Appendix A Modelling

This Appendix describes the approach, assumptions, and data sources used in the modelling undertaken by the Commission's consultants (Frontier Economics or Frontier) in considering the Snowy Hydro Rule change proposal. The analysis also considers a counterfactual case where the Snowy region in split into separate Tumut and Murray regions, where the Murray regional reference node is at Dederang – this will be referred to as the "Split Region Option".

The Appendix begins by discussing the approach the Commission adopted to consultation, before outlining the modelling framework. It then discusses the methodology, assumptions, results and conclusions for the forward-looking investment analysis, dispatch modelling and risk modelling in turn.

A.1 Modelling framework and approach

The modelling framework is oriented towards the decision-making criteria to be applied by the Commission. These criteria, in turn, are guided by the nature of the issue the proposed Rule change is seeking to address and the NEM Objective. The modelling framework for the Snowy Hydro boundary change proposal aims to answer the following key questions:

- How do the proposals affect the **economic efficiency of dispatch**? The economic efficiency of dispatch is concerned with the costs of producing electricity to meet customer demand. The economic efficiency of dispatch will be maximised where the avoidable generation costs of supplying customer load are minimised over a given time period. In particular, the Commission is interested in testing whether the avoidable generation costs of meeting load are likely to be reduced by either the Snowy Hydro regional boundary change proposal or the Split Region Option, and if so, by what degree. As hydro plant have insignificant variable fuel and operating costs, from a dispatch efficiency perspective, they should be run at those times when they can displace the plant with the highest avoidable costs; and

- How do the proposals affect the **risk associated with inter-regional trade**? This is a function of both the price differences between regions and the firmness of IRSR units that can be used to hedge inter-regional price differences. In particular, we are interested in testing whether inter-regional price differences converge and/or IRSR units are "firmed up" by either the Snowy Hydro proposal or the Split Region Option and the implications for inter-regional trade. This is important since the functionality of the hedging market potentially affects both future wholesale and retail prices and participants' future investment decisions. In the medium to longer term, these impacts could affect the achievement of the NEM Objective.

The proposed Rule change potentially gives rise to complex behavioural changes in the market, which means that it is not possible to draw conclusions as to the likely effect of the boundary change purely from analysis of historical data or by reference to a conceptual model. Forward-looking empirical modelling was therefore undertaken to test the effect of alteration of regional boundaries on the economic efficiency of dispatch and the firmness of IRSRs. There are three key parts to the forward-looking modelling analysis:

- Investment modelling to determine a sensible pattern of new plant entry in the NEM. New investment needs to meet both reliability constraints and the range of greenhouse schemes active in the NEM;

- Dispatch/price modelling to examine market outcomes in terms of generator output and revenues and spot market prices, which involves participants being allowed to engage in strategic bidding to maximise their operating margins under different market conditions. This modelling aims to test the behavioural changes resulting from implementation of the Snowy Hydro proposal and the differences in dispatch, price and revenue outcomes relative to the base case and/or other alternatives; and

- Risk modelling to consider the risk management implications for market participants. In particular, this aims to examine whether the proposal increases or decreases the risk of inter-regional trading either by making prices more volatile and hence more difficult and costly to hedge, and/or by making inter-regional hedging more or less valuable.

Both the forward-looking dispatch and the risk modelling analysis were undertaken for three key scenarios:

- a business-as-usual base case. In this case NEMMCO manages counter price flows at times when there are northward flows on the Victoria-Snowy interconnector by clamping and when there are southward flows on the Victoria-Snowy interconnector by re-orientating relevant Snowy constraints to Dederang. Negative settlement residues on the Snowy-NSW interconnector occurring either north or south are manage via clamping;

- a Snowy Hydro case, which reflects the Snowy Hydro Rule change proposal.[118] In this case, Murray is included in the Victorian region while Tumut is included in NSW. The existing Victoria-Snowy and Snowy-NSW interconnectors are replaced with a single Victoria-NSW interconnector. NEMMCO does not clamp flows on this interconnector to manage negative settlement residues; and

- a Split Region Option case. This case involves splitting the Snowy region – Murray and Tumut become standalone NEM regions. The new Murray region includes Dederang as the RRN. The existing Victoria-Snowy and Snowy-NSW interconnectors are replaced with three new interconnectors: Victoria-Murray, Murray-Tumut, and Tumut-NSW. NEMMCO does not clamp flows on these interconnectors to manage negative settlement residues.

Neither the CSP/CSC regime nor the Southern Generators Rule to manage negative settlement residues were included in any of the three scenarios as these are both

[118] Available on the AEMC website at: http://www.aemc.gov.au/electricity.php?cat=rc.

interim congestion management tools that the boundary change proposal was intended to supersede.

The approach to each of these types of modelling, including a brief description of the models used, is discussed in Sections A.2 and A.3 below. Those Sections also present the modelling assumptions, sensitivities, results, and conclusions for each of the scenarios.

A.2 Forward-looking investment and dispatch/price modelling

This Section discusses the approach, assumptions, results, and conclusions for the forward-looking investment and dispatch/price modelling analysis.

A.2.1 Approach

The investment modelling was undertaken using Frontier Economics' least cost investment model, WHIRLYGIG. Using this pattern of investment, the dispatch/price modelling was undertaken using Frontier Economics' game-theoretic wholesale market model, SPARK. It is worth describing some of the key features of these models before discussing the methodology used to calculate the dispatch and price implications of the Snowy Hydro proposal and the Split Region Option.

A.2.1.1 Key features of WHIRLYGIG

WHIRLYGIG incorporates a representation of the physical system and is purpose built to examine strategic behaviour in a wholesale electricity market. The model contains the following features:

- a realistic treatment of plant characteristics, including for example minimum generation levels, variable operation costs, etc.;
- a realistic treatment of the network and losses, including inter-regional quadratic loss curves, and constraints within and between regions;
- the ability to model systems from a single region down to full nodal pricing;
- the capability to optimise the operation of fuel constrained plant (e.g. hydro plant), and pumped storage plant over some period of time;
- the ability to include a range of constraints that represent limitations on the market, such as capacity reserve constraints or greenhouse schemes.

Given this representation of the market, the current stock of committed plant and a "menu" of new investment options, WHIRLYGIG determines the least cost optimal investment and dispatch pattern over the modelling period including the timing, type, location and size of new generating capacity. This capacity reflects the system reliability constraints that the market must meet and other policy factors that influence investment (predominantly greenhouse measures).

A.2.1.2 Key features of SPARK

Much like WHIRLYGIG, SPARK incorporates a representation of the physical system. Furthermore the model is purpose built to examine strategic behaviour in a wholesale electricity market. The model contains the following features:

- a realistic treatment of plant characteristics, including for example minimum generation levels, variable operation costs, etc;
- a realistic treatment of the network and losses, including inter-regional quadratic loss curves, and constraints within and between regions;
- the ability to model systems from a single region down to full nodal pricing; and
- the capability to optimise the operation of fuel constrained plant (e.g. hydro plant), and pumped storage plant over some period of time.

In addition, SPARK uses game theory to determine equilibrium generator bidding patterns in an environment of imperfect competition. Game theory provides a systematic tool for determining generator bids in such an environment, obviating the need for subjective judgements on bidding behaviour. This effectively makes generator bids an output of the model rather than an input. This allows an investigation of the changes in pricing and output behaviour resulting from changes in market rules or structure.

SPARK applies game-theoretic techniques by allowing selected strategic players to choose from a set of quantity change strategies (Cournot competition) and/or price change strategies (Bertrand competition) for each set of market conditions having regard to the market rules, power system conditions and the extent of intervention. In addition, SPARK is capable of modelling portfolios of generators within and across regional boundaries, thereby allowing generators to test, create and exploit transmission constraints to their profit.

Once each participant is provided with a set of bidding choices, SPARK tests the potentially millions of bidding combinations for their sustainability. Sustainability in this context refers to the application of the Nash Equilibrium solution concept. A Nash Equilibrium is a set of strategies for all generators in which no individual generator has an incentive to unilaterally deviate from its bidding strategy. SPARK finds the Nash Equilibrium by assessing the "payoffs" of each generator in response to the bidding behaviour of every other generator in the NEM. The "payoff" relates to the difference between each generator's $/MWh pool revenue and its assumed $/MWh variable cost as well as any contract difference payments the generator may make or receive. If a generator can increase its payoff by changing its bids, that means that its original bid was not consistent with a Nash Equilibrium.

SPARK uses the Nash Equilibria bidding strategies to produce a range of results. The outputs produced by SPARK for each level of demand modelled include:

- Generator bids;
- Generator dispatch/outputs;

- Regional prices; and
- Interconnector directions and MW flows.

A.2.2 Methodology

WHIRLYGIG was used to determine an optimal investment pattern in new generating capacity which incorporates system reliability limits, greenhouse schemes and other factors that effect investment in the NEM. This pattern of investment is then used as an input to the dispatch/price modelling.

As noted above, SPARK can be used to determine optimal bids, market prices, and generator outputs under a given set of market assumptions. As these assumptions change, so too does the model-determined optimal set of bids and, hence, market prices and generator outputs. This enables SPARK to be used to calculate the dispatch and pricing impacts of changes to the market design such as an alteration to the regional boundary structure of the NEM.

The first step in the dispatch/price modelling is to describe the base case scenario against which market design changes can be compared. This allows comparison of the base case with the alternatives, namely the Snowy Hydro proposal and the Split Region Option. Each of these scenarios is briefly outlined below. Detailed modelling assumptions are discussed in the following section.

A.2.2.1 Base case (BAU) scenario

Features of the BAU base case:

- Existing regional boundary structure – structure of the NEM regions represent the current configuration;
- Tumut CSP/CSC Trial excluded – as the Chapter 8A, Part 8 derogation in the Rules states that the Tumut CSP/CSC Trial will end before the period of interest[119] in this modelling exercise, the Trial was excluded from all scenarios in the analysis;
- Southern Generators Rule excluded – again, the Southern Generators Rule, whereby negative settlement residues on the Victoria-Snowy interconnector are funded by positive settlement residues on the NSW-Snowy interconnector (after adjusting for CSP/CSC allocations), ends prior to the modelling period considered in this analysis. It was therefore excluded from all scenarios;
- NEMMCO clamping – in accordance with NEMMCO, Operating Procedure: Dispatch, Document Number SO_OP3705. This includes reducing flows on the Victoria-Snowy interconnector (i.e. "clamping") to manage counter price flows at times of northward flows and re-orientation of the constraints to Dederang to manage counter price flows at times of southward flows. For the Snowy-NSW

[119] The modelling focused on three financial years – 2007/08 to 2009/10 inclusive.

interconnector, flows are reduced (i.e. "clamped") in both north and south directions. Clamping is modelled assuming perfect foresight; that is, setting the Victoria-Snowy interconnector limit to zero when there would otherwise have been negative settlement residues on the interconnector for northward flows for a given combination of market participant bids.

A.2.2.2 Snowy Hydro boundary change scenario

Features of the Snowy Hydro scenario:

- Alternate regional boundary structure – Murray is included in the Victorian region while Tumut is included in NSW. The existing Victoria-Snowy and Snowy-NSW interconnectors are replaced with a single Victoria-NSW interconnector;

- Tumut CSP/CSC Trial excluded – as for the BAU base case scenario;

- Southern Generators Rule excluded – as for the BAU base case scenario; and

- NEMMCO clamping – no clamping included.

A.2.2.3 Split Region Option scenario

Features of the Split Region Option scenario:

- Alternate regional boundary structure –Snowy region is split; Murray and Tumut become standalone NEM regions. The new Murray region includes Dederang as the RRN and Tumut is the RRN for the Tumut region. The existing Victoria-Snowy and Snowy-NSW interconnectors are replaced with three new interconnectors: Victoria-Murray, Murray-Tumut, and Tumut-NSW;

- Tumut CSP/CSC Trial excluded – as for the BAU base case scenario;

- Southern Generators Rule excluded – as for the BAU base case scenario; and

- NEMMCO clamping – no clamping included.

A.2.2.4 Required steps

After establishing each of the scenarios for examination (BAU, Snowy Hydro proposal and Split Region Option), the dispatch modelling analysis was progressed in three main steps:

- first, SPARK is used to model a short run marginal cost (SRMC) bidding scenario to determine the optimal pattern of dispatch for all non-strategic hydro plant (see the discussion of modelling assumptions below for a discussion of this terminology). In the SRMC scenario, all (non-run-of-river) hydro plant (e.g. McKay Creek) are dispatched at those times and in those quantities that minimise the variable dispatch cost of all thermal plant in the system. However, while strategic hydro plant (such as Snowy Hydro) are not restricted to this pattern of dispatch in future scenarios, the pattern of dispatch for all non-strategic hydro plant are not altered for the remainder of the analysis;

- second, SPARK is used to model the dispatch and pricing outcomes of a strategic bidding scenario. Snowy Hydro and key thermal generators in other regions are allowed to bid strategically. The modelling focuses on a number of key demand levels when significantly different market outcomes as a results of boundary change are most likely to occur – i.e. extreme peak demand times in summer and winter; and

- finally, a number of demand levels representing the remainder of the year are modelled under the assumption of competitive dispatch, where the output of the strategic hydro generators is energy constrained to ensure that their output over the year reflects energy limitations.

The detailed assumptions and sensitivities used for the dispatch/pricing modelling are discussed in more detail below.

A.2.3 Modelling assumptions

To the maximum extent possible, Frontier sought to maintain consistency between the approach adopted towards the modelling presented in this Appendix and the modelling undertaken for the Southern Generators Rule change proposal and the Snowy Hydro Re-orientation proposal during 2006. With the exception of demand and generating capacity – which were both updated to account for the new data in NEMMCO's 2006 Statement of Opportunities (SOO) – all assumptions remain the same, particularly those regarding the available bidding strategies of various generators. The specific modelling assumptions used for the analysis of the Snowy Hydro proposal and the Split Region Option were as follows.

A.2.3.1 Generation capacity

Existing and committed generation capacities for scheduled generators were taken from NEMMCO, Statement of Opportunities for the National Electricity Market, October 2006 (the SOO). The portfolio structure of existing generation was based on NEMMCO, List of Scheduled Generators and Loads, 21 February 2006 adjusted for those portfolios where dispatch rights have recently been transferred under contract or via sale.

A.2.3.2 Generator bids

Game theory analysis in a market such as the NEM with multiple pricing zones, transmission constraints and a significant number of players is computationally demanding. There are an infinite number of bidding strategies and, obviously, it is not possible to model all of these.

The number of combinations of bids to be evaluated increases exponentially with the number of strategic players, as well as the number of available bidding strategies available to each strategic player. A number of methods are adopted to ensure the modelling problem is manageable, including:

- The types and ranges of bidding strategies can be limited. In SPARK, bidding strategies can involve bidding the available capacity at different prices, or making more or less capacity available to the market, or a combination of both. Within these choices, the price range over which generators are allowed to bid, and the increments within this range, can be limited. Similarly, the extent of capacity withdrawal choices can be contained to a level that is plausible, and again the number of discrete choices within this range can be restricted to make the computational problem more tractable;

- The number of strategic players can be limited. Players can be categorised as either "strategic" or "non-strategic":

  – Non-strategic players are given fixed bids (i.e. their bids remain constant no matter how other players bid – fixed bids can be in any form or level, just as so long as they are fixed); and

  – Strategic players are given a set of potential bids to choose from and will respond to changes in other players' bids in order to maximise their payoff by choosing the most profitable bid from those available; and

- The set of potential bids available to strategic players can be limited to decrease the number of bidding combinations to be evaluated.

The strategic participants and their strategic power stations used in this analysis are shown in Table A.1. To limit the number of strategic participants, only the largest generation portfolios in each region of the NEM were assumed to behave strategically. They were given options to alter the quantities they offer into the market using a number of strategies (i.e. Cournot competition). For instance a strategy of 75% shown in the table corresponds to a participant bidding 75% of the combined capacity of their strategic power stations at or near SRMC and the remainder at VoLL.

Given the importance of understanding the effect of the boundary change proposal on the incentives for Snowy Hydro, Snowy Hydro was allowed a relatively large number of strategies. Snowy Hydro was given options to offer from 0% to 100% of its capacity in 12.5% increments. Murray and Tumut Power Stations were assumed to be able to separately engage in these bidding strategies. This allowed for nine strategies for each of Murray and Tumut Power Stations, or a total of 81 combinations for Snowy Hydro. Snowy Hydro capacity that was offered into the market was bid at $1/MWh. This allowed Snowy Hydro to engage in behaviour that is anecdotally observed, such as bidding Murray at close to $0/MWh.

Major generators in other regions of the NEM were assumed to be able to offer 80% or 90% of capacity at or close to SRMC (with the remainder at VoLL). The largest players in NSW and Victoria – Macquarie Generation and International Power, respectively – were also given the option to offer only 70% of capacity at or close to SRMC.

Table A.1: Strategic participants

Strategic participant	Strategic stations	Bidding strategies (proportion of capacity offered at or close to SMRC)
Snowy Hydro	Tumut, Murray	0%, 12.5%, 25%, 37.5%, 50%, 62.5%, 75%, 87.5%, 100% (Murray and Tumut given flexibility to bid separately)
Delta	Mt. Piper, Munmorah, Vales Pt, Wallerawang C	90%, 80%
International Power	Hazelwood, Loy Yang B	90%, 80%, 70%
LYMMCO	Loy Yang A	90%, 80%
Macquarie Generation	Liddell, Bayswater, Hunter Valley GT	90%, 80%, 70%
QPTC (Enertrade)	Gladstone, Collinsville, Mt Stuart GT	90%, 70%
TRU Energy	Yallourn	90%, 80%

Hydro Tasmania was not modelled as a strategic player due to its present high level of vesting and other contract cover. This level of contract cover is expected to remain relatively high throughout the modelling period. All of Hydro Tasmania's discretionary capacity was bid into the market during high demand times (the summer and winter peak times when other players were allowed to bid strategically) at an SRMC of $1/MWh to reflect this high contract level and the fact that the plant would not be energy constrained at such times. For the remainder of the year Hydro Tasmania was energy constrained such that its annual energy budget was met. This ensured that Tasmanian pool prices reflected the opportunity cost of Hydro Tasmania's water across the year correctly.

All non-strategic thermal generators were assumed to bid into the market at SRMC. For the demand levels where generators were allowed to behave strategically, non-strategic thermal baseload units were bid in at SRMC for 100% of capacity and peaking units were bid in at five times marginal cost, resulting in bids of $100-1500/MWh. The demand levels comprising the rest of the year were dispatched with all plant (strategic and non-strategic) bid in at SRMC. For strategic and peaking plant, only 90% of capacity was bid at SRMC, with the remainder at VoLL.

Given these bidding choices, over all demand points modelled, SPARK computes prices, outputs, interconnector flows, etc., for nearly 500,000 bidding combinations for each year modelled. The Nash Equilibria are found from the output of these model runs.

Thermal generation SRMC and new entrant plant SRMC and fixed costs were taken from *ACIL, SRMC and LRMC of Generators in the NEM, February 2005*. As noted above, non-strategic hydro plant were assumed to generate in the same manner as in the SRMC scenario.

A.2.3.3 Contract levels and sensitivities

The level of contract cover can be an important determinant of bidding behaviour because some generators manage the risks of unfunded difference payments by bidding their contracted capacity at their SRMC. This approach to risk management can dampen spot prices in the short term.

Therefore, a number of different assumptions on contracting levels were modelled for each of the scenarios. In constructing the various contracting cases four key aspects of contracting in the NEM were considered:

1. Overall levels of contracts in the market – strategic players were assumed to sell contracts equal to "high" and "low" percentages of their installed capacity (see Table A.2 below). These were similar to the levels used in assessing the Southern Generators Rule;[120]

2. Volume of IRSR units Snowy Hydro holds with respect to the contracts it has struck in Victoria and NSW –Snowy Hydro was assumed to hold IRSRs equal to its inter-regional contracting volume;

3. Split of Snowy Hydro's aggregate contract volume between the Victorian and NSW nodes – Snowy Hydro was assumed to split the total volume of inter-regional contracts it sold between the Victorian and NSW nodes. Only the case were contracts were split equally between the Victorian and NSW nodes are presented in this analysis. This 50/50 split was the base case used in the modelling for the Southern Generators Rule;[121] and

4. Type of contracts held by Snowy Hydro – Snowy Hydro was assumed to hold all cap contracts with $300/MWh strike prices, this reflects the fact Snowy Hydro essentially offers insurance products into the market.

Table A.2 summarises the combinations arising from the first two contracting scenarios considered. NSW strategic generators have been assumed to contract to a lower level than players in other regions initially to account for the effect of the ETEF arrangement. This levels increases through the modelling period to reflect the ETEF roll-off. The percentage of NSW regulated retail load supported by ETEF is planned to reduce as follows:

- from September 2008 (100% to 80%);
- from March 2009 (80% to 60%);
- from September 2009 (60% to 40%);
- from March 2010 (40% to 20%); and

[120] AEMC, Final Rule Determination, National Electricity Amendment (Management of Negative Settlement Residues in the Snowy Region) Rule 2006, Appendix C, pp. C20-C21.

[121] AEMC, Final Rule Determination, National Electricity Amendment (Management of Negative Settlement Residues in the Snowy Region) Rule 2006, Appendix C, pp. C20-C21.

- from June 2010 (20% to 0%).[122]

Table A.2: Contracting cases

Contracting case	Snowy Hydro contract level	Snowy hydro IRSR units	NSW players	Other players
High	60% of capacity	Equal to contract level	Initially 65% of capacity, rising to 75% by 2009/10 to account for ETEF roll off	75% of capacity
Low	50% of capacity	Equal to contract level	Initially 55% of capacity, rising to 65% by 2009/10 to account for ETEF roll off	65% of capacity

A.2.3.4 Modelling period

The modelling was conducted for the three financial years 2007/08 to 2009/10 inclusive.

A.2.3.5 Greenhouse schemes

Multiple greenhouse schemes are active during the modelling period. The *WHIRLYGIG* modelling included the following schemes:

- NSW GGAS;
- Queensland 13% gas
- Mandatory Renewable Energy Target (MRET);
- Victorian Renewable Energy Target (VRET); and
- the recently announced NSW Renewable Energy Target (NRET).

These schemes ultimately affect the mix of plant present in the system and the way it is dispatched. The dispatch/price modelling incorporates these effects by assuming the determined investment pattern and the dispatch of "green" generators.

NEMMCO nets out the demand met by embedded generation from its demand forecasts. As a large component of these schemes are met by embedded generation, this demand was added back into the models and explicitly modelled. In should be

122 See Office of Financial Management, Payment rules for the Electricity Tariff Equalisation Fund, April 2006, p 3.

noted that intermittent generation technologies, such as wind, only contribute a percentage of their capacity towards meeting the reliability constraints in the model (in the case of wind, this amounts to 8% of installed capacity being assumed operational at times of peak demand in line with NEMMCO's assumptions).

A.2.3.6 Demand

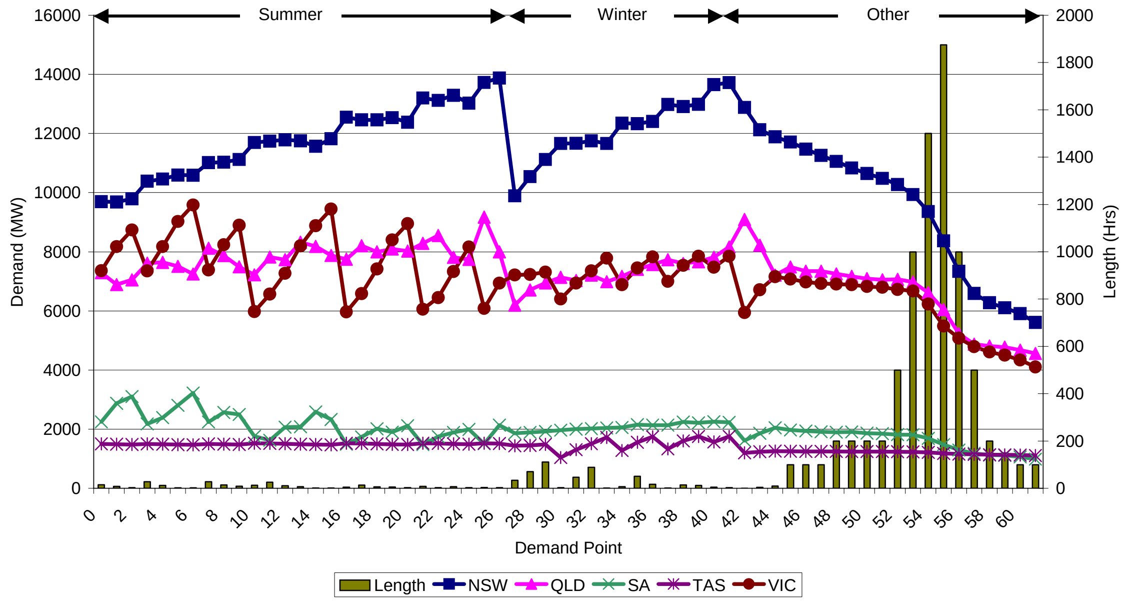
To streamline the modelling the analysis focused on 62 representative demand points per year rather than a chronological modelling of each half hour, or hour, in each year. The time saved by modelling fewer demand points allowed a larger number of strategic players and strategies to be modelled. Each demand point was weighted by its expected frequency of occurrence during the year so that yearly average results could be determined by adding up the frequency-weighted outcomes for each demand point. This meant that points of low and average demand, which occur frequently throughout the year, received a higher weighting than the peak demand points, which occur infrequently.

The electricity demand in each year was based on the medium growth, 50% probability of exceedence (POE) forecasts from NEMMCO's 2006 Statement of Opportunities (SOO) and was characterised using 62 representative demand points. The demand profile was based on the 2004/05 actual load profile.

The first 27 points focused on levels of NSW and Victorian demand that led to clamping (as informed by the previous Southern Generators Rule analysis) during summer peak hours. These points accounted for 250 hours of the year. Another 15 points were allocated to winter peak hours in a similar manner, corresponding to a further 470 hours. The remainder of the year, 8040 hours, was represented by a final 20 demand points. This is shown for 2007/08 in Figure A.1 below where the level of demand is shown on the left vertical axis and the length of each point is shown on the right vertical axis. It is important to note that the definition used here does not correspond to the summer and winter peak periods normally used in the NEM, e.g. AFMA summer and winter peaks.

Demand side bids were included, with the volume taken from the SOO at an assumed bid price of $500/MWh. No additional demand elasticity was assumed at any given demand point.

Figure A.1 Level and duration of demand points (2007/08)



A.2.3.7 Loss factors and equations

Static marginal loss factors and dynamic marginal loss factor equations were taken from a pre-release draft version of NEMMCO's document, *List of Regional Boundaries and Marginal Loss Factors for the 2006/07 Financial Year, March 2006*.

A.2.3.8 Constraint equations

The constraints for the Snowy region were taken from NEMMCO's document, *Constraint List for the Snowy CSP/CSC trial, March 2006*. This document lists the constraints for which Snowy Hydro receives CSP payments, including re-oriented formulations if applicable.

In the BAU base case scenario the constraint equations for all other constraints were taken from the Constraint Spreadsheet provided with the *Annual Transmission Statement (ANTS)* data attached to the NEMMCO 2005 SOO. The full list of system normal, national transmission flow path (NTFP) constraints was included in the modelling.

For the Snowy Hydro and Split Region Option scenarios, NEMMCO provided altered versions of the ANTS constraint set which reflected the relevant change to regional boundaries in each scenario.

These constraint equations incorporate the effect of likely transmission network upgrades via changes in line ratings over time.

A.2.3.9 Interconnectors

For the BAU base case scenario, the analysis used a six region representation of the NEM: Queensland, NSW, Snowy, Victoria, South Australia and Tasmania. As discussed earlier, boundaries between the Victorian, Snowy and NSW regions were altered under the other scenarios and new interconnectors replaced the existing ones. The interconnector transfer capabilities were limited by the network constraints represented in the ANTS and the Snowy constraint list under system normal conditions. Basslink was assumed to be fully commissioned from the commencement of the modelling period, with limits of 590MW north or 300MW south, consistent with the detailed information provided with the 2006 SOO. Murraylink, Directlink and Basslink were dispatched as regulated interconnectors. For Basslink, this was justified on the basis that Hydro Tasmania was not nominated as a strategic generator for the reasons given above.

A.2.3.10 Outages

The modelling was conducted on a system normal basis, meaning it did not include any outages (scheduled or random). This was done to increase flexibility for the gaming analysis and is consistent with the assumption that significant generator outages are unlikely to be scheduled during the peak summer and winter months, which were the focus of the modelling analysis. Random or forced outages were excluded from the analysis for simplicity. While this will understate dispatch costs the comparison between the BAU base case scenario and the other scenarios will not be influenced by this simplification, as the pattern of outages should not be any different between the three scenarios.

A.2.3.11 Energy constrained plant

Hydro plant were modelled to reflect energy limitations. This means that run-of-river plants were assumed to operate at the same level across all demand periods and other hydro plant were assumed to run to meet annual energy budgets, based on the assumption that water would be used at times it was most valuable. The modelling also incorporated pumping units (Wivenhoe, Shoalhaven and Tumut), which were assumed to have a 70% pumping efficiency and be dispatched when optimal (i.e. most valuable).

Snowy Hydro indicated that they have the ability to manage their water reserves between years. To the extent that either of the proposals increase Snowy Hydro’s output over the entire year relative to the BAU base case, we would observe higher production costs savings due to increased hydro output displacing thermal plant. However, for the purposes of this review, Snowy Hydro was assumed to have an energy budget of 4.9 TWh p.a. as reported in NEMMCO’s 2005 SOO.

A.2.3.12 Treatment of VoLL prices

Under some market conditions *SPARK* finds it profitable for generators to set the spot price at the Value of Lost Load (VoLL = $10,000/MWh). In practice, the spot price occasionally rises to VoLL, but generally not as often as *SPARK* finds it is profitable to do so.

The key difference between the modelling results and actual behaviour is the self regulation by generators. Generators will not necessarily exploit every opportunity to set the market price at VoLL when they can. This self regulation could be due to generator concerns about the risk of not being able to meet contract payments triggered by high spot prices (the costs of which are taken into account in the *SPARK* modelling) or concerns that high spot prices will attract unwanted regulatory attention. Instead of setting VoLL prices under these circumstances generators often set prices substantially less than the VoLL; but nevertheless these are high prices compared to the average.

It is difficult to conceive of a systematic approach for incorporating this self regulation into this or any market modelling. There are two key choices for managing this issue: explain that this behaviour exists and take no account of its effects, or accept its reality and adjust for its effects. In this modelling exercise it has been decided to reflect the reality of this self regulation through a systematic and consistent adjustment of VoLL pricing events across all scenarios. More specifically, prices were effectively capped by a notional generator with a bid equal to the recent historical average of high price events ($2,500/MWh), which were classified as any price over $300/MWh (the marginal costs of the most expensive generator).[123] The same adjustment approach was used for all modelling scenarios and therefore ought not distort any comparison of the results.

A.2.4 Investment pattern results

Figure A.2 to Figure A.5 show the new investment pattern for the NSW, Victoria, Queensland and SA regions respectively. In all regions we see a significant amount of green generating capacity being built, which includes technologies such as hydro, biomass and wind. This capacity is being built to meet the growing demand for green generation brought on by the greenhouse schemes active in the NEM and also helps to ensure system reliability.

Beyond green investment, some additional peaking and mid-merit generation capacity is needed in each region for reliability over the modelling period. Tallawarra fulfils this role in NSW while in the other regions generic new capacity is needed.

In NSW and Victoria peaking capacity is all that is required. In Queensland new mid-merit capacity is needed, predominantly to meet the Queensland 13% gas target. In SA, mid-merit capacity is the most cost effective way to meet load growth and reliability constraints.

---

[123] This average price was derived from the Southern Generators Rule Determination: AEMC, *Final Rule Determination, National Electricity Amendment (Management of Negative Settlement Residues in the Snowy Region) Rule 2006*, Appendix C, pp. C24-C25.

Figure A.2 NSW new investment

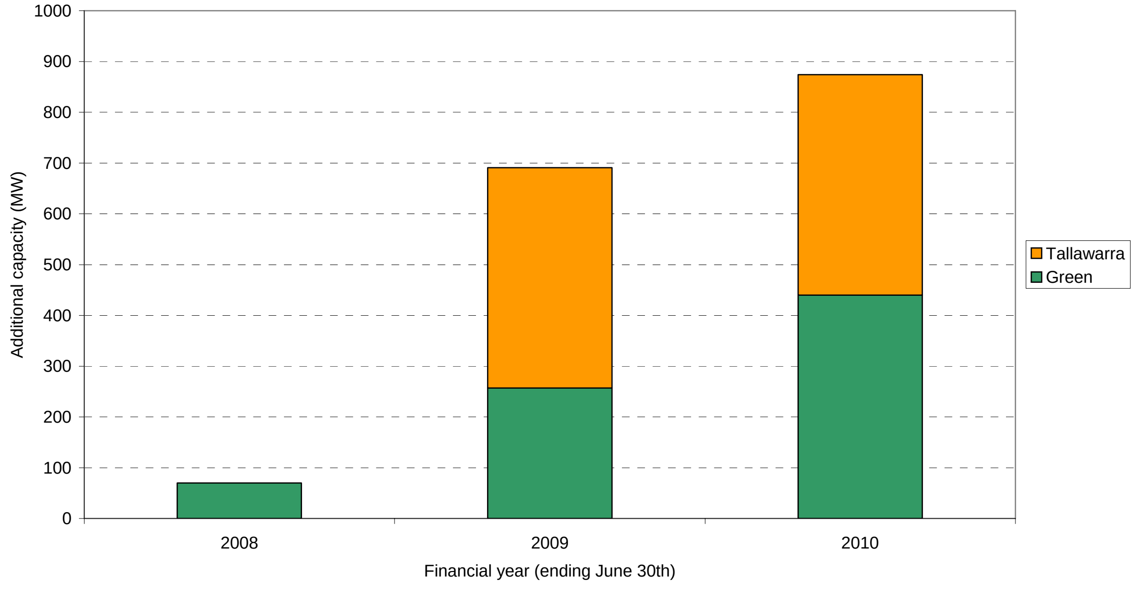


Figure A.3 Victoria new investment

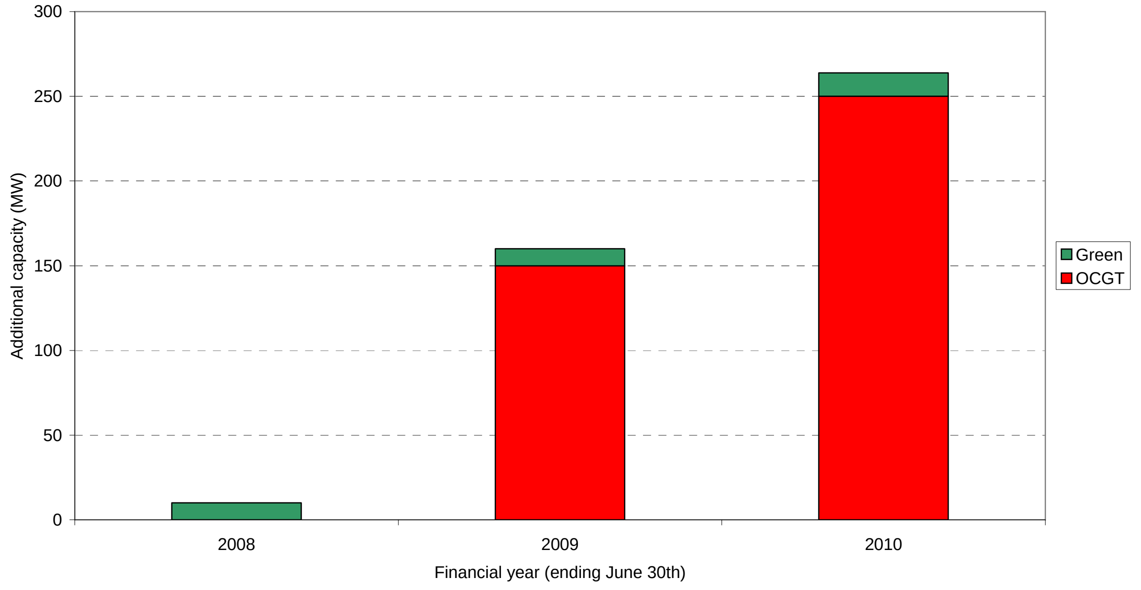


Figure A.4 Queensland new investment

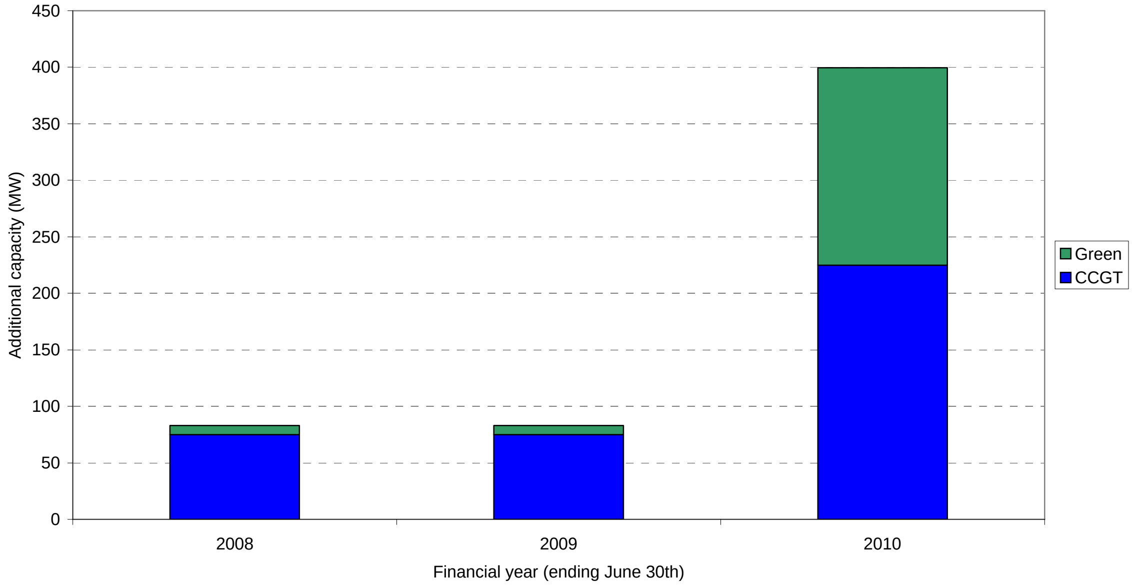
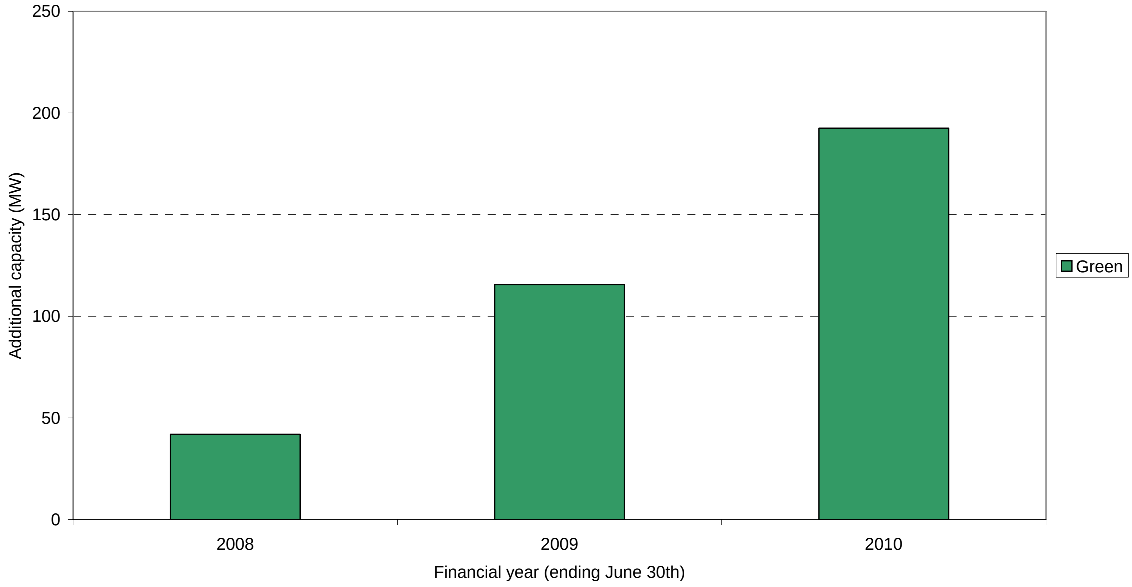


Figure A.5 SA new investment



The investment pattern detailed above was assumed across all three regional boundary structure scenarios for the dispatch/price modelling.

A.2.5 Dispatch/price modelling results

This section discusses the dispatch and pricing modelling results obtained for each of the scenarios described above. The results of interest includes:

- Production costs – annual NEM-wide variable electricity production costs in the summer peak period, winter peak period and remaining ("other") times of the year;

- Generator outputs – Snowy Hydro output, Southern Generators' output and Northern Generators' output in the summer peak period, winter peak period and other times of the year;

- Interconnector outcomes – interconnector flows into NSW, hours of transmission constraints and hours of clamping, as well as confirming revenue adequacy on the Snowy-NSW interconnector to ensure deficits on the Victoria-Snowy interconnector can be fully funded;

- Annual Regional (time-weighted) prices for Queensland, NSW, Snowy, Victoria, South Australian, and Tasmania;

- Instances of intraregional constraint; and

- The frequency and magnitude of counter-price flows and clamping in the various scenarios.

Each of these results is discussed in turn below.

A.2.5.1 Broad conclusions of the modelling

In summary, both the Snowy Hydro boundary change and the Split Region Option led to production cost savings and price reductions. The reason for this is due to the increased levels of competition that occur in the NEM due to freer interconnector flows arising from the:

- new regional boundary configuration and reformulated system constraints;

- removal of NEMMCO's ability to clamp interconnectors to manage negative settlement residues; and

- altered incentives created for Snowy Hydro and other market participants under the new structure.

Specifically, the modelling shows that additional patterns of bidding which involve participants offering almost all their capacity into the market become sustainable under either of the boundary change scenarios. These "competitive" bidding equilibria are not sustainable (i.e. not Nash Equilibria) in the BAU base case due to congestion issues, clamping and the increased ability of participants to unilaterally increase their profits by withdrawing capacity.

These points will be elaborated on and supported by the modelling results presented below.

A.2.5.2 Caveats and limitations of the modelling

When interpreting the following results it must be kept in mind that the modelling exercise was conducted to investigate the effect of a regional boundary change on market outcomes within the NEM, with particular emphasis on the change in Snowy Hydro's bidding incentives. The intention was never to forecast actual market outcomes (particularly prices) for a standalone scenario, but rather, to investigate the relative changes that arise between the scenarios. For this reason the results should not be considered an accurate forecast of, in particular, market price outcomes.

Key assumptions, which are constant across the scenarios, that should be kept in mind when interpreting the results are as follows:

- the majority of the year is dispatched assuming competitive bidding in order to ensure Snowy Hydro does not exceed its energy budget. This results in lower pool price outcomes than may arise in reality, to the extent that strategic behaviour actually occurs at these times; and

- new entrant plant is assumed to be standalone and non-strategic in the absence of more accurate information. Again, this will tend to depress pool prices towards the end of the modelling period as greater amounts of capacity enter the market, to the extent that new entrant plant is built by incumbent generators and/or bid into the market more aggressively (i.e. above SRMC).

A.2.5.3 Production costs

As discussed above, savings in variable production costs represent the dispatch efficiency benefits of a change in the market design. Figure A.6 illustrates the annual production costs from each scenario, while Figure A.6 shows the production cost savings arising under the Snowy Hydro proposal and the Split Region Option relative to the BAU base case scenario (a positive value on the graph represents a saving). As mentioned, both regional boundary changes consistently result in production cost savings. This is the result of an increased likelihood of more competitive bidding under both options. The changes in the Snowy Hydro and Split Region Option scenarios, relative to the BAU base case scenario, give rise to equilibrium outcomes where Snowy Hydro (and other participants) offer more capacity into the market. This leads to greater levels of dispatch for Murray, Tumut, Victorian brown coal plant and cheaper NSW black coal plant displacing more expensive NSW and Queensland black coal and some mid merit gas plant across the NEM. The result is that production cost savings accrue (later results will also quantify the price effect this displacement causes).

Figure A.6 Annual production costs ($m)

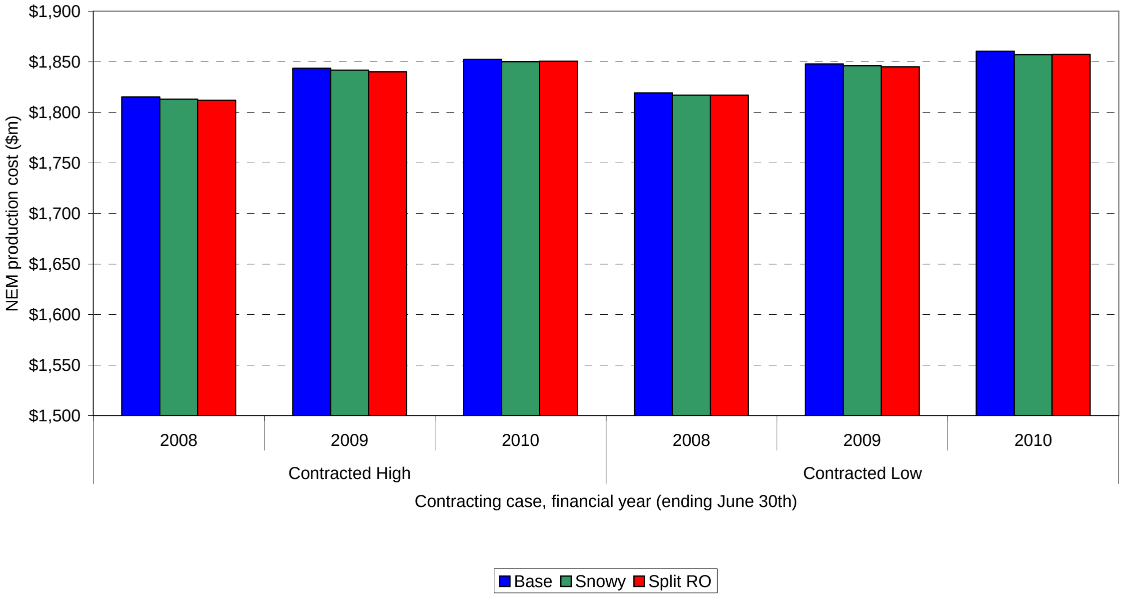
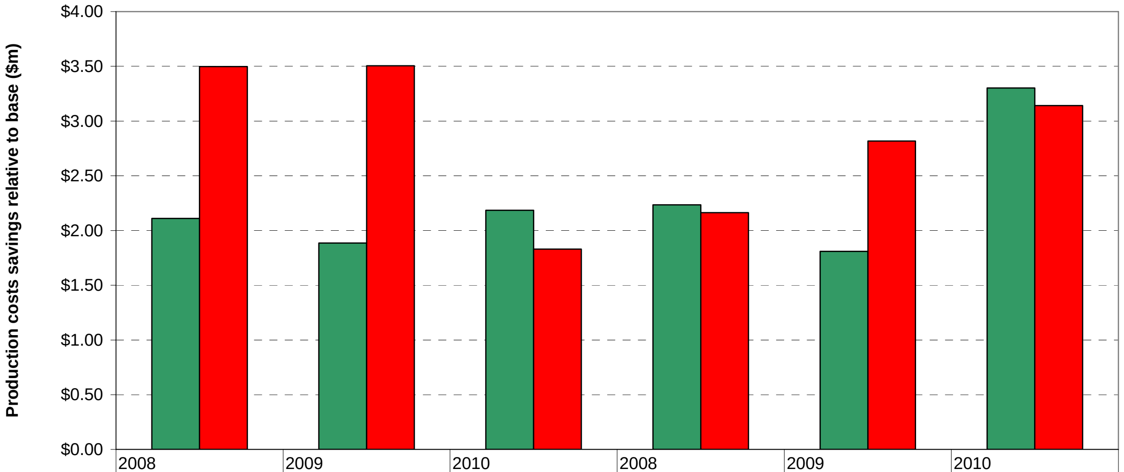


Figure A.7 Annual production cost savings ($m)



	Contracted High 2008	Contracted High 2009	Contracted High 2010	Contracted Low 2008	Contracted Low 2009	Contracted Low 2010
Snowy	$2.11	$1.89	$2.19	$2.23	$1.81	$3.30
Split RO	$3.50	$3.50	$1.83	$2.16	$2.82	$3.14

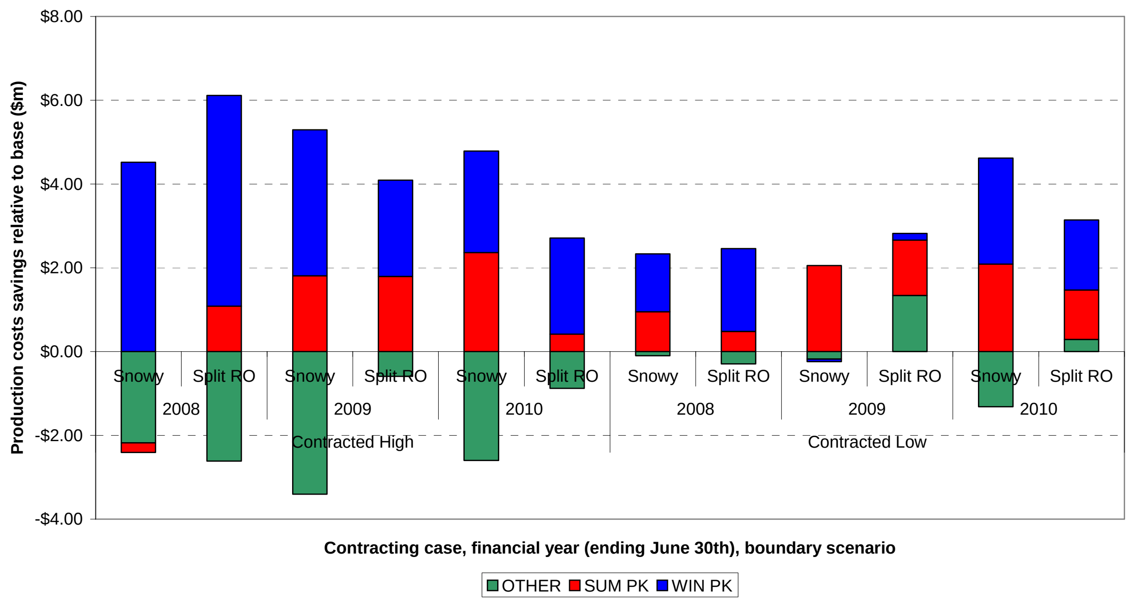
Contracting case, financial year (ending June 30th)

Timing of the production cost savings

Figure A.8 shows the break down of the production cost by category - summer peak, winter peak and other times. The savings occur during the extreme summer and winter peak times of the year when generators have been allowed to bid strategically. Production losses generally occur at the other times of the year, which reflects the fact that Snowy Hydro is energy-constrained across the year. As the production savings occurring during peak times reflect higher levels of Snowy

Hydro dispatch, this means that Snowy Hydro has less water to use at the other times of the year. The net effect across the year is positive, as higher-cost generation is displaced at peak times relative to the plant that is dispatched when Snowy Hydro has a lower residual energy budget and runs less during the rest of the year.

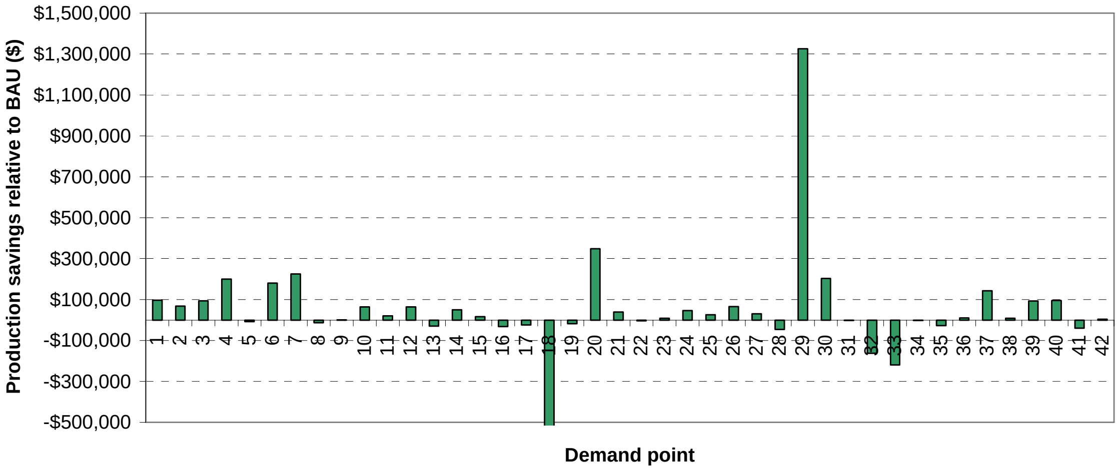
Figure A.8 Annual production cost savings by time of year ($m)



Production cost savings at the demand point level

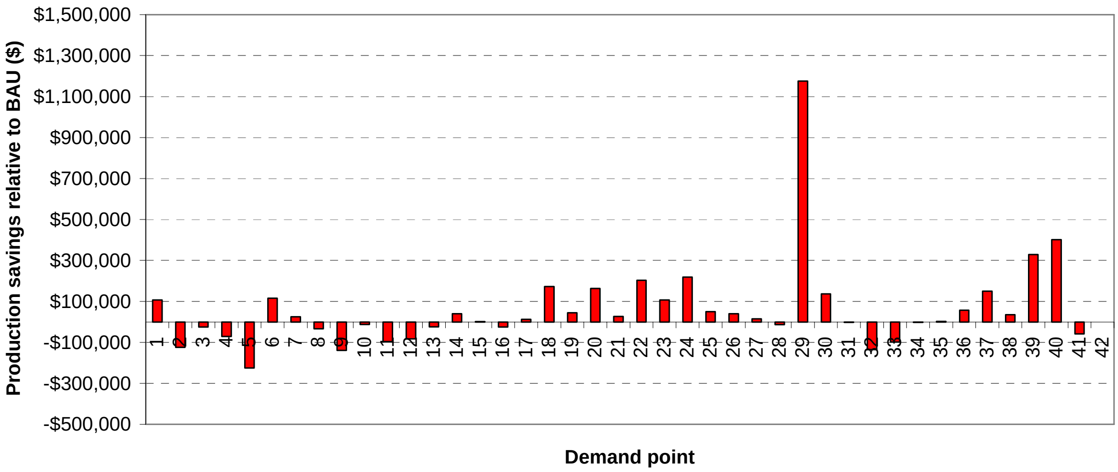
To further demonstrate the effect of increased competition due to regional boundary change, the outcomes at the demand point level are shown in Figure A.9 and Figure A.10 for the Snowy Hydro and Split Region Option scenarios, respectively. Both figures depict the low contracting case for 2007/08. For both scenarios we see that the majority of the savings occur for demand point 29. This demand point represent relatively high levels of NEM demand, particularly Victorian and South Australian demand. Further analysis of the types of equilibria occurring for this point supports the hypothesis that the boundary change scenarios increase the likelihood of more competitive and efficient patterns of bidding occurring in the market. This effect is clearest for demand point 29 but occurs consistently across all the demand points where savings occur.

Figure A.9 Production cost savings by demand point (Snowy Hydro proposal, Contracted Low, 2007/08)



a Note: Positive values denote a savings under the boundary change.

Figure A.10 Production cost savings relative to BAU by demand point (Split RO, Contracted Low, 2007/08)



a Note. Positive values denote a savings under the boundary change.

Demand point 29

Figure A.11 shows a scatterplot of Nash Equilibrium outcomes for demand point 29. The horizontal axis shows the combined amount of capacity offered into the market by Guthega, Murray and Tumut plant, while the vertical axis shows the payoff (profit) received on that output.

It can be observed that a number of equilibria occur on the left side of the graph where Snowy Hydro offers roughly 400 MW to 1,500 MW into the market across all three scenarios. These equilibria also involve withdrawal of capacity by other market participants. In addition to these "strategic" equilibria, a number of "competitive" equilibria (where more capacity is offered into the market) occur under both the Snowy Hydro scenario and the Split Region Option. These points are circled in red. These equilibria involve both Snowy Hydro and other market participants offering almost all their capacity into the market. This effect is observed across the majority of the demand points where production savings occur for all years, scenarios and cases.

Figure A.11 Snowy Hydro equilibria payoffs and output for demand point 29

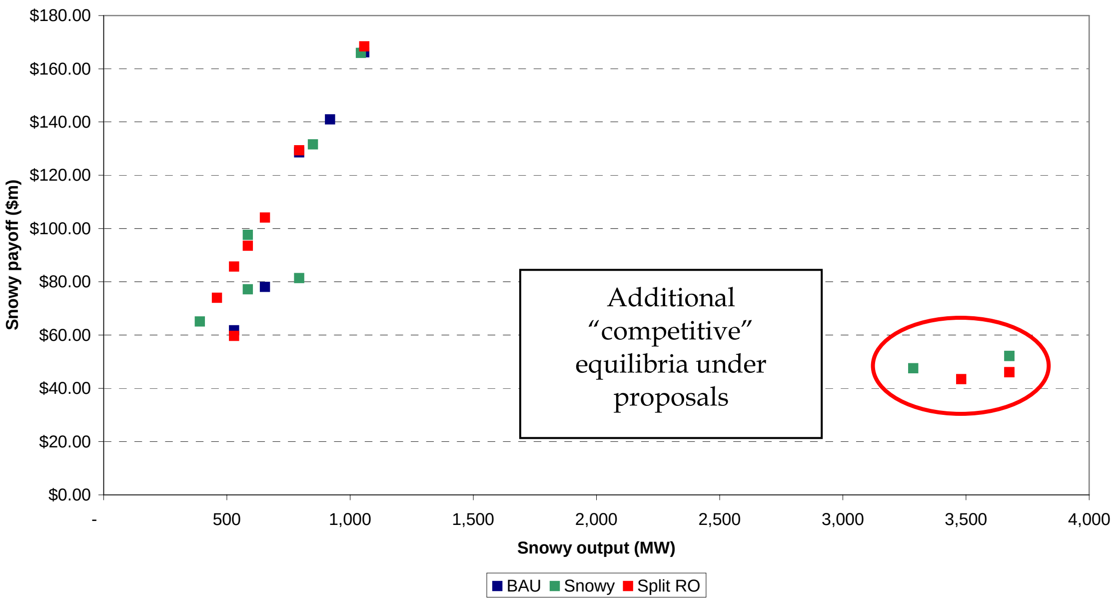


Figure A.12 shows Snowy Hydro's payoff curve for the most competitive of the equilibria in Figure A.11. The modelling assumed 81 different combinations of capacity bids between Murray and Tumut, these are shown along the horizontal axis of Figure A.12, in increasing order (bid combination 1 corresponds to no capacity being offered into the market and bid 81 represents 100% of Murray and Tumut being offered into the market). The vertical axis shows the payoff received on the offered level of output. These curves represent a cross section through the strategic space considered in the modelling, other participants bids have been fixed at their equilibrium values.

It can be observed that in the BAU scenario, the highest payoff occurs where Snowy Hydro offers relatively little capacity into the market, as marked in left of the figure. At this point, southward clamping of the Snowy-NSW interconnector allows the Snowy region to import the higher Victorian price (adjusted for losses). This leads to high payoffs for Snowy Hydro and represents a Nash Equilibrium outcome in the BAU base case scenario. This is because reduced Snowy Hydro dispatch resulting from its offer is offset by a higher price received on output. In the Snowy Hydro and

Split Region Option scenarios, in the absence of clamping, high payoffs are not achieved for similar levels of withdrawal. In fact, the highest payoffs occur where Snowy Hydro offers all of its capacity into the market and it is these points that are found as Nash Equilibria (circled to the right).

It should be noted that Figure A.12 does not fully describe which strategies are sustainable Nash Equilibria. This is because the full set of equilibria are dependent not just on Snowy Hydro's payoff curve but the interaction of all the strategic participants' response curves. However, the figure does give an intuitive insight into why "competitive" equilibria arise under either of the boundary change scenarios.

In the BAU base case scenario under conditions of southward flow, competitive bidding equilibria are not sustainable as Nash Equilibria because Snowy Hydro has an incentive to initially offer a large volume of Tumut generation. This has the effect of inducing clamping of the Snowy to NSW interconnector. Following the implementation of clamping, Snowy Hydro has an incentive to withhold most of its output in order to receive the (high) Victorian price on its entire output.

Withholding has the benefit of both:

- ensuring the Snowy to Victoria interconnector does not bind, which would cause the Snowy RRN price to collapse towards the (lower) NSW price; and

- helping to boost the Victorian RRN price, from which Snowy Hydro benefits *on its entire output*.

This limitation of output also reduces the competitive pressure on plant in Victoria.

Such a strategy leads to inefficient dispatch because reduced levels of Snowy Hydro generation does not allow for the maximisation of flows southward into Victoria at times of high Victorian demand. Consequently, dispatch across the NEM is less efficient than under some potential outcomes of the Snowy Hydro proposal, in which:

- Murray generation has reduced incentives to withhold output. This is partly because it no longer needs to be concerned to avoid constraining the Snowy to Victoria interconnector (which in the BAU base case scenario would push the Snowy RRN price down towards the NSW price). It is also partly because withdrawal of Murray output only benefits the price received by Murray generation, *rather than all Snowy Hydro output*;

- Tumut generation often does not find it profitable to withhold, as the price/quantity trade-off may not be worthwhile. Rather, Tumut has incentives to generate based on the prevailing NSW price. This may lead to a significant increase in Tumut generation (compared to the BAU base case), which competes with NSW generation; and

- In total, Snowy Hydro generation can in some cases be significantly higher than under the BAU scenario.

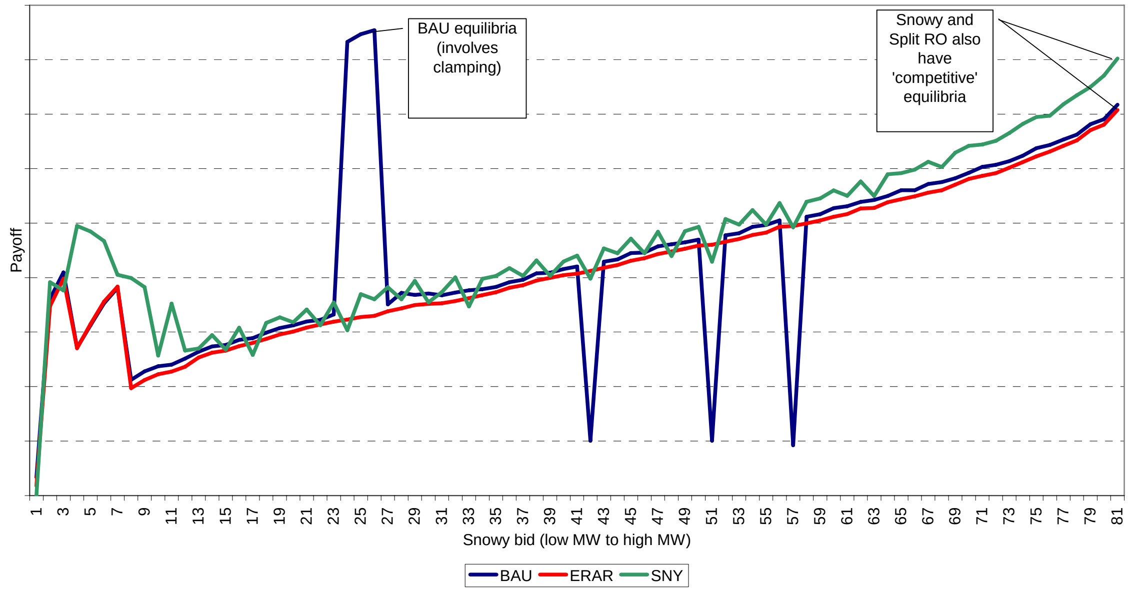
Therefore, under the Snowy Hydro scenario, there may be increased generation at both Murray and Tumut at times of high summer and winter demand. Increased generation at Murray can facilitate higher flows southwards through the cutset. The increased flow into Victoria helps encourage more competitive bidding in Victoria, which in turn helps produce more competitive and efficient dispatch across the NEM.

Under the Split Region Option, both Murray and Tumut have some incentives to withhold some output to ensure that constraints south of them do not bind at times of southward flows. However, unlike in the BAU base case scenario, there are some equilibria in which Snowy Hydro does not find it profitable to withhold its generation. In these cases, a large proportion of Tumut output is offered to the market. This may even lead to a reversal of southward flows on the NSW to Tumut interconnector. This promotes lower-cost and more competitive outcomes in NSW. Meanwhile, Snowy Hydro's incentives to withhold Murray generation are reduced because such withdrawal only benefits the price received by Murray generation, *rather than all Snowy Hydro output*.

The higher output at Murray means that total flows into Victoria are higher than under the BAU (in part due to the position of Murray generation in the Snowy loop). The increased flow into Victoria across the cutset helps produce more competitive and efficient dispatch across the NEM. It is worth noting however, that this outcome is not as efficient at this demand point as the Snowy Hydro proposal (compare Figure A.9 and Figure A.10). This is due to the lack of incentive under the Snowy Hydro scenario for Snowy Hydro to withhold Murray output to some extent to keep the lines south of Murray unconstrained.

The "dips" observed in Snowy Hydro's payoff curve for the BAU base case scenario (bid combinations 42, 51 and 57 in Figure A.12) are the result of relatively large offer quantities from Snowy Hydro leading to clamping of northern flows on the Snowy-NSW interconnector. As such all output from Snowy Hydro flows to Victoria and prices are significantly dampened south of the clamping. The payoffs to the right are related to the "competitive equilibria" identified under the Snowy Hydro proposal and the Split Region Option, which were shown above in Figure A.11.

Figure A.12 Snowy Hydro payoff curve for demand point 71



A.2.5.4 Changes in dispatch

Figure A.13 to Figure A.16 shows the change in output by generator group relative to the BAU base case for the two boundary change scenarios and two contracting cases. The Snowy Hydro output group (blue bars) comprises output at Murray, Tumut and Guthega. The northern generators group (NG) represents all output north of Tumut while the southern generators group (SG) represents all output south of Murray.

As mentioned above, Snowy Hydro is generally incentivised to offer more capacity into the market under both the Snowy Hydro proposal and the Split Region Option during peak times. This is also the case for other strategic market participants, although this is harder to observe in the aggregate figures below. More capacity is offered during either summer or both summer and winter as shown in the figures below. Due to Snowy Hydro's fixed energy budget, this increase in output at peak times must be exactly offset by a reduction in its generation at other times of the year.

Production cost savings occur across the year as a whole because the plant that Snowy Hydro displaces at peak times has a higher resource cost than plant that substitutes for Snowy Hydro at the other times of the year. This also results in a price effect (discussed below).

Figure A.13 Snowy Hydro scenario output changes by generator group, contracted low (relative to the BAU base case scenario)

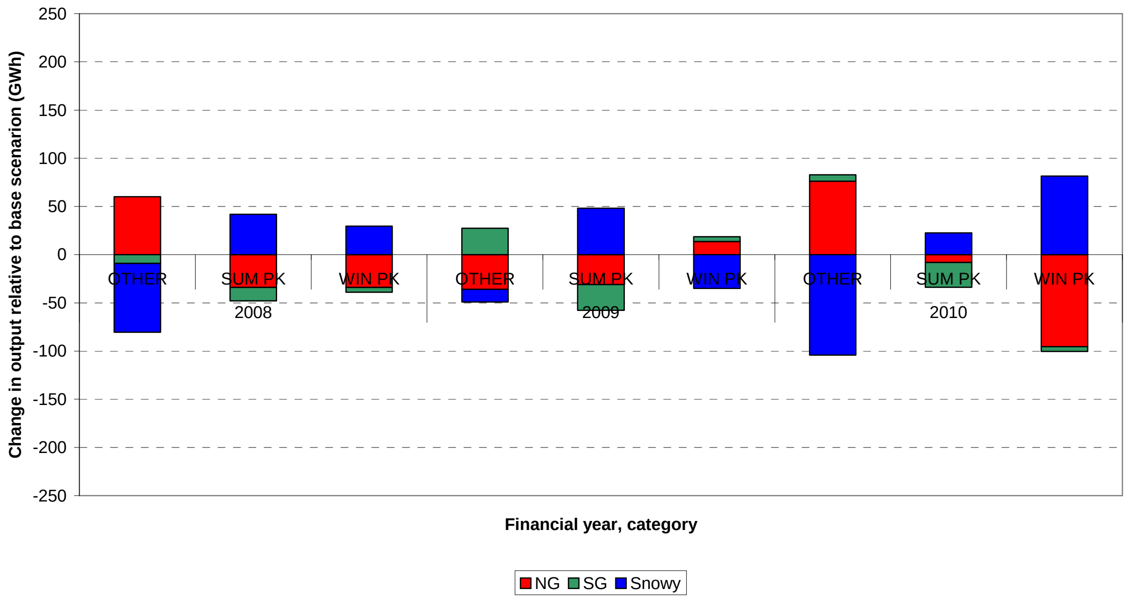


Figure A.14 Split Region Option scenario output changes by generator group, contracted low (relative to the BAU base case scenario)

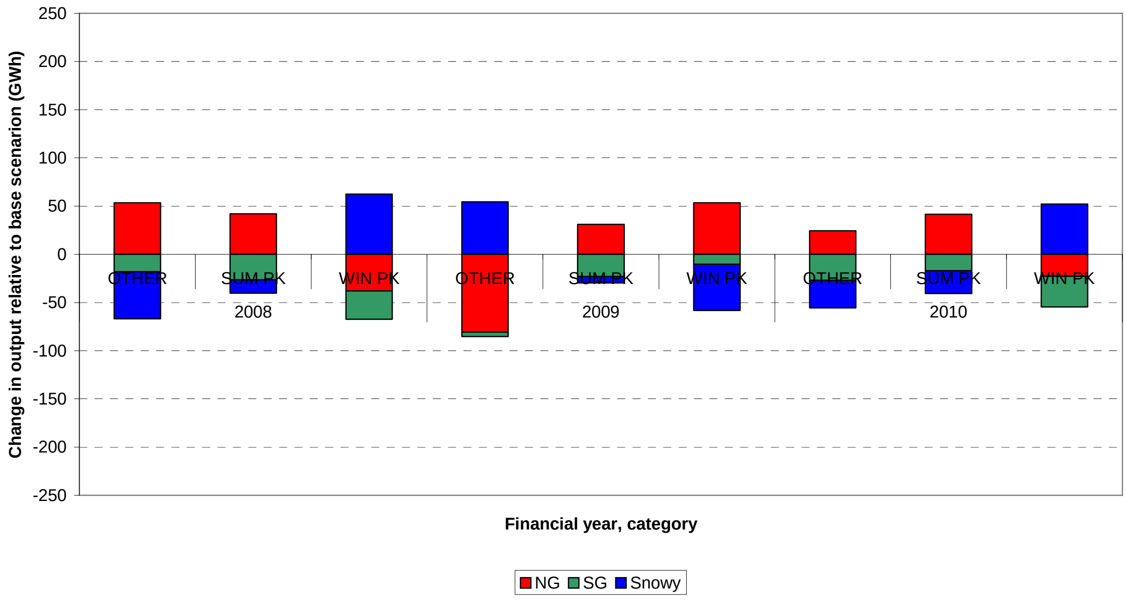


Figure A.15 Snowy Hydro scenario output changes by generator group, contracted high (relative to the BAU base case scenario)

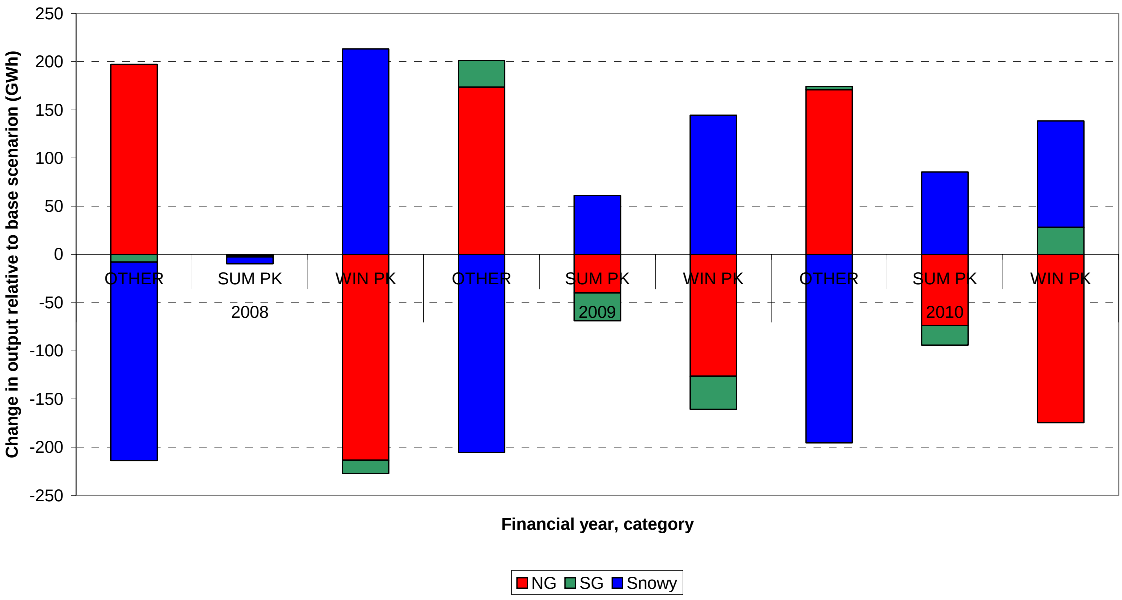
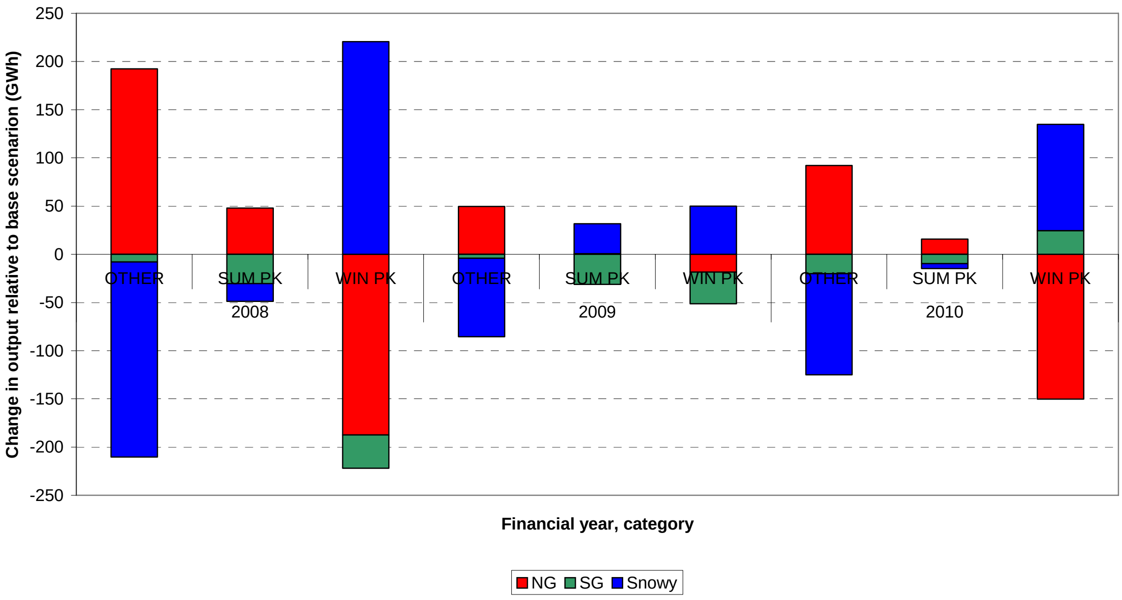


Figure A.16 Split region scenario output changes by generator group, contracted high (relative to the BAU base case scenario)



As discussed above, production cost savings occur because the more competitive equilibria that occur during peak times under either of the boundary changes leads to more expensive plant being displaced. Figure A.17 to Figure A.20 show how output changes across the year by marginal cost band (a positive value indicates that output in that band is higher under a boundary change). In all scenarios, cases and years, it is possible to consistently observe more expensive mid-merit plant being displaced by cheaper baseload plant. Year on year, there are differences as to whether it is brown or black coal that causes the displacement however the trend remains clear.

Figure A.17 Snowy Hydro scenario annual output changes relative to the BAU base case scenario by financial year and cost band, contracted low

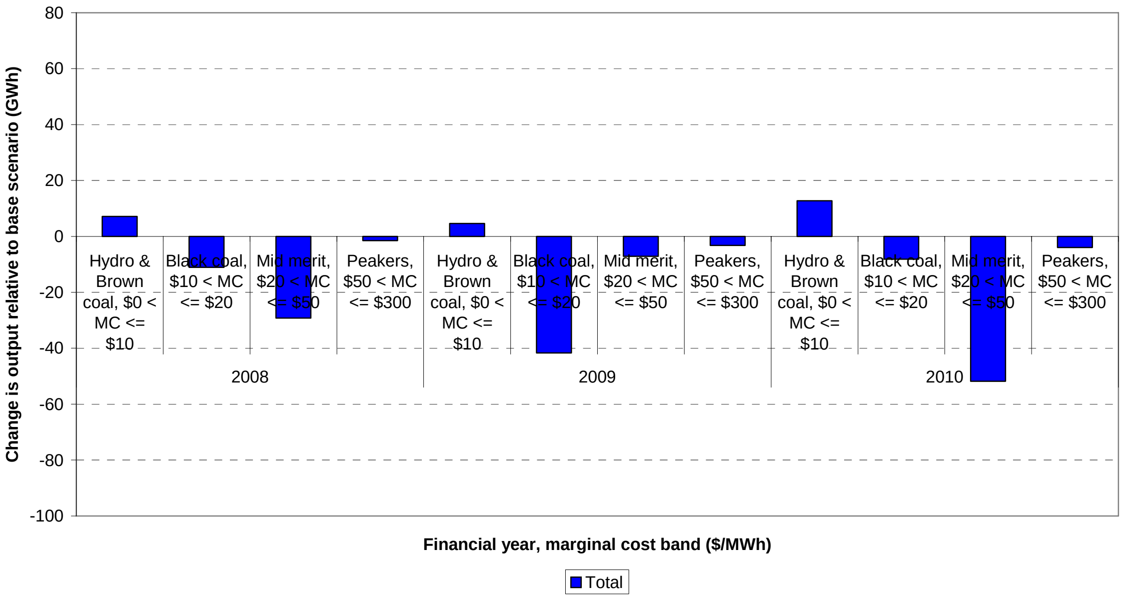


Figure A.18 Split region scenario annual output changes relative to the BAU base case scenario by financial year and cost band, contracted low

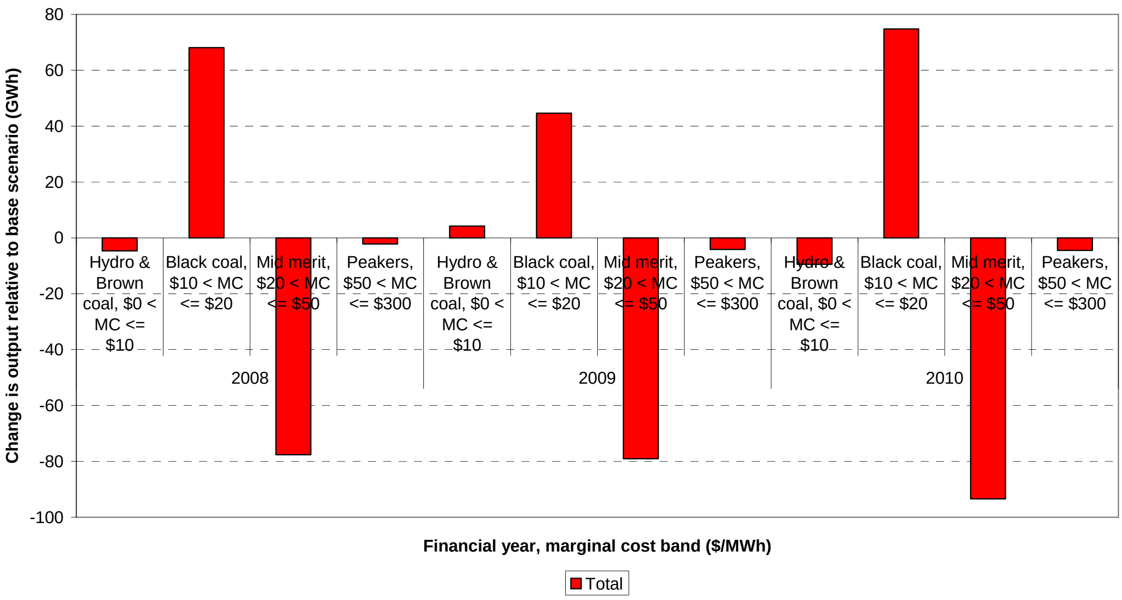


Figure A.19 Snowy Hydro scenario annual output changes relative to the BAU base case scenario by financial year and cost band, contracted high

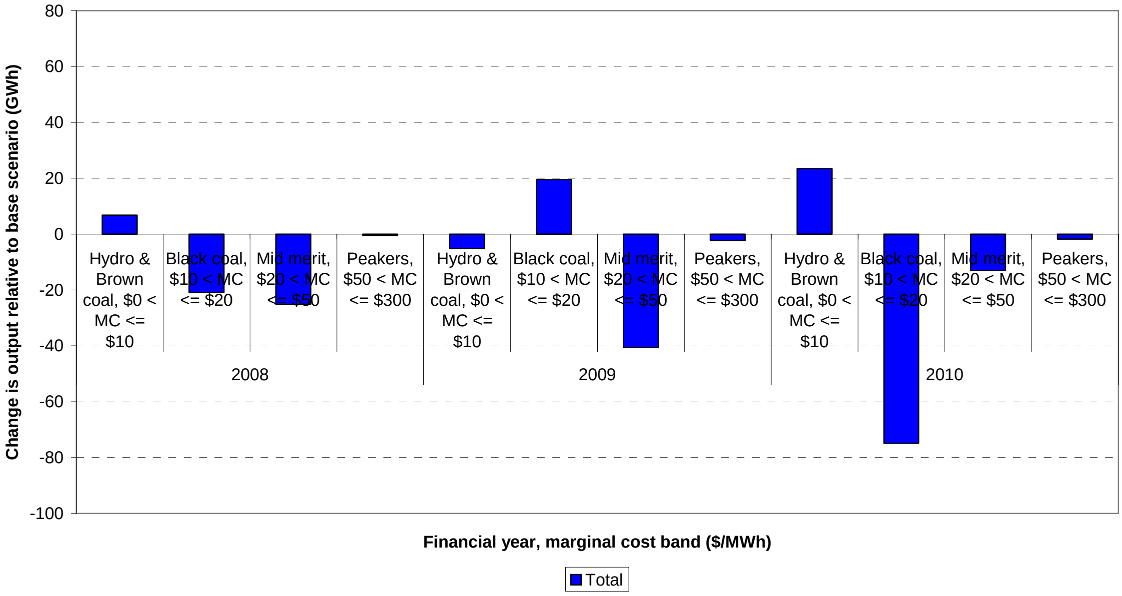
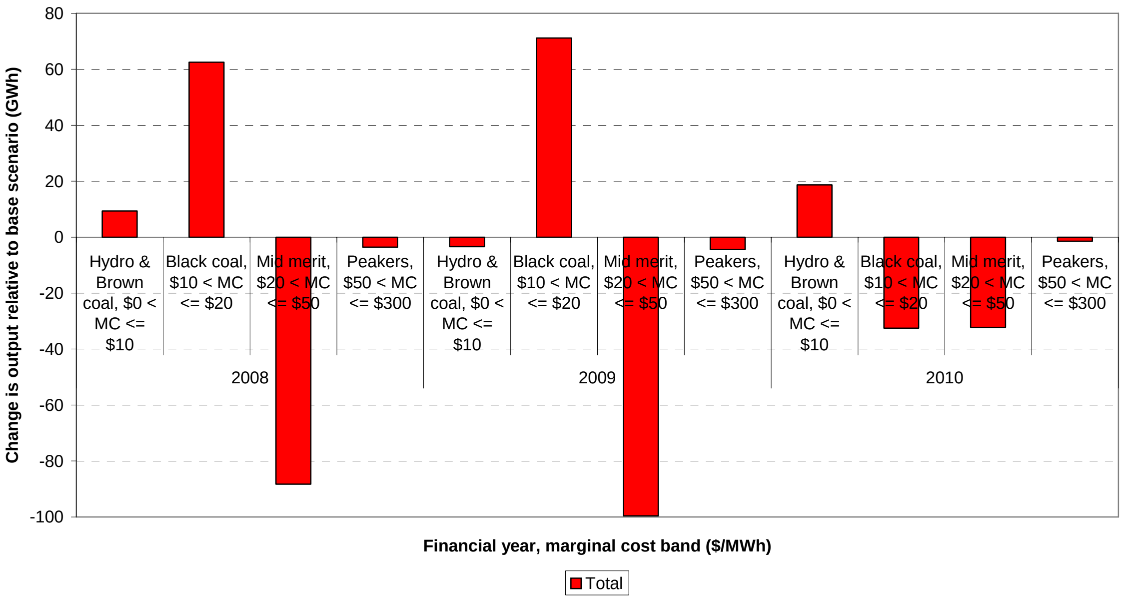


Figure A.20 Split region scenario annual output changes relative to the BAU case scenario by financial year and cost band, contracted high



A.2.5.5 Changes in flows

Figure A.21 shows the Snowy Hydro scenario changes in net annual energy transfers from Victoria to Murray and Tumut to NSW relative to the BAU base case scenario for the peak summer and winter times of the year. Positive Victoria to Murray values indicates that more power was transferred in a southward direction under the boundary change. Positive Tumut to NSW values indicate that more power was transferred northwards under the boundary change.

The Snowy Hydro scenario leads to greater power flows north of Tumut consistent with the observed change in bidding behaviour.

Figure A.21 Snowy Hydro scenario changes in net flows relative to the BAU base case scenario

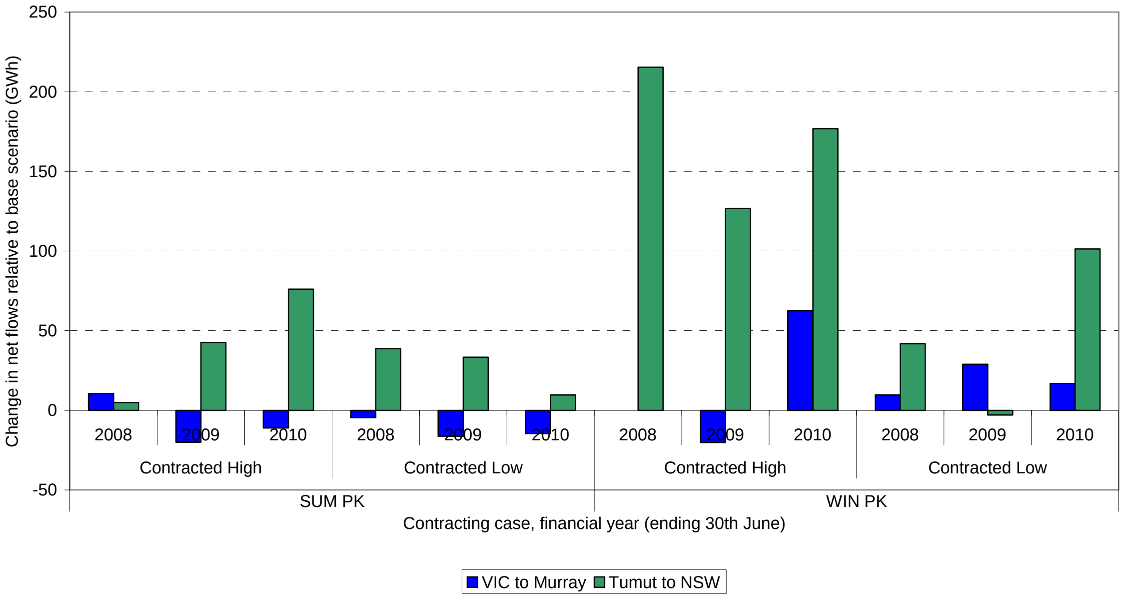
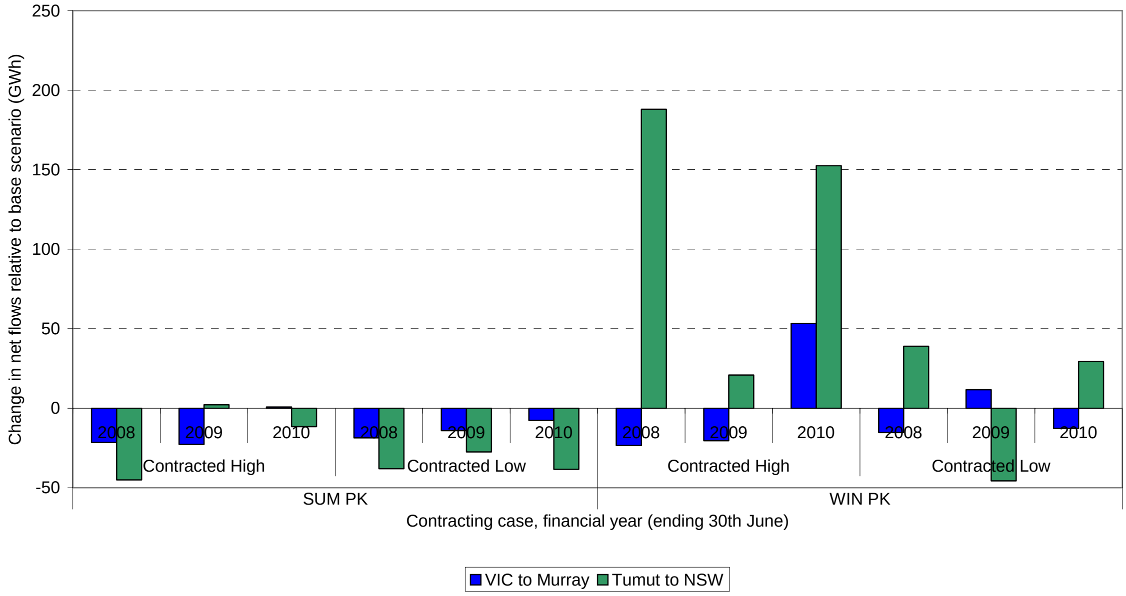


Figure A.22 Split region scenario changes in net flows relative to the BAU base case scenario



A.2.5.6 Price effects

Changing the regional boundary generally leads to a reduction in market prices due to baseload plant displacing relatively expensive plant, as discussed above. This effect is shown in the time weighted average annual prices in Figure A.23 to Figure A.26 for NSW and Victoria under both contracting cases. The exception to this trend is the Snowy Hydro scenario in 2007/08, where prices in NSW increase slightly relative to the BAU base case and the Split Region Option scenarios. This is due to constraints arising around South Morang in Victoria that cause Victorian/NSW price separation and high prices in NSW for key demand points (particularly demand point 18 where production cost deficits are seen in Figure A.9).[124] However, in later years, the Snowy Hydro proposal also leads to reduced market prices.

In NSW, the Split Region Option results in lower prices than the Snowy Hydro proposal. A significant factor in this is that the South Morang constraint is alleviated almost entirely by the Split Region Option resulting price reductions beyond those realised under the Snowy Hydro proposal. In Victoria, lower magnitude price reductions are observed. This is driven by the greater amounts of peaking capacity in Victoria – BassLink, Laverton – which serve to cap high price events and mitigate the price effects of a boundary change.

124 Appendix D discusses the South Morang constraint.

Figure A.23 Average annual prices – NSW, contracted low

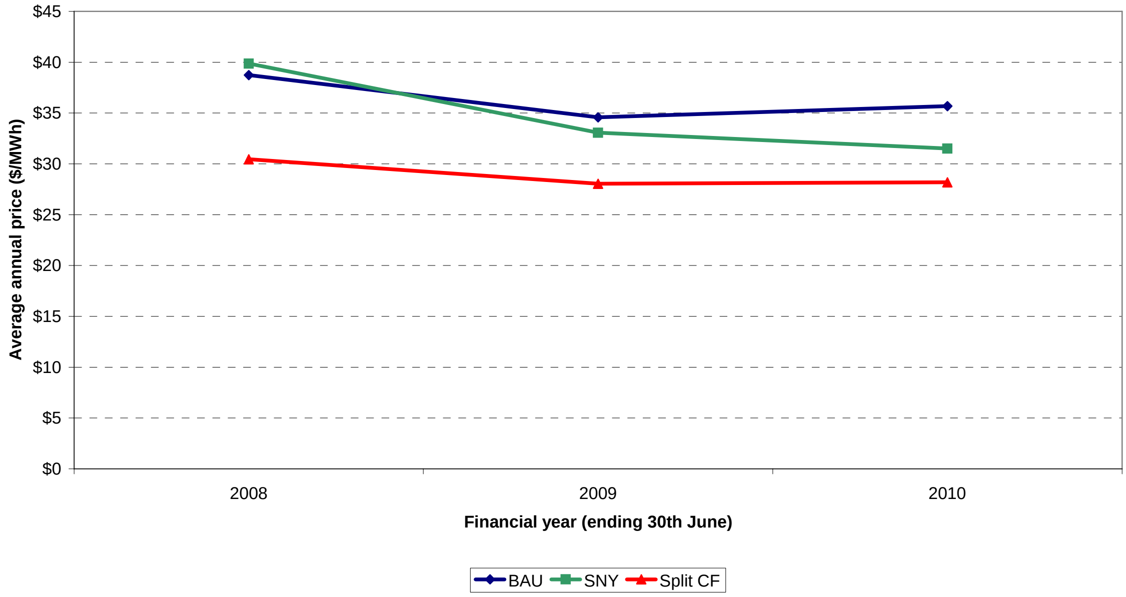


Figure A.24 Average annual prices – NSW, contracted high

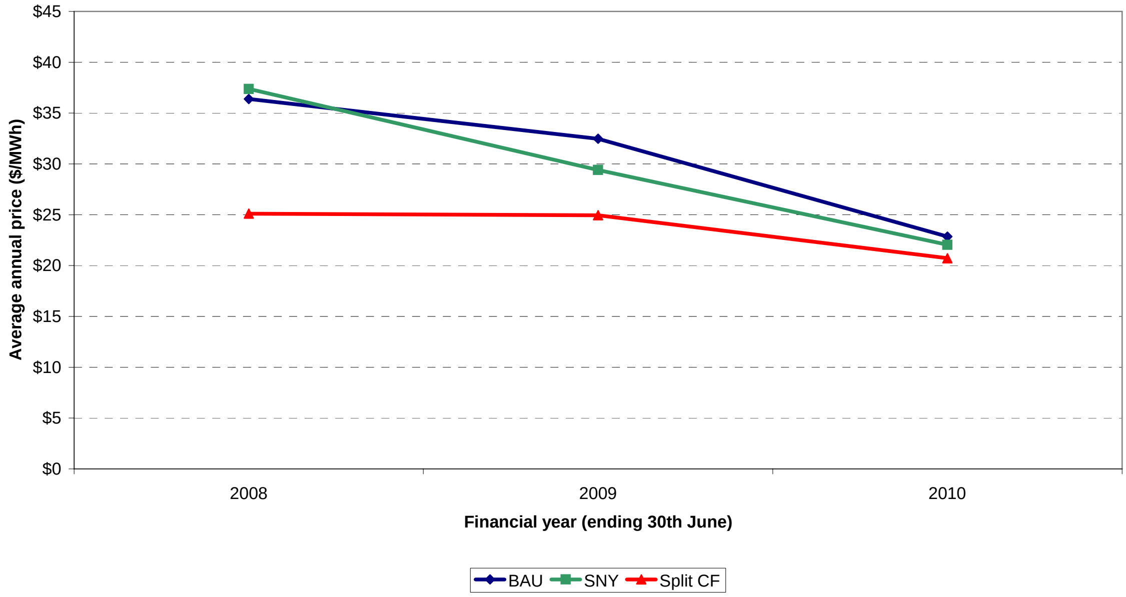


Figure A.25 Average annual prices – Victoria, contracted low

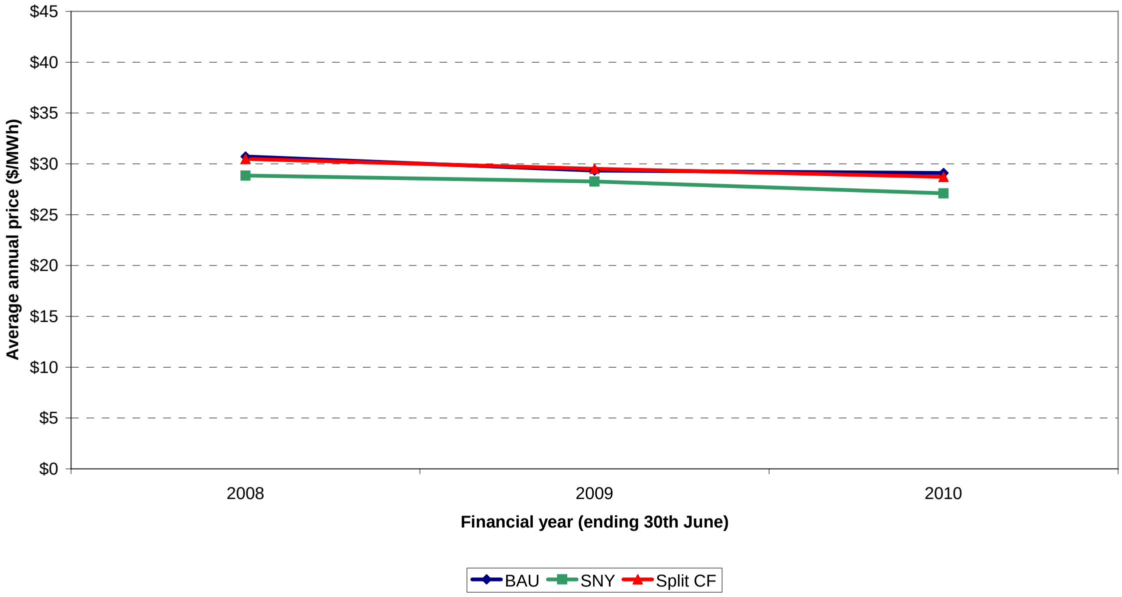


Figure A.26 Average annual prices – Victoria, contracted high

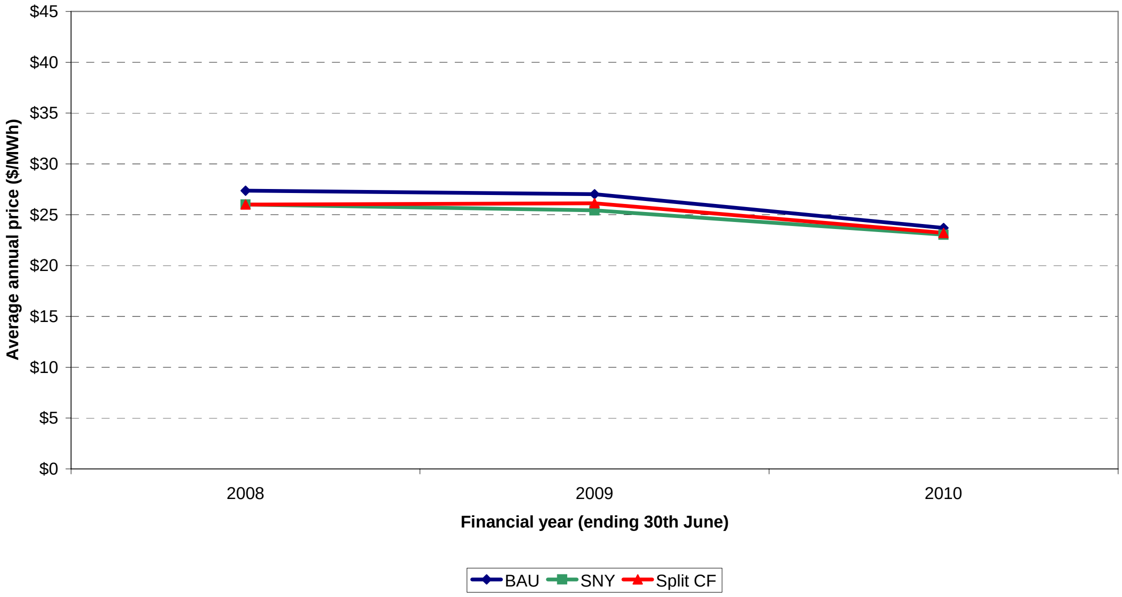


Figure A.27 and Figure A.28 show that across each year and contracting case, only insignificant changes between the scenarios are observed in the average prices for the other times of the year. These figures demonstrate that it is during the peak hours that significant price differences occur. This is consistent with the assumptions regarding bidding behaviour across the year.

Figure A.27 Timing of the price changes – NSW, other times of the year

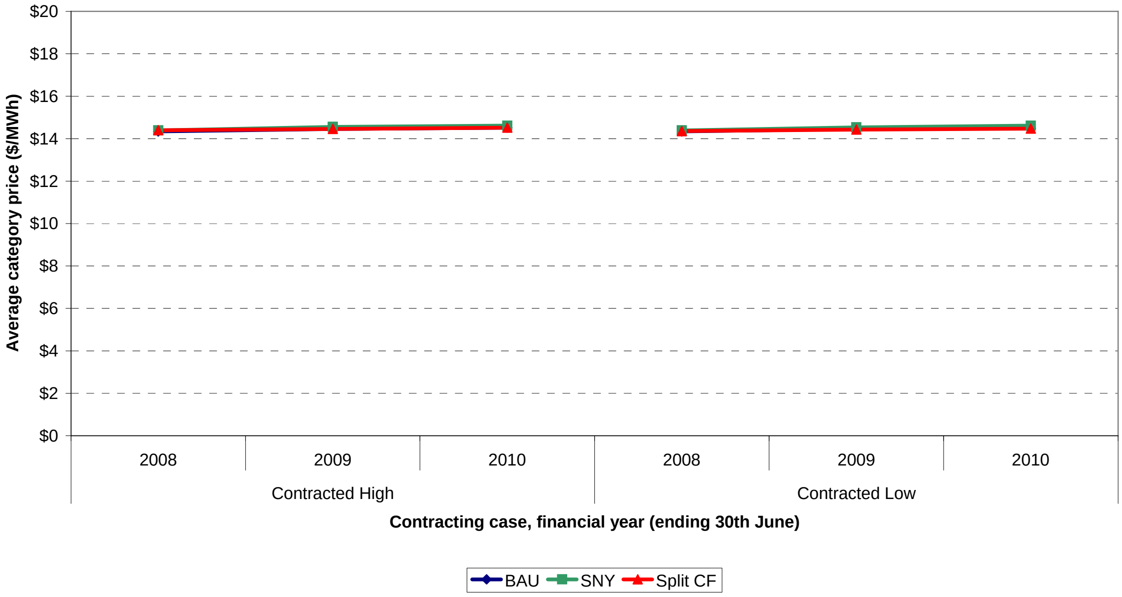
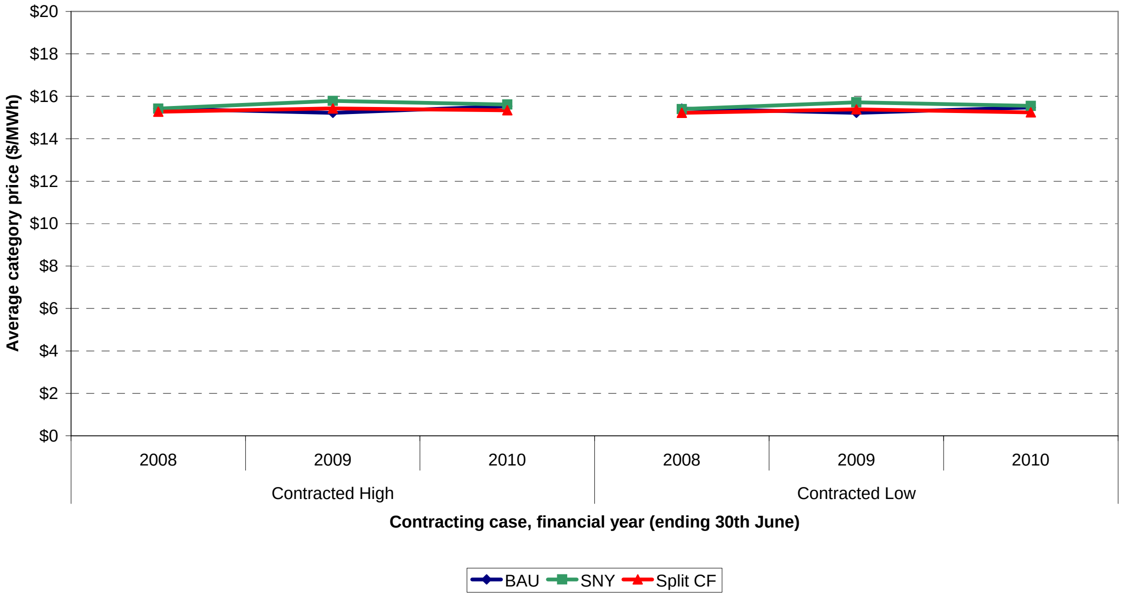


Figure A.28 Timing of the price changes – Victoria, other times of the year



In similar fashion to the previous figures, Figure A.29 and Figure A.30 show the average prices for NSW during summer and winter peak times, respectively. Figure A.31 and Figure A.32 depict the same data for Victoria. It can be observed that the most significant price changes occur during the summer "super-peak" periods. The higher levels of demand occur at these times and we observe correspondingly higher price outcomes between the scenarios. Ultimately, these super-peak effects are driven by the changes in dispatch discussed earlier, particularly the displacement of more expensive plant under both of the boundary change scenarios.

Significant reductions are also observable during winter super-peak times. However, the relatively lower levels of demand and greater amounts of dispatchable capacity (due to summer derating of plant), means that the price effects are not as extreme as for summer peak times.

Figure A.29 Timing of the price changes – NSW, summer peak times

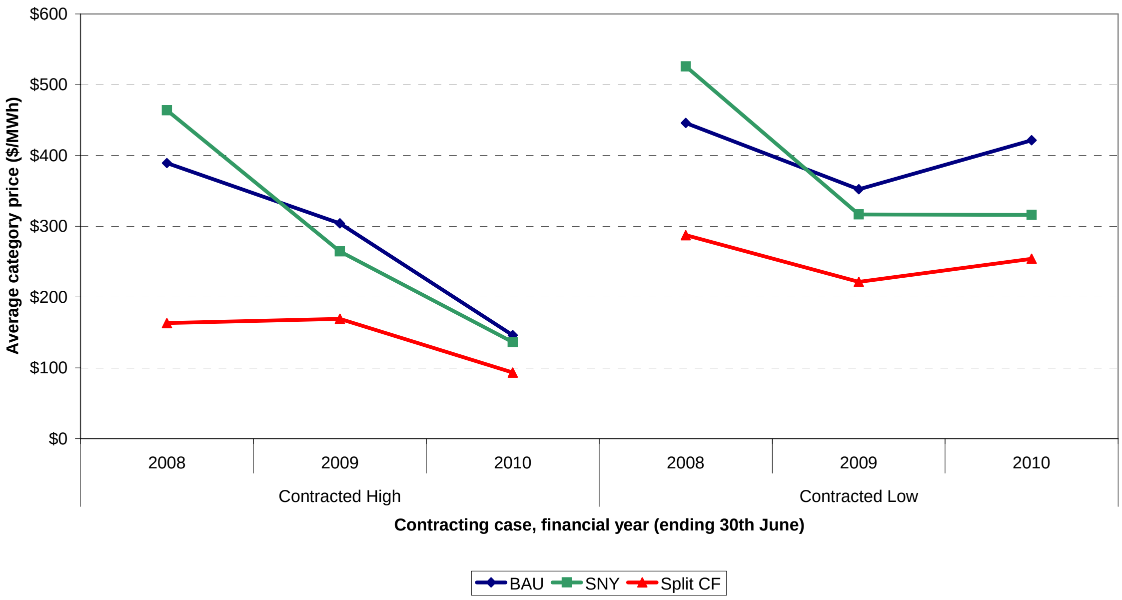


Figure A.30 Timing of the price changes – NSW, winter peak times

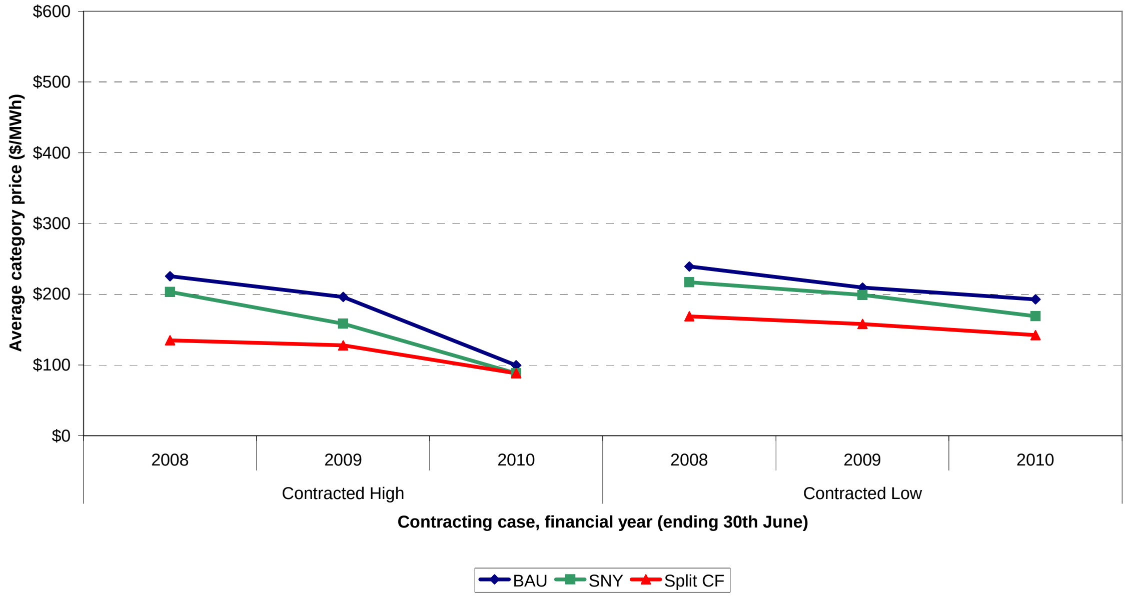


Figure A.31 Timing of the price changes – Victoria, summer peak times

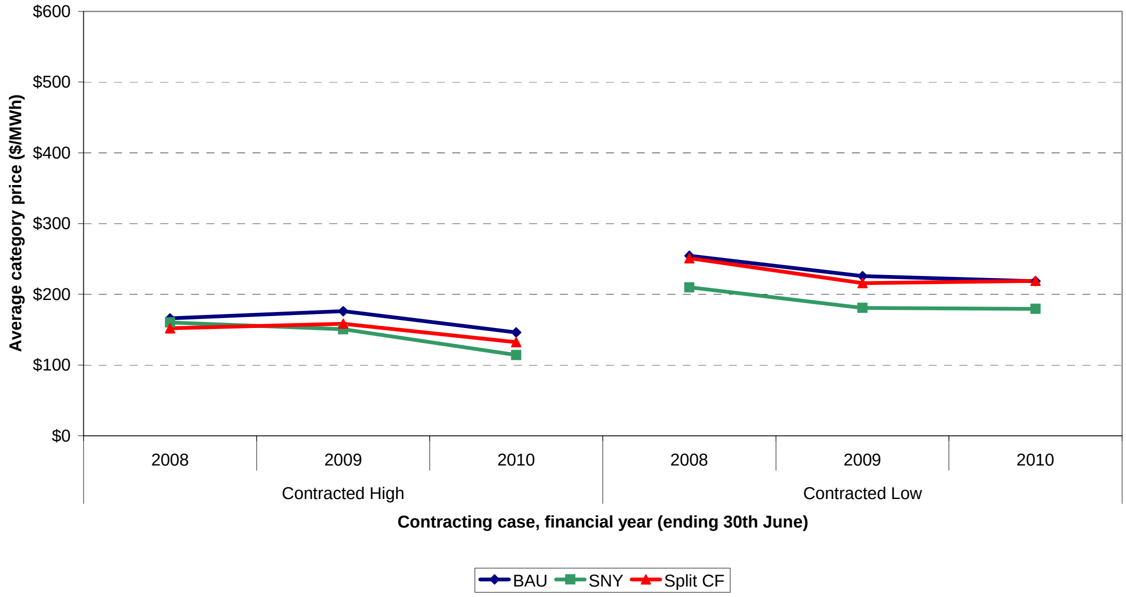
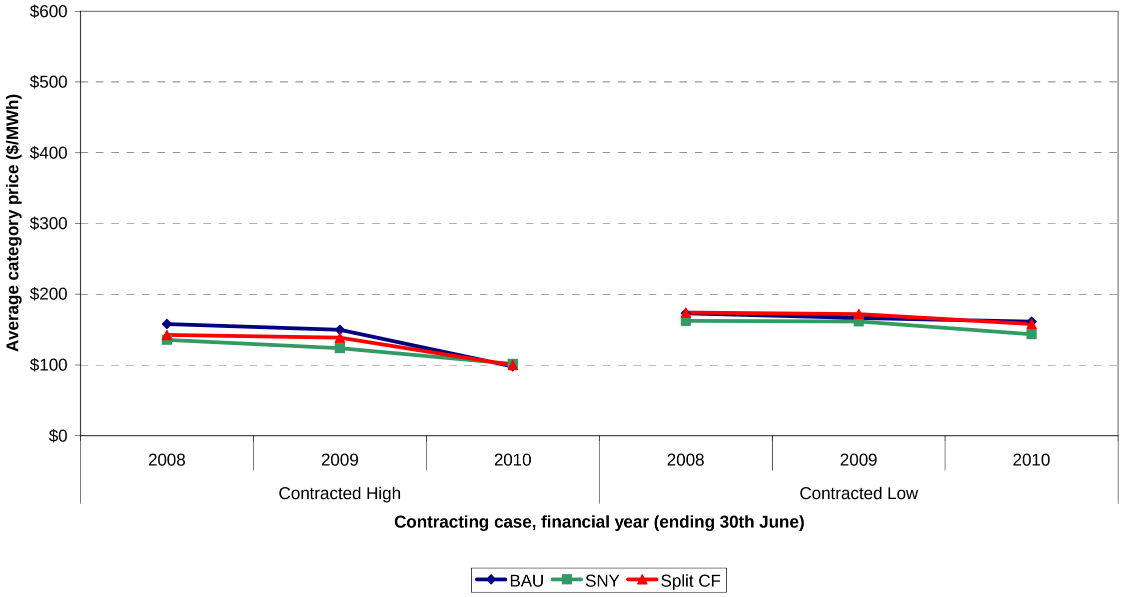


Figure A.32 Timing of the price changes – Victoria, winter peak times



A.2.5.7 Incidence of constraints

The effect of the South Morang constraint has been discussed above, in light of its effect on pricing outcomes. A number of other constraints also bind in the modelling across the various years and scenarios. Main areas of constraint are South East Queensland, NSW western ring and the Snowy region.[125]

Either of the boundary changes leads to an increase of congestion on the lines north of Tumut and the western ring. Some congestion in northern NSW/southern Queensland is relieved by the boundary change, but this transfers the congestion to other parts of the NEM. In terms of hours of constraints under the boundary change scenarios, roughly the same levels of constraint can be observed, but the identity of the constraints that bind are different and they do not affect market outcomes as much. Both boundary change scenarios do lead to increased levels of constraint north of Tumut consistent with its increased dispatch.

This is shown in Table A.3, which details the frequency of constraint binding and the average dual whilst binding across the three scenarios for the Contracted low case (where greater congestion was observed). Only constraints that bound for at least 10 hours have been included in the table. The dual price represents the reduction in the cost of meeting system demand if the constraint in question were relaxed by one unit. As such the average dual figures give an indication of how severe the impact is of a particular constraint binding.

125 The "western ring" constraint is discussed in Appendix D.

Table A.3: Constraints that bind for at least 10 hours – binding hours and average dual while binding (contracted low)

FY	Constraint name	Binding hours			Average dual price while binding		
		BAU base case	Snowy Hydro	Split RO	BAU base case	Snowy Hydro	Split RO
2008	Q>N-NIL_DF	298	330	342	$799	$650	$393
2008	Q>N-NIL_DC	240	193	250	$99	$103	$117
2008	Q>NIL_757+ 758_B_SUMR	190			$16		
2008	Q>NIL_SBMU	134			$1,049		
2008	Q>N-NIL_1N-op3	90	111	116	$596	$391	$376
2008	N>Q+NIL__D	48	66	43	$508	$219	$183
2008	S>VML_NIL1	53	58	16	$1,296	$1,368	$1,262
2008	VSML_210	12	54	45	$45	$92	$92
2008	VH>V3NIL	46	53		$1,993	$2,176	
2008	N>N-NIL_03		50	22		$90	$42
2008	N>N-NIL_01	19	38	10	$289	$119	$38
2008	HV_1900		23	2	$3	$187	$60
2008	N>HV-NIL_1		18	21		$100	$79
2008	SV_300	9	6	15	$1,450	$1,609	$1,316
2008	Q:NIL_CN1	13			$2		
2008	H>>H-64_B			10			$1,104
2009	Q>NIL_SBMU	300			$556		
2009	Q>N-NIL_DF	204	259	291	$863	$395	$318
2009	Q>N-NIL_DC	140	121	149	$82	$68	$68
2009	Q>N-NIL_1N-op3	57	115	85	$417	$309	$285
2009	N>HV-NIL_1	5	25	63	$24	$110	$135
2009	N>N-NIL_03		23	63		$38	$46
2009	Q>NIL_757+ 758_B_SUMR	47			$18		
2009	Q:NIL_CN1	43			$9		
2009	S>VML_NIL1	40	30	11	$1,254	$1,355	$1,035
2009	VH>V3NIL	36	29		$2,021	$2,142	
2009	VSML_210	35	34	14	$45	$94	$59
2009	N>Q+NIL__D	26	32	25	$1,697	$12	$26
2009	HV_1900	3	28	4	$15	$112	$16
2010	Q>N-NIL_DF	353	379	382	$1,081	$564	$545
2010	Q>NIL_SBMU	211			$479		
2010	Q:NIL_CN1	186			$28		
2010	Q>N-NIL_1N-op3	96	113	127	$334	$211	$311
2010	VSML_210	63	91	60	$47	$84	$90
2010	N>Q+NIL__D	52	85	79	$1,454	$317	$398
2010	N>HV-NIL_1		52	78		$84	$116
2010	N>N-NIL_03		52	78		$28	$39
2010	N:H_LTUT	71			$20		

FY	Constraint name	Binding hours			Average dual price while binding		
		BAU base case	Snowy Hydro	Split RO	BAU base case	Snowy Hydro	Split RO
2010	Q>N-NIL_DC	6	32	48	$47	$42	$41
2010	S>VML_NIL1	44	29	10	$1,272	$1,336	$1,083
2010	VH>V3NIL	41	29		$2,001	$2,106	
2010	HV_1900		39	2		$81	$31
2010	N>Q-NIL__A	17			$2,500		
2010	N>N-NIL_18	16			$2,500		

A.2.5.8 Incidence of negative settlement residues

Figure A.33 and Figure A.34 show the hours and total annual value of negative settlement residue by interconnector and financial year for the Contracted Low case. It can be observed that, apart from DirectLink, both the incidence and value of negative residues is negligible. Some negative residues do occur in the Split Region Option on the new interconnectors created in that scenario, but never for more than 10 hours annually or with an annual cumulative value over $100,000. Significant negative residues occur on DirectLink due to its position in an electrical loop and the incidence of binding constraints in Queensland.[126]

Even lower levels of negative residues are observed for the Contracted High case as is shown in Figure A.35 and Figure A.36.

Note that, in the BAU base case scenario, negative residues do not arise on either the Victoria-Snowy or the Snowy-NSW interconnectors due to the assumption of clamping and reorientation of constraints.

[126] DirectLink lies on a loop formed by QNI, northern NSW transmission and Tarong-Brisbane lines.

Figure A.33 Hours of negative settlement residue by interconnector, contracted low

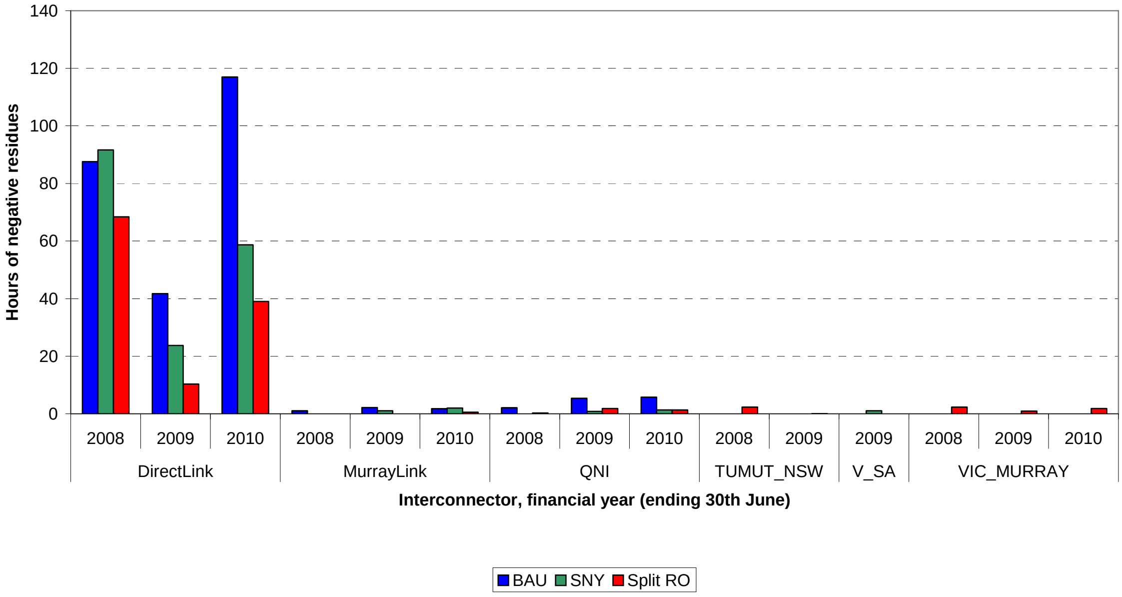


Figure A.34 Total annual negative settlement residue by interconnector, contracted low ($m)

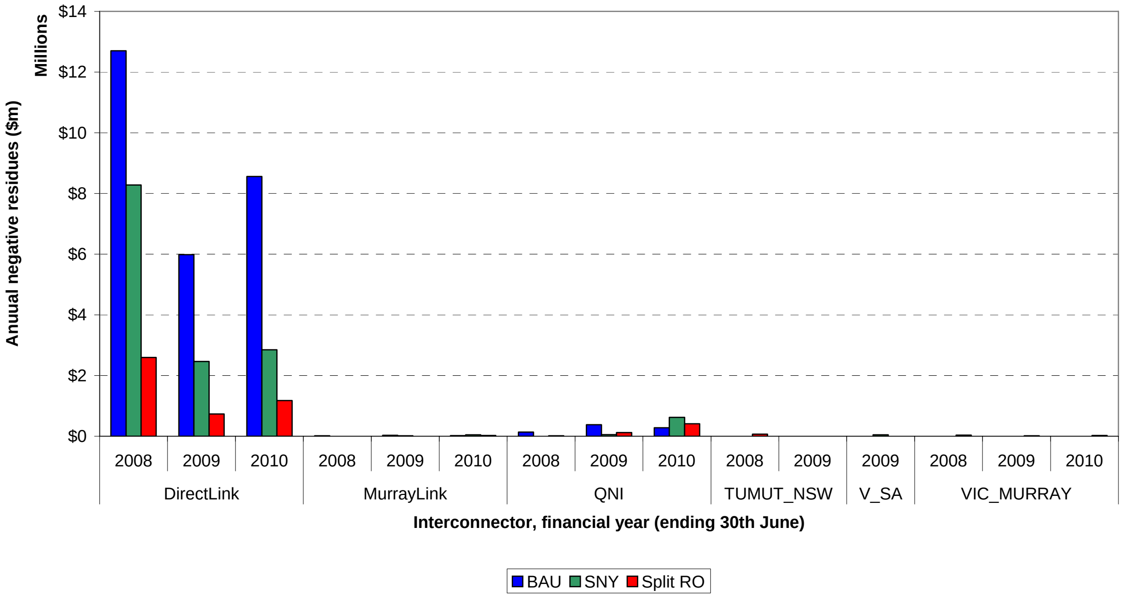


Figure A.35 Hours of negative settlement residue by interconnector, contracted high

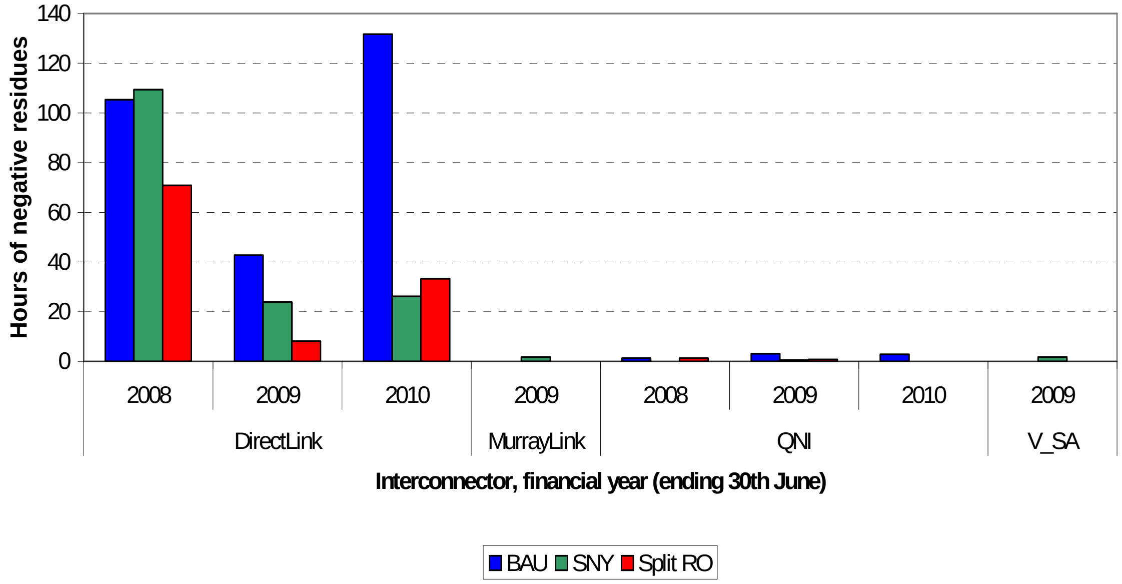
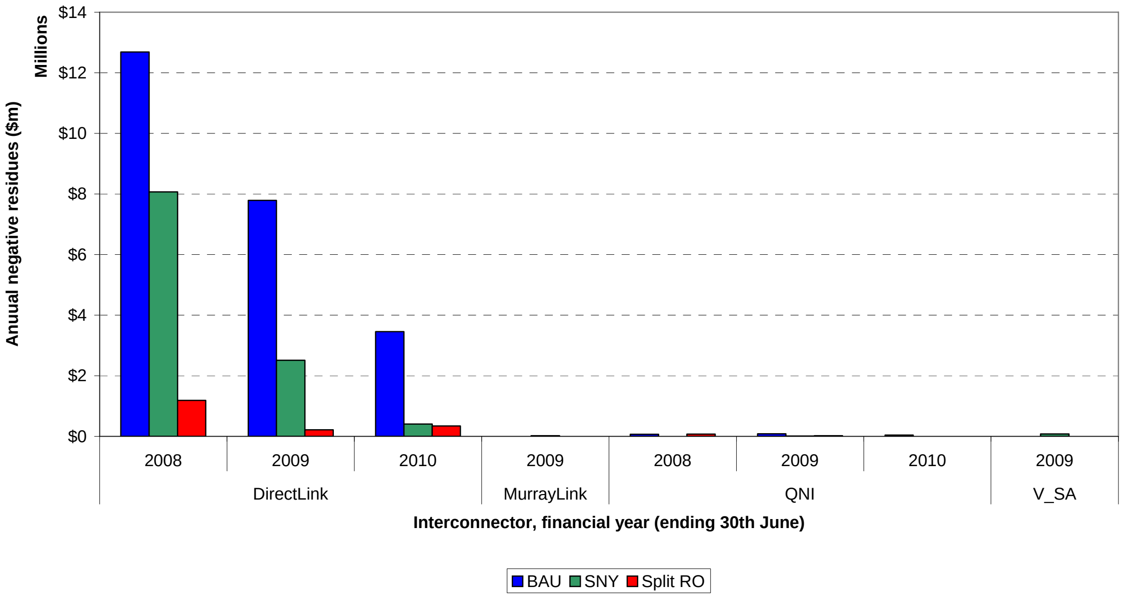


Figure A.36 Total annual negative settlement residue by interconnector, contracted high ($m)



A.3 Risk modelling

This Section discusses the approach, assumptions, results, and conclusions for the forward-looking risk modelling analysis.

A.3.1 Approach

The risk modelling was undertaken using Frontier Economics' portfolio optimisation model, *STRIKE*. This discussion begins by describing some of the key features of this model before discussing the methodology used to calculate the risk implications of the Snowy Hydro proposal and the Split Region Option.

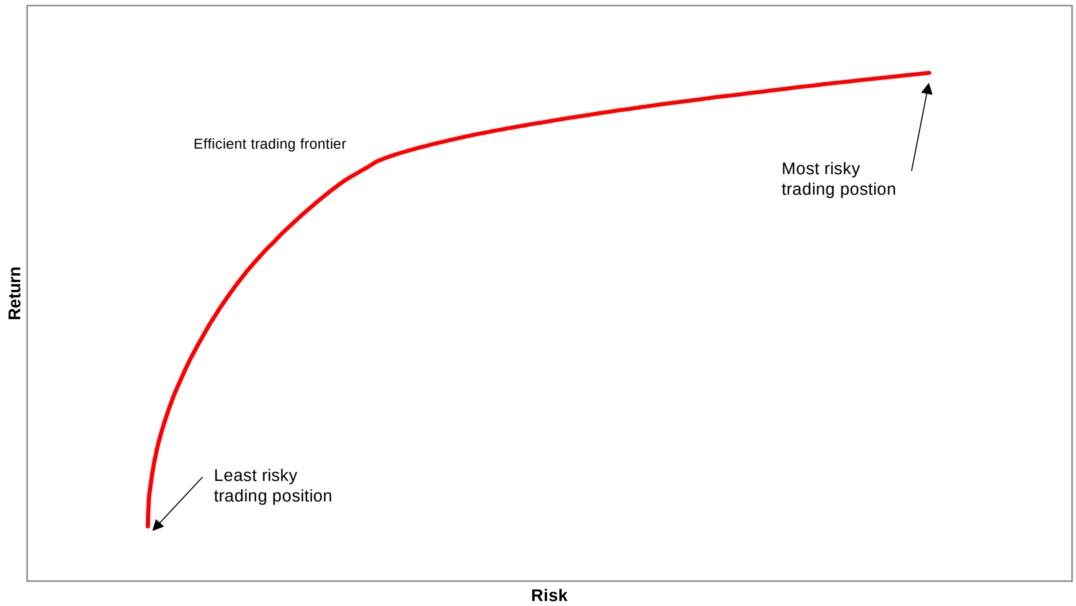
A.3.1.1 Key features of *STRIKE*

The *STRIKE* financial model uses portfolio theory to determine an efficient mix of energy purchasing instruments from a suite of options (spot, physical and financial) for a range of risk levels. Each efficient combination of instruments is represented as a point on a frontier, against which other portfolios can be compared.

Portfolio theory sets out how rational investors would use diversification to optimise their portfolios and how an asset should be priced given its risk relative to the market as a whole. More specifically, portfolio theory estimates the return of an asset as a random variable and a portfolio as a weighted combination of assets. The return of a portfolio is therefore a random variable and consequently has an expected value and a variance. Risk in this economic model is usually identified with the standard deviation of portfolio return (although other measures of risk can be used). For a given expected return, a rational investor would choose the least risk portfolio. In portfolio theory this relationship between risk and reward is represented by an efficient frontier (see Figure A.37).

The efficient frontier describes the outer edge of every possible portfolio of assets that could be plotted in risk-return space. Portfolios of assets along this line deliver lowest risk for a given level of expected return. Conversely, for a given amount of risk, the portfolio lying on the efficient frontier represents the combination of assets offering the best possible expected return. Any portfolio that lies below and/or to the right of the efficient frontier is sub-optimal, delivering either a lower expected return and/or higher level of risk than a portfolio lying on the frontier. It is not possible to construct a portfolio that lies above and/or to the left of the efficient frontier. The model calculates the outer edge (frontier) of every possible portfolio using an advanced quadratic mixed integer programming technique.

Figure A.37 A generalised efficient frontier for hedging energy trading risks



A.3.1.2 Methodology

As market conditions change, so does the efficient frontier. This enables the impact of changes in spot price volatility and IRSR firmness arising from the Snowy Hydro boundary change proposal, to be compared to both the BAU base case and the Split Region Option.

The risk modelling was undertaken for several key scenarios:

- A Victorian generator hedging at the NSW node;
- A NSW generator hedging at the Victorian node; and
- A Snowy Hydro generator hedging at both the Victorian and NSW nodes concurrently.

The Snowy Hydro proposal and Split Region Option affect settlement residues between Victoria, Murray, Tumut and NSW. The above cases cover the range of likely risk-management applications using combinations of the relevant residues.

In each case, *STRIKE* was run to calculate the efficient frontier for the given set of price duration curves and IRSR units.

The precise effect of a regional boundary change on risk will depend on where participants choose to locate on the efficient frontier – that is, their risk preferences. Given that the analysis is primarily concerned with the *relative* effects of the alternative proposals, for simplicity the results are presented for the most conservative risk position on the efficient frontier (that is, the bottom left point of the efficient frontier).

The analysis assumes a generator in a given region has a fixed inter-regional position and determines the minimal risk associated with that same position under each of the BAU base case, Snowy Hydro proposal and Split Region Option.

A.3.2 Assumptions

The risk modelling was based on the spot prices and IRSRs produced by the dispatch modelling for the BAU base case, Snowy Hydro proposal and Split Region Option described above.

For each of the spot price series and associated IRSR units, the analysis compared the efficient frontiers for each of the following hypothetical generators with an inter-regional position using the relevant IRSR units between Victoria, Murray, Tumut and NSW:

- Vic into NSW: A 100 MW Victorian generator with a 100MW position in NSW and able to purchase a mix of relevant northward IRSR units;

- NSW into Vic: A 100 MW NSW generator with a 100MW position in Victoria and able to purchase a mix of relevant southward IRSR units; and

- Murray/Tumut into Vic/NSW: A 100 MW Snowy Hydro generator (50MW at Murray and 50MW at Tumut) with a 50MW position in Victoria and a 50MW position in NSW and able to purchase a mix of relevant IRSR units.

For the purposes of comparison, the generation and inter-regional position were assumed to be consistent in each case. IRSR units were assumed to be available to the generator at actuarially fair cost (i.e. the cost of the unit was equal to the expected return of the residues[127]).

A.3.3 Results

The *STRIKE* analysis found that the Snowy Hydro proposal and the Split Region Option produced, in all cases, lower levels of risk associated with a given inter-regional position compared to the BAU base case (see Figure A.38). The results show the level of risk associated with the inter-regional position (including a risk-minimising mix of relevant IRSR units). Risk is shown in terms of the standard deviation of returns for the optimised portfolio, in terms of $ per MWh covered by the inter-regional position.

The results indicate that the Split Region Option enables lower risk inter-regional hedging for NSW into Vic and Vic into NSW, compared to the Snowy Hydro proposal - assuming that the optimal quantity and mix of IRSR units are available to the generator at actuarially fair cost and ignoring transaction costs and execution risk.

---

127 Note that the assumed cost of the IRSR units is inconsequential to this particular analysis. This is because the analysis focuses on determining the portfolio with minimum risk, and hence has no regard to cost. The minimum risk portfolio would be the same no matter what the assumed cost of the IRSR units.

Whilst the results indicate that the inter-regional price risk may be lower under the Split Region Option, transaction costs and execution risk are likely to be higher compared to the Snowy Hydro proposal. Inter-regional hedging between Vic and NSW (and NSW to Vic) in the Split Region Option involves procuring a mix of three separate IRSR units (Vic-Murray, Murray-Tumut and Tumut-NSW), compared to the Snowy Hydro proposal that would only involve a single IRSR product (Vic-NSW). The transaction costs and execution risk associated with procuring a mix of three IRSR products would be materially higher than that for procuring a single IRSR product. The net result is that is that it is unclear whether the Snowy Hydro proposal or the Split Region Option would deliver less risky inter-regional contracting. It is clear, however, that the Snowy Hydro proposal delivers lower risk inter-regional contracting compared to the BAU base case:

- Inter-regional price risk is lower for Vic to NSW and NSW to Vic hedging – as shown in Figure A.38; and

- Inter-regional hedging between Vic and NSW requires only a single IRSR product under the Snowy Hydro proposal, compared to two products under the BAU base case.

For hedging from Murray/Tumut into Vic/NSW, the analysis indicates that the Snowy Hydro proposal produces the lowest risk outcome. This is intuitively obvious, as there is no inter-regional price risk for Snowy Hydro's generators under its proposal – Murray earns the Victorian price and Tumut earns the NSW price.

Figure A.38 Inter-regional risk results