating or uncertain costs. Thus the Regulator is charged with balancing the needs of customers and Aurora.\textsuperscript{206} The objectives of economic regulation of prices"
\end{quote}

Economic regulation in monopolised markets is a substitute for competition that sets out to mimic the pricing outcomes that would be experienced in a workably competitive market. Given the absence of contestability for customers with electricity use below 50MWh per annum, the potential exists for Aurora Energy to exploit its position as a monopoly business by charging these customers more than the efficient cost of delivering energy to those customers. The regulation of prices is used to provide customers with the confidence that this is not occurring.

\textsuperscript{205} A ‘peaky’ demand profile, for example, will generally cost more to supply with energy than a flat profile.

\textsuperscript{206} Investigation of maximum prices for declared retail electrical services on mainland Tasmania – Final report, Office of the Tasmanian Economic Regulator, October 2010
In competitive wholesale electricity markets, the wholesale price at a point in time reflects, amongst other things, the balance between the available supply of electricity from generators and the level of demand from customers. The market price is not static and as the supply/demand balance changes over time, so does the wholesale price of electricity.

As demand grows, spare capacity to generate electricity declines and the wholesale market price of energy rises. This provides a signal to existing and potential new entrant generators that conditions in the market may support a commercial investment in new generation. As generation investment tends to be ‘lumpy’\textsuperscript{207}, the addition of a single new power station can shift the supply/demand balance from a situation where spare capacity is scarce to one of temporary oversupply. This often causes the wholesale price of energy to soften after a new power station is commissioned.

In a well-functioning, competitive retail market, retail prices will respond to changes in the wholesale price of electricity.

These are the fundamental market dynamics that economic regulation sets out to emulate.

13.2.1. Who sets the energy allowance?

The regulation of non-contestable electricity tariffs, including the setting of the energy cost allowance, is undertaken by the TER in accordance with pricing control regulations (the regulations)\textsuperscript{208}. Since the TER published its first determination of retail electricity tariffs in 1999 there have been a number of instances where changes to the regulations have been made concerning the way in which the wholesale energy allowance is set.

- In the TER’s 2003 investigation of retail electricity prices, the cost of the energy supplied to non-contestable tariff customers was mandated through the regulations. The price was based on an extension of a contract\textsuperscript{209} price struck between Hydro Tasmania and Aurora Energy at the time Hydro Tasmania was disaggregated in 1998, which was in turn based on a determination made by the TER in 1999.

\textsuperscript{207} ‘Lumpiness’ refers to the discreteness or indivisibility of units of capital.

\textsuperscript{208} Electricity Supply Industry (Price Control) Regulations 2003

\textsuperscript{209} Referred to as ‘the vesting contract’.
In 2007, through changes to the regulations, the Tasmanian Government specified the energy allowance that the TER was required to factor into retail electricity prices. That allowance was based on estimates of the long run marginal cost (LRMC) of supply which was taken to be the cost of a new entrant electricity generator in Tasmania – plus an adjustment factor of approximately $3 per MWh, which was added to account for a number of factors external to the calculation of LRMC.\(^\text{210}\)

In 2010, the regulations were amended with the intention of the same methodology applying as that in 2007. The regulations require the allowance to be at least equal to the LRMC of a notional new electricity generating plant, located on mainland Tasmania and supplying non-contestable customers. The determination of the actual allowance was left to the TER. As noted by the TER in the 2010 Retail Investigation - Final Report, regulators in some other jurisdictions\(^\text{211}\) have been given the discretion to choose the basis on which they set the energy allowance in regulated tariffs.\(^\text{212}\)

13.2.2. How is the energy cost allowance currently set?

Consistent with the regulations, the energy cost allowance incorporated into the current regulated tariffs applying to Aurora Energy’s non-contestable customers was set by the TER in 2010 based on the estimated LRMC of energy supply which was taken to be the cost of a notional new generator located on mainland Tasmania and supplying electricity to non-contestable customers in Tasmania.

\(^\text{210}\) With Hydro Tasmania’s revenue raising capacity having been weakened by low hydrological inflows, the adjustment factor was proposed by the Department of Treasury and Finance as a means of ensuring, amongst other things, that Hydro Tasmania and Aurora Energy would have sufficient revenue capacity to earn a commercial return and invest in generation assets. Treasury was of the view that, until the Hydro Tasmania’s water storages were able to be rebuilt, “Some of the burden of additional revenue capacity must fall on non-contestable customers. This would suggest energy prices for the non-contestable load should be higher than the IES recommendations.” IES was the economic consultancy engaged by the TER to develop estimates of Aurora Energy’s cost of procuring energy to supply non-contestable customers. It was estimated by Treasury that the addition of $3 per MWh to the prices recommended by IES would provide an additional $26 million to Hydro Tasmania to bolster its sustainability and enable investment in generation assets. The proposed regulations were also assessed by Treasury, as part of a Regulatory Impact Statement, as “imposing a significant cost as they will result in non-contestable customers paying a higher retail tariff than in the past.”

\(^\text{211}\) South Australia and the Australian Capital Territory. In these jurisdictions, regulators were setting ‘fall-back’ pricing arrangements for customers that do not take up market-based contracts with a retailer of their choice, rather than setting prices for non-contestable customers with no option other than to purchase electricity under a regulated tariff.

\(^\text{212}\) While this option was canvassed with the State Government by the Department of Treasury and Finance in the lead up to the 2010 investigation of retail electricity prices, in its advice to the Treasurer, Treasury dismissed the approach as “an unnecessarily time-consuming process for the Regulator, relevant electricity entities and consumers” because of the need for the TER to consult with a range of interested parties. Source: Minute to the Treasurer “Wholesale energy pricing in regulated electricity tariffs”, Department of Treasury and Finance, 15 June 2009.
The use of the cost of an efficient new generator is a common reference point in the regulation of electricity prices around Australia. Using a non-market reference point for determining prices is particularly relevant in a thinly traded wholesale electricity contract market or in the absence of published data regarding market pricing outcomes, as is the case in Tasmania.

The TER’s calculation of the LRMC was based on the optimal combination of gas-fired generation technologies that would be needed to supply the total Tasmanian load during the regulatory period, if the system were to be constructed ‘from scratch’.

While the regulations do not specify the nature of the ‘notional new entrant’, natural gas fired thermal generation was used as the basis for estimating LRMC because it was considered the least costly means of providing additional large scale generation in Tasmania that is both technically and economically feasible.

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213 The Queensland Competition Authority (QCA) uses a weighted average of LRMC and market prices; the Independent Pricing and Regulatory Tribunal (IPART) in New South Wales is required to use the higher of LRMC or market price; and the Essential Services Commission of South Australia (ESCOSA) has chosen to apply LRMC to its estimates of electricity supply costs for regulated customers.

214 The estimates of LRMC developed as part of previous retail pricing investigations in Tasmania have all been based on the use of a combination of combined cycle gas turbines (CCGT) for additional base load generation, and open cycle gas turbines (OCGT) for the provision of peaking plant.
The Long Run Marginal Cost of generating electricity explained

There are essentially two ways in which the production of electricity can be increased in order to meet an increase in demand.

In the short term, increases in demand can be met by an increase in production using the existing stock of generating plant, assuming that the existing assets have sufficient spare capacity to meet the additional demand. The incremental cost of generating electricity to meet an increase in demand using the existing stock of generators is referred to as the Short Run Marginal Cost (SRMC) of the power system. However, if capacity is scarce, some existing load may be curtailed, and the value (to the consumer) of that load foregone will set the SRMC.

In the long term, the generation stock can be expanded, and the Long Run Marginal Cost (LRMC) of the power system defines the changes in cost of meeting a sustained increment of demand, based on the ability to change generating plant.

Estimating LRMC involves assessing the costs associated with undertaking a forecast capacity expansion sooner than would otherwise be the case. The estimation of LRMC answers the question “if the construction of a new power station in X years’ time to meet demand were to be brought forward say by one year because demand is higher, what would the change in total system costs be, expressed in today’s dollars?”

LRMC is not static and changes over time as the supply/demand balance changes, either as the result of changes in capacity or changes in demand.

When capacity utilisation is low and the next capacity expansion is some time into the future, the LRMC of meeting additional demand will be relatively low. This is because the cost of investing in additional generation capacity sooner, when discounted to today’s dollars, will be relatively low. However, LRMC rises as spare generation capacity declines and the time to invest in new power stations approaches.

Prices in the wholesale electricity market will also rise towards (and beyond) the LRMC of the power system as the need for additional capacity nears. Because of the timeframe over which LRMC is considered (i.e. the longer term), and the fact that capacity constraints are removed from consideration, the LRMC of the power system will be less volatile than the SRMC of the power system and less volatile than wholesale spot prices.
13.2.3. Recent pricing outcomes under the current framework

In recent times, the application of a particular LRMC framework to develop regulated tariffs has diverged from both the regulatory estimates of ‘market prices’ and observed spot and contract prices.\(^{215}\)

Figure 13.1 compares the average annual spot market price for electricity in Tasmania since 2005-06\(^{216}\) with the energy cost allowance factored into regulated tariffs. The energy cost allowance has been based on estimates of the cost of new generation since the beginning of 2008. As the chart shows, the annual average wholesale electricity price in the Tasmanian spot market has decreased markedly since 2005, while the energy cost allowance has increased by almost the same amount.\(^{217}\) Therefore, non-contestable retail tariffs have not moved consistently with the underlying supply/demand balance or the wholesale market price of energy.

**Figure 13.1 Average spot market price v Energy Cost Allowance in regulated tariffs (nominal)**

\(^{215}\) In its submission to the Panel’s Issues Paper, Hydro Tasmania noted ‘that Tasmanian non-contestable contract prices are higher than those charged under contestable contracts’ because ‘the Tasmanian regulatory framework has mandated that the current wholesale energy component of non-contestable customer contracts be calculated using long run marginal costs (LRMC).’ Hydro Tasmania contends that ‘average annual spot prices in NEM regions is not close to LRMC, and Hydro Tasmania’s experience of OTC hedges are also not close to LRMC’.

\(^{216}\) Tasmania joined the NEM in May 2005, however the part-year average price for 2004-05 has been excluded from this analysis as unrepresentative of underlying prices.

\(^{217}\) In both nominal and real terms, recent spot market prices have represented historical lows in the period since Tasmania joined the NEM in May 2005. This experience has been repeated in every other region of the NEM. The reduction in market prices can be attributed to a number of factors, including the Global Financial Crisis which developed during 2007 and 2008, and the consequent reduction in demand that was experienced in 2009 and 2010. In Tasmania, the return to more ‘normal’ hydrological inflows into Hydro Tasmania’s water catchments, and the resulting increase in storage levels, has also been a contributing factor.
This is not to say that the energy cost allowance should not exceed the wholesale spot price of electricity. In fact, the energy cost allowance should exceed wholesale spot prices, on average, given:

- the peakiness of the non-contestable load, which makes it more expensive to serve than the system load profile; and
- the need to provide Aurora Energy compensation for commercial risks arising from volatile wholesale prices.

However, the present concern relates to the divergent direction and magnitude of recent changes to the energy cost allowance in light of trends in wholesale prices.

Further evidence of this divergence can be found in the TER’s 2010 investigation of regulated electricity prices. As part of that investigation, estimates of the cost of meeting the non-contestable customer load were developed using two different methodologies – a market cost approach and an LRMC approach.

As Table 13.1 shows, the estimates of LRMC were 11 to 12 per cent higher than the comparable market cost estimates.

**Table 13.1: Estimated wholesale electricity costs (2010)**

<table>
<thead>
<tr>
<th>Cost per MWh</th>
<th>2010-11</th>
<th>2011-12</th>
<th>2012-13</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Market Cost</strong></td>
<td>$66.23</td>
<td>$65.13</td>
<td>$66.04</td>
</tr>
<tr>
<td><strong>LRMC</strong></td>
<td>$73.50</td>
<td>$73.16</td>
<td>$74.33</td>
</tr>
</tbody>
</table>

Note: All figures expressed in $nominal. Market cost was the estimated cost of contracts required to meet the non-contestable customer load profile, not the spot market price.


A similar disparity emerged in 2007 during the process for determining the regulated tariffs that would apply from 1 January 2008.

In that year, the Tasmanian Government set Aurora Energy’s energy cost allowance. Estimates prepared by consultants engaged by the Government showed the LRMC of new generation to be significantly higher than the estimated market cost at the time. Table 13.2 shows the estimates prepared for the Government by Intelligent Energy Systems (IES), along with its recommendations regarding the allowance for the cost of energy to be incorporated into regulated tariffs.
Table 13.2: Estimated wholesale electricity costs (2007)

<table>
<thead>
<tr>
<th>Cost per MWh</th>
<th>2008</th>
<th>2009</th>
<th>2010 (to June)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market (IES estimates)</td>
<td>$44.49 to $45.36</td>
<td>$43.33 to $44.84</td>
<td>$59.72 to $62.58</td>
</tr>
<tr>
<td>LRMC (IES estimates)</td>
<td>$55.07 to $58.06</td>
<td>$56.10 to $59.17</td>
<td>$64.48 to $68.29</td>
</tr>
<tr>
<td>iES recommendations</td>
<td>$57.02</td>
<td>$59.52</td>
<td>$60.12</td>
</tr>
<tr>
<td>Treasury recommendations</td>
<td>$60.00</td>
<td>$62.50</td>
<td>$63.00</td>
</tr>
</tbody>
</table>

Note: All figures expressed in $nominal. Market cost was the estimated cost of contracts required to meet the non-contestable customer load profile, not the spot market price.


In the Panel’s view, the adoption of an LRMC framework for setting the energy cost allowance for regulated tariffs is appropriate. However, the way in which LRMC has been applied needs to be reconsidered. This is discussed further in the following section of this paper.

13.3. LRMC as the basis of regulated electricity prices

LRMC is not empirically observable. There are a number of definitions of, and methods for calculating, the LRMC of electricity generation. This means that the estimation of LRMC is sensitive to the analytical and modelling methodology used, as well as to variations in the relevant input parameters. These include assumptions made regarding the cost of capital equipment, fuel costs and operational assumptions, such as capacity factors.

For example, the estimates of the LRMC of new generation in Tasmania developed for the 2007 and 2010 pricing determinations were based on pricing the total system load\textsuperscript{218}, and then applying the system marginal price to the non-contestable load being priced. Another alternative could have been to estimate the cost of supplying non-contestable customers in isolation. However, the consultants that prepared the estimates for the energy cost allowance in 2007 contended that such an approach would overstate the cost of supplying the non-contestable market\textsuperscript{219}.

\textsuperscript{218} using a combination of combined and open cycle gas-fired generation technologies

\textsuperscript{219} Intelligent Energy Systems contended that calculating the LRMC of supplying the non-contestable market in isolation would have meant that the cost of reserve capacity would not be shared across all consumers, resulting in regulated tariffs being inflated by the impact on the LRMC of generation of the relatively peaky non-contestable load profile.
Intelligent Energy Systems also noted that using gas to represent existing hydro generation assets overstates LRMC in a Tasmanian context, for two main reasons:

- the forward looking nature of LRMC, and its utilisation of estimates of future capital costs rather than historical costs, means that LRMC reflects the full capital cost of new gas-fired generation, rather than the sunk investment in the existing hydro system; and

- the (opportunity) cost of water was/is less than the price of gas.

In calculating the wholesale energy cost allowance in 1999, the TER concluded that it would be inequitable if customers being supplied under regulated tariffs were expected to pay prices that represented the marginal cost of a new entrant generator. This was in part because the growth in demand was being driven largely by major industrial users\(^{220}\), and the level of growth was only modest in any case.

### 13.3.1. The timing of investment in new generation

As the need for new generation capacity approaches, market prices tend to rise towards and above the cost of new generation.

In these circumstances, prices send a signal to existing and potential new entrant generators that conditions in the market for electricity may support a commercial investment in new generation.

The application of the current framework effectively requires non-contestable consumers to pay electricity prices which reflect the cost of new generation as though it is required now, when the need for additional generation capacity in Tasmania well into the future.

The wholesale energy allowance has been calculated in a way that implies that the entire non-contestable customer load is being met exclusively by a portfolio of new generators, and that the prices paid by customers today should reflect the full cost of this hypothetical investment, without regard to the timeframe in which additional generation might actually be needed.

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\(^{220}\) The TER observed that the contribution to load growth since 1995 from major industrial users of electricity (881 GWh) had, in absolute terms, been more than twice that of the contribution to load growth from the non-major industrial sector (258 GWh).
So, while additional generating capacity is not expected to be needed in Tasmania for at least another 15 years, non-contestable customer tariffs have been implying that prices need to be high enough to attract and support the entry of additional (gas-fired) generation.

13.3.2. Pricing for energy supply security risk

Over 80 per cent of Tasmania’s licensed on-island generation capacity is hydro based. This means that the level of hydrological inflows into Hydro Tasmania’s catchments can materially change the effective supply/demand balance in the Tasmanian region of the NEM, even though there may have been no growth in demand or any change in the capacity of on-island generation.

Although Hydro Tasmania’s dams include several long-term storages, sustained reductions in hydrological yield are out of Hydro Tasmania’s control. This uncertainty in the energy contribution of Hydro Tasmania’s generators gives rise to “hydrological risk” for Hydro Tasmania’s business, and can potentially give rise to energy supply security risk for Tasmania.

Hydrological factors mean that Tasmania’s effective supply/demand balance is more volatile than in other NEM regions, which predominantly face capacity constraints. Given the need to maintain continuous supply, it is appropriate that customers make a contribution to the efficient cost of mitigating hydrological risk through their tariffs.

The energy cost allowance set by the State Government in 2007 arguably factored in the cost of mitigating hydrological risk. It did this through the addition of the $3 per MWh adjustment factor that was added to the estimates of the LRMC of new generation.

The level of hydrological risk, for Hydro Tasmania, and the energy supply security risk for Tasmania has been reduced significantly by Basslink, the Woolnorth and Studland Bay wind farms, and the gas-fired Tamar Valley Power Station operated by Aurora Energy. However, hydrology remains an ongoing risk for Hydro Tasmania’s business.

221 Forecasts prepared by Transend Networks in support of its 2010 Annual Planning Report suggest that Tasmania’s existing generation capacity, together with southwards flows over Basslink, will be sufficient to meet forecast maximum demand until 2028. The Australian Energy Market Operator has also examined Tasmania’s supply/demand balance, and in its 2010 electricity statement of opportunities for the National Electricity Market estimated that installed and committed generation capacity in Tasmania, excluding wind, would be sufficient to meet projected peak demand and reliability requirements until at least 2019-20 under low, medium and high economic growth scenarios.

222 Supply in terms of energy supply, rather than installed capacity.
This overall reduction in energy supply security risk, and its impact on the prevailing supply/demand balance, has been one of the factors contributing to the low wholesale prices in Tasmania since 2008. With projections of relatively modest load growth in the future, capacity/energy constraints are unlikely to be a significant driver of Tasmanian market prices over the medium term. However, it is still appropriate that estimates of LRMC in the Tasmanian context take into consideration the potential volatility in inflows and prevailing water storage levels, and the associated variability in the supply/demand balance at the time that pricing determinations are made. For example, the LRMC determination could consider low, medium and high inflow sequences and include a probabilistic outcome.

13.4. The way forward

To the extent that retail tariff regulation is maintained in the future, determination of the wholesale energy allowance will remain a key task for regulators. It is important, therefore, that any energy strategy developed by Government be underpinned by the objective of ensuring that the regulatory framework provides appropriate pricing signals to customers.

The Panel considers that the current regulations governing the determination of the wholesale energy allowance and their application can be enhanced to provide the TER with clearer guidance on the parameters that need to be taken into account in defining LRMC-based benchmarks.

It is important that the regulations enable the TER to:

- recognise the efficient costs of the existing and future sources of energy that will actually be utilised in delivering the energy that is used by non-contestable customers, rather than basing prices solely on estimates of a notional new entrant;
- take into account the prevailing storage situation and the likely level of hydrological risk over the period for which the allowance is to be set; and
- consider the likely supply/demand balance over the period for which the allowance is to be set and the timing of any new investment needed to meet growth in the non-contestable customer load in the future.

Implementing an approach to determining wholesale energy allowances on this basis will ensure appropriate price signals are provided to customers supplied under regulated tariffs.

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223 Given current water storage levels and assuming average inflows.
An appropriate framework for considering the LRMC of a given load profile is discussed in detail in "What are Marginal Costs and How to Estimate Them?" In brief, the framework involves estimating the costs involved with undertaking a capacity expansion sooner than would otherwise be the case, in response to a change in the regulated load.

A hypothetical increase in demand over and above predicted levels would result in the need to bring forward the investment in new generation that would otherwise not be expected to occur until a later date. LRMC is calculated by estimating the total costs involved with meeting that increment in demand by undertaking the capacity expansion sooner rather than later. The capital cost component of LRMC is calculated by comparing the present values of a forecast capacity expansion with the present value of the same expansion undertaken at an earlier point in time.

As mentioned previously, in Tasmania’s case, future investment in new generation is likely to involve a mix of natural gas-fired thermal generation. In considering overall system costs, the framework would also involve an assessment of the hydrological risk that is relevant to the overall Tasmania system.

Under this approach, the estimate of the LRMC of supplying the non-contestable load would change over time with changes in both capacity and demand in Tasmania. This will ensure that the regulatory approach will be robust to changes in Tasmania’s supply and demand balance and retain a linkage between the prices that are observed in the wholesale electricity market and the pricing signals sent to customers through regulated prices. The current pricing regulations have effectively assumed that new generation capacity is needed immediately.

It is noted that this approach may have the consequence of introducing a level of pricing volatility between regulatory periods, depending on the supply/demand balance and hydrology. The Panel considers this is a worthwhile trade-off as it will introduce better pricing signals for regulated customers to respond to the underlying circumstances existing in the Tasmanian market.

The Panel recognises that prevailing wholesale market prices will not always correspond with estimates of LRMC. Accordingly, the current provision in the regulations for a secondary test of market prices is valid, and needs to be retained. If, for some reason, market prices were higher than LRMC estimates, it would be inappropriate for the regulatory arrangements to place retailers, like Aurora Energy, in a position where they would incur operating losses through not being able to recoup sufficient revenue from regulated customers to cover the costs of supply.

224 What are Marginal Costs and How to Estimate Them, Professor Ralph Turvey, Centre for the study of regulated industries (CRI), The University of Bath, March 2000

225 It is not the role of the framework for determining the wholesale allowance to address issues in the market where prices are above LRMC.
PART 3

THE FUTURE

Terms of Reference number 7 (ToR7), require the Panel to investigate and report on ‘any actions that would guide and inform the development of a Tasmanian Energy Strategy, particularly in relation to the Government’s primary objectives of minimising the impact on the cost of living in Tasmania and ensuring Tasmania’s long term energy sustainability and security’.

The Panel has identified four elements of the TESI that are not consistent with the Government’s primary objectives:

1. The application of the existing methodology for determining the wholesale energy allowance for non-contestable customers is inappropriate given the excess generation capacity in the Tasmanian region during normal hydrological conditions.

2. The TVPS is financially unsustainable in the prevailing market conditions. The fundamental issue is that market prices are not sufficient to cover the power station’s fixed costs.

3. The architecture underlying the operation of the wholesale market in Tasmania gives rise to Hydro Tasmania having latent market power. This increases the risk to other market participants of operating in the Tasmanian electricity sector by comparison to other NEM regions. This additional risk is deterring participation in the Tasmanian region by electricity retailers.

4. Effective retail competition and customer choice has not developed as anticipated, largely because of the perceived risks of wholesale market trading in Tasmania, precluding the introduction of full retail contestability (FRC).

The purpose of this Chapter is to discuss each of these elements in turn and to put forward ways in which the Government could better promote its primary objectives of minimising the impact of electricity supply on the cost of living in Tasmania and ensuring Tasmania’s long term energy sustainability and security.

The Panel has engaged Frontier Economics to undertake market modelling for the purposes of illustrating the implications of the proposed reform measures on energy prices and the financial performance of SOEBs.
15. Wholesale energy allowance for non-contestable customers

Ensuring that the regulatory framework delivers appropriate price signals to non-contestable customers is the first key issue for a State Energy Strategy.

As discussed in Chapter 13, the wholesale energy component of regulated tariffs for non-contestable customers is currently based on the cost of a notional new generator located on mainland Tasmania and supplying electricity to non-contestable customers. Under this approach, energy prices for non-contestable customers are implicitly based on the assumption that new generation capacity is required in the very near future to meet the load of non-contestable customers.

In Chapter 13, a refinement in the LRMC methodology is proposed that more closely reflects the current Tasmanian electricity market conditions by taking into account the prevailing supply/demand balance under normal hydrological conditions and the need for, and timing of, new entry. This alternative approach would result in the regulated energy allowance being more closely aligned to market prices than is currently the case.

The TER would be required to develop the detailed methodology for determining the wholesale energy allowance and undertake the modelling and analysis required to determine is quantum.

This framework would deliver a significantly lower estimate for the LRMC of non-contestable customer load than that determined under the application of the current arrangements, given:

- the current level of water storages;
- the existing excess of capacity and energy relative to demand; and
- that new entry is not required until well into the next decade

The Panel has undertaken initial modelling to determine the broad order of magnitude of the potential differences in LRMC outcomes from the continuation of the existing framework and the implementation of an approach that took into account the abovementioned principles, on the assumption that the current supply/demand balance and hydrological conditions applied at the time of the next determination.

That modelling indicates that the LRMC of a small but sustained increase in non-contestable customer load is broadly in line with currently prevailing Tasmanian spot prices. This reflects that the need for new capacity is not until the late 2020s and given current storages levels and typical inflows, Basslink availability and the TVPS, there is significant scope to meeting additional non-contestable customer load without bringing forward the need for new capacity.
This estimate would change with different hydrological conditions - if at the time the methodology is applied, starting hydrological storages are at low levels (noting that they are currently at historical highs), a materially higher estimate of LRMC would arise - just as market price would adjust to change in scarcity, and therefore, value of water.

As discussed in Chapter 13, it is proposed that the current regulatory test of using the higher of LRMC relative or market prices be retained, so that retailers for which the arrangements apply will not be exposed to unmanageable market risk under regulatory requirements. The Panel has also developed estimates of an efficient market price for non-contestable customer load. The methodology is explained in Chapter 21.

That analysis suggests that for the period the Panel examined (2011-12 to 2015-16), the estimate of the efficient market price of wholesale energy to back non-contestable customer load would be higher than the estimate of the revised estimates of the LRMC of non-contestable customer load discussed above.

It is not possible to provide a definitive estimate of the difference in wholesale allowances and retail prices that would apply for the next pricing determination (which will apply from 1 July 2013) under the Panel’s recommended methodology, relative that which would result from the continuation of the existing methodology. Nonetheless, if the current supply/demand circumstances were to continue and existing hydrological circumstances existed at the time of the next determination, retail prices could be in the order of 5 to 10 percent lower than if the current framework were applied at that time.

Such a change would have implications for the revenues available to Aurora Energy to procure wholesale contracts to back retail customer load.

On the basis that Aurora Energy was able to secure contracts from Hydro Tasmania consistent with that allowance, there would be a corresponding reduction in Hydro Tasmania’s revenues.

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226 Under the current framework, this is only Aurora Energy. If full retail contestability was introduced and regulated fallback tariffs were to be established, new entrant retailers would also be subject to the regulatory arrangements.
Aurora Energy uses the TVPS to back around half of its non-contestable load, and the reduction in the wholesale allowance would have a corresponding impact on either:

- its wholesale energy business - if the existing tolling agreement is not amended; or
- the financial performance of AETV - if the tolling agreement is adjusted to reflect the wholesale allowance - which is the preferred approach and discussed in the Chapter 16.

Again, it is not possible to be definitive regarding the magnitude of the financial impacts from the application of the revised methodology at the time of the next determination, relative to a continuation of the current arrangements.

Based on the abovementioned estimates of a revised wholesale allowance, and assuming no change in the balance between Hydro Tasmania and TVPS contracting for non-contestable customers, the revenue consequences are likely to be in the order of $20 million per annum on average over the next regulatory period for each of the businesses, relative to revenues that would be available from a continuation of the existing framework.

Options for addressing the consequences for the Government Budget of this change are discussed in Chapter 16.
16. Placing Tamar Valley Power Station on a commercial footing

Addressing the financial viability of the TVPS in the context of prevailing market conditions would be the second key issue for the Energy Strategy.

Currently, the revenue that TVPS receives from its tolling arrangement with Aurora Energy’s energy business covers all of the TVPS’ costs, including fixed costs, gas costs, debt management and the delivery of a small return on equity. This results in a unit cost to Aurora Energy’s energy business that is higher than market prices and without offsetting cost reductions or higher revenues than could be obtained from the market, Aurora Energy would not be able to fund the tolling arrangement – which was the situation it faced in 2010-11.

The CCGT plant continues to run at a high capacity factor, due Aurora Energy’s long term gas arrangements which include a take-or-pay obligation until the expiry of the current contract in 2017. Aurora Energy currently utilises a large proportion of its overall gas commitments through the TVPS, which is used to back around half of Aurora Energy’s non-contestable customer contracts.

Reforming the arrangements for determining wholesale energy allowances or if, in any case, an alternative methodology results in lower regulated tariffs for the next regulatory period the resulting reduction in regulated retail tariffs will put further pressure on Aurora Energy’s financial performance in light of the current tolling arrangement. The same is true of a move to full retail contestability and the introduction of market-based pricing for all customers.

In a competitive market, a retailer that invested in an uneconomic power station would face the financial consequences of that investment decision. However, in the case of TVPS, the decision to invest in the power station was not Aurora Energy’s decision, and the decision was not based solely on commercial considerations. Rather, the Government ultimately made the decision that Aurora Energy should acquire TVPS, and did so as a result of obvious concerns over security of supply during the drought.

The Panel considers that the financial arrangements for TVPS should be restructured with the intention of placing it, and Aurora Energy, on a more sustainable commercial footing.
First, the Panel proposes that the tolling agreement be adjusted to reflect the market value of all the energy that the TVPS produces. Prior to the introduction of full retail contestability, the key source of value would be the wholesale energy allowance provided to Aurora Energy under the regulatory framework, which may be adjusted with changes in the regulatory approach discussed in Chapter 13. Other sources of revenue are spot prices, and any revenue from contestable customers that Aurora Energy chooses to utilise the TVPS to back.

This change would precipitate a change in the value of the TVPS and the Aurora Energy subsidiary that owns it, AETV. This is likely to be considerably lower than the current carrying value of $353 million (as at 30 June 2011), but will be necessary to establish a sustainable financial position for the business.

Second, the Panel proposes that the debt associated with the TVPS that cannot be supported on a sustainable basis in light of market revenues be transferred from the Public Non-Financial Corporation sector to the General Government Sector.\textsuperscript{227}

The Government could offset the Budget effects of this portion of debt by making use of improved dividend returns available from Hydro Tasmania resulting from the price on carbon.

An alternative approach is to require the SOEBs to exit underperforming diversification projects that currently require the application of SOEB capital. That capital could be returned to Government, with the financial return on it providing an offsetting source of revenue to fund the TVPS support payment.

Detailed modelling in conjunction with Aurora Energy and Treasury would be required to accurately quantify the nature of the financial restructuring that would be required under this approach.

Based on the Panel’s understanding of the current cost structure of the TVPS, and having regard to its estimates of market-based revenues that may be available to the TVPS, it is likely that the majority of the debt currently held by AETV would not be able to be supported, and need to be transferred back to the General Government Sector.\textsuperscript{228}

There remains a possibility that a transfer of debt may not lower the cost structure of the TVPS sufficiently to provide it with a positive market value. A critical determinant will be the market prices that it is able to achieve.

\textsuperscript{227} From a Total Non-Financial Public Sector perspective, there is no change in net or gross debt arising from this change, as it merely moves debt from one part of the portfolio to another. This is important from the perspective of the State’s credit rating.

\textsuperscript{228} Assuming that $200 million of debt was transferred to the General Government sector, the Government would require additional revenue of $12 million to fund additional debt management expenses.
While there is uncertainty, modelling for the period to 2015-16 suggests that TVPS may not be able to earn sufficient revenue even to meet its operating costs (i.e. gas commodity/transportation, market charges, labour and transmission costs). Gas costs represent around half of the TVPS operating costs. Aurora Energy’s current gas arrangements are in place until 2017, meaning there is little opportunity to restructure TVPS’s operating costs in the short term unless alternative customers could be found for the gas, preferably in Tasmania, or on the mainland. Such a change would also require alternative contractual arrangements be established with Hydro Tasmania to back Aurora Energy’s retail contracts that it currently manages through the TVPS.

In the event that the assessed market value of the TVPS is negative, the Government may need to give consideration to a transparent supplementary funding mechanism which is essentially an energy security insurance premium. This could be levied within the market and provided to Aurora Energy by way of a CSO arrangement, reflecting the Government’s policy decision to acquire the TVPS to provide energy supply security for all customers in Tasmania.

Again, detailed financial modelling is required to determine if such an arrangement would be required and to determine its potential quantum.

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Because the gas transport commitments are fixed until 2017. Aurora Energy would still need to fund these costs if alternative markets on the mainland for the gas were identified.
17. Structural reform of the wholesale market in Tasmania

Changing the structure of the electricity wholesale market in the Tasmanian region to establish greater participation in the wholesale market is the third key issue.

As shown in Chapter 11, reducing the level of risk in the wholesale market for retailers/customers is a necessary pre-condition for developing effective competition and customer choice in electricity retailing.

The central challenge is to create a structure that would constrain Hydro Tasmania’s capacity to exercise market power in the wholesale market and create a more competitive environment for spot and contract market trading in the future. As discussed in Chapter 11, the need to reform the Tasmanian wholesale market is primarily driven by concerns about latent market power. Given this, the objective is to deliver change that provides confidence that Hydro Tasmania is not in a position where it has latent market power and that the Tasmanian wholesale market will routinely deliver efficient outcomes.

The Panel has identified three reform paths which would create a more competitive environment for spot and contract market trading in the future. They can be represented firstly as a regulatory path, secondly, as a means of introducing effective competition within the Tasmanian region and thirdly, as a means of increasing the size of the market available to Tasmanian consumers. These are:

1. An independent, regular auction of standard contracts from Hydro Tasmania to provide retailers with confidence that appropriately priced hedging contracts will be available in the Tasmanian market on an ongoing basis and on reasonable terms.

2. Creating competition in the trading of energy produced by Hydro Tasmania by establishing independent trading entities while retaining Hydro Tasmania as an integrated generating business.

3. Increasing competition for Hydro Tasmania by combining the Victorian and Tasmanian NEM regions.

The reform approaches considered are necessarily constrained by the commercial and physical constraints and realities of the Tasmanian region, including for example:

- The commercial arrangements between Hydro Tasmania and CitySpring Infrastructure Trust relating to the Basslink interconnector;
Hydro Tasmania’s integrated hydrological management approach to its hydro-generation system; and

Tasmania’s concentrated energy demand profile whereby twenty large industrial customers account for around 60 per cent of Tasmania’s electricity consumption, including four major industrial users that between them use around half of the energy supplied by the Tasmanian power system.

While each reform path aims to achieve the same core objective - to constrain Hydro Tasmania’s capacity to exercise its latent market power in the wholesale market to provide retailers with options to manage their wholesale spot price risk, the lack of which is the main barrier to competition - there are differences in the way that they each seek to achieve that goal. Each reform path gives rise to trade-offs and has limitations. The implementation of any of the reform paths will involve the resolution of detailed implementation measures. Each also varies in its degree of complexity and cost of implementation. As such, each should be assessed for its merit relative to the other options.

Ultimately, the extent to which each of these reform paths will deliver the objective depends on the confidence market participants have that the reforms will deliver effective wholesale market outcomes on a consistent basis. This is a key issue on which the Panel is seeking input through submissions and public hearings.

17.1. Reform Path 1 - Auction of contracts

The Panel’s interactions with the retailers licensed to operate in Tasmania indicate an unwillingness to participate in the wholesale market in Tasmania. Discussions with national retailers highlighted the same concerns. Having regard to the analysis presented in Chapter 11, this is a response to Hydro Tasmania’s latent market power resulting from its position as both the dominant presence in the spot market and the principal supplier of hedge contracts.

As discussed in Chapter 11, a high level of contract cover diminishes the incentives for Hydro Tasmania to bid strategically in the spot market. While contracting does not address latent market power per se, it can provide an effective means of reducing its economic impact.

A regulatory approach to wholesale market reform would focus on providing confidence that there will be ongoing access to appropriately priced contractual arrangements in Tasmania, on the back of which retailers can build sustainable retail operations.
Reform path 1 consists of a framework requiring Hydro Tasmania to consistently offer a defined quantity of wholesale contracts for competitive auction. The objective is to provide retailers with confidence that a supply of contracts at volume, liquidity and price that supports retail competition will be available in the Tasmanian region on a sustained basis. The auction would be enforced by legislation in order to give potential new entrants the maximum confidence around the durability of contract supply.

The Panel has also considered alternative regulatory approaches, including:

- increased transparency of Hydro Tasmania’s contract position and a requirement for it to make standing offers;
- the development of a reference water valuation model with published prices against which Hydro Tasmania’s bidding and contracting decisions could be assessed; and
- the regulation of Hydro Tasmanian’s spot market bidding behaviour.

Arrangements that provide references or benchmarks against which market behaviour can be assessed, without material penalties that are independently enforced, are unlikely to provide confidence in outcomes required to attract retail participation in the Tasmanian market. Similarly, there is a tension between a regulatory approach that seeks to constrain Hydro Tasmania’s bidding behaviour and the ability of Hydro Tasmania to respond to market changes – potentially increasing the risk of incorrect pricing signals. For these reasons, the alternative regulatory approaches have been discounted.

### 17.1.1. Objectives

The primary objectives of this reform path are to:

- provide retailers confidence that Hydro Tasmania will provide contracts on an ongoing basis that will enable them to manage wholesale market risk;
- inject additional competitive tension into commercial contract negotiations between retailers and Hydro Tasmania by removing Hydro Tasmania’s ability to determine contract prices and conditions, and by the use of an auction to acquire contracts; and
- protect against a loss of value to Hydro Tasmania through the implementation of a reserve price for contracts.

This reform path preserves the key current features of the TESI and leaves Hydro Tasmania and market participants also free to negotiate terms for bilateral contracts. The only change is that Hydro Tasmania would be required to make available a certain volume of its overall contracting capability through an auction process supported by legislation.
17.1.2. **Key features**

The auction would take place on a routine basis, recognising the importance of liquidity and the ability of market participants to adjust contract volumes on a regular basis. The Panel is seeking input from potential auction participants on the appropriate frequency of auctions and duration of contracts offered through that process.

The total volume of contracting capacity required to be offered through the auction process would be based on Hydro Tasmania sustainable energy yield less the volume it contracts directly with its four largest industrial customers. To preserve the volume of energy to be made available through the auction and is supplied to customers through negotiation with a retailer, Hydro Tasmania’s ability to contract directly with other customers would be prohibited.

The auction would include financial products based on standard terms (i.e. as set out by the International Swaps and Derivatives Association) for swaps and caps. There could be potential to include other arrangements, such as load following hedges and firm inter-regional swap contracts, but establishing a reserve price for these arrangements is likely to be more difficult. Moreover, there is merit in leaving these other arrangements as opportunities for bilateral negotiations within the Tasmanian contract market.

The auction would offer 1 MW units, for at least quarterly contracts, over a three-year time horizon. A medium term horizon is important to enable retailers to build a retail business around the regulated auction framework and the demand for contracts further ahead is considered limited. 230,231

The reserve price would be set independently of Hydro Tasmania and the Tasmanian Government and referenced to water value (which is derived from Victorian contract value, storage levels and inflow expectations). This would provide protection for Hydro Tasmania in that it will not be required to contract at prices below the opportunity value of its water.

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230 The Panel understands that one of perceived limitation of the Basslink IRR auction framework is that it did not provide enough medium term certainty for participants.

231 Setting a reserve price over a longer timeframe could also be more difficult given the limited availability of key pricing data.
Market demand through bidding would set the actual value of the contracts through the auction. If the reserve values were not reached for some or all contract units, Hydro Tasmania would not be obliged to contract at that time for those volumes that failed to achieve the reserve. Unsold volumes would be rolled into future year contract auctions, other than the volume for the immediate next year, which would effectively leave Hydro Tasmania under-contracted in that next year.\textsuperscript{232}

Given the intention of the reform is to provide for the basis of new entry in the Tasmanian retail sector, the auction arrangement would restrict the volume that a single entity could purchase. The Panel does not have a firm view on the maximum volume that could be acquired at any auction and is seeking input from market participants on the costs and benefit of restricted volumes and what level would be most suitable.

Any party related to Hydro Tasmania would be excluded from bidding, and the current arrangements that preclude Hydro Tasmania from having a retail licence in Tasmania would continue.

The auction framework would continue to apply until there is sufficient competition in the Tasmanian wholesale energy market to obviate its need. This is likely to involve an initial pre-commitment to a certain number of auctions over the medium-term, followed by an independent review of the ongoing need for the auction process.

To provide participants with some confidence regarding the durability of the market reform, it is anticipated that the auction framework would be enacted through primary legislation.

Hydro Tasmania would retain full commercial flexibility to negotiate any form of contract with counterparties at prices agreed through bilateral negotiations. There would be no additional regulatory oversight of those commercial negotiations.

17.1.3. \textbf{Risks and implementation issues}

For the reform option to be effective, there needs to be participation in the retail sector of a sufficient number of retailers to compete for contracts, otherwise market power is merely transferred from Hydro Tasmania to existing retailers.

The key risk to the effectiveness of this reform path is whether new participants have confidence that the contract auction will enable them to manage wholesale energy market risk through contract arrangements. Elsewhere in the NEM, retailers have the option to manage wholesale energy market risk through contracts and accept a level of exposure to the spot market. In Tasmania, Hydro Tasmania’s latent market power makes this strategy more risky and it has not proven to be commercially attractive to date.

\textsuperscript{232} For example, based on the illustrative example in Table X, any units of the 500 made available for year 3 that did not reach the reserve price in the Year 0 auction would be rolled into the Year 1 auction for Year 3 contracts.
What volume of contracts should be auctioned?

The volume of contracts to be auctioned would be specified in advance, and would apply regardless of any decisions that Hydro Tasmania makes to enter into bilateral contracts. Hydro Tasmania would be responsible for managing its bilateral negotiations in the context of the auction requirement.

It is anticipated that Hydro Tasmania would be required to make available a large proportion of its contracting capability through the auction process. Where Hydro Tasmania contracts directly with large industrial customers, for example the existing 4 MI customers233, these contracts would be outside the auction process and the volume that is contracted to those customers excluded from auction volumes.

As the size of the contestable market increases with the implementation of full retail contestability, the volume of contract cover made available through the auction would increase.

To provide confidence to market participants that the auction will present an opportunity to meet their hedging objectives over time, contracts for a number of future periods should be available at each auction. For instance, quarterly swap contracts could be offered at each auction for each of the next three years. This would enable mass market retailers to establish an appropriate ‘forward book’ for participating in the Tasmanian market.

Contracts for each period would be available at multiple opportunities, with the volume for each period increasing as that period draws closer. The reserve price would be reset at each annual auction, to reflect the prevailing opportunity value of water.

An example is provided in the following table, based on an illustrative contract requirement of 250 GWh for three periods.

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233 Rio Tinto Alcan, Norske Skog, Nystar and BHP TEMCO.
Table 17.1: Illustrative auction framework

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</tbody>
</table>

Note: The table is illustrative. Period 1 does not refer to the first year in which the auction is implemented, rather it is illustrative period. Contracts for period 3 would be made available in period’s 0, 1 and 2, providing three opportunities for market participants to secure contract cover.

To the extent that bilateral contracts have been entered into prior to the auction, it is likely that the demand for contracts through the auction process will be lower. This should reduce the risk of Hydro Tasmania being ‘over contracted’ through the combination of bilateral negotiations and auction arrangements. Ultimately, the auction itself is unlikely to significantly increase demand for contracts. To the extent that Hydro Tasmania currently is prepared to meet all contract demand in Tasmania subject to its available output, the auction is unlikely to result in Hydro Tasmania having to be more contracted than currently.²³⁴

Requiring Hydro Tasmania to remain contracted to a prescribed level and foregoing the auction process has been considered by the Panel and dismissed on the basis that, depending on demand, Hydro Tasmania could be required to contract at less than the opportunity value of its water and be subject to commercial disadvantage. The reserve pricing arrangements in the auction framework has been proposed to address this risk.

An alternative approach is to utilise the auction as a means of getting to market any contracting capability that Hydro Tasmania has not utilised through bilateral negotiation. Under this approach, a total minimum contract level for Hydro Tasmania would be established in legislation, and Hydro Tasmania would be free to contract as much of that capability bilaterally as it wished. The auction arrangement would effectively be a ‘fallback’ mechanism to put the residual contracting capability to the market. The reserve pricing arrangement would still apply and protect Hydro Tasmania’s value.

²³⁴ Hydro Tasmania has submitted that it stands ready to contract with all comers – “...any retailer or wholesale customer who wishes to obtain a contract can secure one and the volume and profile of the contract will correspond to the retailer’s or customer’s request.” Hydro Tasmania’s submission to the Panel’s Issues Paper page 18.
The Panel considers this approach problematic, as it may be difficult to define the ‘level’ of contracting that has been committed under bilateral negotiations (e.g. defining volume under load following hedges and under swaptions), and therefore determine auction levels. Moreover, it would provide no signals for retailers of the upcoming volumes that might be available through the auction arrangement. On the other hand, it could provide a strong incentive for Hydro Tasmania to contract on sharp commercial terms bilaterally if the risk is the potential of lower value outcomes through the auction.

What contracts should be auctioned?

It is proposed that the auction will include financial products based on standard swap and cap contracts. Depending on retailers’ willingness to take spot market exposure in Tasmania, these standard contracts may not provide sufficient flexibility for retailers to manage wholesale market risk. To ensure retail entry, it may be necessary to offer contracts that provide greater risk management for retailers, including, for instance, load following hedges. In this case, the risk is that there will be no interest in the Tasmanian market by retailers achieved by the auction process, and the auction will be ineffective and costly.

Frequency of auctions

As with the type of contracts being offered, the frequency of auctions will be important to the success of this reform path. If auctions are held too infrequently retailers may be unable to match their contract positions with their retail book, and be materially over or under contracted. Given the risks in the wholesale market in Tasmania, this could still pose an entry barrier. On the other hand, the auction process will involve costs, and conducting them too frequently will add unnecessarily to participant’s costs.235

That an auction process may result in participants being unable to refine their contract position to closely match their retail load is a recognised trade-off in pursuing this reform path. Nonetheless, the Panel is of the view that to the extent that this presents a potential barrier to entry for market participants, that barrier is materially lower than that arising from the current market architecture.236 In particular, retailers would remain able to negotiate bilaterally throughout the year, either with Hydro Tasmania or with other participants (including other retailers).

The Panel is seeking stakeholder comments on the appropriate frequency of auctions.

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235 While the development and design of the auction process will involve material up-front cost, the ongoing cost of each auction would be relatively small.

236 This is a good example of the difficulties arising from assessing these options against a ‘competitive ideal’ that is not deliverable in Tasmania.
Setting a reserve price

A reserve price would be set for each of the standard products, and reset at each auction.

Hydro Tasmania’s contract pricing policy is to set its contract prices by reference to Victorian contract prices within an internally determined upper and lower bound that varies over time, particularly with water value.237

In order for the reserve price to be linked to Hydro Tasmania’s opportunity cost of entering into contracts, the reserve price would need to be based on water value (likely using a similar methodology to that which Hydro Tasmania currently uses to determine the opportunity value of its water) and determined independently of Hydro Tasmania and the Tasmanian Government.

The reserve price would be withheld from bidders; however, the framework and methodology for calculating the reserve price would be revealed to allow bidders to gain some confidence in the process.

Setting the reserve price is critical to this reform path. If the reserve price is too high then retail contracts written on the back of the wholesale prices obtained from the auction will be too high, or the auction will not clear and Hydro Tasmania could have an increased spot market exposure and the commercial driver to engage in strategic behaviour. If the reserve price is too low then there is potential for a value transfer from Hydro Tasmania to the purchaser, impacting negatively on Hydro Tasmania’s profitability.

Who would oversee the auctions?

The auction would need to be undertaken by a party independent of both Hydro Tasmania and the Tasmanian Government to provide confidence in the integrity of the process. The TER could undertake the role, sourcing appropriate expertise as required to advise on the reserve price and establish the required infrastructure and IT systems. The funding of the auction would be from auction proceeds.

237 These bounds have not been disclosed for commercial confidentiality reasons.
17.2. Reform Path 2 - Create competition in the trading of energy produced by Hydro Tasmania

The potential to physically disaggregate Hydro Tasmania to form a number of competing physical generators has been canvassed in the past. A central argument for the retention of Hydro Tasmania as a single integrated generator is water management. The primary argument is that physical optimisation of water use requires integrated planning and decision making regarding which catchment and generation assets are used to meet the desired level of dispatch from the hydro system.

There may be mechanisms that would provide for effective water management if there was a split in the physical assets. However, the Panel considers that investigation of physical separation is unnecessary: the central issue is to create competition in the trading of the energy capability of the hydro system, rather than competition in the management of physical assets. Retaining the physical operations and water management arrangements within a single entity need not prevent the physical system from being used to support more competitive trading arrangements.

The reform path the Panel is proposing would introduce competition into trading decisions. It would do this by creating a number of independent trading entities, each with rights to trade certain amounts of Hydro Tasmania’s available energy output. Hydro Tasmania would be responsible for determining how best to operate the generation system to provide output consistent with the trading decisions of these entities. Under this structure, all responsibility for physical operation of the generation system would remain with Hydro Tasmania, allowing Hydro Tasmania to retain its integrated planning and decision making regarding which catchment and power schemes are used to meet the desired level of output from the hydro system.

The establishment of several trading entities that would trade output of the hydro-system into the market would provide competition and choice in the wholesale market, with the intention of removing the latent market power that exists under the current arrangements.

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238 For example, physical disaggregation of the hydro-generation system was proposed in the ‘National Competition Policy Review of the Structure of the Hydro Electric Corporation’s Generation & System Control Function’s’ (the Garlick Report), May 1999.

239 Recognising that they may involve material transaction costs.

240 A model similar to this was proposed in the Structural Review of Hydro Tasmania by Peter Garlick in 1997. That proposal entailed the establishment of three trading entities that would have dispatch rights over parts of the hydro system. That linkage between trading rights and physical aspects of the system was perceived to have the effect of removing the ability of the physical generator to optimise water usage. The Panel’s proposal does not have that linkage.
This reform path need not be interpreted as a first step toward privatisation of Hydro Tasmania. Irrespective of the private or public ownership of the energy traders, the hydro-generation assets themselves are protected from sale by legislation, the operation of the hydro-generation system and management of water resources remains with Hydro Tasmania and under government ownership on behalf of the Tasmanian community.

The Panel notes some similarities between reform path 2 and the recent restructuring of the New South Wales (NSW) wholesale energy market, where the NSW Government was constrained to maintain government ownership of its generation assets. To achieve that outcome while exiting the risky trading function, the government adopted a generation-trader model under which if offered the trading rights to the output of government owned generation assets to the market. A Special Commission of Inquiry found that while a generator-trader model was not the ideal way of opening the wholesale energy market to competition, under the circumstances it was the best option available for the necessary reform to the electricity sector.

17.2.1. Objectives

The primary objectives of this reform path are to:

- develop competition in the Tasmanian wholesale energy market by establishing a number of independent energy trading entities that have the capability of bidding and contracting at the wholesale level;

- preserve the integrated operation and water management of Hydro Tasmania’s system;

- ensure that the energy traders have incentives to manage hydrological risk and that Hydro Tasmania retains the ‘tools’ to manage hydrological risk; and

- provide greater confidence to market participants – a structural solution is likely to be more durable than a regulatory approach.

The advantage of this reform path is that it delivers a structural change to overcome the key shortcomings in the current architecture. As such, it avoids the need for ongoing regulation of Hydro Tasmania’s behaviour in the energy market. In general, reform of structural arrangements that remove the need for behavioural restrictions provide better outcomes that regulatory approaches that focus on addressing market behaviour.

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241 By comparison, both Victoria and South Australia had disposed of its generation assets through market sale or long-term leases to the private sector.


243 Continued regulation of the FCAS market is likely.
17.2.2. Key features

Figure 17.1 depicts the likely structure of the Tasmanian wholesale energy market under this reform path.

**Figure 17.1 – Structure of the Tasmanian Market**

Hydro Tasmania would be retained as an integrated single hydro generator. Its focus would be on operating and maintaining the hydro system in order to maximise operational efficiency, optimise water use and minimise operational risk. Hydro Tasmania’s incentives to do so would be driven by its obligations to the traders to meet the trader’s contractual rights to capacity and energy.

The traders, which could be government-owned, would have specified rights to dispatch Hydro Tasmania’s generation capacity. The rights of the traders would be rights to ‘virtual’ capacity and energy, rather than rights to physical assets of Hydro Tasmania’s. This distinction is important as it goes to preserving the efficiencies inherent in Hydro Tasmania’s existing generation business: for a given set of dispatch offers by the traders, Hydro Tasmania can decide how best to operate its generation plant to provide the required energy.

In much the same way that Hydro Tasmania’s trading team currently makes decisions about how to dispatch the capacity and energy of its hydro systems within the constraints of the system, the energy traders would individually make commercial decisions about how to dispatch their virtual capacity and energy. The key difference is that there would be a diversity of decision making and the ability for other market participants to choose contracting counterparties.
The traders would each have contractual rights to dispatch Hydro Tasmania’s output within defined limits. These rights would be based on the physical characteristics of Hydro Tasmania’s generation plant and its available water storages. To minimise the potential for inefficient water management, the contractual rights of traders would reflect discretionary and non-discretionary inflows and storage:

- The non-discretionary allocation would reflect Hydro Tasmania’s run-of-river and intermediate storages.
- The traders would be able to choose the timing of the dispatch of the discretionary allocation, and would be able to ‘bank’ the unused discretionary allocation (i.e. store water). However, the traders’ ability to do so would be limited by the physical constraints faced by Hydro Tasmania (in particular, the size of its storages). Storing between years would be possible but would be reflective of the physical inflows and storage capability.

The traders would have the right to specify dispatch offers for Hydro Tasmania’s generation plant, and receive the spot revenues associated with these dispatch offers. Because the traders will ultimately receive spot revenues, they will also be in a position to offer hedging contracts to other market participants.

To assist with ensuring an effective plant dispatch and use of water resources, Hydro Tasmania would continue to manage individual hydro-generator bids into the NEM to achieve the dispatch instructions made by the traders. Hydro Tasmania would retain responsibility to dispatch Frequency Control Ancillary Service (FCAS) to ensure the energy dispatch and that the value of Basslink is maximised. This may require FCAS services to continue to be regulated.

17.2.3. Risks and Implementation Issues

Risk allocation

Under this reform path, the traders would accept long-term hydrological risk because their right to dispatch the capacity of Hydro Tasmania would be subject to water inflows. The traders would also accept and have to manage price risk, because they would be exposed to both spot prices and contract prices.

Hydro Tasmania would principally carry operational risk through its responsibility for ensuring that its assets are able to operate in order to meet the dispatch rights of the traders.
Duration of trading rights

In order for this reform path to achieve its objectives of developing competition and providing greater confidence to market participants, it is important that other stakeholders view the reform path as durable. This suggests that the contractual arrangements between Hydro Tasmania and the traders should be long term; ideally, consistent with the remaining economic life of Hydro Tasmania’s power stations.

Long term contracts will also be important in order to establish and maintain effective trading entities. In particular, in order to attract and retain staff, and in order for the trading entity to have ongoing incentives to develop its business, it will be important that the trading entity’s trading rights are long-term.

Financial arrangements between Hydro Tasmania and the Traders

In return for their rights to trade Hydro Tasmania’s generation plant, the traders would be required to make contract payments to Hydro Tasmania on a predetermined basis. The intention would be that the contract payments would cover the forecast efficient costs faced by Hydro Tasmania in operating and maintaining its assets and Hydro Tasmania’s Basslink related costs. In order to preserve the incentives for efficient dispatch decisions, forecast fixed costs would be reflected as fixed contract payments and forecast variable costs would be reflected as variable contract payments.

Establishing the nature and level of payments for the duration of the long term contract would entail forecasting efficient operating and maintenance costs (including asset reinvestment costs) for the duration of the trading rights. This would require preparation of asset management programs for the duration of the contracts (noting that a 10-year asset maintenance plan is currently developed by Hydro Tasmania) and costing asset management programs (subject to defined cost escalation). This would also expose the counterparties to the risk that the contract payments diverge from costs over the duration of the contract.

Alternatively, the contract payments could be subject to contract re-openers on a periodic basis. Such price re-openers are relatively common in long-term contracts. However, while price re-openers do lessen the risk associated with forecasting error, they also increase the scope for contractual disputes during contract resets. Indeed, it is not uncommon for contract re-openers to result in disputes between the counterparties that need to be resolved through arbitration or the courts.
Dispatch Rights

There would be some complexity in the specification of the dispatch rights of the traders. The objective would be to ensure that the rights that the traders have reflect the physical characteristics of Hydro Tasmania’s assets. Key physical constraints would include:

- the capacity of Hydro Tasmania’s generation assets;
- the rate of waterflow required to generation electricity;
- the capacity of Hydro Tasmania’s water storages;
- the rate of inflows into Hydro Tasmania’s water storages; and
- the quantity of water that Hydro Tasmania is required to release from storages for reasons other than the generation of electricity.

Appropriately specifying the rights that the traders have would ensure that Hydro Tasmania is able to meet its contractual obligations to the traders, as long as Hydro Tasmania continued to operate its assets efficiently.

In order to ensure that the traders faced incentives to dispatch plant efficiently, it would be important that the traders faced the risk of variability in water inflows. This implies that the traders would likely receive a specified allocation of total water inflows. These arrangements would clearly require a high degree of information flow between Hydro Tasmania and the traders, particularly in regard to water inflows.

Operational Efficiency

It is possible that the trader model could result in some inefficiencies in the use of water resources. This would arise to the extent that the physical characteristics of Hydro Tasmania’s assets cannot be perfectly reflected through a set of contractual arrangements. Any gap between contractual rights and physical characteristics could lead to a potential loss of efficiency in dispatch decision.

Without commencing work on the detailed contractual arrangements that would be required under this reform option, it is difficult to estimate the extent to which there would be a gap between contractual rights and physical characteristics. Where a gap does exist, it is likely that the contractual rights of the traders will be set conservatively; otherwise Hydro Tasmania will be exposed to the risk that it is unable to comply with its contractual obligations. While this might lead to some loss of efficiency in dispatch decision, it is important to recognise that this will most likely lead to the accumulation of water in Hydro Tasmania’s storages. This can be managed through some form of true-up of stored water (although this would reduce Hydro Tasmania’s incentive to operate efficiently). Alternatively, arrangements can be left to negotiation: since Hydro Tasmania will not be able to trade this stored water itself, the contractual arrangements are likely to create an incentive for negotiation between Hydro Tasmania and the traders for the use of this stored water.
Allocation of Major Industrial contracts and procurement of Basslink SPS services

A key matter to be resolved in implementing this reform path is how the existing MI contracts would be allocated to the traders. If implemented, this reform option would require that existing contracts are novated, or the terms of the contract are passed through, to the traders. With multiple traders, decisions will have to be made about the appropriate allocation of these contracts to individual traders, and whether large contracts need to be allocated to a number of separate traders. Contract counterparties may have concerns about this process, particularly a novation, due to the potential for increased counterparty risk posed by the traders. It is likely that the Government, one way or another, will have to continue to back these contracts.

A further issue to be resolved with these customers is the Basslink System Protection Scheme (SPS) arrangements within the existing contracts. The SPS ‘value’ may need to be separated from the energy price and allocated to Hydro Tasmania to allow it to manage Basslink contractual and operational matters. Alternatively the traders could be required to negotiate access to the SPS benefit despite the possibility that it may not need or utilise Basslink SPS for pricing these contracts.

The optimal number of traders

The key objective of this reform path is to create competition in the wholesale energy market, while ensuring the efficient operation of the hydro-generation system. While Figure 17.1 illustrates the arrangement with three traders, the actual number of traders required to ensure a competitive outcome may vary from this. For example, modelling undertaken for the Panel by Frontier Economics indicates that three entities, two traders, in conjunction with independent operation of the TVPS would provide effective competition.

17.3. Reform Path 3 - Creating competition by combining the Victorian and Tasmanian Regions

The third reform path is to expose Hydro Tasmania to increased competition by removing the regional boundary between the Victorian and Tasmanian NEM regions to create a combined region with a single regional reference price (RRP) determined at the current Victorian regional reference node (RRN)(a single Vic-Tas region).
17.3.1. Objective

By removing spot price differences between Victoria and Tasmania, this reform path would:

1. Largely remove Hydro Tasmania’s ability to exercise market power in the spot market.

2. Result in the elimination of basis risk in contracting between Victorian based generators and Tasmanian retailers. This would substantially increase competition between Victorian and Tasmanian generators in wholesale contract trading and increase the options for managing wholesale market risk available to retailers when operating in Tasmania.

Under this approach, Tasmania would retain its status as a separate participating jurisdiction, and retain controls of the regulatory arrangements pertaining to the retail sector (such as the requirement to obtain a retail licence in Tasmania). The primary change in creating a single Vic-Tas region in the NEM spot market would be establishing a single regional reference price (spot price) for the combined region in place of the separate regional reference prices currently applying in the two regions.

17.3.2. Key Features

The Victorian market is generally recognised as being highly competitive for both retail and wholesale markets. The change to a single Vic-Tas region would immediately facilitate similar competitive dynamics to underpin wholesale trading in relation to Tasmanian load. While Hydro Tasmania would still dominate the installed capacity in Tasmania, this would not have a direct bearing on wholesale energy prices, as prices would be determined by the supply and demand conditions at the current Victorian RRN.

Since this reform option would expose Hydro Tasmania to price competition on contracting from multiple generators within the new region, there would be no need to apply any additional regulation of Hydro Tasmania’s contracting behaviour, or to restructure Hydro Tasmania’s energy trading operations. Rather than trying to create incentives for, or obligations on, Hydro Tasmania to behave competitively in the wholesale market in the Tasmanian region of the NEM, creating a single Vic-Tas region would consistently expose Hydro Tasmania to competition in a much larger market.

However, one issue that would arise under this option would be Hydro Tasmania’s lack of incentives to generate at times of tight supply-demand conditions in Tasmania and low demand (and hence spot price) conditions in Victoria. This issue is discussed further below.

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In 2008 the AEMC undertook a review of the Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria. This review concluded that the process of effective competition in Victoria protects consumers against the exercise of market power. As a result, Victoria is the only NEM jurisdiction to remove retail price regulation.
Under this reform path, Hydro Tasmania would retain current operational and bidding control of its assets. It is likely that the way in which Hydro Tasmania values the opportunity cost of its water will not change materially as it will be benchmarked to the Vic-Tas region single spot price, which in general will be similar to the Victorian price that Hydro Tasmania currently uses for this purpose.

A single Vic-Tas region would require either Basslink to be converted to a regulated interconnector, or a NEM Rule change to create a new type of intraregional transmission asset. The existing Basslink Service Agreement would most likely have to be replaced with alternative commercial arrangements, as its core underpinning of swapping interregional revenues for the facility is predicated on there being periodic price separation between the two existing NEM regions.

A single Vic-Tas region would remove the current barrier to participation in the retail market in Tasmania that wholesale market risk management presents and create alternative risk management opportunities by comparison with the current arrangements.

Given that a single Vic-Tas region would require a regional boundary change, there would be no real prospect of returning to a separate Tasmanian region. For this reason, new entrant retailers and new entrant major loads would have confidence that competitive benefits would be durable.

For this reform path to progress would require broad stakeholder support. Of the reform options considered, the single region is the most complex in terms of the number of stakeholders involved to achieve agreement and resolution of operational and technical issues. Unlike reform paths 1 and 2, this approach cannot be implemented on the Tasmanian Government’s own initiative. These issues are discussed further below.

17.3.3. Risks and Implementation Issues

Energy Dispatch Issues in Tasmania

This option could create some complications for the operation of the NEM spot market due to changes in Hydro Tasmania’s bidding incentives.

As there would be no change in the physical characteristics of Basslink under this proposal, the Basslink interconnector, which would become an element of the intraregional transmission network, will still constrain in both northwards and southwards directions. Under the current arrangements, this provides signals to market participants regarding the relative value of electricity in each region.

For example, when Victorian prices are low (e.g. overnight when there is ample capacity available to meet demand), Basslink will typically flow south, as it provides a supply option at lower cost than that in Tasmania. Once the link is constrained, and Tasmanian demand is not met, Tasmanian-based generators can signal the costs of their production and prices will rise to meet those bids.
If, following regional boundary change, Tasmanian generators only received the Victorian price in the same circumstances, they may not be willing to offer their output to be dispatched. The market operator, AEMO, will be required to direct some Tasmanian generation to be dispatched to meet Tasmanian demand.

Directions are normally issued for unusual events, not events that are expected to occur frequently. Therefore, AEMO may request Transend to negotiate a contract for a minimum supply service in these sorts of situations (i.e. Network Support Agreement (NSA)).

Alternatively, if Transend did not do this, AEMO may seek to negotiate such an agreement itself under the new ‘last resort’ provisions for network support and control ancillary services (NSCAS) acquisition in the Rules.

In either case, such an agreement might not be efficient as either more service could be contracted than required, resulting in higher prices, or not enough might be contracted, requiring a further direction from AEMO to maintain supply to meet demand.

The manner in which payments under any NSA agreements are funded would be governed by the Rules. The Rules provide that NSCAS procured by TNSPs are recovered from their customers under the chapter 6A provisions governing the regulation of transmission network services. This may or may not involve a partial allocation of costs to Victorian customers. However, NSCAS procured by AEMO are highly likely to be recoverable from customers across the broader Vic-Tas region.245

Mismatch on Supply-Demand Drivers and Spot and Contract Pricing

As the demand profiles of the Victorian and Tasmanian systems are very different, there will be times that the combination of a single regional price and constrained flows on Basslink will lead to inefficient spot pricing outcomes. For example:

- When there is low demand within the combined region there will tend to be low spot prices. However, within Tasmania, local demand may be higher during these periods (e.g. winter peak demand). Under the Vic-Tas option, there will be no local price signal in the spot market reflecting these differences.

- When there is high demand within the combined region there will tend to be higher spot prices. However, within Tasmania, local demand may be lower during these periods. Once again, there will be no local price signal reflecting these differences.

The consequence of the different demand profiles of the Tasmanian and Victorian regions, which currently underpin the arbitrage opportunity provided by Basslink, is that under a single Vic-Tas region, Tasmania will tend to see lower prices in the winter (when Tasmanian demand is higher than Victorian demand) and higher prices in the summer (when Tasmanian demand is lower than Victorian demand).

245 The Rules defining and governing NSCAS are due to come into force on 5 April 2012.
This sends the wrong spot price signals to the market. The extent to which this would harm allocative efficiency would depend on the extent to which the option had a material effect on the structure and level of retail tariffs in Tasmania. If retail tariffs were not materially affected, allocative efficiency would not be compromised by this option. To the extent this option led to a material distortion of Tasmanian retail tariffs, this reform path would only be considered meritorious if the dynamic efficiency benefits of a more competitive retail market outweighed the loss in allocative efficiency caused by less locationally-refined retail tariffs.

**Transmission Constraints**

The location of investment in new generation is influenced by wholesale market conditions including the prevalence of transmission congestion and the extent to which such congestion is priced in the spot market. For example, new generation will have a strong preference to locate on the ‘demand side’ of a transmission constraint so as to avoid either relatively low prices (if the congestion is priced) or dispatch risk (if it is not).

Under the Vic-Tas option, this is likely to mean that price signals for new generation investment in the Tasmanian sub-region at times of southward constraints on Basslink are likely to be muted as compared to under the present regional structure. However, price signals for investment in Tasmania under the option are likely to be enhanced at times of northward flows and constraints on Basslink.

The net effect on generation investment incentives in Tasmania may be neutral. In any case, the Panel notes that the requirement for additional supply in Tasmania is estimated to be past the mid-2020s, so this is unlikely to pose a material issue for some time. In addition, as the NEM continues to evolve, transmission congestion pricing arrangements are likely to change, which may resolve any issue prior to Tasmania needing new generation capacity.

**FCAS Dispatch Issues in Tasmania**

FCAS is currently managed in the NEM by AEMO on a regional basis. Given technical limitations in the Tasmanian generation sector, there are currently constraints on how FCAS is sourced (e.g. when Basslink is FCAS constrained, Hydro Tasmania is the only source of FCAS in the Tasmanian market).

These limitations would most likely require FCAS to be managed within the Tasmanian sub-region if a single Vic-Tas region were implemented. Sub-regional management of FCAS is currently not contemplated under the National Electricity Rules.

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246 See the AEMC’s ‘First Interim Report - Transmission Frameworks Review’ dated 17 December 2011.
Potentially this could be resolved through an NSA to ensure minimum FCAS is available (although Hydro Tasmania is the predominant provider and the regulation of the service would probably need to continue). An alternative would be to revert FCAS to a contractual basis and remove the co-optimisation of the FCAS and energy markets. This would more likely have to be done on a whole-of-NEM basis rather than just for the Vic-Tas single region.

**Treatment of Marginal Loss Factors**

As electricity flows through the transmission and distribution networks from a generator to a load, energy is lost. These energy losses have to be factored into energy production to ensure the delivery of adequate supply to meet prevailing demand and to maintain the power system in balance. The impact of energy losses on spot prices are represented by marginal loss factors.

In general, the further generation is away (in an electrical sense) from the location of load, the higher the marginal loss factor. Within a region, the location of generation is calculated relative to the regional reference node (RRN). Under a single Vic-Tas region, the RRN would be Thomastown in Victoria. This would place Tasmanian electricity customers further away from the current Tasmanian RRN at George Town. This may increase the marginal loss factor cost to Tasmanian customers.

At the same time, under the current NEM rules, Basslink has a dynamic loss factor that changes with its direction and flow, and losses over the link are effectively funded by Hydro Tasmania as it acquires the interregional revenues, which are net of losses. Under the single region approach and existing NEM rules, Basslink would have a static loss factor, which could change significantly through the annual averaging process, depending on the nature of flows over the preceding year. This could lead to greater annual variation in the marginal loss factors faced by Tasmanian participants – both customers and generators.

**Re-writing wholesale contracts**

The removal of the Tasmanian region would mean that current wholesale market contracts would no longer be valid as they are settled against the Tasmanian RRN. All wholesale market contracts in Tasmania would require renegotiation to reference the combined region reference price.

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247 AEMO estimates that these losses are equivalent to approximately 10 per cent of the total electricity transported between power stations and market customers (refer AEMO website).
Conversion of Basslink

Without a NEM rule change that provides for the concept of an intraregional Market Network Service Provider (MNSP), the Vic-Tas region would require the conversion of Basslink from its current status as an inter-regional MNSP to an element of regulated transmission network within the single region. The NEM rules provide for such conversions, and there have been two precedents, although these did not arise from a change in NEM boundaries.

A potential implication of a regulated Basslink is how to continue the current SPS to maximise the flow capability of the network elements. This issue arises because the commercial drivers that currently facilitate SPS provision would not be replicated under the regulated model.

The commercial arrangements under which Basslink currently operates provide strong availability incentives for Basslink. The same incentives would not apply under the regulated model without resolution of a complex negotiation process involving Hydro Tasmania, major Tasmanian loads and Transend.

Complexity in delivery

Implementing this reform path would require considerable work over a long timeframe (perhaps 4-5 years). Given the number of decision makers involved, it would require coordinated agreement. For example, it would require:

- Submission of a complete region change application under chapter 2A of the Rules by a registered participant (or AEMO) to the AEMC and approval of that application by the AEMC.
- Substantial work by AEMO and the AEMC would need to receive and approve the rule change proposal to implement a boundary change and to change Basslink to a regulated interconnector or alternatively to approve its status as an intra-regional MNSP.
- Converting Basslink to a regulated interconnector is not a decision that can be made by the Tasmanian Government. Rather, it is a decision for its owner, City Spring Infrastructure Trust. It would also require the agreement of Hydro Tasmania as the counterparty to the existing commercial agreement. A change in Basslink’s status is likely to involve considerable commercial negotiations between City Spring Infrastructure Trust and Hydro Tasmania (and possibly the Tasmanian Government) to determine what is the current ‘value’ of Basslink, how the change relates to Basslink value under the regulated transmission arrangements and how each party would be ‘kept whole’ from any change. Having reached that agreement, any transition from an MNPS to a regulated link would be complex and take some time to implement.

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248 These were MurrayLink between Victoria and South Australia and DirectLink between New South Wales and Queensland.
Existing wholesale energy market contracts would need to be renegotiated.

### 17.4. Impact of Reform Paths on Financial Performance and Prices

As discussed above, the principal driver for reforms in the market-based sectors of the Tasmanian ESI is to promote competition and to ensure that efficient prices are routinely delivered.

#### 17.4.1. Price outcomes

Analysis undertaken for the Panel indicates that, as long as Hydro Tasmania remains highly contracted, there is unlikely to be any material change to wholesale energy prices arising from reform paths 1 and 2, relative to those prices that are expected under the status quo. As discussed in Chapter 9, this is because Hydro Tasmania’s currently highly contracted position results in spot prices consistent with prices modelled in a competitive market scenario.

Decisions taken by Hydro Tasmania to change its level of contracting in the future could lead to a significantly different outcome for Tasmanian wholesale market prices. Hydro Tasmania’s discretion to vary its contract position and uncertainty about its incentives to take strategic positions in the spot market is the principal reason for retailers’ concerns about the high risk of trading in the Tasmanian NEM region. These reform paths would address that concern by either regulating Hydro Tasmania’s contract behaviour or by exposing Hydro Tasmania’s energy trading to effective competition in both the spot and contract markets.

Tasmanian spot prices under reform path 3 are anticipated to be higher in the short-to-medium term, not due to the reform option itself, but because modelling indicates that prices in the short to medium term are likely to be higher in Victoria than in Tasmania. This is partly a result of the current high levels of water in Hydro Tasmania’s storages.

Of course, as discussed in Chapter 11, while spot prices outcomes are expected to be similar under the reform paths to those under the status quo, the reform paths are expected to offer improved competitive outcomes with the potential for significant dynamic efficiency gains in the medium to longer term as discussed in Chapter 11.

#### Financial outcomes for Hydro Tasmania and the TVPS

Similarly, financial modelling of the financial impacts of the reforms on Hydro Tasmania and the TVPS indicates that, of themselves, reform paths 1 and 2 do not result in material change to the projected financial performance of Hydro Tasmania and the TVPS as wholesale energy prices are expected to move consistently with price projections that are predicated on Hydro Tasmania retaining a very high degree of contract cover.
There will be additional costs associated with the implementation of each of the reform paths that will need to be allocated within the market. The regulatory oversight of Hydro Tasmania’s contract position is envisaged to cost around $0.5 million per annum, likely to be funded by Hydro Tasmania through proceeds from the auction process.

To provide an indication of broad order of magnitude of the costs connected with the trader model, the Panel has estimated the establishment cost of individual traders to be around $1 million each, with annual operating costs of around $4 million each. These costs will be funded from market revenues of each of the traders.

The costs of implementing the Vic-Tas region reform path have not been quantified. However, they are likely to be significant given the numerous processes that would need to be settled in relation to: submission and acceptance of a region boundary change proposal, potential regulation of Basslink, renegotiation of the SPS and negotiation of a possible NSA between Hydro Tasmania and Transend or AEMO to manage dispatch at times of southward constraints on Basslink.

In the event Basslink was regulated, Tasmanian customers (and Victorian customers to some extent) would fund the regulated revenue allowance through applicable charges. Experience elsewhere in the NEM has shown that the transition from MNSP to regulated link has resulted in lower market revenue and asset values for the interconnector than those that applied prior to conversion. To the extent that this is the case with Basslink, and assuming that City Spring would require being kept commercially whole, the, additional cost will need to be borne by one or more parties, possibly Hydro Tasmania as the current counterparty.
18. Development of effective competition in the Tasmanian retail market

Creating the structural basis for effective choice in the retail market to support the introduction of full retail contestability (FRC) is a key issue for the Energy Strategy.

A necessary pre-condition for effective retail competition to be delivered in Tasmania is effective reform of the Tasmanian wholesale electricity sector. On the basis that this reform is undertaken, there are three options for the future of the Tasmanian retail market:

- Maintain the status-quo where retail contestability is halted at the current tranche 5a and small business and residential customers remain non-contestable;
- FRC is declared and development of retail competition is left to emerge ‘organically’, as was done in the previous contestability tranches (referred to as ‘organic retail competition’); and
- FRC is declared and the Tasmanian Government proactively introduces new retailers into Tasmania by splitting Aurora Energy’s retail business into smaller retail parcels and selling those parcels through a competitive process (referred to as ‘proactive retail competition’).

The Panel considers that the reform path of proactive retail competition offers the advantages of:

- Delivering a number of new retail market participants in Tasmania in a rapid timeframe. This would accelerate the achievement of the objectives of customer choice and retail competition, relative to the alternatives.
- Decreasing the State’s financial exposure to the electricity market, and achieving the exit of public sector capital from the risky retail sector of the electricity market.
Maximising the value of the customer base for the benefit of the Tasmanian community and protecting the community's financial value currently in Aurora Energy from FRC. Under the organic retail competition option, the value of Aurora Energy is likely to diminish over time. Analysis undertaken by the Panel indicates that the value of Aurora Energy's retail business is likely to be materially exposed to modest levels of loss of market share in Tasmania, reflecting its diseconomies of scale. The Panel has questioned Aurora Energy on its analysis of the consequences of the entry of new retailers in Tasmania. Aurora Energy's own analysis indicates similar results to the Panel's work. The details of this analysis have not been provided due to commercial confidentiality reasons.

Reform of the Tasmanian retail sector could be implemented under each of the three wholesale energy market reform paths. Allowing retail competition to develop organically over time is not well matched to reform paths 2 and 3 - given the nature of the fundamental reshaping of the wholesale market proposed. To commit to the level of reform without proactively refining the retail sector would be a missed opportunity.

18.1. Proactive retail competition - key features and issues

Aurora Energy's existing retail business would be restructured into three broadly similar parcels (in terms of volume and value) and each would be offered to the market through a competitive tender process.

Each retail parcel would have a combination of:

- a share of Aurora Energy’s contestable customer retail book; and
- a share of the current non-contestable customer base.

There are around 180,000 residential customers and 30,000 small business customers who are currently non-contestable. A three-way split of the portfolio would create a customer base of around 70,000 non-contestable customers per parcel, plus Aurora Energy’s share of around 5,000 contestable customers. Based on discussions with national retailers, the Panel believes this would represent an attractive commercial offering, provided that the existing concerns regarding wholesale market risk are adequately addressed.

Consideration would need to be given to how Aurora Energy's national retail business assets are put to the market. Similarly, Aurora Energy has around 40,000 retail customers in Tasmania utilising its PAYG product. It is likely that the PAYG business would be sold as a single block (complete with the systems required to operate the business). It could be acquired by one of the successful bidders for the customer parcels, but could be acquired by a party that was not a participant in the bidding process or an unsuccessful bidder.
A key issue for purchasers would be the duration for which they would have certainty regarding customer retention, and the wholesale arrangements that would back the retail parcels.

A possible model is that retailers would acquire a retail parcel backed with wholesale contracts. Following an initial settling-in period (say six months), FRC would commence, opening the entire Tasmanian customer base to retail competition. At this time, customers could choose between any of the retailers who had acquired Aurora Energy’s customer base, or any new entrant retailer who wished to participate in the market. This is outlined in table 18.1.

**Table 18.1 - Wholesale energy arrangements to back retail parcels**

<table>
<thead>
<tr>
<th>Customer groups</th>
<th>Allocation to parcel</th>
<th>When at market</th>
<th>Wholesale arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Currently non-contestable customers</td>
<td>Assigned to retail parcel.</td>
<td>Remain non-contestable for settling-in period. At end of initial period, FRC activated and customers free to switch retailers. These customers could elect to continue to pay regulated tariffs or could enter a market based contract.</td>
<td>Aurora Energy’s current wholesale book packaged and re-assigned to buyers to broadly reflect retail contract position. As these legacy contracts expire, retailers would rely on effective wholesale market reform to access contracts.</td>
</tr>
<tr>
<td>Contestable customers</td>
<td>Allocated to retail parcel and contract with Aurora Energy legally assigned to successful purchaser of retail parcel.</td>
<td>Free to switch retailers once existing retail contract ends.</td>
<td>Aurora Energy’s current wholesale book packaged and re-assigned to buyers to broadly reflect retail contract position. As these legacy contracts expire, retailers would rely on effective wholesale market reform to access contracts. If back-to-back arrangements exist these could be packaged with retail contracts.</td>
</tr>
<tr>
<td>MI contracts - allocate one-offs.</td>
<td>Allocated to retail parcel and contract with Aurora Energy novated or passed-through to successful purchaser.</td>
<td>Free to switch retailers once existing retail contract ends.</td>
<td>Back-to-back wholesale contracts currently in place would transfer with customers to back load.</td>
</tr>
</tbody>
</table>
In combination with wholesale market reform, the wholesale contracts put in place backing the retail books would step down over a transition period, based on an estimated churn rate within the market. For example, retailers would acquire an energy contract for, say, 90 per cent of its retail parcel for the settling in period, and this would reduce in line with the expected average retail contract over a transition period, say two years. During this period, retailers would be able to trade energy contracts between themselves as load transferred with customer churn.

In relation to wholesale contracts to support the retail parcels:

- where contestable retail contracts have back-to-back wholesale energy arrangements (larger retail loads), those wholesale contracts would be novated or passed-through to the successful purchaser of the relevant retail parcel.
- for the non-contestable customers, existing contractual arrangements would be re-assigned to retailers to cover the non-contestable retail load during the transition period.

Figure 18.1 provides an overview of how the market would evolve over the transition period.

**Figure 18.1: Transition to full retail competition**
This repackaging may require some refinement of the portfolio (e.g. larger contracts to be disaggregated on the same terms) to create an alignment between wholesale and retail positions. This realignment would involve commercial negotiation between Aurora Energy and Hydro Tasmania as the counterparties to the existing contracts and be sponsored by Government as a part of the reform process.

It would be likely that there will be some level of mismatch, with individual retail packages either slightly 'long' or 'short' in contract cover relative to what purchasers would seek. This would have an impact on the sale value of the retail packages. However, given that this reform would coincide with wholesale market reforms, retailers are likely to be in a position to adjust their wholesale positions following completion. And, as the legacy contracts role off, the new retailers would be required to source wholesale risk management products from the market.

A key step in implementing this reform would be detailed market soundings with potential purchasers to inform the Government about the level of interest prior to a commitment to the strategy, particularly in light of decisions taken in regard to reform of the wholesale market. The detailed specifics of how proactive retail competition would be implemented would form a central element of these soundings.

As a starting point, the Panel is seeking input from potential new entrant retailers regarding their perceptions of the implementation of proactive retail competition and any key considerations that would impact on the attractiveness of the proposal from their perspective. Such information will be important in shaping the Panel’s final advice to the Tasmanian Parliament on the merits of this strategy relative to organic retail competition.

There are necessary inter-linkages between the wholesale market reform paths discussed above and the implementation of proactive retail competition:

- Under the regulatory approach to wholesale market reform (reform path 1) the volume of contracts that would be required to pass through the auction process would be linked to the market exposures of the new retailers, plus the volume of other competing retailers. This would provide confidence that contract cover would be available as market exposure for contestable customers gradually increases over the transition period. At the time of FRC commencing, the auction arrangement would exclude with the volume under the transitional wholesale contracts. At the end of the transition period, the application of the auction arrangement would be fully implemented.
Under the restructuring of the Tasmanian energy trading market (reform path 2) the transition contracts and existing wholesale contracts between Hydro Tasmania and Aurora Energy would need to be assigned to trading entities, before which the realignment to match the retail parcels would be undertaken. It would be expected that the trading entities would need to be in place ahead of the commencement of FRC, and it would be advantageous for them to be established as material volumes of currently contestable contract volumes roll-off and to cover contestable customers not assigned to the new entrant retailers (i.e. those that are not with Aurora Energy at the time).

Under a single Vic-Tas region (reform path 3) wholesale energy contracts would be required to be renegotiated to take into account the referencing of the Victorian regional node rather than the Tasmanian regional node. This would provide an opportunity to restructure contracts to match the retail parcels.

One consideration is the potential for future reintegration of the separate retail entities, which would most likely result from mergers or amalgamation of smaller retailers on a multi-jurisdictional national basis. For example, if two of the three parcels were acquired by second-tier retailers, there would be a risk that one of the larger national retailers could acquire one of those retailers and potentially reduce the number of active retailers in the Tasmanian market. This is an issue for the ACCC if and when it arises and the Panel does not see this as a high risk if the barriers to entry into the Tasmanian market are appropriately addressed.

The Panel notes that Aurora Energy's retail business has roles in the Tasmanian market in addition to the provision of retail services. These roles do not attach themselves to government ownership and can equally be undertaken by other retailers in the market. These include:

Aurora Energy is currently the Retailer of Last Resort (RoLR) for the Tasmanian region.

The Electricity Supply Industry Act 1995 provides for the appointment, under the regulations, of a RoLR to provide customer retail services under the circumstance that their existing retailer is unable to continue doing so. Under the Electricity Supply (Contestable Customer) Regulations 2005, Aurora Energy in its capacity as the distributor of electricity is nominated as the retailer of last resort. The Regulations do not infer that another retailer, other than Aurora Energy, could not be nominated as the retailer of last resort.

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249 For example, the cessation of retailing in Tasmania, the retailers licence is cancelled or the retailer is suspended from trading in the NEM or ceases to be a Market Participant under the National Electricity Rules.
It is proposed that under the new National Energy Customer Framework (NECF), the AER will assume responsibility for the enforcement of the National Energy Retail Law (Retail Law) and National Energy Retail Rules (Retail Rules). Under the Retail Law, the AER will be responsible for overseeing the National RoLR Scheme, including the appointment of default RoLRs and alternate RoLRs.

There is no requirement that a RoLR is also a distributor of electricity, noting that distribution entities are participants in the scheme in their own right.

On this basis, under the current and proposed RoLR frameworks, any retailer may be appointed the RoLR, or indeed, a number of retailers may participate in the scheme. Under the NECF, management of RoLR will be on a consistent basis across the NEM.

Aurora Energy’s community and social activities.

In partnership with TasCOSS, Anglicare and the Salvation Army, Aurora Energy has implemented a Hardship Policy to customers who experience difficulty in paying bills and are vulnerable to disconnection. This includes measures relating to payment terms and the direct provision of funding amounting to $270,000 in 2010.

Under a Community Services Agreement (CSA), Aurora Energy administers the Tasmanian Government’s electricity concession to low-income earners holding pensioner concession or health care cards. This concession is equivalent a rebate of the daily fixed charge and in 2010 amounted to $23 million.

Under similar arrangements to Aurora Energy’s existing CSA, the Tasmanian Government can, through an open tender process, contract into the market for these services should it determine that they are a benefit to the Tasmanian community. The only difference is that these would be funded directly and transparently from the Budget, rather than the costs being internalised within Aurora Energy.

18.1.1. Financial outcomes for Aurora Energy from reform of the wholesale market

The anticipated strengthening of competition in the retail market that would flow from wholesale market reform would be likely to have an adverse impact on the financial performance of Aurora Energy’s retail business. The objective of all reform paths is greater competition in the retail market. This will result of a further loss of Aurora Energy’s market share.

Financial analysis undertaken by Ernst & Young for the Panel indicates that Aurora Energy’s retail business is highly vulnerable to a loss of market share, given its

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250 The Ministerial Council of Energy agreed on 10 December 2010 that jurisdictions would work toward a common target date of 1 July 2012 for commencement of the Retail Law and National Energy Retail Rules.
scale diseconomies. Confidential analysis undertaken by Aurora Energy and provided to the Panel shows broadly similar results to the Ernst & Young work. Aurora Energy is currently implementing reforms within its energy and retail business to manage its cost structures to better enable it to meet increases competition from other retailers.

In this sense, the objective of delivering retail competition will result in the loss of value for Aurora Energy’s retail business. A primary strategy for addressing this potential loss of value is the sale of Aurora Energy’s retail base (as discussed above).

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251 The issue is not the commercial viability of the customer base per se, rather it is the cost structure that Aurora Energy currently faces in meeting smaller volumes of customers. Aurora Energy

252 Even with the existing level of retail competition, Aurora Energy’s Tasmanian retail business delivered a loss in 2010-11. Source: Hansard 8 December 2011
19. Consequential reform to the delivery of network functions

As part of its Review, the Panel has also considered options for structural reform to drive efficiencies in the provision of network services.253

In scoping its review of the delivery of network services, the Panel’s objective was to conduct a high-level examination of whether there is a prima facie case that combining the transmission and distribution networks into a single network entity would offer material savings; and to examine the extent to which those savings could be achieved by closer cooperation between Aurora Energy and Transend Networks remaining as separate commercial entities.

The Panel engaged Ernst & Young to provide advice on the likely benefits, consequences and risks of two integration models, the Collaboration Model and the Network Integration Model having regard to the current composition of Aurora Energy and Transend. The overall conclusions arising from this work (see below) suggests that the benefits from integrating the two network businesses are modest and are unlikely to be sufficient, compared to the potential commercial disruption and risks, to suggest implementation as a stand-alone reform initiative. However, the analysis did conclude that if implemented as part of a broader reform framework, network integration has the potential to deliver some cost savings, or at least not to result in additional costs within the system.

19.1. Collaboration model254

Aurora Energy and Transend have been working together on a mutually commercial basis to identify and capture joint savings through integration measures that do not involve common ownership. The Panel’s first objective was to identify the estimated financial benefit of this commercial collaboration and identify further potential areas to which it could be applied.

19.1.1. Findings - The collaboration model

The focus of collaboration to date has been in relation to network operation, technology, network planning, public relations and other areas in the corporate services function. Financial analysis by Ernst & Young indicates that the financial benefits being achieved through existing collaboration efforts are estimated to be around $1.1 million per annum.

253 Separate to the current agenda within the NEM on reform to the regulatory framework applying to network pricing investigations for distribution and transmission services.

254 It should be noted that the collaboration model is based on the identification of mutually commercial areas of savings. It does not suppose that the entities collaborate on a non-commercial basis to achieve savings on the basis of mutual public ownership.
Under the Collaboration Model, Aurora Energy and Transend continue to operate under their respective organisational structures and business models. Possible areas of further collaboration would require minimal structural changes to be made to either entity.

Estimated additional savings through further potential areas of collaboration are in the order of $0.3 million to $1.2 million per annum. However, the investigation and implementation of these opportunities would require time and investment by the entities.

The advantages of the Collaboration Model is that it maintains the focus on separate regulated transmission and distribution businesses, which is the most common approach within the NEM. It also maintains the commercial interactions between the two businesses with a common goal of maximising returns to the shareholders.

Overall, existing and potential savings range from $1.4 million to $2.3 million per annum. A number of potential non-financial benefits from collaboration activities were also identified, including knowledge sharing in network communication and planning, best practice sharing on occupational health and safety and safety marketing campaigns.

19.1.2. Network integration model

The Panel’s second objective was to identify the net gains available from common ownership and to more fully understand the likely costs and risks of this approach. The Network Integration Model considered the integration of the distribution network into Transend’s business operations which would leave Aurora Energy with a market facing generator, energy trading and retail business.

Specifically, the Panel’s approach excluded the option whereby Transend’s transmission business was integrated into Aurora Energy’s existing business which would create a fully vertically integrated entity. Although, this could appear a more likely approach, as it would result in the merging of two Government owned business into a single business, saving most of the corporate costs of one business, there are important non-financial considerations that excluded this approach. These include:

- The separation of generation and transmission is a longstanding foundation principle of the NEM and was agreed by COAG during the National Competition Policy reforms. The Ministerial Council on Energy Standing Committee of Officials has recently released a Regulation Impact Statement for consultation regarding potential formalised barriers to co-ownership of generation and transmission.

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The integration of generation, transmission, distribution and retail business.
Given the introduction of retail contestability in Tasmania, and the potential application of full retail competition, ‘full integration’ of the dominant incumbent retail business is unlikely to enhance the environment for entry of new retailers.

Capturing the benefits of closer relationships between retail and distribution to deliver better customer outcomes is an issue that policy-makers have grappled with across the NEM, given the degree of separation that currently exists between these functions in the NEM regions. These challenges will remain in Tasmania, given the entry (or potential entry) of new retailers (i.e. it is not that case that Tasmania has integration of distribution with all retail). Bringing distribution into Transend’s current portfolio does not, in the Panel’s view, fundamentally increase the difficulties or make this worse.

The Panel considers it is important that the Tasmania remains closely aligned with the market and regulatory frameworks that are established across the NEM. The structure of the current Tasmanian market already has significant differences from markets that have evolved in other NEM regions, the consequences of which are fundamental to the issues raised in this Draft Report.

19.1.3. Findings – The network integration model

The Network Integration Model considered the integration of the distribution network business into Transend, which under current arrangements would have a stand-alone integrated generator, trading and retail business. As such, the resulting networks business would have full control over the transmission and distribution network for planning, maintenance and fault management – network planning and maintenance decisions could be made with a whole-of-network view, instead of separate transmission and distribution components. The Network Integration Model has the potential to facilitate efficiency and productivity improvement in network management.

The model of separating retail from distribution is one that has been implemented in most other Australian electricity markets (the NEM and elsewhere) over the past ten years. This model has the potential to provide greater market confidence in the independence of the network business from competitive generation and retail interests. Similarly, a vertically integrated generation and retail energy business is also a proven model in energy markets – although this is generally under private sector ownership.

The Network Integration Model identifies additional financial benefits from the Collaboration Model in the order of $2.4 million to $5.6 million per annum, predominantly from the rationalisation of duplicate functions and assets; and the co-location of network and network services staff.

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256 For example the introduction of Smart Metering.
However, the Network Integration Model does have a number of key issues, risks and consequences to manage in order to achieve the possible financial benefits.

The full network integration model is likely to involve significant adjustment and establishment costs compared to the modest administrative costs of continuing and improving the cooperation model. At the same time, full integration appears to offer only a marginal improvement in financial benefits compared to the cooperation model. A decision on this issue would need to be based on an assessment of whether the net benefits of each approach would support a case for change from the status quo.
20. **Summary of actions that would guide the development of an Energy Strategy**

The Panel has identified four elements of the TESI that are not consistent with the Government’s primary objectives:

1. The application of the existing methodology for determining the wholesale energy allowance for non-contestable customers is inappropriate given the excess generation capacity in the Tasmanian region during normal hydrological conditions.

2. The Tamar Valley Power Station (TVPS) is financially unsustainable in the prevailing market conditions. The fundamental issue is that market prices are not sufficient to cover the power station’s fixed costs.

3. The architecture underlying the operation of the wholesale market in Tasmania gives rise to Hydro Tasmania having latent market power. This increases the risk to other market participants of operating in the Tasmanian electricity sector by comparison to other NEM regions. This additional risk is deterring participation in the Tasmanian region by electricity retailers.

4. Effective retail competition and customer choice has not developed as anticipated, largely because of the perceived risks of wholesale market trading in Tasmania, precluding the introduction of full retail contestability (FRC).

The Panel considers that the first two elements should be addressed as a matter of priority, and has suggested a way forward on both issues.

In part, the purpose of this Draft Report is to seek input on the Panel’s proposed reform paths to constrain Hydro Tasmania’s ability to exercise market power in the wholesale market and to create effective retail competition in the Tasmanian market.

Table 20.1 summarises the actions proposed by the Panel that would guide the development of the Tasmanian Government’s Energy Strategy.
### Table 20.1 - Summary of Actions

<table>
<thead>
<tr>
<th></th>
<th>Reform Path 1</th>
<th>Reform Path 2</th>
<th>Reform Path 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Creating competition</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>disaggregating Hydro</td>
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<td></td>
<td></td>
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<tr>
<td>Tasmania’s trading rights</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Creating competition</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>through a combined</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vic-Tas region</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Features

<table>
<thead>
<tr>
<th>Feature</th>
<th>Reform Path 1</th>
<th>Reform Path 2</th>
<th>Reform Path 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Competitive wholesale energy contract market</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Competitive spot market</td>
<td>×</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Retail contestability</td>
<td>Organic or Proactive Reform</td>
<td>Proactive reform</td>
<td>Proactive reform</td>
</tr>
<tr>
<td>Network Integration</td>
<td>×</td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>

#### Assessment Criteria

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Reform Path 1</th>
<th>Reform Path 2</th>
<th>Reform Path 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Risk to successful retail competition</td>
<td>High</td>
<td>Medium/Low</td>
<td>Low</td>
</tr>
<tr>
<td>Complexity/risks</td>
<td>Medium</td>
<td>Medium</td>
<td>High</td>
</tr>
<tr>
<td>Implementation costs</td>
<td>Low</td>
<td>Medium</td>
<td>High</td>
</tr>
<tr>
<td>Implementation timeframe</td>
<td>1 year</td>
<td>2 years</td>
<td>4 years</td>
</tr>
<tr>
<td>Durability</td>
<td>×</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>(depends on the view of retailers)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

✓ - improvement from status quo  × no improvement from status quo

The wholesale market reform paths are not necessarily mutually exclusive. They could be viewed as a progression from the status quo and be implemented in stages over a period of time. In considering the merits of a progressive approach it is important to identify in what way reform path 1 would add value to the staged delivery of reform path 2, and so forth.

It is the Panel’s view that at first inspection, a staged delivery is of little material value. While this is yet to be tested in the market, the Panel considers that the risk of not achieving retail competition is highest under a regulatory approach. Further, it is questionable whether the market would view an interim measure as just that, or whether it would prefer the certainty of the Government’s commitment to competitive outcome rather than a regulatory outcome.

Further, developing and implementing the auction framework would require considerable resources and could be a major distraction from the complex task of developing and implementing the trader model. Ultimately it may be a question of resources; and whether these are best applied to a more enduring reform.
The Panel’s view is that regulation of the wholesale energy market is a poor substitute for competition and that competition within the wholesale market in Tasmania is deliverable. This is a fundamental concept in the NEM framework. The Panel considers that reform path 2 (creating competition in the trading of Hydro Tasmania’s energy capability) is the preferred way forward to address Hydro Tasmania’s latent market power on a durable basis. The Panel considers that, on the face of it, this would provide confidence for retail service providers to enter the Tasmanian market. Effective retail competition is the key to customer choice and is necessary for FRC to deliver benefits to Tasmanian customers.

The purpose of the Draft Report is to test the reform paths with market participants and other stakeholders, so as to more accurately assess the risk of retail competition being successful under each of the models.

In this context, the Panel also welcomes input on the potential merits or otherwise in implementing a phased approach to wholesale market reform.
21. Modelling the impact of reform

21.1. Background

To examine the consequences of energy market reform for the Tasmanian economy, the Panel engaged The Centre of Policy Studies (CoPS) at Monash University to model the economic impacts of changes in electricity pricing outcomes in Tasmania using its Monash Multi-Regional Forecasting model (MMRF).257

For the purposes of this analysis, the nature of reform examined was a change in retail prices for non-contestable customers from the current arrangements to the revised methodology outlined in Chapter 15, which would see the wholesale cost of energy for these customers move towards a market-based price.

This is considered to be broadly representative of the impacts that would be generated from the implementation of wider structural reform of the wholesale and retail sector discussed in Chapter 17, given what has been modelled is the application of market-related wholesale prices for these customers.

The impacts described in this Section are conservative estimates of the consequences of the wider reforms being proposed, as they take no account of any changes in the wholesale pricing for contestable customers as a result of enhanced competition and choice. As well, they do not consider the dynamic efficiency consequences of the development of more effective retail competition in Tasmania, including potentially lower retail costs and prices for all customers. As discussed in Chapter 9, this is a primary aim of the reform proposals.

21.2. Modelling approach and key assumptions

The modelling approach is specified in CoPS’ report, which is available on the Panel’s website. In summary:

- The only change modelled is the reduction in retail prices to currently non-contestable customers;

- The modelling does not take into account the effect of any change in wholesale or retail prices for contestable customers; and

- As all electricity users of 50MWh and above are currently contestable, it was necessary to separate contestable and non-contestable business customers from their industry sectors. For the purposes of analysis, non-contestable customers are assumed to include all households and a portion of customers in the following sectors: construction services; trade services; accommodation, hotels and cafes, business services and other services.

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257 The MMRF is described in the CoPS report, which is available on the Panel’s website.
Consistent with other analysis undertaken by the Panel, it is assumed that the reforms are implemented in 2011-12.\textsuperscript{258}

For the purposes of establishing a base-line retail cost for non-contestable customers the following assumptions were made:

- for 2011-12, the wholesale allowance that was determined by the TER has been used;
- for 2012-13, the estimates made by the TER for a carbon-inclusive wholesale allowance has been used\textsuperscript{259}; and
- for 2013-14 to 2015-16, the 2012-13 wholesale allowance has been maintained in real terms.

To establish a repriced retail path for non-contestable customers under the reform, it is assumed that the wholesale allowance comprises: an efficient spot price plus an energy supply security premium plus a contract premium:

- the efficient spot price was obtained from modelling of the Tasmanian wholesale market prices undertaken by Frontier Economics for the Panel;
- the energy supply security premium was assumed to be $3/MWh\textsuperscript{260}; and
- the contract premium was assumed to be 5 per cent.\textsuperscript{261}

The repriced allowance has not been smoothed for modelling purposes, noting that regulators typically smooth energy allowances to avoid price shocks to customers.

The modelling covers the period 2011-12 to 2019-20. It has been assumed that the difference between the estimated wholesale energy allowance and the repriced wholesale energy allowance in 2016 is maintained over the period until 2019-20.

Under these assumptions, the modelled changes in retail prices for current non-contestable customers are show in Figure 21.1.

\textsuperscript{258} It is noted that any implementation of the reform program would most likely be several years into the future.

\textsuperscript{259} It is noted that these estimates were not based on the current legislated arrangements for the pricing of carbon, but have been used for consistency with the 2011-12 determination. The TER will consider the extent to which the current determination will need to be ‘reopened’ with the implementation of carbon pricing in 2012-13, and a different allowance may be determined.

\textsuperscript{260} This is an indicative value of a potential premium. It was determined by calculating the annuity that would be required to fund the capital cost of an open cycle gas plant over 25 years that would be capable of ‘firming’ the output of the Tasmanian hydro system from its observed minimum inflows to its observed average inflows.

\textsuperscript{261} This is consistent with the allowance provided by regulators in other jurisdictions when determining wholesale energy allowances for setting regulated ‘fall-back’ arrangements in other jurisdictions.
Figure 21.1 - Retail Electricity Price for Non-contestable Customers (percentage deviations from base case)

Source: CoPS Modelling Report, p. 10
Note: The fluctuations in price variation arise from the absence of smoothing in the revised price path and the application of smoothing in the current price path.

21.3. Modelling Outcomes

As the electricity businesses are owned by the Tasmanian Government, changes in their financial performance will have a direct impact on the Government’s revenues, and its ability to provide services to the Tasmanian community. The modelling therefore needs to take account of the Government’s response to such changes in its revenue position.

Two alternative assumptions are made about the Government’s response to the resulting revenue impacts for the purposes of the modelling:

- the projected base-line budget balances are maintained by Government, which is modelled by the imposition of additional taxes and charges on the household sector; and

- the projected base-line budget balances are maintained without additional taxes and charges being levied on households or businesses.
Each scenario and the modelled outcomes are described below.

**Scenario 1 - no change in Budget balances**

The first modelling case considered assumes that all of the changes in the revenues accruing to the SOEBs flow through to the profitability of the businesses and then directly to Government revenues. In the modelling, it is assumed that the Government seeks to maintain its Budget position, and the change in revenues is recouped from households in taxes and charges, all else unchanged, to maintain the same budget balance. This means that the changes in real private consumption from the reform are substantially muted, because the savings that householders achieve from lower electricity prices are effectively recouped by Government to maintain its revenues. There are, however, positive net economic gains from the reform under these assumptions.

The effects of the change in retail pricing on Tasmania’s real GSP are shown in Figure 21.2. The reduction in retail prices has a positive impact on real GSP in Tasmania. In 2012, real GSP rises by about 0.03 per cent, or $7 million. The increase widens to 0.1 per cent, or $22 million, in 2016 and to 0.13 per cent, or $33 million, in 2020. Over the period to 2020, the NPV of the increase in GSP is around $150 million.262

Real GSP increases because the reduction in electricity prices for small business imparts a competitive improvement to Tasmanian industries, resulting in Tasmania attracting resources from the rest of Australia and increased exports to the rest of Australia and overseas. The source of this competitive improvement is direct via a fall in electricity costs in a number of key service sectors, and indirect via reductions in CPI and a consequential moderation of nominal wages growth.

262 Assuming a societal discount rate of 5 per cent.
Figure 21.2 - Real GSP in Tasmania (percentage and absolute deviations from base case)

![Graph showing Real GSP in Tasmania](image)

Source: CoPS Modelling Report

The outcomes for employment are also positive. The effects of the change in retail electricity pricing on employment in Tasmania are shown in Figure 21.3 in terms of percentage and absolute persons-employed changes.

Figure 21.3 - Employment in Tasmania (percentage and absolute deviations from base case)

![Graph showing Employment in Tasmania](image)

Source: CoPS Modelling Report.
In terms of total jobs, in 2016 around 320 jobs are created by the change in retail pricing. In 2020, nearly 350 new jobs have been created. Note that the year-to-year pattern of deviations in employment shows an up and down pattern which corresponds to the up and down pattern in electricity price deviations as result of the absence of smoothing in prices that is typically applied under regulatory frameworks (Figure 21.2).

The effects of the change in retail pricing on real private consumption in Tasmania are minimal over the period, because of the assumption that shortfalls in Government revenues arising from lower revenues to the SOEBs are recouped from households. The value of the estimated transfers from households to Government required to maintain the same budget balance is shown in Table 21.1.

Table 21.1 - Value of transfer from households to government ($m, 2010 prices)

<table>
<thead>
<tr>
<th>Year</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>28.1</td>
</tr>
<tr>
<td>2013</td>
<td>53.7</td>
</tr>
<tr>
<td>2014</td>
<td>40.4</td>
</tr>
<tr>
<td>2015</td>
<td>25.9</td>
</tr>
<tr>
<td>2016</td>
<td>37.4</td>
</tr>
<tr>
<td>2017</td>
<td>37.9</td>
</tr>
<tr>
<td>2018</td>
<td>38.1</td>
</tr>
<tr>
<td>2019</td>
<td>38.6</td>
</tr>
<tr>
<td>2020</td>
<td>38.4</td>
</tr>
</tbody>
</table>

The second modelling case considered assumes that the Government’s revenues are not affected by the change in revenues to the SOEBs and, therefore, households are not required to make additional payments to the Government to maintain the Budget balance.

This would be the case if all of the revenue losses were offset by matching productivity improvements and cost savings within the SOEBs. The Panel has identified scope for the entities to improve their efficiency, but recognises that achieving the levels of savings required to offset to total loss of revenues assumed here would be difficult to achieve.263

A similar outcome to that assumed in this second scenario could be achieved by requiring the SOEBs to exit underperforming diversification projects that currently require the application of SOEB capital. That capital could be returned to Government, with the financial return on it providing an offsetting source of revenue for the lower dividend revenues from the SOEBs. Under some of the reform scenarios suggested by the Panel earlier in this chapter, considerable capital could be raised by such a strategy.

In this context, the modelling outcomes under this second case represent maximum positive economic consequences of reform.

263 The more likely outcome is somewhere between the two cases assumed for modelling purposes, with the change in revenue being moderated by SOEB productivity improvements and the balance being recovered through taxes and charges to maintain the same budget balance.
Figure 21.4 shows the consequences for GSP from the change in electricity prices to non-contestable customers, assuming no net revenues shortfalls to Government, and Figure 21.5 shows the consequences for employment. The economic impacts are comparably larger than under scenario 1, with almost 550 new jobs created by 2020. The positive effect on economic is also larger, as show in Figure 21.6, which shows the estimated potential range of the economic impacts of pricing reform for non-contestable customers.

Figure 21.4 Real GSP in Tasmania - percentage and absolute changes from base case, scenario 2

![Graph showing real GSP in Tasmania from 2012 to 2020](image)

Source: CoPS

Figure 21.5 - Employment in Tasmania - percentage and absolute changes from base case, scenario 2

![Graph showing employment in Tasmania from 2012 to 2020](image)

Source: CoPS
Based on the assumptions above, the modelling suggests that reform of non-contestable customer pricing could generate improvements in GSP in the range of $150 million and $240 million in NPV terms over the period 2011-12 to 2019-20. This amounts to $600 to $960 per household.

Figure 21.6 - Changes in GSP from non-contestable customer pricing reform

Source: CoPS modelling

21.4. Conclusions

The modelling results from this case study based on reform of the non-contestable customer price regulation arrangements demonstrate that material economic gains could be achieved from reform of Tasmania’s electricity sector. The Panel has adopted a conservative modelling approach to provide an indicative estimate of the broad order of magnitude of the potential impacts.

The approach has been to consider the likely economic impacts of changes in the way in which prices for currently non-contestable customers are set. The Panel is recommending that changes to determining the wholesale energy allowance for non-contestable customers is made as a priority in the development of an energy strategy.

The outcomes delivered by this regulatory change would be similar to the first-round benefits accruing to currently non-contestable customers if reforms to the wholesale market in Tasmania were made, and full retail competition is introduced.

The analysis suggests that Tasmania’s GSP over the period 2011-12 to 2019-20 would be between $150 million and $240 million higher as a result of reform to non-contestable customer pricing, or $600 to $960 per household. The impacts on employment would also be positive, an additional 340 to 550 jobs created over the same period.
The eventual level of benefit from reform between these two estimates would be determined by the degree to which the SOEBs were able to find efficiency offsets for lower revenue and the degree to which underperforming capital with the SOEBs could be realised and returned to Government with the investment of those funds offsetting reductions in returns from the SOEBs.

The Panel has not sought to model additional economic gains from dynamic efficiencies that such a reform could generate for all energy customers and the Tasmanian economy. Capturing dynamic efficiencies is a key driver for implementing the reform measures proposed by the Panel. As noted by the Productivity Commission:

Establishing competition in any market should not be regarded as an end in itself. However, competition does serve as a mechanism for achieving allocative, productive and dynamic efficiency gains, and economic growth. For example, competition can provide a strong incentive for service providers to:

- seek out cost efficiencies and minimise costs, putting downward pressure on prices;
- innovate, providing consumers with a wider range of goods and services;
- undertake efficient investment; and
- improve the quality of services provided to customers.

Achieving these outcomes in the wholesale and retail electricity markets in Tasmania is at the heart of the Panel’s reform proposals. These modelling results are therefore conservative in terms of estimating the full economic benefits to Tasmania arising from fundamental reform of the competitive elements of the electricity sector.

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264 Source: Australia’s Urban Water Sector, Productivity Commission, 2011, Volume 1, Chapter 12, p333.
22. Governance: Issues and Recommendations

Key Messages:

Good governance is essential for achieving efficient prices for Tasmanian electricity consumers and driving the sustainable financial performance of the SOEBs.

The Panel limited its investigation on governance to those issues that emerged from its broader analysis of the efficiency and effectiveness and financial performance of the SOEBs, as well as major infrastructure decisions.

The evidence led the Panel to focus primarily on the Government’s stewardship, as Shareholder, of the broad direction, operation and performance the SOEBs.

The key arrangements that formally underpin Tasmania’s SOEB governance framework are consistent with good practice principles. However, the Panel’s investigation suggests a need to strengthen the practical application of certain elements of the framework.

Specifically, the Panel has identified six key recommended reform areas, which focus on:

- Providing further clarity to the SOEBs, the Parliament and the community on what the Tasmanian Government is ultimately trying to achieve as a business owner;
- Continuously improving the SOEBs’ focus on, and accountability for, the efficiency and financial performance;
- Providing a better - and more dynamic - picture to the Parliament and the community of the SOEBs’ direction and performance;
- The consistent and transparent delivery by the Government of non-commercial activities through the SOEBs; and
- Ensuring market participants’ confidence in the independence of the regulatory framework, particularly when it comes to price-setting.

The recommendations do not represent radical change. In most instances, the Panel believes that effective improvements to governance outcomes can be made simply by the more rigorous application in practice of principles and frameworks that are already in place.

In some key areas the Tasmanian Government is already working to improve the clarity and effectiveness SOEB governance arrangements. This is consistent with the Panel’s view that there should be continuous improvement to align the Tasmanian governance framework with ‘best practice’.
22.1. Introduction

Governance is a central component of the broader framework of incentives that influences the operation of the TESI, which is aimed at driving both efficient prices for Tasmanian electricity customers and sustainable financial returns to SOEBs. In this context, ‘governance’ is used to describe the way in which the Government exercises its various functions of strategic energy policy-setting, economic and technical regulation and business ownership (including major capital investment decisions) within the TESI.

The Panel has not sought to conduct a comprehensive audit of all relevant governance arrangements across Tasmanian energy sector. Rather, it has focused on key issues that have emerged from its investigation into the efficiency and effectiveness and financial performance of the SOEBs, as well as major infrastructure development decisions.

Most of these issues are linked, in one way or another, to the framework and processes established by the Government, in its role as Shareholder, to oversee the broad direction, operation and performance the SOEBs. Accordingly, the Panel has focused on the current functioning of the Shareholder/SOEB relationship and has not sought to assess in detail the internal corporate governance arrangements that are in place in within each of the individual businesses.

The effectiveness of current governance arrangements can be judged by how well they deliver the following outcomes:

- Confidence within the Tasmanian community - both from their perspective as electricity customers and as the ultimate owners of the businesses - that the SOEBs are being operated according to a clear and consistently applied set of goals;

- Clearly specified roles and delegations from the Government, as custodians of public capital - both equity and debt - invested in the SOEBs, through to the SOEB Boards and senior management, such that there is a clear ‘line of sight’ between the strategic objectives set by Government and the operational and investment decisions of the SOEBs; and

- Competitive neutrality across the energy sector (between energy sources and market participants) where market outcomes are not distorted by virtue of the Government’s ownership of the SOEBs;

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265 The Panel’s Terms of Reference do not specifically require an investigation into governance matters. However, the Panel has determined that governance is directly relevant to the scope of its Review, in view of its influence on a range of observed outcomes in the TESI.

266 In this Chapter, ‘the Government’ refers to the Tasmanian State Government in the general sense, and does not refer to the current State Labor Government specifically.
This Chapter summarises the Panel’s findings and recommendations in relation to Governance. A Supporting Paper, Governance: Issues and Reforms, details the principles for good governance in the key outcome areas, discusses the evidence that the Panel has obtained in relation to how well the current governance arrangements are meeting those principles and discusses the Panel’s recommended changes.

The key arrangements that formally underpin Tasmania’s SOEB governance framework are consistent with good practice principles. The Panel’s approach has been to establish whether key aspects of the framework are working to deliver the governance outcomes described above. The Panel has drawn on advice and input from a range of key stakeholders, including those with practical experience of how governance and decision-making currently plays out in the Tasmanian sector.267

The evidence gathered by the Panel in the course of the Review suggests a need to strengthen certain elements of the framework. The Panel has identified six key recommended reform areas, which are discussed in this Chapter.

### Governance: Recommended Reform Areas

1. **Clearer Shareholder ownership objectives**
2. **A stronger Shareholder focus on business performance**
3. **Effective Shareholder oversight and strategic energy policy functions**
4. **Enhanced public reporting and accountability**
5. **Transparent identification, delivery and funding of all non-commercial activities**
6. **Confidence in the independence of regulatory processes**

The Panel makes a number of recommendations for strengthening SOEB governance in Tasmania. The recommendations do not call for significant changes. In most instances, the Panel believes that effective improvements to governance outcomes can be made simply by the more rigorous application in practice of principles and frameworks that are already in place. Therefore, the focus is on the incremental improvement and more closely aligning the Tasmanian governance framework with ‘best practice’.

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267 The Secretariat, on behalf of the Panel, conducted a series of one hour semi-structured interviews with key stakeholders, including Chairpersons and senior management from the SOEBs, heads of relevant Government agencies, Shareholder Ministers, Greens and Liberal Party Energy Spokespersons, Members of the Legislative Council, representatives from the Tasmanian Chamber of Commerce and Industry and an academic with corporate governance expertise. Interviewees were provided with a schedule of interview questions ahead of time, which was used to guide the discussions. In all cases, interviews were given on the understanding that responses provided would not be individually attributed in the Panel’s report(s).
22.1. Clearer Shareholder ownership objectives

Clear and unambiguous Shareholder ‘ownership objectives’ are an important aspect of the SOEB governance framework for a range of reasons. Firstly, they provide the SOEBs with established parameters within which to operate (particularly with regard to non-commercial expectations) and, secondly, they send a clear message to the community about what the Government is seeking to achieve through public ownership, including how this is consistent with and contributes to the Government’s broader strategic policy goals. 268

Strategic objective-setting is also the ‘foundation stone’ upon which the accountability and oversight of the SOEBs is based. Having clear objectives enables the establishment of sound performance measurement and reporting mechanisms, based on a shared understanding of what is to be achieved.

Strategic direction should be provided with regard to both the Government’s general expectations of its State-owned businesses from an overall ‘portfolio’ perspective, as well as at the individual business level. Therefore, objective-setting for the SOEBs can be considered at two levels:

- the overall rationale, goals and objectives that the Government is seeking to achieve through public ownership of the SOEBs (within its wider portfolio of assets); and
- the more specific commercial and strategic direction that is set for each of the businesses over the short, medium and long term, within this broader context.

The Tasmanian Government, as a Shareholder, has not always communicated its overarching strategic objectives for the SOEBs in a clear and consistent way.

This issue has manifested itself in two key areas:

1) The Shareholders’ expectations with regard to the delivery of broader non-commercial outcomes through the businesses, particularly where these objectives are not specifically prescribed in CSOs - Stakeholders from the SOEBs indicated that they have difficulties in resolving the inherent tension between their obligations under legislative and other instruments to act commercially in one hand, and the expectations that the Shareholders may or may not have explicitly stated with regard to delivering broader policy objectives (for example reducing the impact on cost of living for customers or the retention of members of the local Tasmanian workforce as employees of the businesses). SOEB feedback indicated that, outside the established CSOs, there is an element of ‘second guessing’ involved in determining what the Government’s broader policy expectations of the Businesses were, and therefore how these should be delivered.

2) The Shareholders’ views on whether the SOEBs should be pursuing growth opportunities in national and international markets or whether they should be focused on the delivery of core, on-island services to Tasmanians - There has at times been a lack of consistency with regard to the Government’s risk appetite as a Shareholder and what this means at a practical level for the expansion of the businesses into areas beyond ‘core business’. Despite the Government identifying itself as a ‘risk-averse shareholder’, it has nonetheless approved the SOEB corporate objectives of pursuing business diversification opportunities, often outside of the Tasmanian market. As a consequence, the SOEBs are now operating in areas that are well outside their traditional core business. While some of these diversification activities have been pursued primarily as defensive, risk mitigation measures, others have been sought as value-creating in their own right, often with relatively high levels of attendant risk. Examples include Hydro Tasmania’s national and international expansion of its interests in wind farms (through Roaring 40s) and its pursuit of retail growth opportunities on mainland Australia (through Momentum) beyond the level that can be backed by its existing generation portfolio. Similarly, Aurora Energy has recently diversified into the wholesaling and retailing of gas, in Tasmania and elsewhere.

Fundamentally, the Government’s position on these high-level, strategic issues should be guided by its overall ownership objectives for the businesses - the fiscal, wider economic and broader social policy outcomes that the Government is seeking to ultimately achieve through its ongoing public ownership of the SOEBs.

The Panel agrees with the observation made by a number of stakeholders that, instead of being maintained for the achievement of clear policy goals, the policy of public ownership of the SOEBs has become a ‘default position’ or ‘an end in itself’, for all three parties in the Tasmanian Parliament. Consequently, there is a policy gap at the strategic level around what the outcomes of public ownership are, or should be.

Without a clear set of overarching ownership objectives to guide its decision-making as a Shareholder, the Government will not have a reference point from which to consider, in a clear and consistent way, fundamental questions of strategic business direction. Further, the SOEBs, other stakeholders and the broader Tasmanian community will be left with a degree of uncertainty with regard to the Government’s policy intentions. This is a less than ideal outcome from a governance perspective.

270 See the Panel’s Information Paper: A Review of the Financial Position of the State Owned Electricity Businesses
The Panel is of the view that the Government should return to ‘first principles’ and establish a set of clear ownership objectives - including an explanation of how and why these objectives are best delivered through ongoing public ownership - through the development of an Energy Business Ownership Policy (Ownership Policy). The Ownership Policy should be revised and updated with changes in government to reflect changes in direction, priorities and business drivers.

The Ownership Policy should provide clear answers to key questions relevant to setting long-term strategic business direction. For example, to what extent does the Government need or wish to expose its ability to maintain a steady rate of growth in General Government Sector services to the commercial success or otherwise of its SOEBs? And does the Government wish to forgo short-term returns from the SOEBs in the form of dividends, which could be used to fund other policy priorities for the benefit of the community, in pursuit of potentially higher returns from commercial investments that have attendant risk?

These are particularly important questions when considering major new investment decisions by the SOEBs, such as business acquisitions (e.g. Momentum) or the construction of new generation capacity (e.g. wind farms), neither of which is required to maintain security of supply or serve to deliver lower electricity prices to Tasmanian consumers.

Irrespective of how these kinds of investments are funded, be it any combination of retained earnings from the business or additional debt - or, as has been observed, the direct provision of equity by the Government - the capital has an opportunity cost in terms of its ability to support General Government Sector service delivery.

Such investments may or may not be commercially successful or have an acceptable level of earnings volatility. In making these investments, the Government may have a reasonable expectation of earning a commercial return. However, it may also be asked whether such investments and activities are appropriate investments for government at all, given that, in making them, the Government is also accepting that General Government Services will need to be adjusted in the event that they are not successful.

These issues are germane to the scope of the businesses activities that the Government specifies or, in other words, the boundaries of the field on which it allows the SOEBs to ‘play’. The SOEBs need to be as commercially successful as possible within the parameters set by the Government, but it is critical that the scope of business activities is firstly precisely defined, with clear reference to broader strategic policy objectives. This is a primary function of the Shareholders. Significant input from the SOEBs is both necessary and appropriate in understanding the consequences and trade-offs involved in strategic policy direction-setting.
An Ownership Policy would also improve transparency and accountability, by making clear which objectives for the SOEBs are set by the Shareholders and which are set by the businesses themselves. This would allow more public scrutiny of who is accountable for the ultimate delivery of each of the various objectives.

The Panel notes that improvements to the strategic objective-setting process for Government Businesses are already in train. The Government’s February 2011 release of its Reform Principles for the Oversight and Accountability of Government Businesses271 has re-opened the discussion between the Government and the SOEBs on the Government’s overarching ownership objectives, particularly in the context of what constitutes core and non-core business activities for each of the entities.

For example, the Principles now explicitly refer to the need for clear objectives to be set by the Shareholder Ministers, including core activities of the businesses and any public policy objectives. The Principles also reinforce the Government’s low risk appetite as an investor and suggest a focus on ‘on-island’ activities, unless the businesses can provide a strong, risk-based business case.

While the Principles have been broadly welcomed, some stakeholders from the SOEBs raised questions about how they will be applied in a practical sense, and in particular how they will interact with existing legislation, where it appears in some instances there may still be the potential for ambiguity or conflict, particularly with regard to the Board and management’s businesses’ legal obligations to operate commercially.

The new Principles must therefore be cognisant of Directors’ duties and the intent and objectives of the relevant Acts in order to resolve potential confusion or ambiguity. Specifically, clear guidance should be given as to how Boards are expected to prioritise objectives provided via the new Principles in relation to their existing legislative and other responsibilities. As noted above, there is a need to specify the scope or ‘reach’ of business activities, thereby setting the boundaries within which their commercial performance will be judged.

22.2. A stronger Shareholder focus on business performance

The oversight of SOEB performance by the Shareholder Ministers should provide a sufficient level of accountability to drive continuous improvement in the efficiency, effectiveness and financial performance of the businesses.

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From the perspective of the Shareholder Ministers, efficiency within the SOEBs is critical as it drives financial performance and, ultimately, returns to the community in the form of dividends. From a customer perspective, the market and/or the regulatory framework can only go so far in driving efficiency and the longer-term trend in electricity prices.

Responsibility for initiating and driving efficiency improvements primarily falls to the SOEB Boards. However, the Shareholders also have a key role to play in ensuring that the Boards remain clearly focused on high levels of productivity and efficiency to achieve sustainable financial returns. The Shareholders must then subsequently hold the Boards accountable for the achievement or otherwise of relevant efficiency and financial performance targets.

The Panel has observed a trend that where efficiency-based expectations have been communicated to the Tasmanian SOEBs via the corporate planning process, these have often been at a high-level, and corporate plans have consequently lacked specific targets or performance measures that can be used to monitor the effectiveness of productivity or efficiency efforts.

One possible view is that the economic regulatory environment and independent regulators will provide the dominant drivers for SOEB’s efficiency and effectiveness. The Panel’s view, however, is that the regulatory framework can, at best, provide a level of assurance that a business that is not exposed to strong and sustained competitive disciplines are not able to routinely operate at generally inefficient levels. A culture of performance must come from within the business – it cannot be effectively imposed by regulation.

In Tasmania, there are two key reasons why the Shareholders must be even more active in driving the efficient performance of the SOEBs. Firstly, both the wholesale and retail markets lack effective competition, being dominated by Hydro Tasmania and Aurora Energy respectively. Secondly, because the SOEBs are under public ownership they are not subject to the same market discipline as private sector entities.

Responsibility for embedding an efficiency-based business culture must start ‘from the top’ by ensuring robust accountability measures exist between the Shareholders and the Boards. The relationship between the parties should recognise that optimising business performance within the broad parameters established by the economic regulatory environments remains the domain of management and Boards, but that Shareholders provide the ultimate incentives and sanctions for efficiency and effectiveness.

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272 See the Panel’s Information Paper: A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses/Chapter 8.1
In recent times, efficiency has become more of a focus in the corporate governance arrangements between Boards and Shareholders of the SOEBs. For example, Letters of Expectation have become more specific with regard to the Shareholders’ expectation that the SOEBs will develop efficiency improvement programs.

Representatives from the SOEBs have also noted an increase in the level of detail more generally in the most recent Letters of Expectation, compared to previous years. This represents a shift towards oversight that is seeking to better understand and actively engage with the strategic direction of the SOEBs. For example, from this year the SOEB Boards and the Shareholder Ministers will be required to put in place a formal agreement which sets out key performance measures based on agreed objectives, including target dividends and end of year financial results.

The Panel endorses the recent improvements in SOEB accountability and oversight. However, it is crucial that these arrangements continue to be refined and improved over time, given that it has not always been clear in the past how expectations are being incorporated into the business strategies of the SOEBs or are then in turn being monitored by the Shareholders. It is also important that, where possible, these improvements are reflected and enshrined in formal and enduring mechanisms (e.g. legislation or subordinate regulations).

Of prime importance are the development of specific accountability and incentive mechanisms that provide a ‘clear line of sight’ between Shareholder expectations and the requirements of the regulatory framework on the one hand, and Board, management and staff performance on the other. The Panel notes Transend’s Employee Regulatory Incentive Scheme as good example of this kind of approach in action.273

However, these kinds of mechanisms need to be supported by sound and sufficiently detailed ongoing monitoring, reporting and follow-up processes. This is particularly important where the Shareholders have approved investments in non-core diversification activities that may have a higher risk profile.

It is also important given the growing diversity and complexity of the SOEBs. The intra-entity financial linkages within Hydro Tasmania and Aurora Energy means that there is significant scope for value to be shifted within different parts of these businesses, either by explicit design, or by changes in one part of the business impacting on another.

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273 See the Panel’s Information Paper: A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses
For example, there have been implications for the financial performance of Aurora Energy’s distribution business arising from the debt levels required to be held by Aurora Energy as a result of the TVPS acquisition. In relation to Hydro Tasmania, as an integrated generation-retail business in the NEM, there are opportunities to shift value between the retail and generation arms.

Detailed reporting of disaggregated or segmented financial information - and a clear explanation and interpretation of this information - is important to ensure that Shareholders and their advisers are in a position to understand core value drivers and how the financial targets established for parts of the SOEBs are being achieved. For example, Aurora Energy’s energy business now comprises wholesale electricity trading, wholesale gas trading, Tasmanian retailing of gas and electricity and retailing activities in the wider NEM. While there are strong commercial reasons for this structure to be adopted, including efficiency rationales, the potential trade-off is that it is more difficult to understand what is driving overall performance - what aspects are generating genuine value and what areas are underperforming.

In this context, Shareholders and their representatives need access to sufficiently detailed and disaggregated financial information that allows them to determine how well individual aspects of the businesses are performing in relation to clear expectations and targets that have been set. Aggregation of financial results should not be used as a way of obfuscating the identification of value drivers of the business.

The Panel has reviewed a range of information provided by the SOEBs to Shareholders, including Corporate Plans and ongoing performance reporting. It has also reviewed monthly management accounts and board reporting within the SOEBs and notes that segment reporting is provided. While not identifying any material deficiencies, the Panel emphasises that access to information at an appropriate level of detail is a cornerstone of the SOEB accountability framework and must be preserved and, where possible, enhanced.

22.3. Effective Shareholder oversight and strategic policy functions

The ability for the Shareholder Ministers to effectively monitor and drive efficient SOEB performance through the Boards relies in large measure on the ability of the Shareholder’s agent (in this case Treasury) to access and interpret performance information. Equipped with good information, the Shareholders should be in a position to respond to emerging issues in a timely and effective manner.

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274 This is not to suggest that the management and Boards of the SOEBs do not adequately monitor the financial performance of the various aspects of their businesses.
The Panel’s Terms of Reference (ToR 8) require it to review the “advice that was provided to the State Government by the senior management or Directors of Aurora Energy from 1 October 2009 to 16 June 2010 inclusive”, in the context of the Company’s changing financial position over this period. This example provides a good insight into the practical functioning of communication channels between a SOEB and its Shareholders.

From its analysis of the relevant documents, the Panel has observed that senior management in Aurora Energy and officers within Treasury were in regular dialogue throughout 2009 (beginning in February 2009) with regard to the significant financial impact of the TVPS acquisition on its balance sheet, particularly in relation to the likelihood that the asset would need to be impaired or ‘written down’ in its financial accounts.

Further, when the wider financial issues in Aurora Energy’s energy business began to fully emerge late in 2009 and early 2010, the Panel notes that the Board took urgent and appropriate action in informing the Shareholders of these developments by firstly writing to the Shareholders and then tasking a special Board sub-committee to hold extraordinary Shareholder briefings in January 2010. These briefings were followed up with presentations in April 2010 (upon the return of the Government after the 2010 State Election) that contained more detailed financial projections of the severity of Aurora Energy’s position, once this was known.

These observations support the Auditor-General’s findings from his investigation into the circumstances around the Labor Party’s ‘five per cent cap’ promise, that reporting by Aurora Energy to the Shareholders with regard to its financial circumstances over this period was adequate.

The Government’s Principles for Strengthening the Oversight and Governance of Government Businesses reinforce the requirement that the businesses notify the Shareholding Ministers and Treasury as their principal financial adviser, of any business specific issues and risks that have the potential to impact on the State and its balance sheet. The Panel supports this ‘continuous disclosure’ approach and notes that in this particular instance the process functioned as intended.

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275 Chapter 9.2 discusses in more detail how and why Aurora Energy’s financial difficulties deteriorated so rapidly over this period.

276 Tasmanian Auditor-General (2010) Special Report No.94, Election promise: five per cent price cap on electricity prices, pp.1
However, this example highlights a broader issue. While the nature of the financial risk exposure itself was known (and had been communicated to the Shareholders), what was not anticipated was its potential (and subsequently realised) magnitude. As noted in Chapter 9.2, the large and sustained falls in the financial performance of Aurora Energy’s Energy business were not anticipated by the Company, given the number of ongoing revisions to expected earnings throughout 2009-10. In other words, it was not known in advance what Aurora Energy’s position would be at June 2010 (which saw EBIT some $50 million below the original Budget, at -$31 million), as unanticipated losses continued to emerge as late as May 2010.

While the circumstances surrounding Aurora Energy’s deteriorating financial position during 2010 were unusual, this example does highlight the inherent risks of being an owner of merchant energy businesses in a highly complex market.

In its submission to the Panel on governance matters, the Government notes in broad terms that it will be considering the current distribution of its various energy responsibilities across the bureaucracy, in the context of the Panel’s findings and recommendations. A strong Shareholder oversight function is clearly a fundamental function that will need to be continued, if not further enhanced.

The Panel has not undertaken a detailed review of the resourcing or operation of key functions relevant to the TESI across the Tasmanian bureaucracy. However, reflecting the separate but interrelated roles that government plays in the sector, the Panel highlights that SOEB oversight must also be complemented by an effective strategic energy policy function within the portfolio Department.

Currently, despite having a legislative basis, DIER’s energy policy function appears to have a relatively broad but indistinct mandate. Stakeholder feedback indicates that in practice, DIER’s limited energy resources are currently heavily committed to the support of Tasmania’s involvement in national energy policy forums (e.g. the Ministerial Council on Energy), leaving little opportunity to focus on State-based strategic policy development.

Treasury has held a central coordinating role in the delivery of a number of major energy reform projects over the past ten years, including NEM entry and Basslink, and retains formal responsibility for managing the progressive roll-out of retail contestability. This has led to the accumulation of expertise and credibility by Treasury in the eyes of decision-makers.

However, if Treasury holds the major responsibility for strategic energy policy advice - in addition to SOEB oversight - this can potentially blur the lines between these two functions, as well as adversely impact on the diversity of perspectives being brought to bear in advice to Executive Government on major energy policy decisions.
22.4. Enhancing public reporting and accountability

The Panel suggested in its Issues Paper that, prima facie, there appear to be limitations on the extent to which SOEB performance could be driven by ‘external’ accountability mechanisms (which includes answering to both the Parliament and the broader Tasmanian community). In many respects, these limitations are not unique to the Tasmanian context, but instead reflective of the State-owned enterprise model more generally, where the focus tends to be on executive accountability (i.e. to the Shareholder Ministers) rather than broader Parliamentary or ‘public’ accountability.\textsuperscript{278}

As the ultimate owners of the SOEBs, however, it is important that the Tasmanian community, as well as the Shareholders, can access regular information about how well the businesses are achieving their stated objectives. In this way, the Parliament plays a key ‘intermediary’ role in holding the SOEBs to account on behalf of the community.

The principle of transparent public disclosure needs to be balanced against a range of other important considerations, including commercial confidentiality and the compliance burden of reporting. It is also important that performance reporting is genuinely informative, particularly given both the inherent complexities of the energy market and the public’s inability to trade their shares in the SOEBs.

Currently, the Tasmanian public accountability framework comprises the Annual Reporting process and Government Business Scrutiny Committee Hearings, with little in the way of more dynamic, ongoing disclosure of performance information. In this way, public accountability of the SOEBs is largely static and focused on end-of-year performance.

In their submissions to the Panel, the SOEBs noted their existing reporting burden, suggesting that they already face a higher level of scrutiny than listed companies due to their status as State-owned enterprises. It is certainly true that the SOEBs, by virtue of being owned by the State, face different kinds of scrutiny to publicly listed private companies, including the unique requirement to appear before Parliamentary Committees.

However, publicly listed companies face their own - and in some cases more stringent - accountabilities, both more broadly through their exposure to the discipline of the share market and under the various reporting requirements specified under the ASX's Listing Rules. In this context, the publication of annual financial statements and annual appearances by the SOEBs before the Government Business Scrutiny Committees are a relatively weak substitute for the kind of close market scrutiny that continuous public disclosure places on listed companies.

The existing public reporting regime for the SOEBs attracted extensive comment from Members of Parliament, a number of whom expressed the view that the current level of information available to the Parliament in particular was insufficient for it to perform its accountability and oversight function on behalf of the Tasmanian community.

The most significant barrier to more effective public accountability is the inherent (and growing) complexity of the energy sector and information asymmetry between the SOEBs and those seeking to understand their business activities. However, the Panel also acknowledges concerns that some key information, such as the Government’s and SOEBs’ business objectives for forthcoming year, is often not available, which makes it difficult to determine if relevant goals had been met, even at a very high level.

In a number of other jurisdictions, public reporting by State-owned Enterprises comprises a combination of ‘ex-ante’, ‘process’ and ‘ex-post’ reporting mechanisms, which provide a more dynamic picture of business performance throughout the financial year. This typically comprises the publication of a summary of the corporate plan at the start of the financial year, a half-yearly report and a final annual report.

The Panel believes that there is merit from a public transparency perspective in improving the timeliness and currency of key SOEB performance information provided to the Tasmanian Parliament, consistent with good practice arrangements in other jurisdictions. Specifically, this should include a Statement of Corporate Intent, a Half-Yearly Report and an Annual Report.

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279 For example, the requirement to immediately disclose to the ASX any matter that in the view of a reasonable person would have a material impact on the share price of the company - see ASX Listing Rules, Chapter 3.

280 A number of interviewees made the observation that without a background in energy markets, Members of Parliament and the general public would (and indeed did) find it very difficult to understand important contextual information about the operation of energy markets relevant to scrutinising the performance of the businesses.

281 For example, the New South Wales State Owned Corporations Act 1989 requires SOCs to provide to the Parliament a Statement of Corporate Intent (SCI), Half-Yearly and Annual Reports (within specified timeframes), as well as any directions issued to the SOCs by the Shareholder Ministers. Similarly, New Zealand State-owned Enterprises are required under statute to lay before the House of Representatives a copy of their SCI and both half-yearly and annual reports. The Commonwealth Government also applies a very similar reporting framework to its Government Business Enterprises.

This kind of reporting regime is unlikely to result in any significant additional compliance burden for the SOEBs, given the existing Corporate Planning process, and the fact that more detailed half-yearly reports are already provided by the SOEBs to the Shareholders. It is noted that Treasury proposed a very similar reporting regime in its 2010 Position Paper on the conversion of Government Business Enterprises to State-owned Companies.²⁸³

Through its Issues Paper, the Panel also sought stakeholder views on whether there might be some accountability benefits in exposing the SOEBs to public 'continuous disclosure' requirements, analogous to those that currently apply to companies listed on the ASX. This was met with mixed responses from stakeholders, most notably from the SOEBs themselves.

After further analysis of similar arrangements in other jurisdictions and discussion with stakeholders, the Panel is not convinced that public, continuous disclosure for the SOEBs would yield sufficient accountability benefits to justify the burden of its imposition on the businesses at this stage.

While not within the Panel’s remit, it should also be noted that a number of stakeholders were highly critical of the effectiveness of the current Government Business Scrutiny Committee Hearings process, specifically its ability to provide a genuine forum for the discussion of the SOEBs’ operational and financial performance. Many stakeholders thought the Hearings had become unduly politicised, which was seen by some as having the unhelpful effect of blurring the line between accountability for SOEB performance (including the oversight performance of the Shareholder Ministers) and the general performance of the Government of the day for the delivery of other policy objectives (which are often unrelated to the operations of the businesses).

The conduct of Scrutiny Committee hearings is a matter solely for the Parliament to determine and the Panel makes no further comment or recommendations in relation to this specific aspect of SOEB oversight and accountability. However, the Panel nonetheless considered it appropriate to make mention of stakeholders’ concerns given the strong feedback received during consultation.

The Panel’s proposed improvements to the provision of relevant and timely SOEB information, proposed above, may enhance the Committees’ capacity to perform its SOEB oversight function in a more informed and effective manner.

22.5. Transparent identification, delivery and funding of non-commercial activities

The Tasmanian Government has in place a clear framework through which the SOEBs may undertake non-commercial activities for the achievement of broader policy objectives. In the case of the electricity concession and Bass Strait Island Community Service Obligations (CSOs), the cost of delivering these activities is transparently recorded through the annual State Budget process.

The CSO process is a key component in minimising the potential disconnect between directors’ duties and the legislative framework on the one hand and the delivery of broader policy objectives on the other. The treatment of CSOs in this way also enables the SOEBs to be held accountable for efficient delivery of the service and for the Government to be held accountable for the policy itself and its overall cost.

The Panel has observed a level of non-transparency in the funding of some non-commercial activities. The most prominent example relates to Aurora Energy’s operation of the TVPS. As noted in Chapter 9.2, the TVPS has not been recovering its costs from the market. Rather, the current commercial viability of the TVPS has been underpinned by the current regulatory regime that determines the wholesale energy allowance and imposes controls over the contractual arrangements with Hydro Tasmania for supplying the non-contestable load. The arrangement effectively transfers the shortfall in market value for the TVPS to Hydro Tasmania. This is not transparent or sustainable.

As discussed in more detail in Chapter 11.3, there are alternative, more transparent means to support the TVPS on the grounds of energy supply security ‘risk insurance’ that the Panel’s considers more appropriate.

The Panel has observed other examples where the CSO framework has not been deployed where it would have been appropriate to do so. For instance, in 2009 the Government wrote to Aurora Energy to express a desire for tariff increases charged under the Aurora Energy Pay as You Go (APAYG) billing system to be effectively ‘capped’ for concession cardholders at a rate below that at which Aurora Energy was intending to charge.284

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284 As a ‘product of choice’ for Tasmanian customers, APAYG tariffs are not set by the Regulator, but at commercial rates determined by Aurora Energy.
The Panel understands from its discussions with Aurora Energy that an agreement was subsequently reached with the Shareholders through a negotiated process, which resulted in the Shareholders accepting a commensurately lower dividend in order to cover the cost of delivering the price cap for these customers. While the APAYG ‘price cap’ was publicly announced by the Government and Aurora Energy, its actual cost was only ever captured in confidential Corporate Plans, rather than transparently as a line item in the State Budget, as would be expected for an activity of this kind.

The Panel has also viewed evidence that shows the Government had also planned to deliver its ‘five per cent price cap’ promise through an arrangement where it would accept reduced dividends from the relevant SOEBs.

The practice of accepting a lower rate of return from businesses in return for the internal funding of a CSO runs contrary to the agreed policy of operating government businesses on a fully commercial basis and reduces the businesses own retained earnings. The practical consequence of reducing dividends to fund non-commercial activities is that it undermines government’s ability to be an effective business owner and sends mixed messages to Boards and management as to what the owner regards as success. Businesses without clear, unambiguous lines of accountability to their owner or where the owner sets mixed or contradictory objectives invariably begin to be run in the interests of the management, with consequences for both customers and owners.

The central issue is not whether the Government should utilise the SOEBs to deliver wider policy objectives – this is one of the core reasons that governments continue to own the businesses. Rather, it is the way in which the Government implements these policy outcomes that is central. The funding of non-commercial activities via CSOs rather than through the acceptance of lower than otherwise dividends, is not an accounting ‘nicety’ or a reflection of technocrats’ desire to tie things up in neat boxes. It is fundamental to good governance, performance management and ability of the Government to hold the businesses to account.

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285 On 8 July 2009, Aurora Energy announced that APAYG prices would be increased by an average 12 per cent in 2009-10, largely as a result of “…the product’s higher technology costs, higher than expected transmission charges and inflation” (Aurora Energy Media Release, 26 July 2009). Following intervention from the Government, average price increases for eligible APAYG concession customers were subsequently brought down to the rise approved for customers on regulated tariffs – 7.2 per cent. The reduction was achieved by the abolition of the daily standing charge and a reduced increase in the standard and off-peak winter prices in the 11am to 4pm, 4pm to 8pm and 8pm to 6.30am time-slots.

286 Cabinet documents

22.6. Confidence in the independence of regulatory processes

It is the Panel’s position that financial value in the SOEBs should be an outcome of efficient operations, not a core driver of policy or regulatory settings. Given the sector’s economic and social significance to the State, policy and regulatory settings should be primarily focused on economically efficient outcomes in the energy market.

Economically efficient prices may or may not be consistent with good financial outcomes for the SOEBs at a particular moment in time. As electricity consumers, the Tasmanian community’s interests are best served through economically efficient pricing. As the ultimate owners of the major electricity businesses, the community’s interests are also in achieving good financial outcomes as dividends paid by SOEBs, relieving the pressure on the need to raise Budget revenue through other means.

Achieving both of these objectives simultaneously depends on a range of variables, including the efficacy of decisions around the scope of the businesses activities and investments, the incentives for productivity improvements provided by the way shareholder oversight working in practice and the overall demand and supply balance. It is vital that a framework is established that clearly allocates risk and reward between owners/taxpayers on the one hand and electricity users on the other.

In the Tasmanian framework, the TER is responsible for the setting of the Maximum Allowable Revenue that Aurora Energy may recover from its non-contestable retail customers through regular (typically three-yearly) pricing determinations. In determining maximum prices, the TER is required to take into account all cost components of the supply chain, including the wholesale price of energy, which is the single largest component.288

Under the Electricity Supply Industry Act 1995 (the ESI Act), the TER is independent of Ministerial direction in carrying out its functions, including the setting of retail prices for non-contestable customers. The Act provides the TER with a high level of flexibility in how it undertakes its key functions. However, Parliament remains responsible for defining the framework within which the TER operates, including through the State-based PCRs. Within this framework, government appropriately provides for the consideration and balancing by the TER of a range of broad objectives, including the quality and efficiency of services, the financial sustainability of the businesses and the ‘public interest’ (among others).

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288 For a detailed description of how the Regulator determines prices for non-contestable, see the Panel’s Pricing Discussion Paper ‘Tasmania’s electricity pricing trends’
In its investigation of recent pricing trends, the Panel has observed that the Government has provided additional, specific direction to the TER with regard to either prices themselves (as in 2007), or the methodology that should be used for arriving at these prices. Chapter 13 describes in further detail the process through which wholesale energy allowances have been set under recent Pricing Determination processes.

Under the 2007 Determination - where the Government, not the TER set the wholesale allowance - , one of the key principles applied Government was that the price should contribute to the sustainability of Hydro Tasmania and Aurora Energy to ensure sufficient revenue capacity to earn a commercial return.\(^{289}\) This ultimately resulted in an ‘adjustment factor’ of approximately $3 MW/h\(^ {290}\) being applied to the price that had been recommended by independent consultants based on the application of a long-run marginal cost methodology.

Regulatory frameworks must be adaptive and responsive to change where it is demonstrated that they are not delivering the objectives they have been primarily established to achieve. However, given the primary aim of the regulatory framework is to support the efficient operation of the energy market, it is important that market participants cannot form the impression that specific direction provided by the Government to the Regulator, through changes to the regulatory framework, is driven by Shareholder value considerations. When the Government is both a business owner and regulator, it is crucial that clear demarcations between these functions are, and are seen to be, maintained.

The Government’s involvement in specific elements of recent pricing determinations - beyond the establishment of the broad principles and objectives that underpin the regulatory framework - raises potential concerns about the actual or perceived level of ‘functional’ independence that the TER is afforded in making pricing decisions.

The PCRs are designed to provide a high-level of flexibility in the mechanisms that the TER uses in achieving the objectives set out in the regulatory framework. The Panel endorses the Office of the Tasmanian Economic Regulator’s (OTTER) view\(^ {291}\) that the high level regulatory framework - once appropriately set by Government - should remain consistent between regulatory periods as far as is possible. Crucially, it should also permit the TER sufficient independence, particularly with regard to the application of technical and methodological approaches.


\(^{290}\) The Panel understands that the adjustment was justified in part based on Hydro Tasmania’s weakened revenue raising capacity while it rebuilt its storages during a period of drought but has found no evidence or clear explanation of how the $3 MW/h figure was derived.

\(^{291}\) See OTTER’s submission to the Issues Paper.
Complete transparency in regulatory pricing arrangements will become critically important for the new entry of private capital in the market with the introduction of full retail contestability and attendant ‘fall-back’ contract arrangements. A number of electricity retailers have raised this as an issue in their discussions with the Panel.

**22.7. Recommendations**

The Panel recommends that:

1. The Tasmanian Government develops a publicly available Energy Business Ownership Policy to more clearly articulate its overarching strategic objectives for the SOEBs.

2. The Tasmanian Government transparently identifies, endorses, costs and funds all CSO activities undertaken by the SOEBs, consistent with its existing CSO policy framework. CSOs should be directly funded through the budget process, rather than through internal transfers and acceptance by the Shareholders of reduced rates of return.

3. SOEB oversight continues to be refined and improved over time with a specific focus on putting in place accountability and incentive mechanisms that provide a clearer ‘line of sight’ between Shareholder expectations and the requirements of the regulatory framework on the one hand, and board management and staff performance on the other.

4. The following key functions should underpin any Government review of energy responsibilities across the bureaucracy:
   - A strong SOEB ownership and oversight function, focused on driving the efficient performance of the businesses from a Shareholder perspective;
   - An expert energy policy function with the sufficient mandate, capacity and authority to provide robust advice to Government, preferably through the portfolio Minister; and
   - A strategic, ‘whole of government’ policy oversight capacity with the ability to weigh and consider the impacts of energy policy proposals from a more holistic perspective, taking into account broader social, economic and environmental impacts, preferably coordinated by a central agency.
5. At a minimum, each of the SOEBs provide to the Parliament - and therefore the wider Tasmanian community - the following:

- an annual Statement of Corporate Intent at the commencement of the Financial Year, summarising the key objectives and performance targets from the SOEB’s Corporate Plan;

- a Half Yearly Report that provides a summary of year-to-date performance against targets set out in the SCI; and

- an Annual Report.

6. The TER is given the discretion to independently apply appropriate approaches and methodologies, within the context of the broad principles and objectives set by the regulatory framework.
23. Consultation Process

23.1. Statement of Approach

The Electricity Supply Industry Expert Panel held its first round of Community Hearings, based on the Statement of Approach, in Hobart on 19 April 2011 and in Launceston on 20 April 2011. The Community Hearings were a key part of the Panel’s evidence-gathering processes for the Review. They were designed to provide interested members of the community with an opportunity to raise and discuss issues directly with Panel members in an open and transparent way.

The Hearings were publicly advertised in Tasmania’s three daily newspapers and widely promoted to a broad range of stakeholders, including Parliamentarians, local government representatives, industry participants and community and business bodies. The Hearings were well attended, with approximately 50 and 30 attendees at the Hobart and Launceston sessions respectively.

Panel members took questions about the Review and heard a range of comments directly from attendees on the core issues that they believe should be covered in the Panel’s forthcoming Issues Paper. The Panel also used the Hearings to share some facts and initial observations on the Tasmanian electricity industry based on its investigations to date, including key findings from the Panel’s three initial Discussion Papers.

Interested parties were invited to register if they wished to make specific submissions or presentations to the Panel at the Hearings. In total there were sixteen presentations made; ten at the Hobart Hearing and six in Launceston. The full list of participants who made presentations to the Panel is provided below:

**Hobart**

- David Asten (DA Electricity Consultants)
- Penny Cocker
- Geoff Fader (Tasmanian Small Business Council)
- Paul Fulton (Joule Logic)
- Simon Himson (TasGas)
- Tony Horsham (Competitive Change International)
- Kath McLean (TasCOSS)
- Des Le Fervre
- Mark Manning (Derby Products)
- Warren Papworth
Launceston

- Dennis Collins
- Neville Dobson (National Electricity Contractors Association)
- Hugh Grimes
- Craig Owens (Hill Michael Associates)
- Ian Peck
- Peter Schulze

The main themes that arose from the Community Hearings and the subsequent submissions were:

- Tariff Structures and Capacity to Pay Issues
- Structure and Efficiency of the State-Owned Energy Businesses
- Competition in the Retail Sector
- Cross-Subsidies
- Impact of Broader Contextual Factors, Including Climate Change Policy
- Improving Governance and Long-Term Decision Making in the Sector

In response to the Statement of Approach, the Panel received 17 submissions from:

- Anglicare
- Aurora Energy
- Penny Cocker
- DA Electricity Consultants
- Derby Products
- EUAA
- Goanna Energy
- Hydro Tasmania
- Robin Maguire
- NECA
- NGF
- Ian Peck
- Peter Schulze
- Tas Gas
- TasCOSS
- Greg Todd
- Transend
23.2. Issues Paper

The Panel released its Issues Paper on 24th June 2011. The purpose of the Issues Paper was to seek input from interested parties on the key issues that the Panel identified in response to its Terms of Reference.

The opportunity to make submissions on the Issues Paper was advertised in Tasmania’s three daily newspapers and widely promoted to a broad range of stakeholder.

In response to the Issues Paper, the Panel received 18 submissions from:

- AER
- Alinta Energy
- John Ameaud
- Aurora Energy
- Eco Energy Options Pty Ltd
- ERM
- Sandra Healey
- Hobart City Council
- Hydro Tasmania
- Loy Yang
- Nyrstar
- Office of the Tasmanian Economic Regulator
- Rio Tinto Alcan
- TasCOSS
- TasGas
- Tasmanian Chamber of Commerce and Industry
- Greg Todd
- Transend Networks

The main themes that arose from the submissions were:

- Full Retail Contestability
- Competition and Market Power
- Hydro Tasmania’s Utilisation of Basslink and Non-Scheduled Generation
- Structural Reform of the Wholesale Market
- Long Run Marginal Cost
- Current Investment Incentives
- Review of the Network Regulatory Framework
- Fixed and Variable Charges
- Cross-Subsidies
- Major Investment and Policy Decisions (Basslink, TVPS etc)
- Governance
23.3. Ongoing Process

The Panel is keen to emphasise that the engagement and consultation process is ongoing. The Panel will be inviting submissions on its Draft Final Report and will also be holding another round of Community Hearings in relation to its Draft Report in February 2011.

The Panel has been open to hear from Interested members of the community at all stages of the Review process and is happy to accept relevant information and evidence at any time.