Electricity Supply Industry Expert Panel

Tamar Valley Power Station: Development, Acquisition and Operation

Information Paper

December 2011

Electricity Industry Panel - Secretariat

GPO Box 123
Hobart TAS 7001
Telephone: (03) 6232 7123
Email: contact@electricity.tas.gov.au
http://www.electricity.tas.gov.au

December 2011

Contents

Glossary 1

Foreword 2

Executive Summary 3

Introduction 15

1. TVPS Development, Acquisition and Operation: a Chronology 17

1.1 Initial Development of the TVPS Project 17

1.2 Acquisition and Completion of the TVPS by the State 24

1.3 Post-Acquisition Commercial and Operational Arrangements 37

2. Economic and commercial considerations 48

2.1 Core underpinnings of the Alinta-Aurora Energy transaction 48

2.2 Babcock Brown Power Purchase the Alinta Assets 50

2.3 What changed when Aurora Energy Acquired the TVPS? 52

2.4 Aurora Energy's Energy business financial outcomes for 2009-10 58

3.1 Key differences between the Babcock and Brown model and Aurora Energy's outcomes 61

3.2 AETV's current position 62

Glossary

TERM	MEANING
ACCC	Australian Competition and Consumer Commission
AEATM	Alinta Energy Australia Trading and Marketing
AEMC	Australian Energy Market Commission
AETV	Aurora Energy Tamar Valley Pty Ltd
ASX	Australian Stock Exchange
BBPS	Bell Bay Power Station
BBP	Babcock and Brown Power
CCGT	Combined Cycle Gas Turbine
EBIT	Earnings Before Interest Tax
ECAC	Electricity Coordination and Advisory Committee
GSA	Gas Supply Agreement
GTA	Gas Transport Agreement
HoA	Heads of Agreement
JV	Joint Venture
LCW	Lazard Carnegie Wylie
LRMC	Long Run Marginal Cost
MW	Megawatt
MWh	Megawatt Hour (= 1 thousand kWh)
NEM	National Electricity Market
SOEB	State Owned Electricity Businesses
SPA	Sale Purchase Agreement
TER	Tasmanian Economic Regulator / Tasmanian Energy Regulator
TNGP	Tasmanian Natural Gas Pipeline
ToR	Terms of Reference
TVPS	Tamar Valley Power Station

Foreword

The Panel's Terms of Reference (ToR 2) 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.

The Panel has taken this to include the gas-fired Tamar Valley Power Station (TVPS).

This Paper examines the TVPS project in detail from the point of initial development through to commissioning and present-day operation, including key processes, decisions and their outcomes. It also considers the State Government and Aurora Energy's objectives for the project and assesses the extent to which commercial and other outcomes achieved to date have delivered on initial expectations.

The Panel considers that 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.

In its analysis, the Panel has drawn on a wide range of information, including briefings from senior representatives from both the Government and Aurora Energy. The Panel has also used its extensive information gathering powers to access a wide range of otherwise confidential documents pertaining to the development, acquisition and operation of the TVPS, including relevant Cabinet materials, internal briefing notes and advice and Aurora Energy board papers and meeting minutes.

While issues of Cabinet confidentiality and commercial sensitivity preclude the release of much of this source material, the Tasmanian community should be confident that the Panel has been able to arrive at its own, independent understanding of the circumstances and key decisions around the TVPS project based on this information.

John Pierce

Chairman

Electricity Supply Industry Expert Panel

Executive Summary

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). [1]

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[2].

The TVPS' entry has resulted in more available energy[3] and capacity than is required to meet demand, at least until well into the next decade. Reflecting market conditions in Tasmania and the National Electricity Market (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[4] 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.

---

1 Initially, this was achieved with the conversion of the Bell Bay Power Station to natural gas in 2003.

2 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.

3 Noting that, in Tasmania, this is a function of hydrology.

4 Hydro Tasmania current 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, the 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 the 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, non-contestable customers and Hydro Tasmania are carrying the financial burden of the costs of having the TVPS available as 'supply reliability insurance'. 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.

The Panel's key findings are summarised below.

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 National Electricity Market (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 10 and 25 per cent of the load required to support non-contestable customers from a party other than Hydro Tasmania. The contractual arrangements with Alinta also provided Aurora Energy with options on the forms of contractual cover provided by the TVPS, which gave Aurora Energy broader scope to manage contract negotiations with 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[5], which had been entered into by Hydro Tasmania[6] and was valued by Hydro Tasmania at approximately $90 million.

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 Babcock and Brown Power (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.

5 Which was originally negotiated with Duke as a foundation for the Tasmanian Natural Gas Project.

6 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.

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.

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 Bell Bay Power Station 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 BBP 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, BBP 'carved out' gas supply arrangements for the TVPS on terms consistent with a wider package of gas commodity and transport agreements that were in place in a related Babcock and Brown entity. The nature of the gas arrangements (volume and conditions) were consistent with the use of gas implied under BBP's operating model for the TVPS.

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.[7] 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 unsustainable 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.

In response, Aurora Energy restructured its energy business to improve efficiency and implemented a tolling agreement[8] 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.

---

[7] 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)

[8] 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.

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 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;
- 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[9]; and
- On a per unit basis, the 2009-10 wholesale energy allowance factored into non-contestable tariffs and, therefore, Aurora Energy's revenues was 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.[10]

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

---

9 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).

10 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.

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[11] – 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.

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.

Aurora Energy's changing risk profile with TVPS ownership

Aurora Energy's risk position fundamentally changed once it became the owner of the TVPS, instead of the counterparty to a set of financial arrangements linked to the TVPS. Aurora Energy's ownership of the TVPS involved it assuming a number of significant risks that would have been borne by BBP under the previous contractual arrangements. This has been a major driver of the financial implications of the TVPS for Aurora Energy. These are summarised in Table 1 and discussed in more detail below.

11 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.

Table 1 - Aurora Energy's risk position pre and post TVPS acquisition

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

BBP-Aurora Energy transaction

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.[12]

What changed when Aurora Energy acquired the TVPS?

The Government's direction that Aurora Energy would acquire, complete and operate the TVPS fundamentally changed Aurora Energy's risk profile. 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.

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.

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 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.

[12] 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.

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 (formerly 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.[13]

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 was some $50 million below budget, at minus $31 million.[14] The financial impact on Aurora Energy during 2009-10 is discussed in more detail in Section 3 of this Paper.

---

13 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.

14 There were other contributors to this overall outcome, including the performance of Aurora Energy's national retailing activities.

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'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:

- it placed Aurora Energy, in the position of having a long-term large take or pay gas exposure[15], 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.

[15] Noting that it is not uncommon for CCGT plants to have take or pay gas supply contracts.

The Future of the TVPS

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

- its costs, relative to prevailing 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 rather than in line with 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 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
- 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.

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 the Draft Report.

Introduction

The initial development of the TVPS project was a key component of Tasmania's 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 hydro generation and increasing competition.[16]

The completion of the TVPS in October 2009 heralded significant changes to the Tasmanian electricity sector, in terms of providing a new source of generation and changing the State's hydrological risk profile. However, by the time it was completed, the TVPS was operating under a very different set of arrangements than had been originally envisaged when it was proposed by Alinta Energy in 2006. Most significantly, instead of a new private sector entity competing in the generation sector, the State acquired the project and in doing so retained control of all of Tasmania's significant on-island generation capacity.

The State's acquisition of the TVPS has had a substantial financial impact on Aurora Energy as the acquiring entity. Subsequent actions taken by 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 Paper is divided into two main sections, with analysis covering the key elements of TVPS development, acquisition and operation identified by the Panel.

The first section provides a factual chronology of the evolution of the project through its initial conception to commissioning and operation by AETV. It focuses on key events and associated commercial, policy and regulatory decisions across three time periods:

- The Initial Development of the TVPS Project;
- The Acquisition and Completion of the TVPS by the State; and
- Post-Acquisition Commercial and Operational Decision-Making.

[16] The three 'core energy objectives' that have been pursued by successive governments in Tasmania since the Rundle Government's 1997 *Directions Statement* are discussed in more detail in the Panel's April Discussion Paper *The Evolution of Tasmania's Energy Sector*

Section 1 also includes a brief discussion of the acquisition decision from an energy supply risk perspective, including a summary of relevant information and advice provided to the Government at the time.

Section 2 considers in more detail the commercial aspects of the TVPS project. It compares initial expectations of the TVPS project with the outcomes that have been observed since its commissioning, and explains the apparent divergences. More specifically, it addresses the evolution of the TVPS operating model and explains how 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 Aurora Energy.

1. TVPS Development, Acquisition and Operation: a Chronology

1.1 Initial Development of the TVPS Project

The initial development of new gas-fired generation in the Tamar Valley was driven by three key factors:

- Firstly, the TNGP delivering large scale natural gas to Tasmania and the commercial desirability of developing a foundation customer for that project;
- Secondly, the development provided the potential for competition in the wholesale generation market, as well as another significant source of on-island generation to provide energy diversity and a buffer against hydrological risk; and
- Thirdly, the approval of some of the arrangements that formed part of Tasmania's NEM entry required a commitment from the Government to separate the BBPS from Hydro Tasmania.[17] Under its Vesting Contract[18] for non-contestable customers, Aurora Energy was also required to source at least 10 per cent (and up to 25 per cent) of its energy from an alternative party to Hydro Tasmania. This opened up the possibility for private sector involvement, post separation, in redeveloping the BBPS and/or the development of new gas-fired generation, in the context of the Duke Energy TNGP project.

The TVPS project experienced a long gestation period from initial proposals in 2001 through to the commencement of construction in 2008, during which various commercial and operational models were considered. The evolution of the TVPS from initial concept to finalised project is briefly outlined below.

---

17 Separation was scheduled to occur in April 2006 to coincide with the physical connection of Basslink.

18 Note that the Vesting Contract, and therefore the ACCC requirements in relation to it, terminated at the point Tranche 2 customers become contestable, or no later than 31 March 2007.

1.1.1. Original Joint Venture Proposal between Hydro Tasmania and Duke Energy

In April 2001, as part of the Tasmanian Gas Pipeline Development Agreement, Hydro Tasmania signed a Joint Venture (JV) Heads of Agreement with Duke Energy International for the redevelopment of the BBPS to a 234MW combined cycle plant.[19] The Agreement subsequently transferred to Alinta after its takeover of Duke Energy's Australian and New Zealand assets in April 2004.

Initial Development of the TVPS - Key Events and Decisions

April 2001 – Hydro Tasmania and Duke Energy enter into a Heads of Agreement as part of the TNGP Development Agreement for redevelopment of the BBPS

14 November 2001 – The ACCC delivers its final decision regarding derogations and Vesting Contract arrangements for Tasmania's entry to the NEM.

23 April 2004 - Alinta acquires the Australian and New Zealand assets of Duke Energy, including the gas pipeline and interests in the Bell Bay Power Station (BBPS)

26 April 2006 - Alinta publicly announces plans for the Greenfield development of TVPS near BBPS, following the collapse earlier in the year of joint venture negotiations with Hydro Tasmania.

October 2006 - Alinta and Aurora Energy announce 203MW CCGT project with a target commissioning date of 31 March 2009

March 2007 - Alinta acquires the BBPS site and the three 35MW FT8 gas-fired turbines from Hydro Tasmania. As part of the deal, Alinta grants a licence to Hydro Tasmania for it to continue to operate the Bell Bay 1 and 2 thermal units until the later of 31 March 2009 or the commissioning of the new combined cycle gas turbine.

March 2007 – Aurora Energy executes energy supply contracts with Alinta.

April 2007 - The Tasmanian Parliament approves the sale of the Bell Bay Power Station.

August 2007 - Alinta commences TVPS construction.

31 August 2007 - Babcock and Brown acquires Alinta, including the existing hedge contract with Aurora.

[19] The Bell Bay Power Station was first commissioned in 1971 and was owned and operated by Hydro Tasmania. Initially comprising two oil-fired thermal units, Unit 1 was converted by Duke Energy to run on gas in March 2003 and Unit 2 was similarly converted by Hydro Tasmania in 2004. In 2006, three 35 MW gas turbines (Pratt & Whitney FT8 open cycle units) were installed in light of hydrological inflows and concerns about the State having access to sufficient capacity ahead of Basslink commissioning.

The Agreement provided for the establishment of a JV company between Hydro Tasmania and Duke Energy (later Alinta) to operate the BBPS Unit 2 from 1 January 2006. Under this arrangement, Bell Bay Unit 1 would continue to be owned and operated by the BBPS as a 'stand by' generator while Unit 2 would be repowered to a combined cycle gas turbine and operate competitively in the market.

Alongside the JV agreement, Hydro Tasmania was party to a Pipeline Capacity Agreement (PCA) with Alinta for an annual capacity of 10PJ of gas at an annual cost of $8.6 million (2007 dollars) until March 2017. In the event that the JV was to proceed, the PCA would have been transferred as part of that Agreement.

However, after extensive negotiations between the parties, no landing could be reached on the commercial basis for the development of the JV and these arrangements were not progressed.

1.1.2. Development of Alternative Proposals

As an alternative to redeveloping the BBPS site, in 2005 Alinta (following its 2004 acquisition of Duke Energy's Australian and New Zealand assets) had begun to develop a stand-alone proposal to construct a new power station on a site adjacent to the BBPS. Negotiations between Alinta and Aurora Energy continued through 2005 and into 2006 in relation to potential wholesale energy contracts that would underpin the viability of the development.

In March 2005, the Government also requested the management and independent directors of Bell Bay Power Pty Ltd[20] to develop a commercially viable business plan for the BBPS under a state ownership model as an alternative to Alinta's proposals to Aurora Energy. At a minimum, the Bell Bay Power business plan was intended to act as an 'analytical benchmark' against which the Alinta proposal could be assessed.[21]

In response, Bell Bay Power submitted a proposal to the Minister for Energy and the Treasurer under which the subsidiary would be separated from Hydro Tasmania in the short term and the existing assets would be operated for profit ahead of re-powering Unit 2 to a combined cycle gas turbine.

[20] Bell Bay Power was a subsidiary of Hydro Tasmania responsible for the operation of the BBPS

[21] Energy Policy Steering Committee, *Assessment of Proposals for Power Generation in the Bell Bay Area*, 26 September 2006 (Draft)

In early 2006, Alinta re-approached Aurora Energy with regard to pursuing the Greenfield option and by August 2006 had negotiated a new commercial arrangement that, according to Aurora Energy, offered an attractive product mix that allowed for peak load management. Aurora Energy notes that the proposal was highly appealing as it provided the company with flexibility to change the nature of wholesale risk protection over time, which would broaden its scope in hedge contract negotiations with Hydro Tasmania over the long term. The commercial arrangements between Alinta and Aurora Energy are further discussed in Section 3 of the Paper.

The Aurora Energy Board approved the proposal on 24 August 2006.

In September 2006, the then Energy Policy Steering Committee made a number or recommendations to the Government regarding its assessment of the respective Bell Bay Power and Alinta proposals for generation at Bell Bay. The Steering Committee recommended that the Government support the Alinta Greenfield proposal, provided that the Aurora Energy Board was satisfied that it could enter into the necessary arrangements on a fully commercial basis without Government support or intervention and that Alinta did not seek any form of Government support for the development to proceed.[22]

Alinta publicly announced its yet-to-be-finalised agreement with Aurora Energy on 26 October 2006. The relevant electricity supply contracts between Alinta and Aurora Energy were executed on 7 March 2007, with some minor adjustments in July 2007 following unexpected changes to Alinta's gas supply arrangements. The final hedge arrangements with Alinta included provisions for regular gas price reviews and price increase 'pass through' to Aurora Energy. Aurora Energy considered the gas price risk to be commercially acceptable given the prices offered under the hedge and the linkages between gas costs and electricity prices in the NEM generally.

At this stage, Alinta was still proceeding on the basis that the new station would be built on an adjacent site in the Bell Bay industrial zone and not at the existing BPPS.

[22] Energy Policy Steering Committee, *Assessment of Proposals for Power Generation in the Bell Bay Area*, 26 September 2006. While both project proposals were judged to have substantial merit, the Committee favoured the Alinta proposal "*...on the basis that it provides a new entrant generator, is acceptable to the Board of Aurora Energy, will not threaten the commercial viability of Hydro Tasmania, and does not increase the State's exposure to the highly volatile energy market*".

1.1.3. Sale of the Bell Bay Power Station

Following the public announcement of the TVPS project in October 2006, Alinta re-opened negotiations with Hydro Tasmania for the acquisition of the BBPS site. The BBPS site had value to Alinta for a range of reasons, including existing environmental permits, its proximity to the gas pipeline, electricity transmission lines and the node, access to cooling water and the existing of the turbines on site, providing some back-up plant.

Following Cabinet approval in March 2007[23], Hydro Tasmania agreed to sell the BBPS site to Alinta. Key features of the sale agreement included that:

- Hydro Tasmania would sell the site and the BB3 generating facilities[24], together with all licences, approvals and spare parts;
- Alinta would pay $30 million in full consideration for the assets;
- Alinta would grant a licence to Hydro Tasmania for it to continue to operate the thermal units until the later of 31 March 2009 or completion of construction (defined by receipt of certificate of completion);
- The PCA (negotiated by Hydro Tasmania and Duke Energy) would be terminated from 31 March 2009;
- The JV agreement would be terminated with neither party retaining any residual rights;
- Hydro Tasmania would complete the demolition of the Bell Bay thermal units and associated plant by 31 March 2017; and
- Hydro Tasmania would provide Alinta with a zero premium option to execute a swap for up to 100MW electricity for the period 31 March 2009 to the earlier of the commercial operation of the new closed cycle units or 31 December 2009.[25]

---

[23] Cabinet approval was obtained prior to the tabling of a motion in the Tasmanian Parliament for the sale of the BBPS, which was required under section 7(4) of the *Hydro-Electric Corporation Act 1995.*

[24] These were the 3 FT-8 gas-fired generators originally acquired by Hydro Tasmania in 2005 as back-up plant when the State was experiencing very low inflows.

[25] This option provided backup for Alinta in case of delays in finalising the project, given its contract with Aurora Energy, which was to commence on 1 April 2009 and contained no conditions relating to the completion of the CCGT plant.

The early release of Hydro Tasmania from the PCA was a key component of the sale agreement. The status of the PCA following the break-down of JV negotiations between Hydro Tasmania and Alinta was legally unclear.[26] Analysis at the time suggested that the sale had a positive net present value (NPV) of $22 million, as compared to an estimated negative NPV of minus $135 million if the deal had not been agreed to.[27] Hydro Tasmania's 2007 Annual Report stated that the release represented almost $90 million in savings (in addition to the $30 million direct cash benefit for the sale of the assets themselves).

The Tasmanian Parliament approved the sale of BBPS on 19 April 2007.[28]

1.1.4. Babcock and Brown's Acquisition of Alinta Assets

On 31 August 2007, shortly after construction of the TVPS had commenced, BBP acquired Alinta, including AETV, the entity that owned the TVPS project.

---

26 In the Parliamentary debate on the motion to sell the BBPS, the Greens' Energy Spokesperson, The Hon Kim Booth MP, cited advice apparently provided by the Hydro Tasmania Chairman that he believed that the PCA would 'fall away' if the JV did not go ahead. Evidence sighted by the Panel suggests that the prevailing view at the time within Government was that there remained a material risk that Hydro Tasmania would have been left with PCA obligations, notwithstanding the failure of the JV.

27 Draft Cabinet Minute, *Sale of Bell Bay Power Station*, March 2007

28 The Sale was supported by the Liberal Opposition but opposed by the Greens.

Initial Development of the TVPS - Summary

- ACCC conditions placed on Tasmania's entry to the NEM required the separation of the BBPS from Hydro Tasmania, which opened up commercial possibilities for new gas-fired generation at Bell Bay in the context of the TNGP project.
- The ACCC also required Aurora Energy, under its Vesting Contract for the non-contestable load, to source at least 10 per cent (and up to 25 per cent) of its wholesale energy from an alternative generator to Hydro Tasmania.
- The original JV proposal between Hydro Tasmania and Alinta (under the Gas Pipeline Development Agreement) for the redevelopment of the BBPS was set aside in 2006.
- Alinta was successful in developing an alternative Greenfield TVPS proposal, which was supported by electricity hedge contract arrangements with Aurora Energy. Aurora Energy notes that the proposal was highly appealing.
- This development was supported by Government over an alternative 'benchmarking' proposal under which Bell Bay Power would be separated from Hydro Tasmania in the short term (but continue under State ownership) and operate the existing assets for profit, ahead of re-powering Unit 2 to a combined cycle turbine.
- Alinta subsequently acquired the BBPS site and FT8 units from Hydro Tasmania. Alinta granted a licence to Hydro Tasmania for it to continue to operate the Bell Bay gas-fired 1 and 2 thermal units until the later of 31 March 2009 or completion of construction. A key component of the sale agreement was Hydro's release from its PCA liability with Alinta, which was valued by Hydro Tasmania at around $90 million.
- Shortly after commencement of construction, on 31 August 2007 BBP acquired the TVPS project as part of its acquisition of Alinta.

1.2 Acquisition and Completion of the TVPS by the State

Just under a year into the construction of the TVPS, new owners BBP began to experience financial difficulties. BBP's financial position - and the resultant risks to project completion - would ultimately prompt the Government to take the decision to instruct Aurora Energy to acquire and complete the partially-built TVPS.

There were less than three months between the Government first becoming aware of the seriousness of BBP's financial difficulties and the finalisation of a Sale and Purchase Agreement (SPA) between Aurora Energy and BBP for the TVPS. The key events during this period are described briefly below.

1.2.1. The Government's Initial Response to BBP's Financial Issues and Threat to the TVPS Sale Process

The first public indication of BBP's financial problems occurred when BBP announced to the Australian Stock Exchange (ASX) on 4 June 2008 that it was embarking on an asset sale program, which, it was subsequently revealed, included the TVPS project.

On 13 June 2008, BBP formally approached Hydro Tasmania as one of a number of selected parties to submit an expression of interest for the purchase of the TVPS. On 16 June 2008, Hydro Tasmania advised the Government of BBP's approach and on 20 June 2008 the Government approved Hydro Tasmania making a non-binding offer "*...as an interim step to preserve the State's interest in any potential sale process*".[29] By 23 June 2008, BBP had advised Hydro Tasmania that it had not been short-listed in the bid process.

The Government was aware of a number of outstanding issues that had the potential to jeopardise the sale of the TVPS to another private operator. Key amongst these was the uncertainty of the TVPS not having a connection agreement in place with Transend. The connection agreement was ultimately contingent on the results of a review by the Australian Energy Market Commission (AEMC) National Reliability Panel of Tasmania's frequency standards. At the time, the prevailing frequency standard was too wide for TVPS's turbines to meet the minimum access standard of the network.

[29] Ministerial Statement, 19 August 2008.

TVPS Acquisition: *Key Events and Decisions*

4 June 2008 –BBP announces asset divestment program

13 June 2008 – BBP approaches Hydro Tasmania seeking expressions of interest in purchasing the TVPS

20 June 2008 – Hydro Tasmania submits a non-binding bid for the TVPS, following approval by Government. Hydro Tasmania is not short-listed

9 July 2008 – The Treasurer agrees at meeting with BBP to consider TVPS acquisition proposal

11 July 2008 – BBP submits a written purchase proposal to Government

7 August 2008 – The Premier approves the Treasury Secretary entering into formal acquisition negations with BBP

10 August 2008 – Cabinet agrees that Government will enter to TVPS acquisition negotiations with a view to purchase

18 August 2008 – The Government announces a Heads of Agreement for TVPS acquisition

28 August 2008 – The Tasmanian Parliament passes legislation approving the acquisition and funding of the TVPS

1 September 2008 – The Sale and Purchase Agreement is executed

15 September 2008 – The Sale and Purchase Agreement is completed

26 October 2009 – TVPS is officially commissioned.

While it was widely expected that the outcome of the Review would be a tightening of the standard allowing the TVPS to connect[30], the uncertainty in the context of the sale process was considered likely to impact on the value of the station in the market, as well as affecting timely divestment and potentially delaying commissioning.[31]

---

[30] It should be noted that the Frequency Standard Review was not instigated specifically in response to, or to accommodate, the development of the TVPS. Following Tasmania joining the NEM in May 2005, the Reliability Panel acquired responsibility for the Tasmanian frequency operating standards and was required to perform a review within one year. In its 2006 review, the Panel determined that the existing Tasmanian frequency operating standards should continue to apply until NEMMCO had gained sufficient experience operating Basslink. It was agreed that the Panel would again undertake a benefit cost assessment of tightening the standards at a future time. In February 2008 the AEMC provided the Panel with terms of reference for this follow up review. The Panel commenced its review in April 2008. (See: AEMC Reliability Panel, *Tasmanian Operating Frequency Standard Review: Final Report*, December 2008).

[31] Infrastructure Committee of Cabinet, *Tamar Valley Power Station*, 7 July 2008. Another key issue raised by BBP was that certain features of the Aurora hedge prevented the station from running at full capacity. Aurora disagreed with BBP's assertions with regard to this matter but had offered to consider alterations to the contract to relieve these concerns.

The Government's Electrical Technical Advisory Committee[32] (ETAC) had been working through the range of TVPS connection issues, but had been largely adopting a monitoring function and "*...had not reached any conclusions on a recommended way forward*".[33]

On 7 July 2008, in the context of BBP's financial position and timelines for divestment of the asset, the Government agreed to a strategy to facilitate the timely resolution of the TVPS connection issues, underpinned by a decision to task the CEO of Transend Networks with handling negotiations between the relevant parties, including BBP, Basslink, Transend, Aurora Energy, Hydro Tasmania and the AEMC National Reliability Panel. The Transend CEO agreed to take on the facilitation/negotiation role and report back to Government on the outcomes of negotiation by 31 August 2008.

In recommending its preferred option of a Government-facilitated solution to the TVPS connection issue, Treasury initially advised against any move for the State to acquire the asset and noted that "*...from a strategic perspective, there is no inherent benefit in State participation in the TVPS sale process*" in terms of the resolution of the connection issues.

However, it was noted that State ownership may need to be considered in the scenario that BBP "*...fails to, or does not proceed to, sell the TVPS and subsequently does not advance construction rapidly enough to give the State confidence that the asset will be available to meet BB Power's obligations under the Aurora contract as required in mid 2009*".[34] By this time, Treasury had already commenced preliminary work to understand any potential issues or barriers in the event that a quick response to this situation was required.

1.2.2. Discussions Leading up to the Heads of Agreement

Efforts to support and facilitate a sale of the TVPS to another private operator proved unsuccessful. Given its financial situation, its need to act swiftly in selling the TVPS and the frequency standard/connection issue, BBP had indicated that the TVPS was unattractive to third parties and would be difficult to divest.[35]

---

32 ETAC was a subcommittee of ECAC tasked with providing analysis and advice on technical matters.

33 Infrastructure Committee of Cabinet, *Tamar Valley Power Station*, 7 July 2008

34 Infrastructure Committee of Cabinet, *Tamar Valley Power Station*, 7 July 2008

35 Department of Treasury and Finance *'Tamar Valley Power Station Acquisition Counterfactuals'*, undated.

On 9 July 2008, the then Treasurer met with BBP representatives, on the Company's initiation. At the meeting, BBP indicated that it was having difficulties in arranging finance to complete the project and that the outcome of the sale process was uncertain and that, in this context, there were risks to the timely commissioning of the TVPS. BBP suggested that, given energy security concerns related to the drought, the Government may have an interest in acquiring the TVPS. The Treasurer agreed that BBP would submit a range of purchase options for the Government's consideration.[36]

On 11 July 2008 BBP submitted its written proposal to the Government. BBP advised that the only way for it to continue work on the project was if the State agreed to either enter into a purchase agreement or provide finance to BBP for both the uncompleted work and bridging finance of $100 million. BBP's position appears to have been driven largely by timeframes to put in place project finance by 31 August 2008 and complete the sale of the TVPS as soon as possible.

The Government subsequently sought the views of Aurora Energy with regard to BBP's proposal. Aurora Energy's advice at that time, similar to Treasury's initial position, was that "*...energy security issues in the context of the TVPS are best facilitated through providing a clear 'completion and connection pathway' for potential purchasers*", rather than acquisition of the asset by the State.[37]

Treasury sought further advice from Aurora Energy on a proposed Government purchase in late July. In its 8 August reply, Aurora Energy's preferred outcome was for BBP "*...to negotiate project financing and then the commercial sale of the TVPS to a reputable and experienced energy market player, with Aurora Energy's current contract remaining in place*", due to concerns about the financial impact of the acquisition on the Company. Aurora Energy indicated that it would support the State's acquisition of the TVPS if it was taken on by a new State-owned company unattached to Hydro Tasmania and the existing BBP hedge deal remained on foot.[38]

---

36 Infrastructure Committee of Cabinet, *Tamar Valley Power Station*, 11 July 2008

37 Aurora Energy, *TVPS Arrangements – Comments on BBP Paper of July 2008* (undated)

38 Letter from Aurora Chairman to Treasury Secretary, 8 August 2008. In the event of Government acquisition, Aurora Energy proposed two possible options. The first (and preferred) option was for the purchase by a new state-owned entity (unattached to Hydro Tasmania) and the retention of Aurora's existing contract. The second option was that the Government could direct Aurora Energy to purchase the TVPS at its real market value – based on the Aurora off-take agreement and timing of connection, rather than construction cost, on the condition that the Government put in place 'necessary strengthening' of Aurora's balance sheet to enable purchase while still retaining its investment grade credit rating.

On 8 August 2008, senior Treasury staff met with the Premier, the DPAC Secretary and the Minister for Energy's senior adviser to discuss the TVPS situation.[39] Treasury was authorised to enter into preliminary purchase negotiations with BBP, commencing with a meeting to be held the next day. It was noted at the meeting that legal, technical and financial consultancies had already been put in place to provide advice to the Crown: Worley Parsons to provide technical advice, Lazard Carnegie Wylie (LCW) to provide financial and valuation advice and Allens Arthur Robinson to assist with legal and contractual matters.[40]

Treasury raised a range of issues and risks to Government associated with the proposed acquisition, including the outstanding connection/frequency standard issue, the ability to 'reshape' contractual arrangements post-acquisition to create a 'workable, valuable entity', the terms and nature of key contracts (including gas supply and transportation) and the potential impact on Tasmanian electricity entities, both in terms of their value and operations.

[39] D Challen, *File note – Meeting with Premier re Tamar Valley Power Station*, 7 Aug 2008

[40] The Panel has viewed the substantial due diligence materials provided by the consultants.

Energy Security Risk and the TVPS Acquisition

The Government's decision to acquire the TVPS took place against the backdrop of sustained, very low inflows to Tasmania's hydro system.

Inflows for the period November 2007 to April 2008 were the lowest ever recorded. This followed on from ten years where inflows were well below the long-term average, which substantially depleted water in storage. At the end of January 2008, total system storage was at 23.2 per cent and by 11 June 2008 this figure had reached 16.5 per cent.

Low storages were exacerbated by the failures to both Basslink and the BBPS at the end of 2007. Basslink was out of service from 31 December 2007 to January 8 2008 due to a failed transformer at Loy Yang, while Bell Bay unit 2 was out of service for five weeks after it failed on 24 December 2007, also due to a transformer failure.

The Government was concerned about the maintenance of supply reliability through 2009 in the event that extremely low inflows in continued conjunction with a sustained outage of either Basslink or the BBPS.

The Government had a number of processes in place to monitor the storages situation and provide with regard to potential contingency options. The main forum for the discussion of hydro storages and energy security was the Electricity Coordination and Advisory Committee (ECAC), which was chaired by the Director of Energy Planning (the statutory officer with responsibility for providing advice to the Minister on energy supply and security issues).

Hydro Tasmania was the key source of advice on supply security risk during the period prior to the TVPS acquisition. Throughout 2007 and the first half of 2008, ECAC received regular presentations from Hydro Tasmania on the storages situation. In addition to participation at ECAC meetings during the first half of 2008, Hydro Tasmania was also preparing reports on storages and providing this advice to the Minister on a weekly basis. It was also participating in a weekly 'Low Inflows Liaison Group' meeting with the Director Energy Planning, which in turn informed discussion of the inflows situation (among other issues) at regular fortnightly meetings between the Director Energy Planning and the Minister.

Hydro Tasmania's overall risk assessment remained consistent over the first half of 2008 - essentially that even in the face of ongoing low inflows, it believed energy security would be maintained through 2008 and 2009, barring the prolonged outages or failure of Basslink, the BBPS or any significant hydro generation.

ECAC did not directly advise Government on the risk to supply posed by the potential delay of the TVPS, nor was the Director of Energy Planning involved in the decision-making in relation to the power station's eventual acquisition. Instead, interactions with BBP about the TVPS divestment process were coordinated and managed by Treasury, which coordinated supply risk information provided directly by the State Owned Energy Businesses (SOEBs).

Energy Security Risk and the TVPS Acquisition – Cont.

Modelling provided by Hydro Tasmania to the Minister for Energy and the Treasurer showed that, in the scenario where the TVPS was delayed and Hydro Tasmania could not utilise any of its existing thermal generation beyond 31 March 2009, meeting Tasmanian electricity demand in the second year of a further two extreme low inflow years would be 'difficult'.

However, this assessment was based on what Hydro Tasmania considered an 'extremely unlikely' inflow sequence, albeit the one that had just been experienced, suggesting that the risk of supply restrictions, even without any thermal support, were low.

Hydro Tasmania had concerns about its ability to continue to run the BBPS beyond the end of 2009 in the event that TVPS commissioning was delayed, due to both conditions contained in existing contractual relationships with BBP and the technical reliability of the plant. The existing thermal units were not considered a reliable source of generation, noting that one of the BBPS units had experienced a five-week outage at the end of 2007.

Given the BBPS was due to be de-commissioned when the TVPS came online in 2009, it was effectively being run without regard to longer-term reliability. This is reflected in its performance. For example, in 2008-9, the availability of Bell Bay Unit 1 was only 7 per cent, while the forced outage rate was 90 per cent. By way of comparison, the forced outage rate of the hydro system is approximately 2 per cent.

It should also be noted that the three FT8 units were not available at this time, as they were in the United States being refurbished and upgraded from 35MW to 40MW.

Therefore, the Government's decision to acquire the TVPS was based on an unwillingness to accept a low probability, but high consequence risk of having insufficient energy to meet on-island demand, in the medium term, in the event that very low inflows continued, combined with the inability to source sufficient capacity from Basslink and thermal generation.

The Panel has not seen any evidence (including Cabinet materials) that any suggests that the acquisition was motivated by any factors other than ensuring the project's timely completion in order to support energy security.

1.2.3. Heads of Agreement, Parliamentary Approval and Sale and Purchase Agreement

On 11 August 2008, Cabinet agreed that the Government would to enter into negotiations with BBP for the acquisition of the TVPS. As part of its Decision, Cabinet authorised the Premier, Treasurer and Minister for Energy to approve the final transaction, approved the creation of either a new State-owned company or subsidiary to own and fund the purchase of the TVPS and authorised the Treasurer to enter into any necessary contracts on behalf of the Crown.

On 15 August 2008, following accelerated negotiations with BBP, the Government agreed to a binding Heads of Agreement (HoA) for the acquisition of the TVPS. The Government also endorsed the model that the TVPS would be owned and operated by a wholly-owned subsidiary of Aurora Energy, AETV.

The AETV subsidiary model was selected on the basis that it was relatively simple to implement (i.e. not requiring the creation of a new State-owned company) and would be able to 'draw on existing management capabilities and systems within Aurora'. The key consideration was that the model could be established within BBP's timeframes for the TVPS sale.[41]

The HoA provided for the acquisition by the State of all shares and related assets of AETV for an agreed purchase price of $100 million, plus development costs between 8 August 2008 and completion of the sale, plus 50 per cent of the unused project contingency included in a works program agreed between the parties. As part of the transaction, the State would receive the three refurbished FT-8 gas turbines that were previously sold as part of Hydro Tasmania's 2007 BBPS sale to Alinta. Total estimated project completion costs at the time were $360 million, which included the $100 million acquisition costs.

The HoA was subject to a number of Conditions Precedent (in addition to standard due diligence provisions) including:

- **Approval by the Tasmanian Parliament and the Australian Competition and Consumer Commission (ACCC);**
- **A draft ruling by the AEMC Reliability Panel that would indicate that the TVPS would be able to be connected to the network;**
- **The novation of gas supply and transportation contracts to Alinta Energy Tamar Valley prior to sale completion; and**
- **Arrangements to ensure that AETV would have the benefit of key contracts required for the completion and subsequent operation of the TVPS.**

[41] Minute to the Treasurer, '*Tamar Valley Power Station – Ownership Options*', 15 August 2008.

On 19 August 2008, the Premier made a Ministerial Statement to the Parliament announcing the Government's HoA with BBP. On 21 August, the Minister for Energy introduced the *Tamar Valley Power Station Bill 2008*, which provided for the Shareholder Ministers to direct Aurora Energy to acquire from BBP shares and assets in AETV.[42] The Bill was passed by the Parliament on 28 August 2008.[43]

The Government indicated at the time of acquisition that it did not intend to be the long-term owner of the TVPS, with the intention that it would be sold to a private sector operator after an 'appropriate' period of operation[44] (considered to be between three to five years).

At the same time that supporting legislation for the transaction was being considered by the Parliament, the Government was simultaneously progressing with legal, technical and financial due diligence and accelerated negotiations with BBP to finalise a SPA for the TVPS. The final SPA was based largely around the terms and conditions already laid out in the HoA and retained the same purchase price and conditions precedent to that agreement.

The Shareholder Ministers issued a formal direction to the Chairman of Aurora Energy on 27 August 2008 for the Company to acquire the shares and assets of Alinta Energy Tamar Valley. The SPA was subsequently executed by Aurora Energy on 1 September 2008.

The $100 million purchase price was funded by an equity injection from the Government to Aurora Energy under an appropriation from the Consolidated Fund, with the $260 million for estimated project completion costs debt funded through a finance facility with Tasmanian Government lender Tascorp, provided at 'arms length' from Aurora Energy's existing finance facility. Because the development costs took Aurora Energy beyond its approved borrowing limit, Tascorp financing was provided on the condition that the Treasurer issue a 'letter of comfort' to essentially underwrite the TVPS borrowings.

1.2.4. Satisfaction of Conditions Precedent and Completion of the SPA

Gas Supply and Transportation Arrangements

At the time BBP had decided to include the TVPS in its asset sale program, there were no signed contracts with AETV for either gas supply or transportation to the power station. Instead, the supply and transportation arrangements were contained within a broader suite of agreements within the Babcock and Brown Group, which covered the supply of gas to other facilities in Tasmania and elsewhere in Australia.

---

42 The Bill also provided for the future sale of the TVPS (included to ensure that future sale was not prevented by the *Electricity Companies Act 1997*) and for the transfer of assets and liabilities between state-owned businesses and between the Crown and state-owned businesses.

44 Department of Treasury and Finance (2008) – *Legislation Briefing: Tamar Valley Power Station Bill* ('Questions and Answers')

Aurora Energy indicated to Treasury that a key issue that needed to be addressed in the negotiations by the Government for the purchase of the TVPS was for it to obtain certainty around gas prices, due to the material impact that changes in these prices could have on the cost base and broader financial viability of the power station.

Aurora Energy considered it essential that signed contracts for gas supply and transportation were on foot prior to the finalisation of the sale agreement. The stated rationale was that it considered that it would be in a weak commercial position in trying to negotiate for gas supply and transportation in the market having being directed to acquire a partly-built power station with a clear requirement for gas.

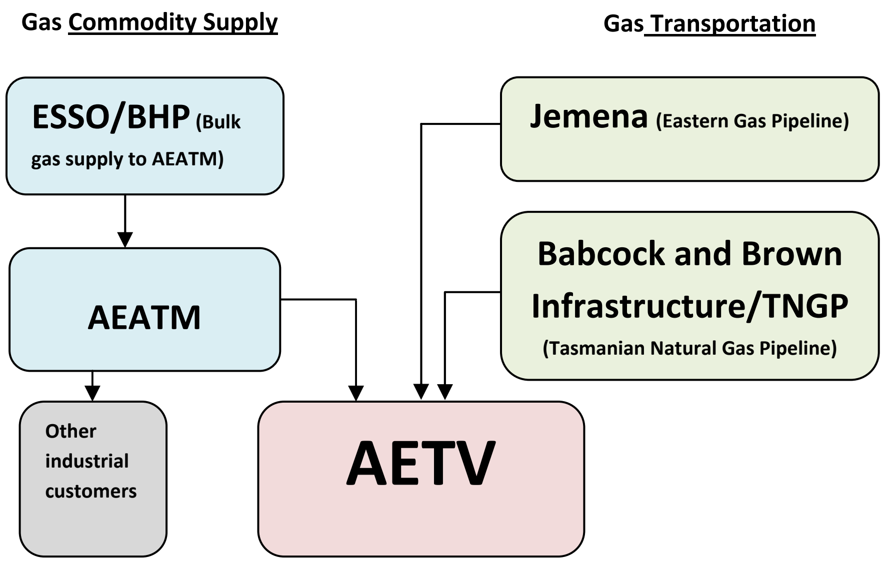
Under the SPA, BBP was required to put in place gas supply arrangements for the TVPS on terms consistent with a wider package of gas commodity and transport agreements that were in place in a related Babcock and Brown entity. The nature of the gas arrangements (volume and conditions) were consistent with the use of gas implied under BBP's operating model for the TVPS.

At the completion of the SPA for the acquisition of the TVPS, AETV (now owned by Aurora Energy) had in place:

- A Gas Supply Agreement **(GSA)** with Alinta Energy Australia Trading and Marketing (AEATM) (a subsidiary of Babcock and Brown), which was directly linked to a larger, aggregated GSA with Esso/BHP; and
- Gas Transport Agreements **(GTA)** with Babcock and Brown Infrastructure (for transport through the TNGP) and Jemena (for transport through the Eastern Gas Pipeline connecting with the TNGP).

The TVPS gas supply and transportation arrangements acquired under the SPA are outlined in Figure 1**,** below.

Figure 1 - TVPS Gas Supply and Transportation Agreements under the SPA



ACCC Approval

Following the execution of the SPA, the ACCC raised significant concerns with regard to the potential competition impacts of the TVPS acquisition, including an indication that it may seek a Federal Court injunction to prevent the completion of the transaction. Treasury had earlier written to the ACCC outlining a range of principles that the Government was applying in relation to the acquisition, including a commitment to sell the TVPS within the short to medium term.[45]

Initially, the ACCC's position was that its approval of the transaction would be conditional upon the sale of the asset to another operator within a pre-determined timeframe. The Government considered the forced sale provision unacceptable as a sale under these circumstances could precipitate significant value loss on the asset.

Following further discussions, it was agreed that, subject to Aurora Energy preserving the asset, the ACCC would undertake a more rigorous assessment of the competition impacts of the transaction that would take into account the "*public interest and specific circumstances of the acquisition*" by early 2009.[46]

Because ACCC approval was a condition precedent for the completion of the SPA, the Shareholder Ministers had to formally direct Aurora Energy to waive this requirement to allow the sale to proceed, which they did in a Members' Direction on 14 September 2008.

In its subsequent review, the ACCC concluded on 29 October 2008 that the acquisition was unlikely to result in a substantial lessening of competition in any of the relevant markets. The ACCC arrived at its conclusion based on a number of factors, including the nature and extent of the hedge contracts in place between AETV and Aurora Energy and its belief that the likely 'counterfactual' to Aurora Energy's acquisition of the TVPS would have been that the station would have been delayed, or at worst terminated, based on its assessment that the sale to a private operator would have been unlikely in the circumstances.[47]

Frequency Standards Review

The condition precedent relating to the AEMC Reliability Panel's review of Tasmanian frequency standards was satisfied on 28 August 2008, when the Panel handed down its draft report, which indicated that there should be no impediment to negotiating a connection agreement with the generator.[48]

With the satisfaction and/or waiver of all relevant conditions precedent, the SPA was completed on 15 September 2008.

---

45 *Treasury Secretary to Chairman ACCC,* 4 September 2008

46 Minute to the Treasurer, *Completion of the Tamar Valley Power Station Acquisition*, 12 September 2008

47 ACCC, Informal Review - *Aurora Energy acquisition of the Tamar Valley Power Station Project* 29 October 2008 - http://www.accc.gov.au/content/index.phtml/itemId/847380/fromItemId/751043

48 Letter from CEO Transend to Minister for Energy, 10 September 2008.

1.2.5. Project Completion and Commissioning

Following completion of the SPA, AETV took on responsibility for project construction and completion. Under the SPA, all existing employees of BBP involved in the building of the TVPS transferred to AETV on equivalent terms and conditions.

The TVPS was commissioned over a six month period, commencing in June 2009 with the testing of the Trent open cycle generator and the commissioning of the three FT-8 units. Delays to the implementation of the revised frequency standards approved by the AEMC Reliability Panel in December 2008 required AETV to seek a 'non-controversial participant derogation' in order to allow the connection of the TVPS for commissioning testing. The new frequency standards were implemented on 28 October 2009, following the official opening of the power station on 26 October 2009.

The project was delivered for around $20 million under the original $351 million dollar budget.

In considering project delivery issues, the Panel notes that at the time the Government made the decision to acquire the TVPS, Aurora Energy was a combined retailer/distribution business, with no experience in generation construction or operations. The complexity associated with this fundamental change in corporate direction required a step-change in Aurora Energy's structure at the functional and at the corporate level. In the event, Aurora successfully executed the construction program while creating the internal capacity to ensure that the power station was successfully commissioned into the Tasmanian electricity supply industry.

Acquisition and Completion of the TVPS by the State - Summary

- In June 2008, BBP embarked on a divestment program for a range of assets, which included the TVPS.
- Uncertainty regarding a connection agreement that would permit the station to connect to the Tasmanian system (or, less critically, delays caused by the Frequency Standards review process) was one issue impacting on the commercial attractiveness of the TVPS in the market.
- The Tasmanian Government initially attempted to act as facilitator to help BBP resolve the connection issue and assist with the sale to a third party operator.
- However, with no other likely buyers in the market and with pressure being applied by its financiers, BBP approached the Government and proposed acquisition within an extremely compressed timeframe.
- Threats to timely completion of the project came at the same time as near-record low hydrological inflows and storages and falling reliability of the BBPS, which had increased the risk of potential energy shortfalls in Autumn 2009.
- The Government determined that it would acquire and complete the TVPS project on energy security grounds.
- The Government paid $100 million to BBP and took on responsibility for what was estimated at the time to be $260 million in project completion costs. The transaction was approved by the Tasmanian Parliament.
- The acquisition was completed on 15 September 2008.
- TVPS construction and commissioning proceeded under the control of AETV, with project staff transferred from BBP. The station was officially opened on 26 October 2009. Project execution by Aurora Energy was very strong, with the TVPS being completed on time and $20 million under budget.

1.3 Post-Acquisition Commercial and Operational Arrangements

The period following the acquisition of the TVPS involved a number of key events and decisions that have shaped the commercial and operational arrangements that currently underpin the operation of the TVPS.

These included, most significantly:

- Aurora Energy's acquisition of additional significant gas commodity and capacity contracts; and
- a range of actions taken by Aurora Energy and the Government to address AETV's worsening financial position, including internal restructuring of Aurora Energy's business groups, the establishment of revised commercial arrangements between AETV and Aurora Energy, and the passage of the *Electricity Supply Industry (Price Control) Amendment Regulations 2010* (Price Control Regulations).

These matters are discussed in more detail below.

1.3.1. Aurora's Purchase of AEATM Assets/Gas Contracts[49]

Following the completion of its sale of the TVPS to Aurora Energy, in November 2008 BBP approached the market to sell the full suite of AEATM assets/contracts, which included the GSA for the TVPS, as well as a larger aggregated GSA with Esso/BHP. The asset package also included the GTAs between AEATM and BBI and Jemena from which the TVPS GTA was 'carved out' and a Tolling Agreement over the output of the Bairnsdale Power Station in Victoria.

Aurora Energy was approached as one of a small number of participants to purchase the AEATM assets. BBP's sale timetable was extremely compressed, with binding bids due by 10 December 2008 and financial close on 15 December.

Following a short due diligence process, the Aurora Energy Board approved the submission of a bid for the assets, which was based on a significant discount for risks associated with the quick sale process.[50]

In acquiring the AEATM gas assets, Aurora Energy was driven largely by a defensive, risk mitigation strategy that focused on securing control over its gas supply arrangements.[51] Aurora Energy was concerned that the acquisition of the AEATM 'head' GSA by a competitor might see increases in gas prices. Aurora Energy saw value in being able to negotiate directly with Esso/BHP rather than relying on a third party with no obvious interest in securing a good gas price for AETV.

[49] This Paper does not examine the commercial rationale or decision-making for the AEATM asset purchase, but a brief discussion has been included in light of the fact that the decision was primarily triggered as a result of Aurora Energy's acquisition of the TVPS.

[50] Aurora Board Paper, 8 December 2008

[51] *Ibid*

Commercial and Operational Arrangements: *Key Events and Decisions*

December 2008 - Aurora Energy acquires BBP's AEATM gas assets.

February 2009 – Aurora Energy confirms that the TVPS' fair market valuation is likely to be substantially lower than its completion costs or its replacement value.

March 2009 - Aurora Energy approaches Government seeking assistance with regard to AETV solvency concerns. Treasury and Aurora Energy commence a joint work program to address identified financial issues.

July 2009 - Aurora Energy implements a new integrated Energy Business structure and replaces the existing Aurora Energy/AETV hedge contract with a tolling agreement. The Treasurer advises Aurora Energy that the Government will be directing the Regulator to apply 'long-run marginal cost' to the 2010 Pricing Determination in order to provide a level of comfort to Aurora around future revenues for its retail business and its capacity to fund the tolling agreement for the TVPS.

December 2009 - The Aurora Energy Chairman writes to the Shareholder Ministers on 11 December 2009, outlining a range of concerns regarding the financial position of the Company.

January 2010 - The Aurora Energy Board tasks a special subcommittee to hold separate, extraordinary briefings with both Shareholder Ministers (the Minister for Energy on 12 January 2010 and the Treasurer on 18 January 2010) to further discuss the issues raised in the 11 December 2008 letter.

February 2010 - The Government announces its election commitment of a 'blanket' five per cent electricity price cap for non-contestable customers for 2010-11, with the LRMC – based Pricing Determination to be delayed until 2011-12.

April 2010 – Aurora Energy makes formal presentations to Government with regard to its worsening financial situation – including the likely impairment at the end of 2009/10 in the order of $340 million.

June 2010 – The Government publicly announces that it will not be proceeding with its promise to cap electricity price increases to 5 per cent or all customers (instead committing to a $100 one-off increase in the electricity concession). The Parliament passes amendments to the energy Price Control Regulations, which have the effect of increasing revenues and revenue certainty for Aurora Energy.

28 June 2010 – the amended Price Control Regulations take effect.

1 July 2010 – Aurora Energy and Hydro Tasmania enter into new hedge arrangements for the non-contestable load, on terms consistent with those prescribed in the Price Control Regulations

Aurora Energy was also concerned that, in the circumstances where BBP were to fail, AEATM's GSA with Esso/BHP would be 'disclaimed', leaving AETV with no gas and finding itself in the situation where it would have to negotiate new supply arrangements from what Aurora Energy had determined would be a weak bargaining position. This was a similar rationale to that which drove the Government and Aurora Energy to secure of GSA/GTA arrangements as part of the SPA.

The AEATM acquisition increased the potential flexibility of the operating regime for the power station, as it removed a contractual 'partition' in the broader and larger take-or-pay arrangements between AEATM and Esso-BHP that applied to the TVPS. Aurora Energy

Aurora Energy also saw some value in the acquisition in terms of growth potential in the supply of gas to major customers in Tasmania as well as retail customers. Aurora Energy created the option of reducing the gas obligations in relation to the TVPS if it could find alternative markets for the gas, either in Tasmania or elsewhere in Australia. However, the gas transport arrangements do not offer such flexibility – these have large fixed obligations, regardless of whether the gas is transported across the network to Tasmania or not.

1.3.2. Initial Decisions and Actions in Response to AETV's Emerging Financial Difficulties

In September 2008, Aurora Energy wrote to the Treasurer raising concerns over the impact of the purchase and construction of TVPS on Aurora's balance sheet and financial position.

By February 2009, Aurora Energy had developed a baseline budget for AETV's ongoing operations and established the 'fair market' valuation of the TVPS. Based on modelling that it had commissioned, Aurora Energy found that the TVPS' valuation, at $228 million, was substantially lower than its acquisition and completion costs or its replacement value. The valuation was based on a greater understanding of the BBP model, lower than expected market revenues available to the TVPS than assumed in that model and the recognition that the ongoing costs of TVPS were going to be higher than expected.[52]

Given the significant difference between Aurora Energy's revised market valuation and the expected completion costs, Aurora Energy faced the prospect of having to significantly impair or 'write down' the value of the TVPS in its accounts. These concerns continued through 2009, with AETV internally concerned with potential impairment of the value of the TVPS of around $140 million in June 2009.

---

52 This valuation assumed that the contractual arrangements that were in place for the TVPS with Aurora Energy remained in place.

The Aurora Energy Chairman subsequently wrote to the Shareholder Ministers on 27 February 2009 ‘as a matter of urgency’[53] with regard to the financial position of the TVPS. The Chairman advised that Aurora Energy would have to impair the asset and that, in the absence of other viable alternatives, would need to seek financial assistance from Government.

As a result of discussions with the Shareholder Ministers in March 2009, Aurora Energy and Treasury jointly agreed a work program in the first part of 2009 to address TVPS’ financial difficulties. A key issue for the value of the TVPS was the value derived from the contractual arrangements between AETV and Aurora Energy[54], together with the ability of the TVPS to generate other sources of value from the market. Solutions were aimed at reducing the operating costs and enhancing both revenue and revenue certainty for the TVPS.

Aurora Energy pursued measures to maximise efficiencies and increase value in the TVPS, the key elements of which are summarised below.

‘Functional Integration’ of the Aurora Energy Group Structure

In February 2009 the Aurora Energy Board approved a revised operating structure for the Group, based around the establishment of an integrated retailer/generation relationship and the creation of a new wholesale energy function to manage and optimise energy generation, wholesale supply and hedge contracts. This effectively integrated the commercial –distinct from the operational - functioning of TVPS within the Group so that it now operated as a ‘gen-tailer’.

AETV was maintained as a separate legal entity (as required under the operating model originally agreed by the Shareholder Ministers), responsible for the construction, commissioning and operation of the TVPS, while a Wholesale and Trading Division was established and have clear commercial relationships with TVPS and Aurora Energy’s Retail Business.

The new integrated Energy Business was subsequently approved by the Shareholder Ministers and established from 1 July 2009, comprising generation and wholesale energy, with the subsequent inclusion of Retail from 1 January 2010.

[53] Letter from the Chairman to the Treasurer, 27 February 2009.

[54] At this time, this was the hedge that was in place between Aurora Energy and Babcock and Brown prior to the acquisition of the TVPS by Aurora Energy.

Tolling Fee Arrangements

As part of its revised Energy Business model, Aurora Energy also replaced the hedge contract[55] between AETV and Aurora Energy with a new 'tolling fee' arrangement to govern the relationship between the Energy Business and AETV.

The new tolling agreement took effect from 1 July 2009. Under the arrangement, TVPS's rights and obligations associated with the pool income from generation are transferred from AETV to Aurora Energy, in return for a fee. The Energy Business owns the gas arrangements and makes the decision as to when TVPS will operate and at what level and provides the gas to it to produce at that level.

However, given that the new tolling agreement essentially replicated financial outcomes under the previous hedge contract, the new arrangement did not in and of itself make a material difference underlying commerciality of the TVPS or impact on its fair value.

Aurora Energy's Board subsequently agreed to an increase in the effective hedge price/tolling fee revenue in July 2009[56], following a request by the AETV Board. The revised tolling fee comprised two components:

- a base component that reflected the financial value inherent in the original financial contracts with Alinta/Babcock and Brown; and
- an additional payment based on Aurora Energy's assessment of the market value of the TVPS to deliver additional value that would secure financial stability to AETV, valued at around $7 million per annum.

Approval of the increase was given on the understanding that Aurora Energy's retail business could cover the increase in the short term but would likely be able to recover the additional cost of the price adjustment from future adjustments to regulated wholesale energy prices[57], given that the Treasurer had advised Aurora Energy that the Regulator would be required to apply long-run margin cost (LRMC) for the 2010 Determination, which was expected to closely reflect the costs of the TVPS. The intention was that this would carry forward the existing basis for determining the wholesale energy allowance that was established in 2007.

While the tolling agreement was between AETV and Aurora Energy's energy business, there was a subsequent transfer price agreement between the retail business and the energy business. At this time, however, there was no new net additional value created within Aurora Energy to underpin the tolling agreement – rather the arrangement concentrated the value implications of the TVPS' function in the Tasmanian market with Aurora Energy's energy business.

---

[55] This was the hedge that was originally negotiated between Alinta and Aurora Energy, discussed in more detail in Section 3.

[56] The TVPS was yet to enter commercial service at this time

[57] Aurora Energy Board Paper, 22 July 2009.

Aurora Energy's Board ultimately decided that impairment at the end of 2008-09 was not required, based in part on the increase in the effective hedge price paid by Aurora Energy to AETV and also because the station had not yet been fully commissioned and so had no actual substantive operating period in which to assess its cost and revenue base to fully inform any change in the TVPS value.

1.3.3. Further Decisions and Actions relevant to AETV's Financial Position

After the TVPS was commissioned in October 2009 and had been operating for a period of time, it became clear that its operating costs were still significantly higher than the revenues that were being delivered under the terms of the tolling agreement, leading to a loss on every MW of electricity produced.

In short, operational restructuring and an increase in the value contained within new tolling arrangements had not been enough to ensure that the TVPS could operate on a commercially sustainable basis. Moreover, wider changes in the energy market, coupled with the financial challenges facing the TVPS, gave rise to the potential significant impairment of the entire Aurora Energy energy business at the end of 2009-10. This is because Aurora Energy had by this time developed a consolidated position on impairment. Under the new structure, for accounting purposes, the TVPS was considered to be part of the broader Energy Business Cash Generating Unit.

The Aurora Energy Chairman wrote to the Shareholder Ministers on 11 December 2009, outlining a range of concerns regarding the financial position of the Company, including:

- AETV's unsustainable debt levels;
- A need to increase borrowing capacity; and
- Wholesale energy arrangements that were preventing Energy business from generating enough revenue to cover operating costs.

The Aurora Energy Board also tasked a special subcommittee to hold separate, extraordinary briefings with both Shareholder Ministers (the Minister for Energy on 12 January 2010 and the Treasurer on 18 January 2010) to further discuss the issues raised in the 11 December 2008 letter. Aurora Energy was by now concerned that overall profitability was being impacted by large losses starting to appear in the Energy Division.[58]

---

[58] The presentation given to the Shareholders concluded with the comments that: "*the Aurora Board is deeply concerned about Aurora's projected financial position*" and that the "*Directors of Aurora are increasingly concerned about their future ability to properly discharge their responsibilities while these key issues remain unresolved*". Pricing decisions (including uncertainty around Hydro Tasmanian pricing for non-contestable customers after June 2010) were raised as one of the four key issues driving the current outlook.

Further detailed information about the extent of Aurora's financial difficulties became evident when it submitted its draft Corporate Plan on 31 March 2010. Aurora Energy's briefings to Government in March, April and May 2010 suggested that "*...if action is not taken in the very short term most of the value of the Energy Business assets, including the TVPS will be impaired at 30 June 2010, and the business will be unsustainable in the medium to long term*".[59]

Aurora Energy's main concerns related to uncertainty around a number of outstanding external issues of material impact on the performance of the Energy Business, including the revenue it could recover from non-contestable customers under the 2010 Pricing Determination and contractual arrangements with Hydro Tasmania for the supply of wholesale energy for the non-contestable market.[60]

Aurora Energy's poor financial situation was also being compounded by a significant annual finance charge arising from operating results for TVPS which, in the absence of sufficient cash flows, had to be further financed by debt.

Amendments to the Price Control Regulations passed by the Parliament in June 2010 were ultimately central to ensuring AETV's viability in two key respects.

- Firstly, the Regulations specified that the TER apply an LRMC methodology to the wholesale energy allowance for non-contestable customers, which would have the effect of delivering an allowance at levels that were broadly consistent with (but not the same as) the costs of generation from the TVPS; and
- Secondly, the Regulations gave the Treasurer ultimate 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, if required. [61]

The regulations were subsequently approved by the Tasmanian Parliament and became effective from 28 June 2010.[62]

---

59 Aurora briefing to Treasury, May 2010.

60 Aurora Briefing Note to the Expert Panel, 18 May 2011

61 The effect of this regulation is that to the extent that Aurora Energy elects to utilise the TVPS to back non-contestable customer load, and those costs are in excess of the wholesale energy allowance, the value consequence is passed through to Hydro Tasmania.

62 The motion to pass the PCR amendments was carried with the support of the Tasmanian Greens. However, it should be noted that this support was contingent on the Government's agreement to establish the independent inquiry into the Tasmanian electricity supply industry.

The outcomes delivered by the Regulations were critical to improving Aurora Energy's financial position and facilitated a further increase in September 2010 of the tolling fee paid by Aurora Energy to AETV.[63]

In its covering letter to its final 2010-13 Corporate Plan, Aurora Energy noted that "*...profit before tax has changed from a negligible amount (or small loss in the later years) to levels not inconsistent with those achieved by Aurora Energy in the years prior to the Tamar Valley Power Station acquisition*".

The two key elements of the amended Price Control Regulations are briefly described below.

1) <u>*Wholesale Energy Allowance for Non-Contestable Customers*</u>

Aurora Energy had been in discussions with Treasury since early 2009 regarding its position on the Regulator's 2010 Pricing Determination[64] for non-contestable customers, arguing that the methodology and principles applied by the Regulator needed to reflect costs that would be reasonably be expected to apply in Tasmania (essentially, the cost of generation at the TVPS).

The Treasurer wrote to the Aurora Energy Chairman in July 2009, confirming the Government's intention to apply LRMC to the wholesale energy component under the 2010 Pricing Determination. It is noted that LRMC had also been applied in the 2007 Determination and in this sense its application in 2010 represented a continuation of the broad approach to setting the wholesale energy price. The Treasurer sought confirmation from Aurora Energy that certainty that LRMC would again be applied would provide sufficient comfort so that it would not be necessary to impair the TVPS. Aurora Energy subsequently confirmed that this was the case.

There was the potential for a departure from this approach in with the Labor Party's announcement on 15 February 2010 (during the State Election campaign) that, if re-elected, it would cap 2010-11 price increases for non-contestable customers at five per cent and defer the next Pricing Determination by the TER for one year.[65] This would have resulted in a delay in the implementation of the revised LRMC arrangements. However, the five per cent price cap commitment was subsequently changed to a $100 one-off in increase in the electricity concession for eligible customers. The passage of the amended Price Control Regulations[66] saw the implementation of the original LRMC position with regard to the wholesale energy allowance.

---

63 Aurora Energy noted in a 17 September 2010 letter to the Treasurer that "...the impacts of the Hydro agreement and energy price are by far the most material changes that have driven a significant positive turnaround in Aurora's financial projections"

64 The 2010 Pricing Determination is discussed in more detail in the Draft Report.

65 Please note that the 'five per cent price cap' issue is not discussed any further in this Paper, as this matter is covered in the Draft Report.

66 Please note that the 'five per cent price cap' issue is the subject of a separate Term of Reference and is not discussed in any further detail in this Paper.

2) <u>Contractual Arrangements between Aurora Energy and Hydro Tasmania for the Non-Contestable Load</u>

In addition to the outcomes of the 2010 Pricing Determination, the establishment from July 2010 of new contractual arrangements with Hydro Tasmania for the non-contestable load block was critical to the financial fortunes of AETV and avoiding the impairment of Aurora's Energy Business, including the TVPS.

Aurora Energy's key objectives in securing new arrangements from July 2010 were for "*…an acceptable contract price that would ensure that Aurora Energy's total costs of supplying wholesale energy to non-contestable customers did not exceed the revenues that customers would pay under regulated tariffs*",[67] along with better utilisation of the TVPS.

To prevent the situation where Aurora Energy might face overall energy costs for non-contestable customers in excess of the revenues allowed by the Regulator, the amended Price Control Regulations contained a provision that, any contract between Hydro Tasmania had to be approved by the Treasurer, but only if he or she was satisfied *"…that the effect of the terms and conditions of the relationship or arrangement is that Aurora Energy may expect that it will not cost Aurora Energy more, during the relevant period, to supply energy to non-contestable customers as a whole, than Aurora Energy is permitted, under any retail price determination in relation to the relevant period, to charge those customers as a whole for that supply".*[68] If no commercial agreement could be reached, the Treasurer could mandate, by notification in the *Gazette*, a default contract arrangement for Hydro Tasmania to supply wholesale energy to Aurora Energy that satisfied this test.

Treasury had prepared a draft 'fall-back' contract for implementation under the Regulations, which would set the energy price paid to Hydro Tasmania for the non-contestable load at a level that did not exceed the energy allowance as determined by the Regulator.

However, before the terms and conditions of that contract were potentially required to be given effect, Aurora Energy confirmed that it had negotiated a suite of hedge contracts to back the non-contestable load with Hydro Tasmania on terms that were commercially acceptable to both parties, and which met the test under the Regulations, so a regulated contract was not required.

The revised hedging contracts for the non-contestable load addressed Aurora Energy's previous issues with underutilisation of the TVPS and exposure to pool prices. As a consequence, Aurora Energy has since sought to utilise the capacity from the TVPS, (particularly from the CCGT) to back the higher-value non-contestable load.[69]

---

67 Aurora Energy briefing note to the Expert Panel, 30 March 2011

68 *Electricity Supply Industry (Price Control) Regulations 2003*

69 Aurora Briefing Note, 28 Feb 2011.

Reduced Volatility of Frequency Control Ancillary Services (FCAS) Costs

The volatility of FCAS[70] costs was also a major influence on the viability of the TVPS, prior to FCAS raise services being declared by the Tasmanian Regulator as a 'prescribed service'.

On 1 April 2009, at the expiry of the previous load following hedge between Aurora Energy and Hydro Tasmania, FCAS raise contingency services increased from an average weekly cost of $45 000 to approximately $10 million per week and stayed at this level for a period of three weeks, up until the signing of a hedge contract between Aurora Energy and Hydro Tasmania, at which point they returned to 'pre-spike' levels.

The investigation by the ACCC and the Tasmanian Regulator into this event, and the subsequent prescription of raise FCAS services in late 2010, resulted in an obligation being placed on Hydro Tasmania to provide a new 'safety net' hedge contract in line with the Regulator's pricing control arrangements.[71] In essence, the safety net contract removes AETV's (and other market participants') exposure to FCAS market volatility and therefore provides a stable hedge cost (less than half that previously paid before FCAS was declared a prescribed service) that AETV is able to budget for.

70 FCAS is used by AEMO to maintain the frequency of the transmission system. 'Regulation' FCAS constantly provides for the correction of minor deviations in load or generation output and is mainly supplied by generators. Generally, this involves a generator with fast response times either being started in order to correct a low frequency in the system, or generation plant being rapidly unloaded to correct a high frequency event. Less frequently used is 'contingency' FCAS, which is used to correct the large variations in system frequency that can result from events such as the tripping of a generator, an element of the transmission or distribution network (including Basslink) or the sudden loss of a significant customer load. Contingency FCAS is also generally supplied by generators. FCAS providers are paid by AEMO for being on standby, as well as when they are actually called upon. AEMO recoups these expenses from other generators (on a 'causer pays' basis) or customers (such as electricity retailers). The cost of lowering the network's frequency is reflected in charges to customers while the cost of 'raise' services is met by generators and, ultimately, through energy prices.

71 In its 2009 determination on the matter, the Regulator found that Hydro Tasmania had been misusing its market power, extracting monopoly rents and bidding anti-competitively on FCAS at high prices – see the Tasmanian Energy Regulator's
FCAS Pricing Investigation – Final Report, 17 December 2010. 2

Post-Acquisition Commercial and Operational Arrangements - Summary

- The fair value of the TVPS and its relativity to book value was considered in early 2009 when Aurora Energy was going through the process of establishing a baseline budget for the new entity.
- Without increases in revenue, and reductions in gearing and operating costs, the TVPS faced significant impairment at the end of 2008-09.
- Aurora Energy pursued a number of strategies to address AETV's financial circumstances, including a restructure to improve the efficiency of its energy business and the establishment of a tolling fee arrangement with AETV.
- Impairment was avoided in 2008-09, in part because of an increase in the effective hedge price under the new tolling fee arrangement funded by Aurora Energy's retail business, and also on expectations regarding the 2010 Pricing Determination for non-contestable customers.
- A number of issues during 2009-10 contributed to a worsening of the Aurora Energy Business' financial position, including a significant annual finance charge arising from operating results for TVPS which, in the absence of sufficient cash flows, had to be further financed by debt.
- A range of external issues were also impacting on Aurora Energy's financial outlook, including its ability to negotiate a hedge contract with Hydro Tasmania for the non-contestable load at a price that did not result in its overall energy costs for non contestable customers exceeding the Regulator's allowance.
- Aurora's Energy Business was facing significant impairment at the end of 2009-10. Aurora Energy briefed the Government in January 2010 and then again in April 2010 (by which time it had more detailed financial projections) on its financial position, requesting significant and immediate assistance.
- Government policy intervention was ultimately central to ensuring AETV's viability in two key respects. Firstly, the Government set the parameters around the Regulator's 2010 pricing determination for the wholesale energy allowance for non-contestable load which, in effect, broadly reflect the cost of generation at the TVPS. Secondly, it changed the regulatory framework within which Aurora Energy contracts with Hydro Tasmania for non-contestable load, which had the effect of providing Aurora Energy with the financial headroom to cover the TVPS' costs.

2. Economic and commercial considerations

2.1 Core underpinnings of the Alinta-Aurora Energy transaction

The core commercial underpinnings that led to the development of the contractual arrangements between Aurora Energy and Alinta in respect to the TVPS were:

- Alinta owned the TNGP, and had a commercial driver to see the gas transmission pipe utilised – with the TVPS providing a key foundation load[72];
- Alinta had experience in building, owning and operating gas-fired power stations in Australia – this was its core business;
- Alinta had a portfolio of gas arrangements, which it acquired from Duke Energy and experience in the wholesale gas sector;
- Aurora Energy had exposure to the Tasmanian spot market to back its contestable and non-contestable customers, and the ACCC authorisation of the vesting contract between it and Hydro Tasmania precluded the contract from covering between 25 and 10 per cent of its vested load under that vesting contract; and
- Aurora Energy had a commercial interest in the development of an alternative generator in the Tasmanian region to provide competitive tension in its dealings with Hydro Tasmania.

Constructing and operating a long-term asset like the TVPS involves considerable risk – the longest-term of these (and a critical one in respect of financing such a development) is managing revenue risk. Securing a medium-long term arrangement in respect of the value of output is typically critical in moving a project from concept to reality. Like any off-take arrangement, this involves that producer transferring some or all of the value risk to the purchaser.

In the case of the TVPS development, Alinta took on the construction, operational, gas trading and some output value/trading risk and Aurora Energy took on the majority of the value/trading risk, and along with retail market risk[73] – see Table 2.

72 This is a key consideration. In the event that a power station did not emerge in Tasmania, the gas pipeline would be heavily underutilised (in the absence of some other large-scale gas load).

73 That is that it would have ongoing contractual backing from the Alinta but a mismatch of customer contracts to ‘on-sell’ that energy.

Table 2 - Risk Allocation under the Alinta-Aurora Energy arrangements

Risk	Description	How managed	Responsibility
Construction	Risk of cost increases and not delivering to performance specifications (ie not fit for purpose)	Engage a developer with experience in gas development (ie Alinta)	Alinta – had that experience
Operations	Ensure plant operates to requirements and when required	Experienced operator of Gas plant with suitable incentives to operate at appropriate times	Alinta – had that experience
Maintenance	Plant is well maintained to ensure performance requirements are meet	Experienced maintenance company as owner or engaged.	Alinta – had that experience
Gas supply	Gas supply quantities available and transported when required for power station to operate	Managed by a experienced Gas supplier ideally with a portfolio of gas contracts to manage volume risk	Alinta – had access to gas and owned the gas transmission pipe
Electricity Trading	Fluctuating future spot market energy prices impact on sustainable returns	Managed by a contract with a wholesale or retail counterparty to lock in a sustainable price for sufficient volume to achieve desired risk profile	Alinta had dispatch risk[74] and Aurora had price risk associated with managing their retail requirements

In 2006, Aurora Energy and Alinta had agreed to a five-year suite of swap and cap arrangements and that provided a further ten-year extension for either financial or physical options. These arrangements were subject to the finalisation of the gas supply arrangements, which subsequently were not completed, due to Beach Petroleum not proceeding with its Bass Strait gas developments.

By July 2007, Alinta had decided to use an existing gas supply agreement to back the TVPS operations with an increase in the both the swap and cap price and changes in the terms to 25 year deal (9+6+5+5 years), with a three-year review of gas prices.

[74] Dispatch risk is the risk that the power station does not achieve output levels consistent with contract levels and therefore creates spot market exposures for the generator (if prices are high and dispatch is not achieved, the generator has no spot market revenue to back its contract position with the retailer).

There was some flexibility provided to Aurora Energy under these arrangements, after five years, to change its nominations between the level of swap and caps on an annual basis. This was attractive from Aurora Energy's perspective, as it enabled it to optimise its position in light of prevailing Tasmanian market dynamics. It allowed Aurora Energy to match potential changes in Hydro Tasmania's contracting appetite and/or spot market behaviour, such that Aurora Energy could avoid being significantly over contracted, and therefore reducing its exposure to the spot market and volatility in value that this creates.[75]

A change in the mix of swaps and caps could significantly change the operating regime for the TVPS, and the level of gas it required. Under these arrangements, this was Alinta's risk.[76] It would appear that given its position in the national gas and electricity markets, Alinta considered it was able to manage these risks.[77]

While the Aurora Energy contract was a key underpinning revenue source for the TVPS, Alinta was also relying on value extracted from their operation and management of their gas infrastructure, the spot market and the green products market.[78] Therefore, Alinta was not wholly reliant on the contract to cover the costs of TVPS.

2.2 Babcock Brown Power Purchase the Alinta Assets

Babcock and Brown's acquisition of the TVPS project as part of its nation-wide acquisition of Alinta led to an important change in the commercial framing of the transaction – Babcock and Brown effectively 'partitioned' the value arising from the project into separate (but related) entities – the TVPS was allocated to Babcock and Brown Power, and the gas pipeline was allocated to Babcock and Brown Infrastructure. This separation meant that the value attributable to each entity was not 'seen' by the other and eliminated any value Alinta had attributed to the joint management of the package of TVPS, gas and gas transport arrangements.

---

75 It should be noted that this flexibility was limited by the option nominated by Aurora in the contract. In one option the flexibility was increased but needed 12 months notice, while the other was limited in flexibility but had a shorter notice period. If the first option was chosen the ability to change volumes at short notice would have been lost. The latter option was similar to a tolling agreement for higher volumes and favoured an expectation of high production from TVPS.

76 If the change in swap volume was substantial, there was financial compensation for Alinta from Aurora Energy. The Panel considers that this was likely to reflect the potential impacts in terms of generation and gas supply costs.

77 Discussions with Aurora Energy staff that were involved in the negotiations highlighted their view that the structure and pricing of the hedge arrangements were not built around capturing a value margin on a long-term gas (commodity) contract. Rather, the arrangements were more structured around securing value against the fixed costs associated with the TVPS and the gas transmission pipeline. The Aurora Energy staff view was that Alinta considered the risk it faced in securing alternative markets for gas relatively low by comparison with these other risks.

78 New South Wales Greenhouse Gas Abatement Certificates

The Panel has reviewed the financial model Babcock and Brown Power used for the TVPS.[79] The model indicates that it was anticipating generating value over-and-above the direct swaps and caps with Aurora Energy. It expected to generate value from the Tasmanian spot market, through:

- arbitrage from the spot market when prices were lower than the costs of running the power station to support the hedge contract volumes;
- operating base load plant to its maximum capacity of 203 MW during peak priced hours and capturing additional value[80]; and
- operating the peaking plant at high priced times, when base load plant is also operating, to capture the high prices.

In this context, the model indicates that Babcock and Brown Power proposed to take wholesale market risk in relation to the TVPS development. This aligns with the need to use gas in the order of 13PJ[81]. The risk allocation between the parties under the BBP contract arrangements is summarised in Table 3.

Table 3 - Market-related risk allocations under the Aurora Energy – Babcock and Brown contractual arrangements

Event	Aurora Energy	Babcock and Brown
Tas spot prices soft	BBP contract 'out of the money' – mark-to-market loss in Aurora Energy's financial accounts.	BBP contract 'in the money' – mark-to-market gain in BBP financial accounts Spot market revenues fall, reducing of profitability of TVPS.
Tas spot price firm	BBP contract 'in the money' – mark-to-market gain in Aurora Energy financial accounts.	BBP contract 'out of the money' – mark-to-market losses in BBP financial accounts. Spot market revenues increase, improving profitability of TVPS.
Aurora Energy decreases volume covered by swap and increases cover for caps	Cost of cap cover increases. Aurora Energy can replace with Hydro Tasmania swaps or spot market exposure.	May reduce volumes of gas for TVPS and BBP may need to find alternative market for gas, depending on gas contracts.
Gas price increases	No impact within contract period. Gas price reset would increase hedge costs. Aurora Energy faces some gas price risk.	Higher costs passed through to Aurora Energy at price reset. Any price increase within period impacts on BBP profitability.
Spot market revenue opportunities	No exposure	Modelled value from spot market activities all BBP risk

79 This was provided to Government as a part of the sale processes and obtained by the Panel from Treasury under the Panel's information gathering powers.

80 Noting that the difference between the swap volume and the full output was effectively 'at market', unless the spot price was equal to or greater than the cap price.

81 With some additional gas required for the additional peaking plant operations.

2.3 What changed when Aurora Energy Acquired the TVPS?

The Government's direction that Aurora Energy would acquire, complete and operate the TVPS fundamentally changed Aurora Energy's risk profile. Three key changes related to:

- The internalisation of the contractual arrangements that were in place between the TVPS and Aurora Energy;
- The risks facing Aurora Energy arising from contractual arrangements that were in place between it and Hydro Tasmania in relation to the non-contestable customer load; and
- Aurora Energy's financial exposure arising from all the operating costs of the TVPS including the gas contracts that were put in place as a part of the acquisition of the TVPS and debt associated with the acquisition and completion of the power station.

2.3.1. Internalisation of the previous Aurora Energy – BBP contracts

With Aurora Energy's acquisition of the TVPS, the value to the TVPS inherent in the hedge between Aurora Energy and BBP was nullified, as Aurora Energy 'sat on both sides' of the transaction.

In the absence of another third party being willing to take a longer-term position in terms of contracting with the TVPS, this effectively turned the TVPS into a 'merchant' plant, with its value being a function of the outcomes in the Tasmanian spot market.[82]

As discussed in Section 1.2.1, the financial due diligence undertaken by LCW during the TVPS acquisition process identified the likely enterprise value of the TVPS under two scenarios – the Aurora Energy contracts remaining in place (effectively the value of the TVPS to any party other than Aurora Energy), and the enterprise value of the TVPS if it did not retain those contract (effectively the value of the TVPS if it were to be acquired by Aurora Energy).[83]

[82] As discussed above, with the contractual arrangements in place, Aurora Energy had already accepted a large share of this risk. A key difference is that changes in the Tasmanian spot price relative to the contract price would be shown as a non-realised mark-to-market movement in the value of its overall contract book. As owner of the TVPS however, the same change could potentially arise as a realised loss (or profit) in Aurora Energy's accounts. Also, with acquisition, Aurora Energy was faced with all of the value risk, rather than a portion.

[83] The valuation also examined the estimated replacement cost and the estimated actual cost to complete.

The valuation advice highlighted that the enterprise value of the TVPS under Aurora Energy ownership was around $200 million, having regard to the projected spot market outcomes for Tasmania over the period to 2034 (modelled by IES). By comparison, the enterprise value with the BBP contracts in place was estimated to be between $330 million and $415 million.[84]

The market forecasts on which the valuation was based assumed that hydrological inflows at 90 per cent of long-term average.[85] LCW highlighted that the merchant valuation of the TVPS contained no consideration of the potential security of supply benefits to Tasmania of having thermal plant located in Tasmania as the modelling assumed that there would be no availability constraints on Basslink or prolonged dry inflow sequences.

LCW considered how to quantify the security of supply benefits that the TVPS might bring to Tasmania and approached this task by estimating how long Tasmanian spot prices would be required to be at the market price cap (which was $10 000/MWh at the time) to enable the TVPS' estimated merchant value to exceed the estimated cost to complete.

The analysis concluded that if Tasmania spot prices were at the market price cap for an average of 96 minutes per annum and the TVPS were able to generate from all of its capacity during those periods (which was assumed to included the Bell Bay thermal plant), the merchant valuation of the plant would be around $350 million. The valuation concluded:

> *"We consider an average of only 96 minutes per annum (when any Basslink outage could be for significantly longer) is at a level that electricity retailers (and consumers) in Tasmanian would be willing to enter contracts to avoid/reduce the risk, which should underpin a value of TVPS in excess of the estimated purchase price."*

The valuation advice did not address the mechanisms by which any 'energy supply security premium' could be raised and secured by Aurora Energy so that the ongoing revenue stream available to it would offset its operating and capital costs of owning and operating the TVPS. Were such arrangements in place, the value of the TVPS in Aurora Energy's accounts would correspond with the combination of the merchant value and the energy supply security risk value.

---

[84] The variation between $330 million and $415 million was a result of differences in assumed discount rates and the assumptions made about the utilisation of the OCGT units.

[85] Another key assumption was that all output sold would be at spot market rates as it excluded any hedge cash flows and contract premia – the model assumed effectively assumed that Aurora Energy would own the TVPS throughout its operational life and that Aurora Energy would use the plant to back its long-term retail position in Tasmania.

The modelling also included a sensitivity analysis that concluded that if the real dispatch prices assumed were increased by 10 per cent in real terms over the whole period, the valuation of the TVPS would be around $400 million, which was around $50 million in excess of the cost of acquisition plus the costs to complete the power station.[86]

2.3.2. Hydro Tasmania contracts for the non-contestable customer load

Until 31 March 2009, the non-contestable load in Tasmanian was backed by load-following hedge arrangements between Aurora Energy and Hydro Tasmania, with the hedge price directly linked to the regulated customer price set in the non-contestable tariffs.[87]

In anticipation of the commencement of the BBP contracts discussed above, Aurora Energy negotiated two fixed volume profile hedges with Hydro Tasmania to back the non-contestable load for the periods 1 April 2009 to 31 December 2009 and from 1 January 2010 to 30 June 2010.[88] Aurora Energy considered that the combination of the Hydro Tasmania hedges, BBP hedges and some spot market exposure would maximise its commercial position.[89]

The base notional quantity under these hedges was equal to the estimated average non-contestable customer load. Under each contract, Hydro Tasmania had the option to elect to reduce the notional quantity by either 75 MW or 150 MW. Aurora Energy has advised that when it entered into the hedges with Hydro Tasmania, it was effectively over-contracted and expected to use the BBP contract to back the contestable load as the Hydro Tasmania contracts 'rolled off'. Aurora Energy expected the BBP contract to be 'in the money' compared to the spot market and other contracting options.

With Aurora Energy's acquisition of the TVPS, it 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, and higher than anticipated in the BBP financial model.

---

86 In the event, since the TVPS was commissioned, spot prices have tended to be softer than historical norms.

87 As noted in other Panel documents, such as the 'A review of the financial position of the State Owned Electricity Businesses' and the Draft Report, 'An Independent Assessment in to the Tasmanian Electricity Supply Industry' prior to the finalisation of the current contracts to support Aurora Energy's non-contestable load, all of the value available from the wholesale energy allowance determinations under the Tasmanian regulatory arrangements were captured by Hydro Tasmania – Aurora Energy's retail business did not capture any additional premium through wholesale contracting.

88 The Panel has been advised that this optionality was implemented at Hydro Tasmania's request, given its then-concerns regarding inflows and storage levels.

89 Aurora Energy reached this conclusion after independent expert advice.

The Panel has not identified any evidence that shows Aurora Energy sought to address this very significant financial exposure through attempted renegotiations with Hydro Tasmania of the non-contestable customer contract or approaches to Government to facilitate a reopening of those arrangements, in light of the fact that it was the Government's decision to instruct Aurora Energy to acquire the TVPS.[90]

Rather, the financial consequences for Aurora Energy were left to unfold as the contracts came into effect (this is discussed below).[91]

For the April-December 2009 period, Hydro Tasmania elected to reduce the volume under the non-contestable contract by 150MW. This meant that for this period, Aurora Energy was able to use output from the TVPS to cover its shortfall in non-contestable load requirements, as well as some of its contestable customer load requirements. This reduced the exposure of Aurora Energy's energy business to the spot market.

For the January-June 2010 period, Hydro Tasmania elected not to reduce any of the volume covered by its contract, reflecting, amongst other things, a return to stronger inflows.[92] With the relative attractiveness of the prices available under the non-contestable customer contract, Hydro Tasmania had a strong commercial driver to take up all of its volume entitlement under the contract that was in place.

This left Aurora Energy's energy business exposed to the subsequent falls in spot market prices. The financial consequences of these events are discussed below.

2.3.3. Gas supply

The gas supply and transport agreement that were put in place at the time of Aurora Energy's acquisition of the TVPS mirrored the arrangements that would have supported the anticipated production required to underpin the hedge with Aurora Energy.[93] The gas supply agreement defined a 13PJ annual quantity with an 80 per cent take or pay requirement. Gas transport arrangements were also secured that supported the transfer of gas from Longford to the TVPS.

---

90 Aurora Energy has indicated that the risk was evident at the time, but the magnitude of its consequences were not foreseeable, as they were linked to spot market outcomes. It argues that it debatable whether the Government would have supported any change on the basis that there could have been major financial exposures. In hindsight, the risk was large and ultimately required Government intervention to address its significant consequences.

91 This is unlike the arrangements that applied in relation to debt that Aurora Energy was obliged to incur to complete the TVPS, which were subject to direct support measures from Government in light of its direction.

92 Another key change from Hydro Tasmania's perspective was that for part of the April-December 2009 contract period, it had a 100MW option contract that was negotiated with Alinta to provide Alinta cover for market prices it in the event that the TVPS was not completed at the time the hedge with Aurora Energy commenced. That potential exposure was no longer current for the January-June 2010 period, increasing its contracting capability.

93 The Panel has examined how the costs of transport arrangements negotiated as a part of the TVPS acquisition compared with the previous arrangements between Hydro Tasmania and Duke Energy/Alinta under the Pipeline Capacity Agreement and found them to be broadly comparable on a cost per PJ basis.

While this strategy arguably optimised the timing of gas negotiations and removed the risk of a weak bargaining position, having 'locked in' a gas supply regime at the time of acquisition had two other material consequences:

- it placed the TVPS, and accordingly Aurora Energy, in the position of having a long-term large take or pay gas exposure[94], which has had significant implications for the financial consequences of the operation of the TVPS (see below);
- it provided a stronger underpinning of Babcock and Brown's Tasmanian gas pipeline business.[95]

2.3.4. Summary

The key changes in Aurora Energy's risk position with it becoming the owner and operator of the TVPS are summarised in Table 4

[94] Noting that it is not uncommon for CCGT plants to have take or pay gas supply contracts.

[95] Without a foundation customer, the value of the Tasmanian gas pipeline would have been materially impacted. As noted in footnote 126, the costs under the PCA and those under the GTA are broadly comparable, which suggest that the negotiated neither a saving nor an uplift by comparison with then-existing gas transport costs.

Table 4 - Aurora Energy's risk position pre and post TVPS acquisition

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

In short, Aurora Energy's risk position increased significant with the Government's direction to acquire and complete the TVPS, particularly given:

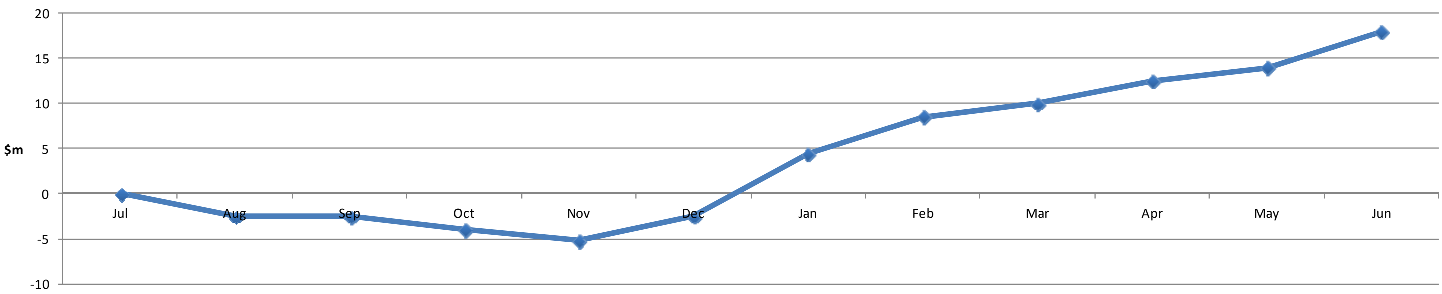
- it had no gas power station development management capability and experience;
- it had no gas station operational or maintenance experience;
- it had a large gas supply commitment on a take-or-pay basis; and
- the internalisation of the Alinta contract meaning the TVPS was now exposed to the spot market and effectively a merchant plant.

2.4 Aurora Energy's Energy business financial outcomes for 2009-10

With Hydro Tasmania electing to reduce the volume under its non-contestable customer contract with Aurora Energy by 150MW for the April 2009 to December 2009 period, Aurora Energy was able to utilise a reasonable proposition of the output of the TVPS to meet that reduction in non-contestable customer load. The cost structure of the TVPS was higher than the wholesale energy allowance, and the value impacts of the differential were absorbed by Aurora Energy.

The 2009-10 budget forecast for the Energy business is show in Figure 2, and demonstrates that the original budget for the Energy business was an EBIT outcome of around $18 million for 2009-10.

Figure 2 - Aurora Energy's Energy business 2009-10 budget cumulative EBIT



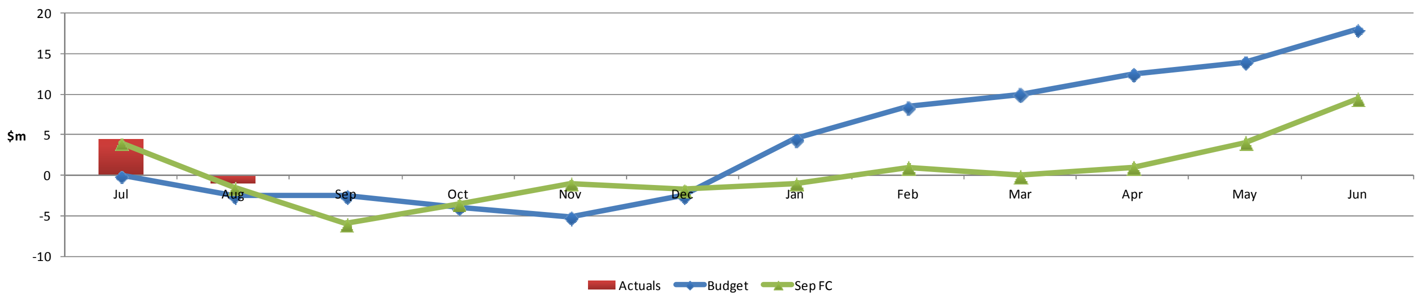
Source: Aurora Energy

Based on the arrangements with Hydro Tasmania and the tolling agreement with the TVPS, EBIT for the energy business was tracking close to Budget in October 2009. Aurora Energy revised down it forecasting EBIT by 50 per cent to around $9m for that year, with most of the fall expected in the second half of the financial year. This forecast fall in financial performance reflected a change in expectations by Aurora Energy of the financial performance of the TVPS, given Hydro Tasmania's election to not reduce the volume under its non-contestable customer contract with Aurora Energy, which had the effect of exposing a greater proportion of the TVPS output to the spot market[96].

The revised EBIT forecast for Aurora Energy's Energy business is show in Figure 3.

[96] This had a negative effect on the financial outcomes between the TVPS and Aurora Energy's Energy business, as the tolling fees paid by Aurora Energy were in excess of the revenues achieved through production. Production remained driven by the take-or-pay nature of the gas contracts for the TVPS –spot market revenues offered income to offset gas costs that would have been incurred regardless of the output of the TVPS.

Figure 3 - September 2009 forecast cumulative 2009-10 EBIT for Aurora Energy's Energy business



Source: Aurora Energy

The performance of the Energy business deteriorated during the period November - December 2009. Low spot prices in Victoria led to a loss on the Bairnsdale tolling agreement (acquired as a part of the AEATM asset purchase) due to lower running, and high volatility in NSW and SA in November saw Aurora Energy's interstate retail exposures lead to an EBIT shortfall in the order of $11 million relative to Budget. During this period, Aurora Energy continued to utilise the TVPS to back its non-contestable load.

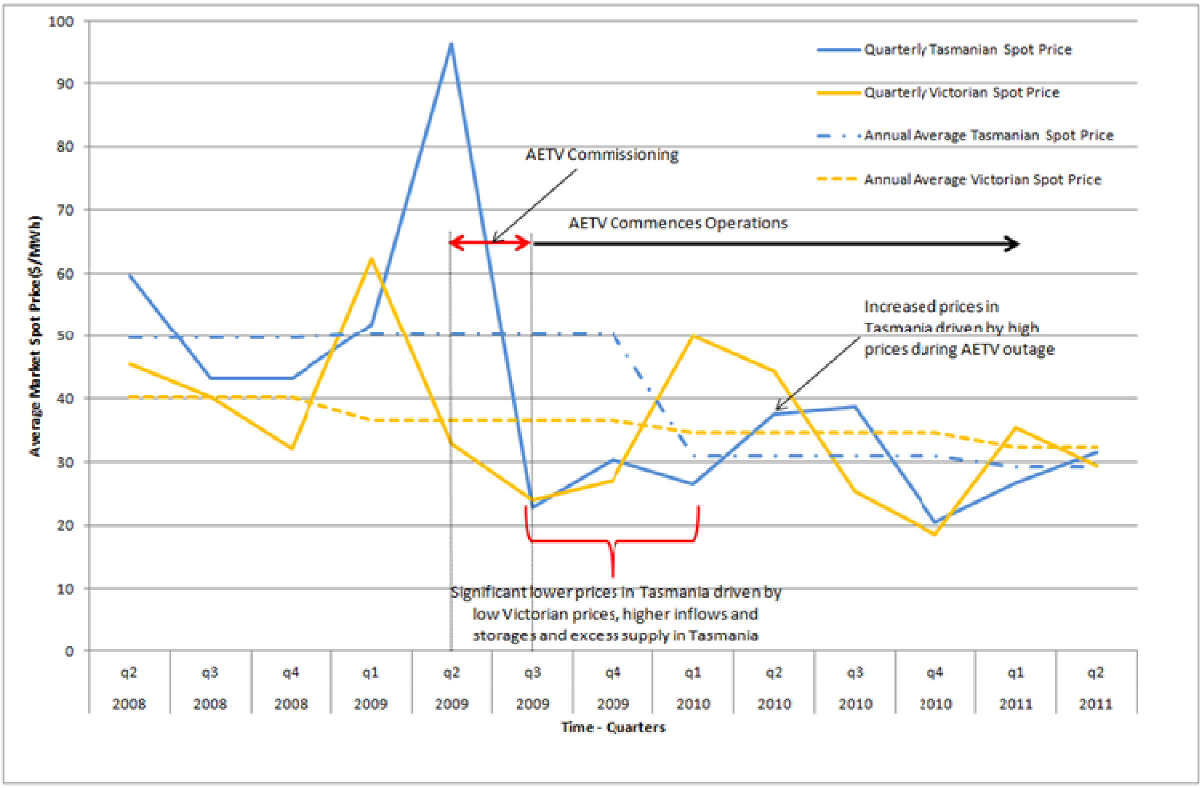
As a result, Aurora Energy's December 2009 forecast was for a further $12 million reduction in expected 2009-10 EBIT, with the expectation at this time for a loss of $3 million, compared to the original budget of a profit of $18 million.

With Hydro Tasmania's election to not reduce the load covered by its non-contestable customer contract with Aurora Energy coming into effect in January 2010, the Energy business became substantially exposed to the Tasmanian spot market in relation to revenues generated by the TVPS.

Figure 4 shows the significant change in Tasmanian spot prices over this period, reflecting a number of outcomes:

- low spot market prices in Victoria, which coupled with relatively fewer Basslink constraints, resulted in a softening of Tasmanian prices;
- more water availability in Tasmania, reducing the opportunity value of hydro electricity, reflected in Hydro Tasmania bidding also delivering softer spot prices; and
- substantial excess capacity in Tasmania, with Hydro Tasmania bidding to back the full non-contestable customer contract with Aurora Energy, and the TVPS bidding for dispatch reflecting its gas contracts.

Figure 4 - Tasmanian and Victorian spot prices 2008-2011, quarterly and annual averages



Source: AEMO data

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).

The falling Tasmanian spot price had a significant impact on the financial performance of the Energy business, with January EBIT falling short of revised budget expectation by around \$7 million.

The February - April 2010 period saw continued exposure to low spot market prices lead to further erosion in the expected end of year EBIT outcome. The March 2010 forecast was for a loss of \$20 million, a fall of \$38 million from the original 2009-10 Budget.

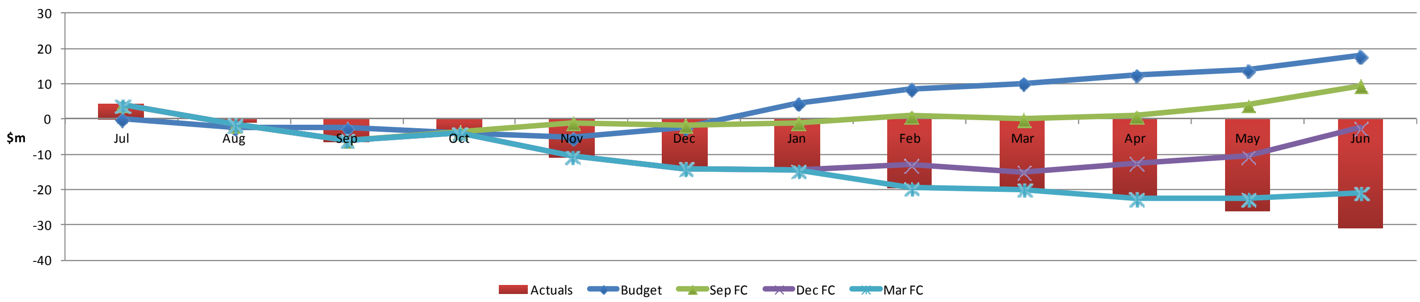
There was an outage of the TVPS's CCGT plant in May 2010, and Aurora Energy took a partial hedge to cover its exposure to the spot market. This resulted in some spot market exposures for Aurora Energy – and corresponding spot revenue opportunities for Hydro Tasmania, which it successfully captured - which led to prices above $1700/MWh for eight half hour periods (this is evident in the monthly average spot price shown in Figure 4). Due to the CCGT plant outage, Aurora Energy was exposed to the high spot prices.

This, and the subsequent lower prices for the remainder of the month on the return of the TVPS CCGT plant, resulted in further reductions in EBIT relative to Budget of around $6 million.[97]

The final cumulative EBIT outcome for June 2010 saw EBIT some $50 million below the original Budget, recording a loss of $31 million.

These outcomes are summarised in Figure 5, which shows actual cumulative EBIT by month for 2009-10 for Aurora Energy's Energy business.

Figure 5 - Aurora Energy's Energy Business actual cumulative EBIT, 2009-10



Source: Aurora Energy

3.1 Key differences between the Babcock and Brown model and Aurora Energy's outcomes

It is clear that the sustained and large falls in the financial performance of Aurora Energy's Energy business that coincided with the acquisition of the TVPS were not fully anticipated by it, given the number of ongoing revisions to expected earnings throughout 2009-10.

---

97 This highlights the vulnerability of Aurora Energy in the wholesale market with the current architecture. When the TVPS was available, Aurora Energy was effectively over-contracted (given the TVPS' gas contracts) and is therefore exposed to the spot price. Aurora Energy was unable to earn sufficient revenue from the spot market to cover the tolling fee, and incurred losses as a result. With the CCGT TVPS unit out of service, Aurora Energy became under-contracted and again exposed to the spot market. Hydro Tasmania's strategic bidding (see Chapter 9 of the Draft Report) drove up spot prices, which again had a negative financial impact on Aurora Energy's energy business.

The emerging performance of the TVPS did not correspond with the expectations contained in the Babcock & Brown financial model, which anticipated positive spot market opportunities for the TVPS and much firmer prices.

The Panel has identified other key differences between ‘expectations’, as documented in the Babcock and Brown model and observed outcomes, which included:

- the anticipated value of NGAC revenue dropped by around 50 per cent from the time of the original agreements being put in place – in the BBP model, these revenues were expected to be in the order of $8 million-$9 million per annum.

- the operating costs of the plant have increased from the provisions made in the Babcock and Brown model, particularly in relation to operating and maintenance costs, rather than the gas supply and transport contracts, which are broadly in line with the model assumptions. Aurora Energy advises that there were a number of other items that were not included in the BBP model, including FCAS and interruptible load costs. In reviewing the actual operating and maintenance costs for the 2010-2011 financial year, there is approximately $10 million in additional costs compared to the assumptions in the BBP model.

Taking the change in revenue and costs, the new tolling arrangement has provided the necessary revenue to keep AETV profitable and in many respects provides the cash flow to match the original expectations under the BBP model. For example, in 2010-2011 the tolling fee is approximately $119 million versus expected revenue in the BBP model of $116.6 million.

3.2 AETV’s current position

In summary, the fundamental drivers of the TVPS’ negative financial position prior to 30 June 2010 was that:

- Aurora Energy was effectively ‘over contracted’ with the combination of the non-contestable customer contract it had with Hydro Tasmania and the commercial driver to produce electricity from the TVPS, given the gas contracts that were finalised as a part of the acquisition process;
- With the substantial softening in the Tasmanian spot market prices coinciding with the TVPS coming online, the revenues available to Aurora Energy to fund output from the TVPS were insufficient to cover its costs;
- a number of market events where spot market opportunities were available to, and captured by, Hydro Tasmania further compounded the poor financial position.

From Aurora Energy's perspective, these financial issues have been addressed in the medium term through the arrangements that apply until June 2013, which:

- provide revenue certainty for the wholesale energy allowance for non-contestable customers, with the allowance broadly reflecting (but not equal to) the costs of production from the TVPS;
- enable it to access contractual cover for non-contestable customers with Hydro Tasmania at a cost less than the wholesale energy allowance.

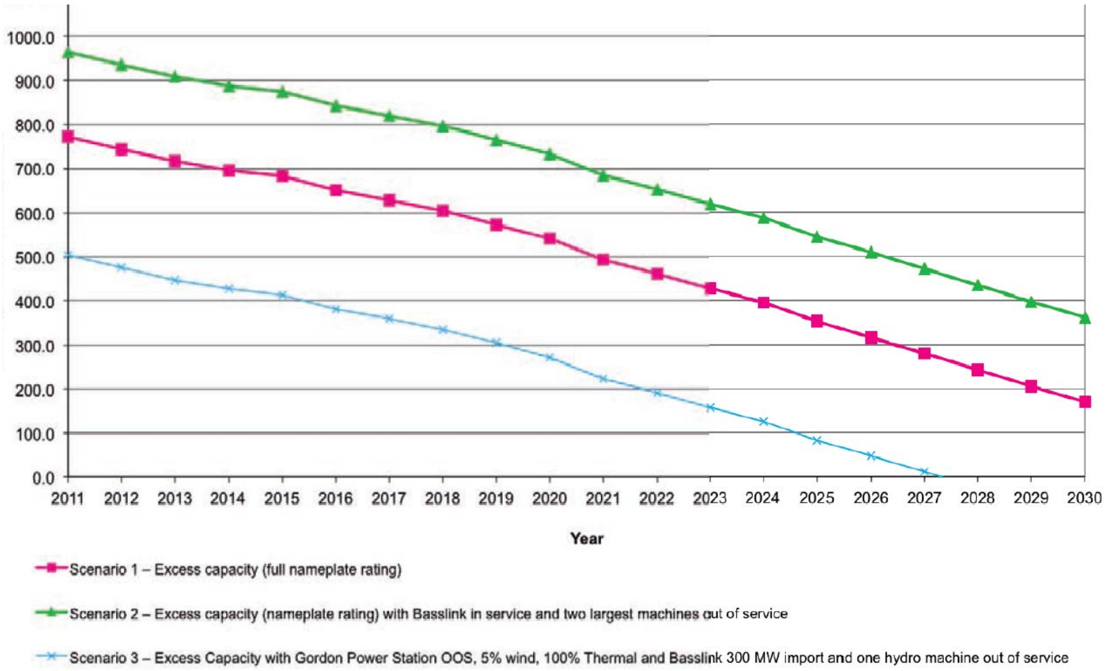
The **combination** of these two factors provides the financial 'headroom' for Aurora Energy to be able to contract with the TVPS through its tolling agreement to fund TVPS' full costs, including debt retirement over the economic life of the plant and a level of profitability. However, these arrangements are potentially vulnerable to change at the next retail pricing determination and/or once the current contract with Hydro Tasmania expires.

By providing Aurora Energy the financial headroom to utilise the TVPS to part back its non-contestable load requirements, the TVPS no longer appears as a merchant plant to Aurora Energy, and its financial outcomes do not reflect the underlying circumstances in the Tasmanian region.

In short, depending on inflows into the hydro system, Tasmania currently faces an overcapacity in generation in relation to its ability to meet peak demands, as illustrated in Transend's Annual Planning Report - see Figure 6.[98]

[98] The methodology assumes that excess capacity represents the total capacity of all current hydro and thermal generators in Tasmania, wind generation is assumed to be out of service unless otherwise specified, and the excess capacity is determined by deducting the 10 per cent POE medium forecast for winter MD from generator capacity.

Figure 6 - Projected Excess Generator Capacity, MW



Source: Transend Annual Planning Report 2011, page 45

With storages currently at high levels by long-term historic standards, Basslink remaining available and prevailing Victorian spot prices, the underlying market value opportunities for gas-fired electricity in Tasmania are substantially limited. The revenues available are not sufficient to cover the gas, operating and capital costs of the TVPS.

Were circumstances to change – for example the types of low probability scenarios contemplated by the Government at the time of its decision to acquire the TVPS to emerge (critically low water storages and a sustained outage of Basslink over several months), the market prices would rise very significantly, providing a funding mechanism to support the production and capital costs of the TVPS.

Over time, as the supply/demand balance changes, the financial position of the TVPS will similarly change. Outcomes that tighten the supply/demand balance, such as growth in Tasmanian load will see an increased need for base-load, on-island capacity and the underlying economics of the TVPS will improve. The timing of this is uncertain – a large industrial development that requires energy will bring this forward, and similarly, the loss of one of Tasmania's current large industrial customers would push this back.[99] Large-scale development of renewable energy, stimulated by the Australian Government's renewables target, will similarly push back the need for additional capacity.

99 In recent times, residential electricity demand has been relatively static, and it is difficult to see this sector having a major structural impact on Tasmania's supply demand balance.

Reforms to the wholesale market architecture in Tasmania may reduce some of these risks, which could improve the TVPS' financial performance.

The Government's decision to acquire and complete the TVPS as a hydrological risk mitigation strategy saw the public sector take on the direct financial consequences of this 'bring forward' of capacity that is in excess of the State's current requirements. If the development had progressed as anticipated, many of these risks would have been borne by the private sector.

At the same time, the additional capacity has had a positive impact for contestable customers that are exposed to market-determined wholesale energy costs – these are lower than they would otherwise be if TVPS was not operating as it currently is.

A key matter for the future is, in the absence of a structural shift in the Tasmanian supply/demand balance that would improve the economic opportunities for the TVPS, how will the financial consequence of the 'bring forward' of base load capacity be funded and/or the cost structure of the TVPS be reduced?