FINAL CRR REPORT APPENDIX

Prepared For:

AEMC: Reliability Panel

Modelling Methodology, Input Assumptions and Results Second Stage Modelling

Prepared By:

CRA International

Level 31, Marland House

570 Bourke Street

Melbourne Vic 3000, Australia

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A.1 INTRODUCTION

This Appendix presents the methodology, input assumptions, data and results of quantitative modelling of the National Electricity Market (NEM) used to:

- update modelling undertaken for the interim report of three alternative market designs using the most recent input data; and
- investigate a wider range of different levels of VoLL than was considered in the interim report and the effect of different levels the Cumulative Price Threshold (CPT) within the current design of the NEM.

A summary of the cases is provided in Table 1.

Table 1: Summary Modelling Cases

Case	Design Specification
Base Cases	1.VoLL: $10,000/MWh Real 2. VoLL $10,000/MWh Nominal CPT: $150,000
Update Reliability Ancillary Service (RAS)	RAS payments create a revenue stream to plant that provides reserve capability. Reserve duty is assigned within the dispatch algorithm as a new ancillary service. The price for RAS is calculated by the dispatch algorithm in the same way as for energy and other ancillary services and therefore varies with operating conditions and will be high only at times of low reserve. The analysis updates similar calculations in the interim CRR report where the RAS was designed to give the same improvement in USE as an increase in VoLL by $2,500/MWh (i.e. 0.0003% reduction). VoLL: $10,000/MWh Real
Update Standing Reserve	Reserve Generating Capacity is assumed to be installed across the NEM in proportion to regional demand. VoLL: $10,000/MWh Real
Update Reliability Option	Reliability Option contracts are assumed to be won by all generators and provide a steady payment (but limited to the reserve requirement necessary to give USE equal to the reserve standard). VoLL: $3,000/MWh Real A bid cap of $300/MWh is applied for all generators.
Nominal VoLL Cases (new)	Case 1 with VoLL set to the following nominal values: $5,000/MWh; $10,000/MWh; $12,500/MWh, $15,000/MWh; $17,500/MWh, $20,000/MWh; and $30,000/MWh.
CPT Cases (new)	$10,000/MWh nominal VoLL with CPT set to (nominal) values: $50,000; $100,000; $200,000; and $500,000.
Standing Demand Side Reserve Case	Approximately 25% of reserve requirement met by demand side response at VoLL in place of generation reserve.

Further detail on the alternative market designs is given in the main report.

A.1.1 Basis for comparison of scenarios

Where practicable, investment profitability was used as a benchmark parameter in modelling different market settings to ensure that comparisons between different cases are made on a like-for-like basis. For example, where the level of VoLL was altered it was assumed that investors would invest until the same level of profitability was achieved as in the status quo. In this way, the modelling was able to assess the *relative* impact of the alternatives on the level of Unserved Energy (USE) and on market price. In practice we found that the results were highly sensitive to the level of profitability achieved by generators.

A.1.2 Limitations of modelling

Modelling is a valuable tool to inform analysis but the results can be no better than the methodology, assumptions and data that are used. The model described here takes into account the technical and commercial characteristics of the NEM. It does not incorporate the possible impacts of introducing significant new features to the market, such as emissions trading arrangements, or of material investments made for reasons other than in response to electricity market prices.

An important assumption made for the purposes of analysis is that spot and contract arrangements work in tandem and that investors will make commitments on the basis of expected spot price outcomes. Consequently if an investor requires a contract in order to achieve revenue certainty then it is assumed that contract prices will be aligned with spot prices without a material premium.

While the limitations noted in the previous paragraph are also made in other analyses (e.g. by NEMMCO) they are particularly significant in this work because unserved energy is relatively a small percentage of demand. As a result unserved energy can be materially affected by minor differences in the level of generation and responses of different investors to forecasts of future market outcomes. Consequently, the modelling presented here is only part of the overall picture. It assesses the performance of the NEM under these assumptions and the effect of different settings on the market under the same assumptions.

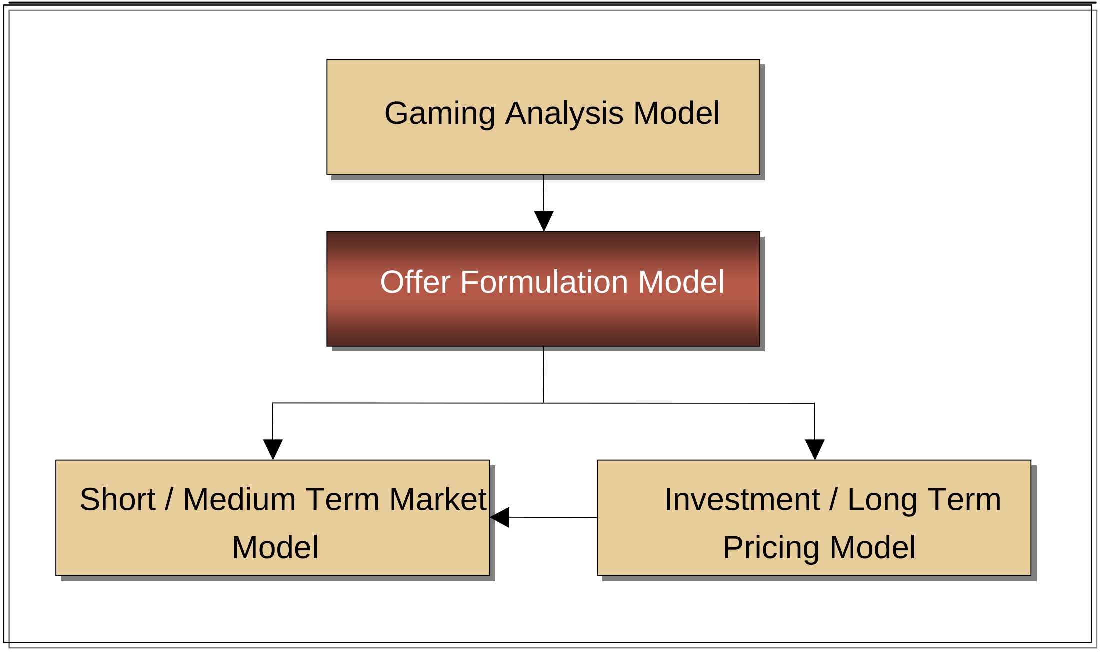
A.2 MODELLING APPROACH

Analysis was undertaken using CRA's CEMOS modelling suite. CEMOS is a comprehensive suite of tools to analyse:

- Long term market expansion opportunities;
- Short term simulation of existing plant; and
- Strategic generator bidding scenarios.

Figure 1 highlights the broad CEMOS functionalities, each of which is described in further detail below.

Figure 1: Overview of CEMOS Functionality



A.2.1 Long Term Investment Commitment and Outage Simulation

PEPPY is the component of the CEMOS suite that handles long-term investment simulation. PEPPY optimises electricity market investment and operational decisions over several years, taking into account the physical realities of the electrical power system. PEPPY provides a framework for developing insights about the implications of key market drivers over the longer term, including demand growth, load shape, type and amount of future generation entry, and the longer term effects of market power on system reliability. PEPPY models the supply and demand sides together, and the fixed and variable costs associated with both resources.

Key features include:

- Consideration of fuel costs, load growth and its temporal/spatial distribution, and new entrant capex;
- A Monte Carlo "engine" to simulate the random outages of generators around an *optimised* capacity plan;
- Transmission among interconnected regions; and
- Ancillary services (represented as a single spinning reserve requirement).

PEPPY uses annual load duration curves for each of the NEM regions. Within each load "block", PEPPY resembles the market clearing process in the NEM. By using load duration curves, PEPPY achieves relatively rapid solution times with relatively little loss of detail relevant to long-term investment decisions.

PEPPY is used to determine the market expansion using the following process as shown in Figure 2:

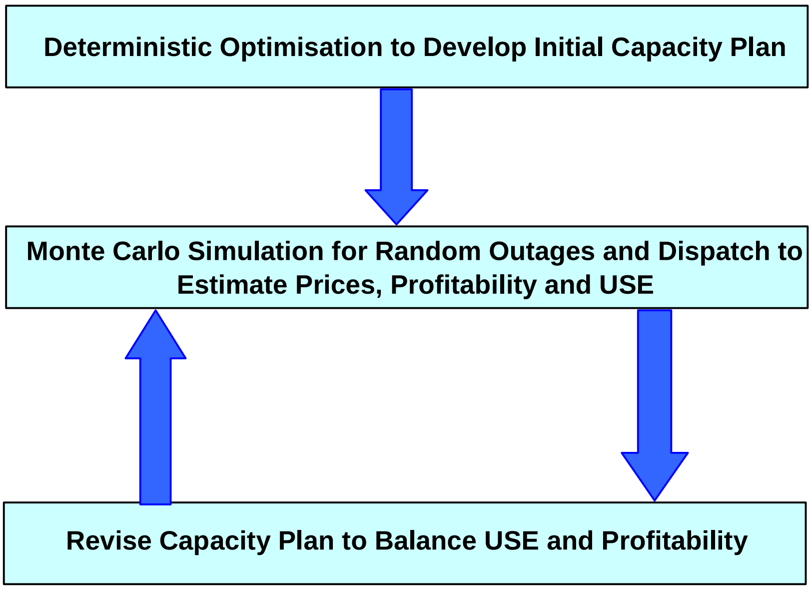
- A *deterministic* optimisation is used to decide the optimal location, timing and technology of generic new entrants such as total volume of coal, combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) plants using a de-rated capacity for planned and forced outages and a starting transmission plan, e.g. the projects identified in the Annual National Transmission Study (ANTS) as discussed later;

- The Monte Carlo engine is used to simulate random outage of generators and dispatch of existing and optimised new entrant generators for 100 randomly selected outage plans. The dispatch, Unserved Energy (USE), profitability, etc. are calculated using the *average* outcome across these samples. These averages represent the expected outcome over a range of potential futures. Of particular importance are the expected USE statistics for each region and year that are compared against the NEM standard; and

- The generation and transmission capacity that the deterministic optimisation used / predicted may fall short of the NEM reliability standard because such optimisation of new generation capacity and utilisation of assumed transmission lines does not accurately reflect the impact of random breakdown of generators and may typically underestimate the USE. The deterministic optimisation of peaking investment may also predict new entry that does not necessarily meet a profitability target that may be reasonably be expected by a commercial investor – for instance, if a region has a very low load factor, peaking investments will be needed that achieve limited utilisation and hence revenue – given the VoLL cap on prices. In this way, the need for larger numbers of iterations is avoided, and a balance is obtained between profitability, generation expansion, network enhancement and reliability with sufficient accuracy for policy analysis.

Assessment of the status quo considered the sensitivity of USE to changes in VoLL.

Figure 2: Capacity Plan Methodology



A.2.2 Generator Bidding Simulation

The CONE module is used to develop generator bids. CONE models the strategic interaction among competing suppliers operating in an oligopolistic industry structure. Each company is assumed to maximise its own profit by adjusting its generation while considering the generation from all other companies and the level of demand response in the market. This is known as a Cournot game, the solution to which is defined as the generation levels at which each company has no incentive to adjust its supply further – because doing so would reduce its profit.

A version of CONE, T-CONE, has been developed so as to develop generator bids in transmission constrained markets. T-CONE is used to develop generator bids in the NEM for a range of demand growth, load shape, capacity entry and interconnection scenarios. CONE models the strategic interactions among generating companies for a range of demand conditions (e.g. peak and off-peak demand across different seasons) taking into account their short run marginal costs, availability, energy limits and contract positions.

A.2.3 Half-Hourly Dispatch Simulation to Validate the Long Term Model Results

STEMM is a short term (daily/weekly) unit commitment model. The key features of STEMM include:

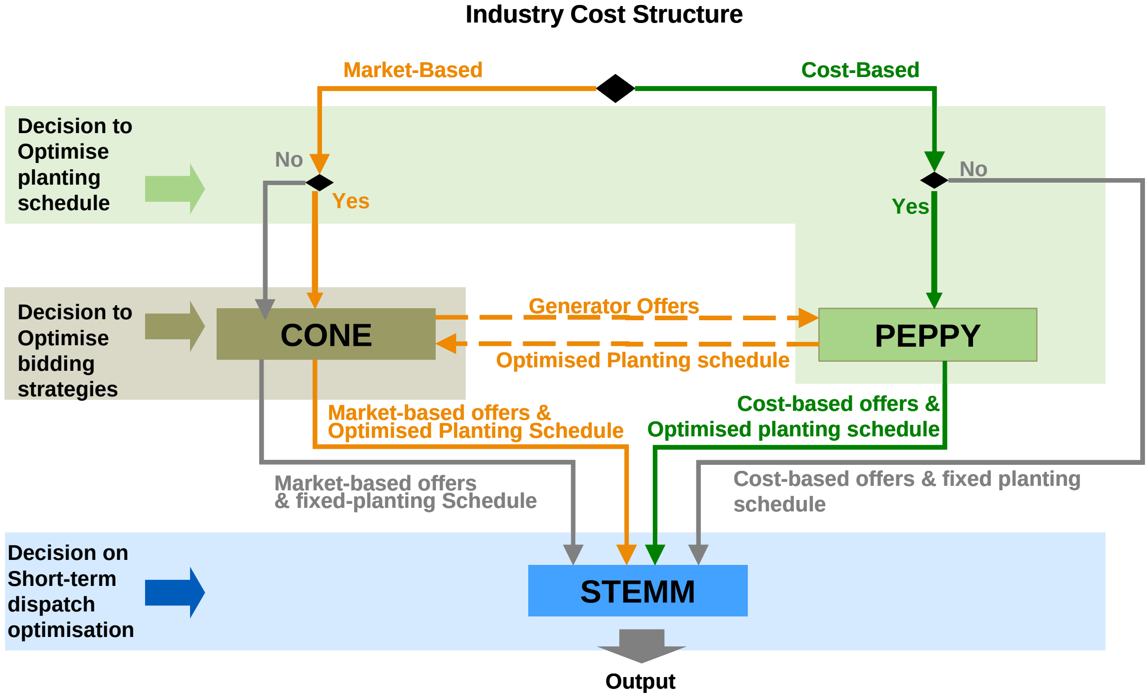
- Detailed consideration of generating unit start-up/shutdown, and ramping for energy/ancillary services;
- Replication, where possible, of the market clearing process of the system;
- Chronological load profile;
- Transmission; and
- Ancillary services.

A.2.4 Interaction Among the CEMOS Modules

For the CRR, we linked the operation of some of the modules within the CEMOS suite, especially PEPPY and CONE. Figure 3 shows the linkages.

Both PEPPY and STEMM use the offers created by CONE. These offers are then used as the "cost" for dispatch of the generators. Both STEMM and CONE use the capacity plan created by PEPPY. This allows for the optimal new entry determined by PEPPY to be used in these other models.

Figure 3: Interaction Between CEMOS Modules



A.3 KEY INPUT ASSUMPTIONS

A.3.1 Modelling Timeframe

Any long-term analysis including expansion of the market requires a sufficient “look ahead” period to develop a view on the long term supply-demand equilibrium. One issue that arises in this context is the “end effect” (or limited horizon effect) that may distort the investment decisions towards the end of the planning period because the model has inadequate information on the future profitability for the investments that are made close to the horizon. In order to minimise such distortions, we have run the analysis over the period from 2007 to 2050 and have used the results for the period up to 2020. In this way, the distortions due to “end-effects” for the period of interest are minimised.

A.3.2 Demand

The long term analysis in CEMOS uses annual load duration curves developed using the peak and energy projections shown in Table 2. We have used the medium economic growth scenario to project regional energy requirements from the NEMMCO "2007 Energy and Demand Projections Summary Report". This report presents projections up to 2016, beyond which we have extrapolated the growth between 2015 and 2016 for the remaining four years of our analysis.

Since reliability issues and investment in peaking generation are intricately linked with the shape of the load duration curves, especially at high loads, we have analysed the 10% POE demand together with 50% POE demand. Table 2 presents the demand and energy projections used in the study.

Table 2: Regional Energy and Peak Demand Projections

Year	Region	Annual Energy (GWh)	Peak Demand (10% POE)	Peak Demand (50% POE)
2008	QLD	51058	9981	9461
2009		53129	10435	9883
2010		55109	10850	10268
2011		57355	11273	10660
2012		59389	11687	11042
2013		61730	12135	11457
2014		63764	12527	11818
2015		65672	12916	12174
2016		67790	13340	12564

Year	Region	Annual Energy (GWh)	Peak Demand (10% POE)	Peak Demand (50% POE)
2008	NSW	75710	15020	14070
2009		76900	15500	14370
2010		78000	15930	14650
2011		78890	16350	14970
2012		80060	16760	15320
2013		81520	17220	15740
2014		82900	17670	16140
2015		84330	18110	16530
2016		85990	18420	16800
2008	VIC	47599	10026	9198
2009		46468	10124	9263
2010		46362	10297	9409
2011		47085	10515	9601
2012		47713	10720	9780
2013		48574	10940	9975
2014		49293	11173	10182
2015		50086	11370	10359
2016		50955	11582	10551
2008	SA	12631	3311	2990
2009		13064	3421	3089
2010		13212	3483	3146
2011		13410	3522	3180
2012		13628	3592	3244
2013		13834	3684	3329
2014		13989	3799	3418
2015		14160	3838	3465
2016		14323	3919	3535

Year	Region	Annual Energy (GWh)	Peak Demand (10% POE)	Peak Demand (50% POE)
2008	TAS	10221	1805	1781
2009		10418	1840	1816
2010		10661	1864	1839
2011		10781	1898	1873
2012		10927	1927	1902
2013		11087	1949	1923
2014		11205	1988	1962
2015		11470	2024	1997
2016		11653	2045	2018

Data Source: NEMMCO "2007 Energy and Demand Projections Summary Report" July 2007.

A.3.3 Supply Capacity

CEMOS uses the supply system characteristics including committed plants shown in Table 3, and the investment costs for (generic) new investment shown in Table 4. The short-run marginal cost of generation calculated as variable fuel and operating expenses forms an input to the formation of strategic bids.

Over time, additional generation will need to be added to meet demand. The nature and timing of new entry will depend on a variety of factors including the level of competition in the NEM. We project market conditions beyond the period of interest to the study to ensure that the most cost effective additions to the generation fleet are made, in this way we avoid the risk that the model will make short term low cost plant choices at the end of the period because it is not “looking” for the best long term solution. Our assumptions on strategic bidding recognise the effect of competitive new entry on the market behaviour of existing generators, and generally drive prices down to the long-run marginal cost of new entrant plants reflecting the need for new investors to recover capital cost. We have presented the optimal capacity entry outcomes as part of the model results in the next section.

Existing Generation Capacity

Table 3: Existing Generation Characteristics

Station	Type	Capacity (MW)	Variable O&M ($/MWh)	Heat Rate (MJ/MWh)
AGLHal	OCGT	188	9.15	10588
AGLSom	OCGT	160	9.15	10286
Angaston	OCGT	40	9.15	10588
Anglesea	Sub_Cr_brownCoal	154	1.13	13235
Bairnsdale	OCGT	90	2.15	10286
Barcaldine	CCGT	49	2.28	7200
BarronGorge	Hydro	60	0	1000
Bayswater	Sub_Cr_BlkCoal	2760	1.13	10028
BellBay	Steam_Gas	228	7.54	11250
BellBayThree	OCGT	108	7.54	12414
Blowering	Hydro	80	0	1000
Braemar	OCGT	450	7.54	10588
CallideA	Sub_Cr_BlkCoal	0	1.15	9972
CallideB	Sub_Cr_BlkCoal	700	1.15	9972
CallidePP	Sub_Cr_BlkCoal	920	1.15	9231
Collinsville	Sub_Cr_BlkCoal	187	1.26	12996
DartMouth	Hydro	154	0	1000
DryCreek	OCGT	140	9.15	13846
Eildon	Hydro	120	0	1000
Eraring	Sub_Cr_BlkCoal	2640	1.13	10170
Gladstone	Sub_Cr_BlkCoal	1680	1.13	10227
Guthega	Hydro	60	0	1000
Hazelwood	Sub_Cr_brownCoal	1600	1.13	15000
HumeNSW	Hydro	0	0	1000
HumeV	Hydro	29	0	1000
HVGTS	OCGT_Oil	51	9.15	12000

Station	Type	Capacity (MW)	Variable O&M ($/MWh)	Heat Rate (MJ/MWh)
JeeralangA	OCGT	232	8.62	12000
JeeralangB	OCGT	255	8.62	12000
Kareeya	Hydro	88	0	1000
KoganCreek	Sup_Cr_BlkCoal	763	1.19	9474
Ladbroke	OCGT	84	3.43	10588
LavertonNorth	OCGT	340	7.54	12414
Liddell	Sub_Cr_BlkCoal	2100	1.13	10651
LoyYangA	Sub_Cr_brownCoal	2190	1.13	12500
LoyYangB	Sub_Cr_brownCoal	1032	1.13	13534
MackayGT	OCGT_Oil	34	8.62	12857
McKay	Hydro	150	0	1000
MillmerranPP	Sub_Cr_BlkCoal	860	1.13	9600
Mintaro	OCGT	88	9.15	12000
Morwell	Sub_Cr_brownCoal	148	1.13	15000
MtPiper	Sub_Cr_BlkCoal	1400	1.26	9704
MtStuart	OCGT_Oil	294	8.62	10588
Munmorah	Sub_Cr_BlkCoal	600	7.54	11613
Murray	Hydro	1500	0	1000
Newport	Steam_Gas	510	2.15	12000
NorthernPS	Sub_Cr_brownCoal	540	1.13	11429
NSWWind	Wind	17	0	1000
Oakey	OCGT_Oil	320	9.15	10588
Osborne	Cogeneration	190	4.84	7200
PlayfordB	Sub_Cr_brownCoal	240	2.86	15652
PortLincoln	OCGT_Oil	50	9.15	13846
PPCCGT	CCGT	474	4.84	7200
QLDWind	Wind	12	0	1000
Quarantine	OCGT	92	4.84	6923

Station	Type	Capacity (MW)	Variable O&M ($/MWh)	Heat Rate (MJ/MWh)
Redbank	Sub_Cr_BlkCoal	150	1.13	12040
RomaGT	OCGT	68	9.15	12000
SAWind	Wind	388	0	1000
Shoalhaven	Hydro	240	0	1000
Smithfield	Cogeneration	160	2.28	8781
Snuggery	OCGT	63	9.15	13846
Stanwell	Sub_Cr_BlkCoal	1440	1.13	9890
SwanbankB	Sub_Cr_BlkCoal	480	1.13	11502
SwanbankE	CCGT	370	4.84	7059
Tallawarra	CCGT	434	4.84	7059
Tarong	Sub_Cr_BlkCoal	1400	1.37	9945
TASHydro	Hydro	2281	0	1000
TasWind	Wind	142	0	1000
TNPS1	Sub_Cr_BlkCoal	443	1.37	9184
TorrensA	Steam_Gas	504	0	13044
TorrensB	Steam_Gas	824	0	12000
Tumut3	Hydro	1500	0	1000
Upptumut	Hydro	616	0	1000
ValesPt	Sub_Cr_BlkCoal	1320	1.13	10170
ValleyPower	OCGT	336	9.15	13846
VICWind	Wind	134	0	1000
Wallerawang	Sub_Cr_BlkCoal	1000	1.26	10876
WestKiewa	Hydro	72	0	1000
Wivenhoe	Hydro	500	0	1000
Yabulu	OCGT_Oil	243	8.9	11976
Yallourn	Sub_Cr_brownCoal	1487	1.13	13846

Note: Sub_Cr_BlkCoal = Sub critical black coal. Sub_Cr_brownCoal = Sub critical brown coal.

Data Source for capacity data: SOO 2006 Aggregate Scheduled Generation Capacity. Data Source for VOM and Heat Rate (calculated from Thermal Efficiency): Report to NEMMCO by ACIL Tasman, 2007.

New Generation Capacity

Table 4: New Generation Characteristics

Station	Type	Annualised Capital Cost[1] ($/MW/year)	Variable O&M ($/MWh)	Heat Rate (MJ/MWh)
NSW_CCGT_2010	CCGT	104021	4.85	6793
QLD_CCGT_2010	CCGT	104021	4.85	6793
SA_CCGT_2010	CCGT	104021	4.85	6793
TAS_CCGT_2010	CCGT	104021	4.85	6793
VIC_CCGT_2010	CCGT	104021	4.85	6793
NSW_Sup_Cr_BlkCoal_2010	Sup_Cr_BlkCoal	168414	1.2	8571
QLD_Sup_Cr_BlkCoal_2010	Sup_Cr_BlkCoal	168414	1.2	8571
VIC_Sup_Cr_brownCoal_2010	Sup_Cr_brownCoal	188228	1.2	10588
NSW_UltraSup_Cr_BlkCoal_2010	UltraSup_Cr_BlkCoal	178321	1.2	8000
QLD_UltraSup_Cr_BlkCoal_2010	UltraSup_Cr_BlkCoal	178321	1.2	8000
Wind_2010_(all regions)	Wind	224041	0	1000
NSW_OCGT_2010	OCGT	71328	7.5	11250
QLD_OCGT_2010	OCGT	71328	7.5	11250
SA_OCGT_2010	OCGT	71328	7.5	11250
TAS_OCGT_2010	OCGT	71328	7.5	11250
VIC_OCGT_2010	OCGT	71328	7.5	11250
NSW_Smallhydro_2010	Smallhydro	257614	7	1000
QLD_Smallhydro_2010	Smallhydro	257614	7	1000
TAS_Smallhydro_2010	Smallhydro	257614	7	1000
VIC_Smallhydro_2010	Smallhydro	257614	7	1000

Data Source for Annualised Capital Cost for Smallhydro: CRC report for Coal in Sustainable Development (CCSD)- Technology Assessment Report 44, Jan 2005; for Wind and Ultra Supercritical coal: AEO 2006 estimate, converted to installed cost; and for all other technologies: Report to NEMMCO by ACIL Tasman, 2007. Data Source for VOM and Heat Rate (calculated from Thermal Efficiency): Report to NEMMCO by ACIL Tasman, 2007.

Fuel Prices

To ensure consistency with other studies of the market, fuel price projections are based on the estimates developed by ACIL Tasman in 2007 in its report to NEMMCO/IRPC. These are shown in Figure 4 to Figure 6.

Figure 4: Gas Price by Region: 2008-2017 ($/GJ)

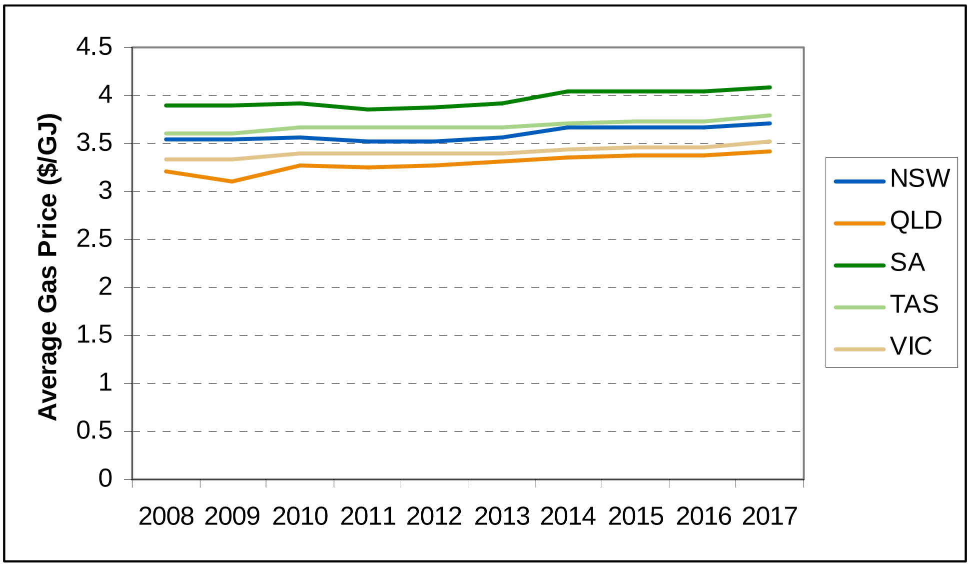


Figure 5: Black Coal Price by Region: 2008-2017 ($/GJ)

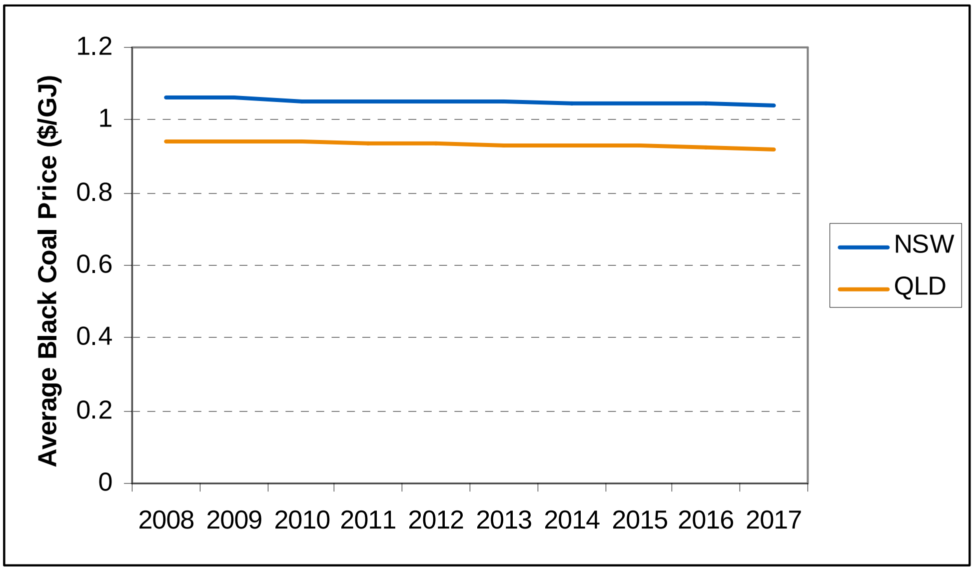
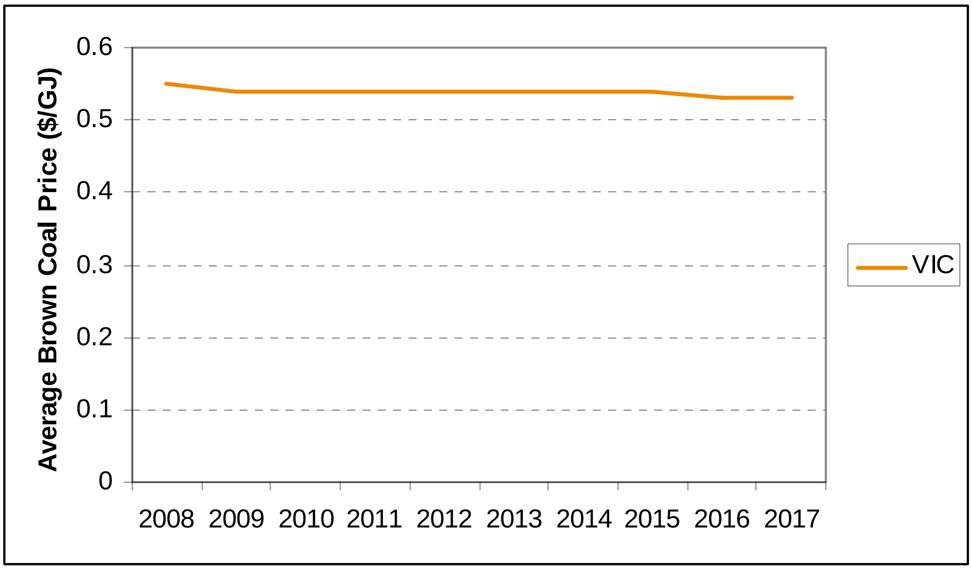


Figure 6: Brown Coal Price by Region: 2008-2017 ($/GJ)



A.3.4 Interconnection Capacity

Transmission upgrades noted in the SOO/ANTS have been included, and interconnection limits from the SOO/ANTS have been applied; these are listed in Table 5. The initial optimisation derived by the modelling for augmenting generation within the constraints of the transmission network supplied as input is inherently conservative. Interim results were reviewed to examine the potential for augmentation during the period of the study. Additional peaking capacity has been added where profitability measures after accounting for volatility of load and generation performance have shown further capacity would be commercially viable. The methodology we have employed involves augmentation of the transmission network where sustained differences in price or sustained regional differences in USE are observed. These differences indicate the potential for reliability or market based upgrades of interconnectors. The upgrades have not been subject to comprehensive cost benefit tests and thus are indicative only, but nevertheless they are adequate for the purposes of this study.

Table 5: Interconnector Capacities (Existing and SOO/ANTS)

Interconnector	Year	From	To	Forward Capacity (MW)	Reverse Capacity (MW)
BassLink	Existing	TAS	VIC	600	480
NSW-QLD (MNSP1)	Existing	NSW	QLD	152	196
NSW-QLD (MNSP2)	Existing	NSW	QLD	30	234
NSW-QLD	Existing	NSW	QLD	589	1078
SNOWY-NSW	Existing	SNY	NSW	3559	1150
VIC- SA (MNSP)	Existing	VIC	SA	220	214
VIC-SA	Existing	VIC	SA	460	300
VIC-Snowy	Existing	VIC	SNY	1313	1842

Source: SOO 2006.

A.4 SCENARIO DESIGN AND ANALYSIS

SUMMARY Table 6 presents a summary of the results of analysis for each of the alternative designs and varying levels of VoLL. Results of CPT analysis are presented separately in section A.6. The following sections provide further details of each case.

Table 6: Summary of results for alternative designs and varying levels of VoLL

	Nominal VoLL Scenarios							Alternative Market Design		
	$5,000/MWh Nominal VoLL	**$10,000/MWh Nominal VoLL**	**$12,500/MWh Nominal VoLL**	**$15,000/MWh Nominal VoLL**	**$17,500/MWh Nominal VoLL**	**$20,000/MWh Nominal VoLL**	**$30,000/MWh Nominal VoLL**	**RAS**	**Standing Reserve**	**Reliability Options**
USE (max/min trendline)	0.0014% - 0.0085%	0.0004% - 0.0055%	0.0003% - 0.0032%	0.0002% - 0.0029%	0.0002% - 0.0025%	0.0007% - 0.0022%	0.0019% - 0.0021%	0.0014% - 0.0027%	0.0014% - 0.0027%	0.0018% - 0.002%
NEM Average Price (TW $/MWh)	42.28	43.98	43.46	43.54	43.41	43.66	46.32	41.42	40.12	27.69 Excludes separate Reliability Option Fee
Peak Generation: Utilisation Factor (%) for new entrant OCGT	n/a	10.63%	10.67%	10.61%	10.51%	10.47%	6.75%	10.11%	8.83%	2.27%
NEM Peak Generation (NEM wide average): Annual Average Price ($/MWh) received by new entrant OCGT	n/a	140.70	135.76	139.85	136.65	138.83	237.72	136.00	149.70	67.30
NEM Peak Generation (NEM wide average revenue:cost ratio for new entrant OCGT	n/a	1.00	0.99	1.00	1.00	1.00	1.06	1.29	0.99	0.90
Base Generation (new entrant coal): Utilisation Factor (%)	92.28%	93.57%	92.84	92.86%	92.87%	92.83%	93.11%	92.73%	93.38%	93.16%
Base Generation: Annual Average Price ($/MWh) received by new entrant coal	42.64	42.80	44.70	44.75	44.55	45.18	46.16	41.89	40.00	28.00 Excludes Option Fee (Assumes 100% energy contracts at $35/MWh)

A.4.1 Alternative Levels of VoLL and CPT

Thirteen cases were considered covering a wide range for VoLL and the CPT and the effect of facilitated demand side. Details of each case are provided in Table 7.

Table 7: Scenario Descriptions

CASE	DESIGN Specification	Comments
1. VoLL $10,000/MWh real	1 VoLL: $10,000/MWh (Real) CPT: $150,000	Profitability ratios noted as benchmarks for scenarios
2. VoLL $10,000/MWh nominal	Case 1 with VoLL set to $10,000/MWh nominal	Capacity plan re-optimised to maintain profitability across scenarios. Different levels of VoLL modelled as step changes at the start of the modelling period with no transition (results in a transition period in the first few years under study).
3. VoLL $5,000/MWh nominal	Case 1 with VoLL set to $5,000/MWh nominal	
4. VoLL $12,500/MWh nominal	Case 1 with VoLL set to $12,500/MWh nominal	
5. VoLL $15,000/MWh nominal	Case 1 with VoLL set to $15,000/MWh nominal	
6. VoLL $17,500/MWh nominal	Case 1 with VoLL set to $17,500/MWh nominal	
7. VoLL $20,000/MWh nominal	Case 1 with VoLL set to $20,000/MWh nominal	
8. VoLL $30,000/MWh nominal	Case 1 with VoLL set to $30,000/MWh nominal	
9. CPT $50,000 nominal	Case 2 with CPT set to $50,000 nominal	Assess in two stages: Assess number of weeks in which CPT breached by mapping annual load blocks onto typical half hourly profile.
10. CPT $100,000 nominal	Case 2 with CPT set to $100,000 nominal	
11. CPT $200,000 nominal	Case 2 with CPT set to $200,000 nominal	
12. CPT $500,000 nominal	Case 2 with CPT set to $500,000 nominal	
13. Standing Demand Side Reserve	25% of reserve margin deemed to be supplied through demand side response distributed uniformly across regions in proportion to regional peak demand. Demand side configured to interrupt at $VoLL-$1	Capacity Plan re-optimised accounting for initial demand side

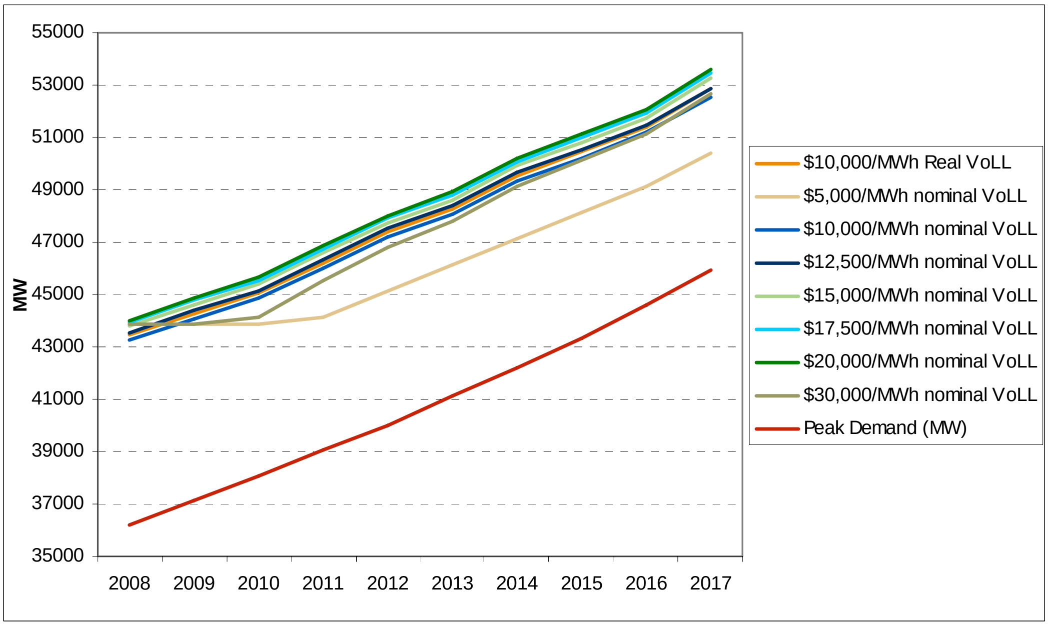
A.4.2 Analysis and Discussion: VoLL

The relationship between capacity and VoLL

VoLL is a key reliability setting in the NEM. It also has a significant impact on financial risk and investment returns, particularly to investments at the margin which rely on very short periods of relatively high price in order to allow generators to recover their fixed and variable costs. All else being equal, more generation will be commercially viable the higher market price can rise at times when peaking plants run. As a result less customer load will be at risk of not being supplied, but prices will be higher overall. The following sections summarise key results of modelling of the NEM with different levels of VoLL.

Figure 7 illustrates the varying level of capacity that enters the market in the modelling under the different levels of VoLL.

Figure 7: Peak Demand, Installed Capacity and VoLL



Distribution of Regional USE

This section presents a summary of the detailed regional USE for different levels of VoLL that have been studied.

In the analysis for the interim report we noted that considerable care should be taken in interpreting regional results and this caution also applies to the results reported here. In particular, the timing of peaks and troughs for any single region and the relativity between regions at any given time should be regarded as indicative only. During the course of the analysis it was evident that small shifts in the timing and location of investment in generation and in transmission can lead to significant reordering of the relative results for the regions.

A valuable insight from the studies was that we found evidence that outcomes are very sensitive to minor variations in profitability achieved by new investors. This observation supports commentary about energy-only market designs in general, that note the inherent variability of outcomes from year to year. The observation also underlines the difficulty of assuming idealised responses from market participants as a part of the process to set parameters in the market such as VoLL.

The figures show that at a higher level of VoLL a general declining trend of USE is observed for all regions, although there is a significant variation in USE level across the regions and over the years. Smaller regions such as SA and regions with relatively high sensitivity to temperature with large base load units such as Victoria are more prone to outages if peaking investment is lacking.

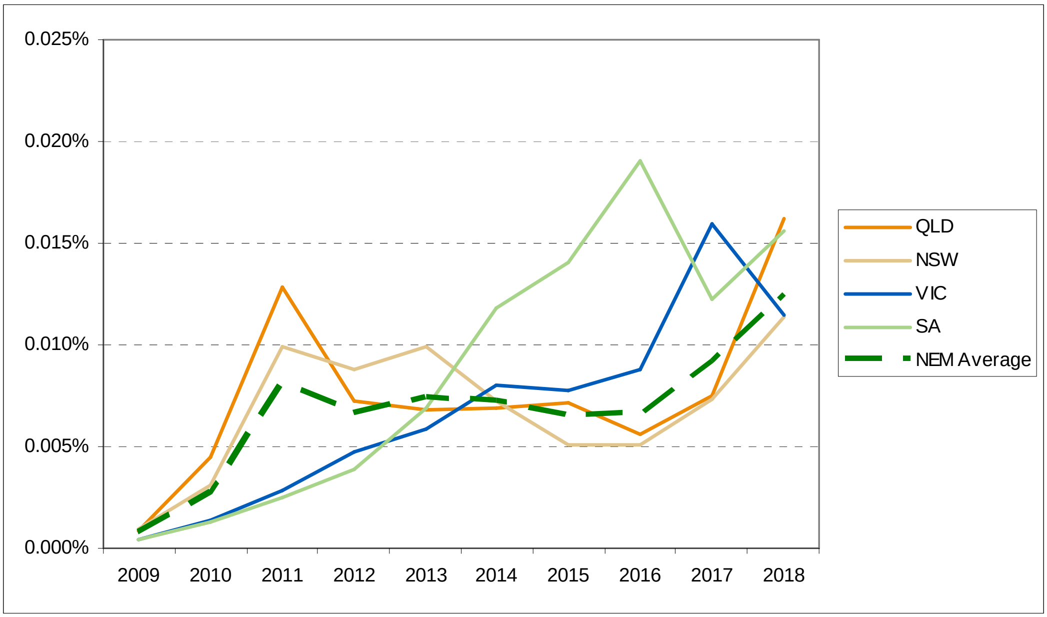
It should be noted that the simulations used in this study did not consider hydrological risks, and therefore the median hydrology assumed for hydro-based generation in NEMMCO data does not result in USE in Tasmania – that is, reliability in Tasmania is expected to be dominated by capacity expansion driven by long term energy assurance, whereas the other regions are driven by capacity limitations alone. Drought, however, can make a material difference to energy production and capacity available from hydro resources. Drought can also indirectly affect some thermal plant where cooling water is restricted. These matters are discussed in some detail by NEMMCO in reports prepared for the Ministerial Council on Energy that can be found on its website.[1]

Figure 8 through to Figure 14 shows the regional results we found for the different levels of VoLL considered in the study. It is important to note that the results presented are the average across simulations of many years and individual years. There was considerable variation in the results for different simulations of the each year. Section A.6 provides further discussion on the variability.

If VoLL were set to $5,000/MWh (nominal) there would be progressively worsening reliability with results for South Australia most affected in later years of the study consistent with South Australia's high sensitivity of demand to temperature resulting in a very "peaky" demand duration characteristic. USE would be progressively lower for higher levels of VoLL.

1 Potential Impact of Drought on Electricity Supplies in the NEM, NEMMCO 2007. http://www.nemmco.com.au/nemgeneral/900-0001.htm

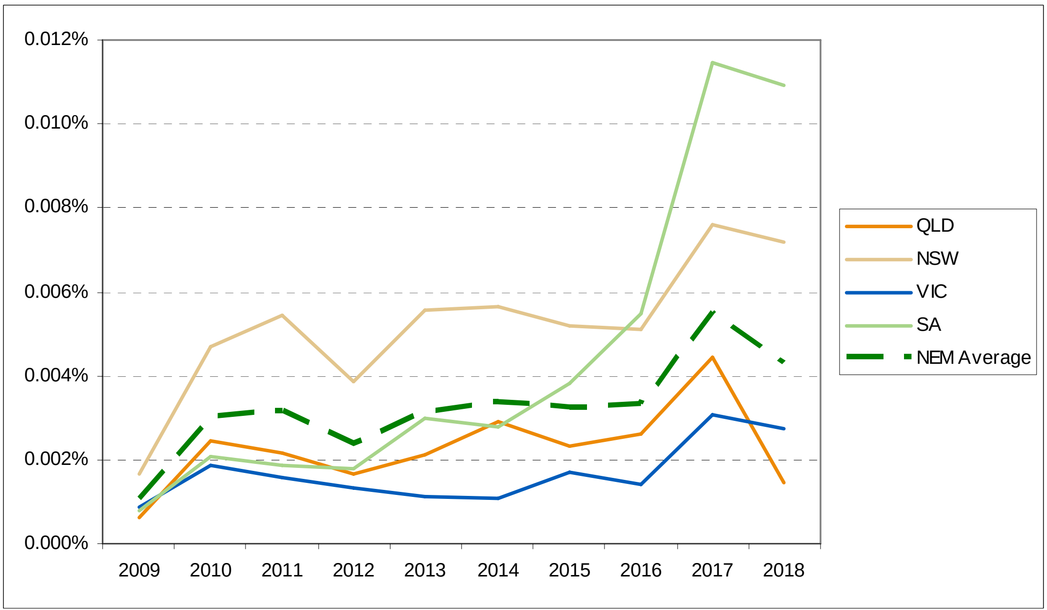
Figure 8: Annual USE by Region (VoLL $5,000/MWh)



Note: TAS has zero USE as it is assumed to remain an energy constrained region with adequate capacity and is not shown.

Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.

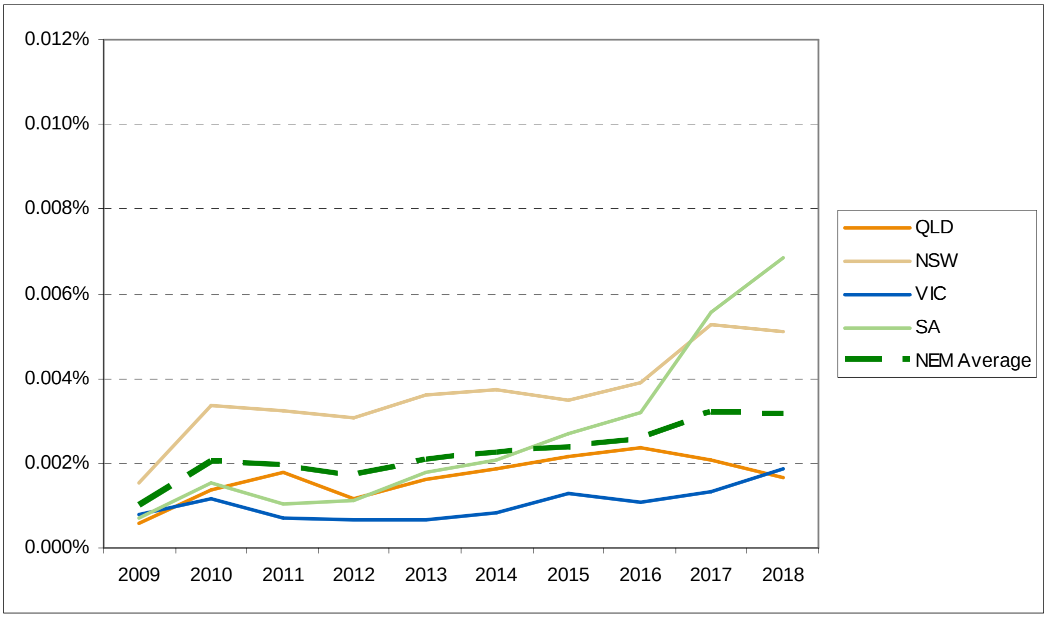
Figure 9: Annual USE by Region (VoLL $10,000/MWh nominal)



Note: TAS has zero USE as it is assumed to remain an energy constrained region with adequate capacity and is not shown.

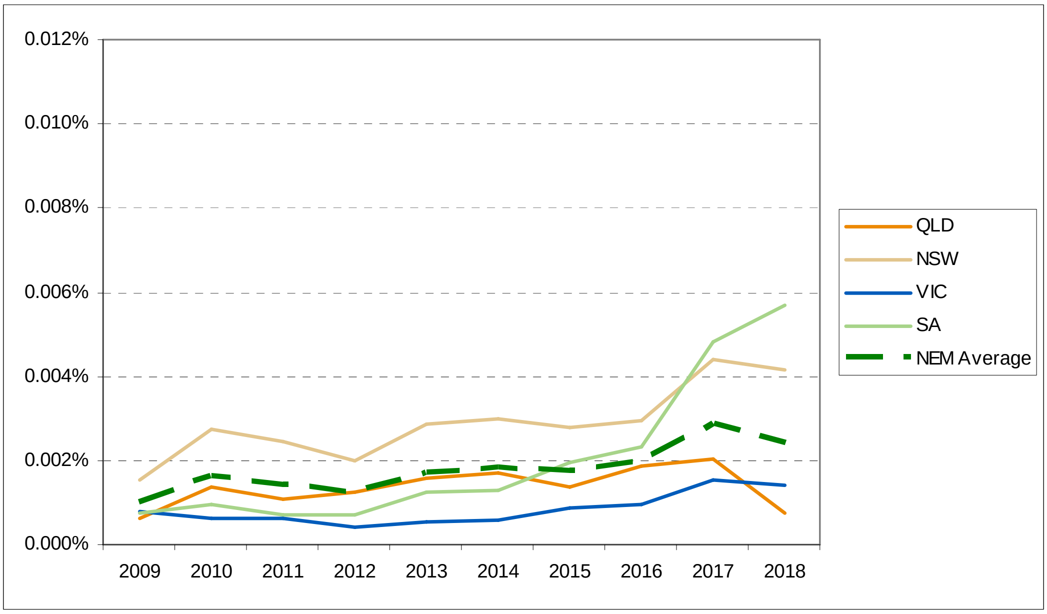
Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.

Figure 10: Annual USE by Region (VoLL $12,500/MWh nominal)



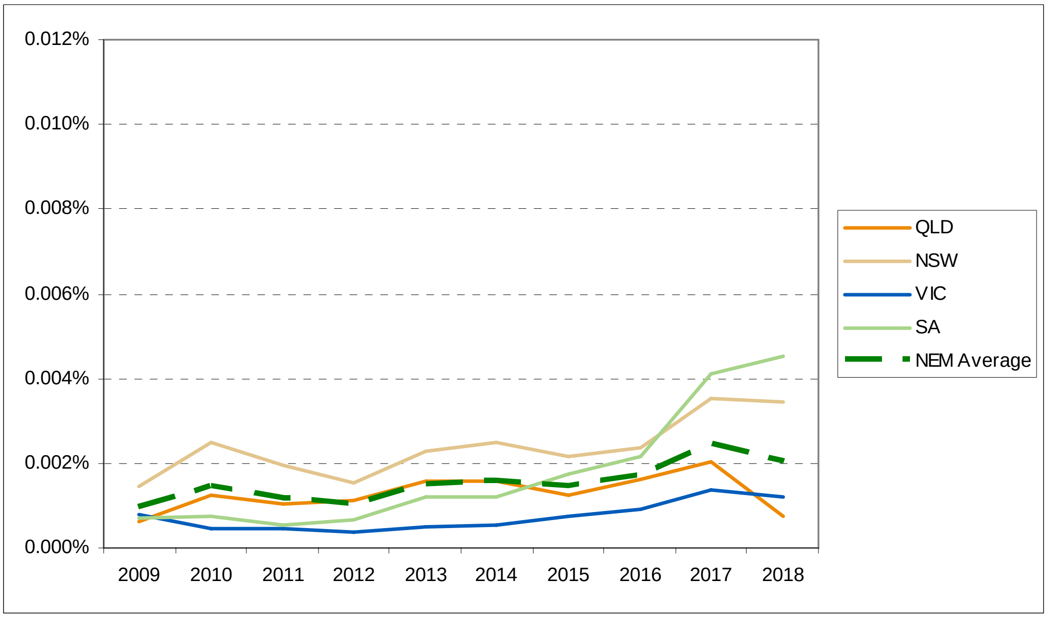
Note: TAS has zero USE as it is assumed to remain an energy constrained region with adequate capacity and is not shown.
Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.

Figure 11: Annual USE by Region (VoLL $15,000/MWh nominal)



Note: TAS has zero USE as it is assumed to remain an energy constrained region with adequate capacity and is not shown.
Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.

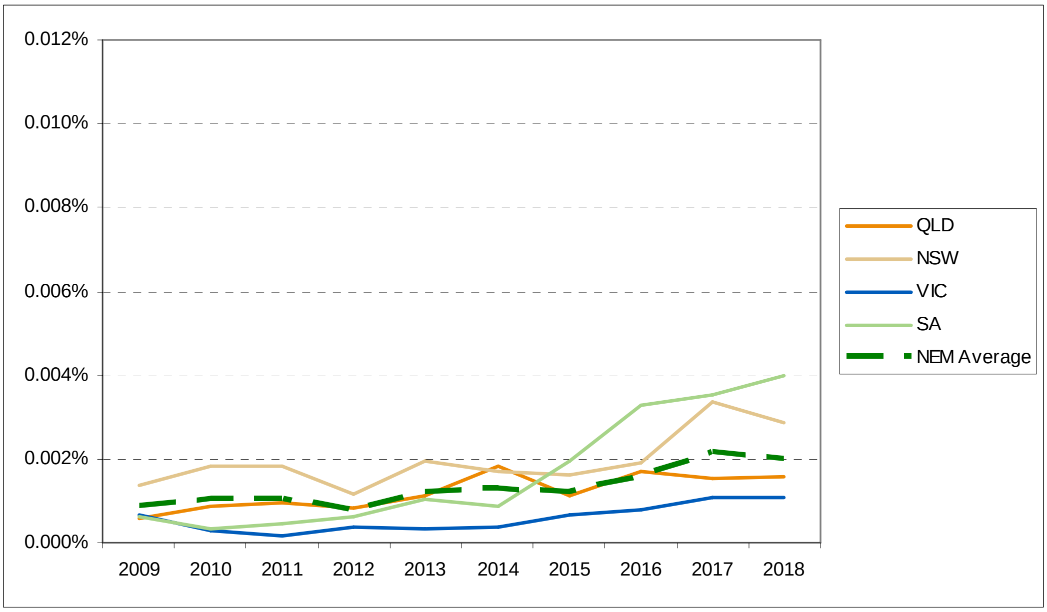
Figure 12: Annual USE by Region (VoLL $17,500/MWh nominal)



Note: TAS has zero USE as it is assumed to remain an energy constrained region with adequate capacity and is not shown.

Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.

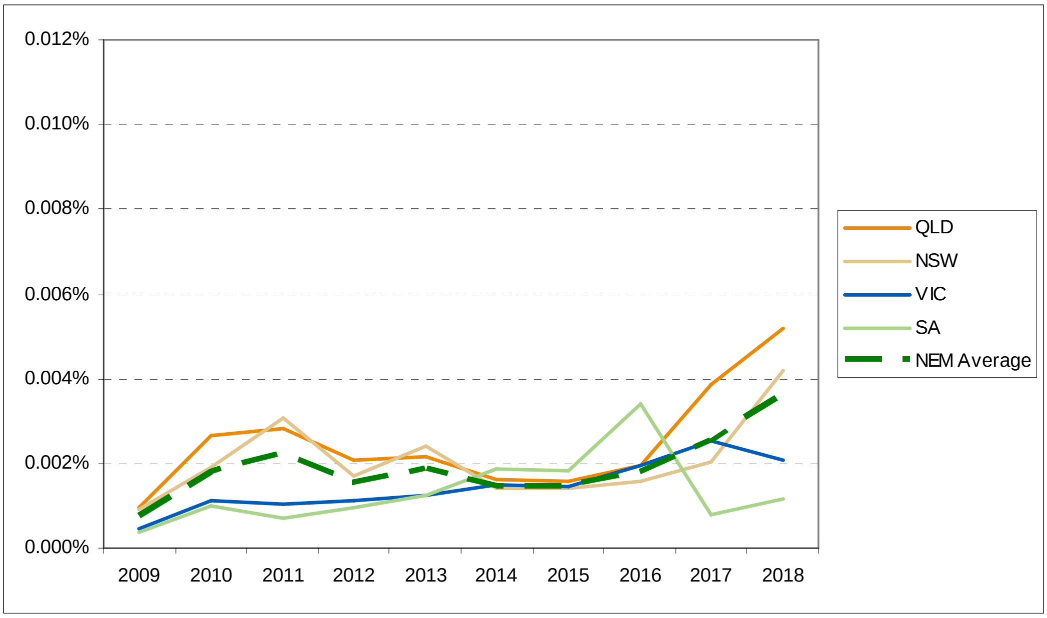
Figure 13: Annual USE by Region (VoLL $20,000/MWh nominal)



Note: TAS has zero USE as it is assumed to remain an energy constrained region with adequate capacity and is not shown on the plot..

Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.

Figure 14: Annual USE by Region (VoLL $30,000/MWh nominal)[2]



Note: TAS has zero USE as it is assumed to remain an energy constrained region with adequate capacity and is not shown on the plot.
Differences in USE between the regions over time are indicative only, and have been derived from the average of the Monte-Carlo simulations in the analysis. In practice, fluctuations in USE between regions will depend on the relative timing of investments in generation and transmission and demand growth in the different regions.

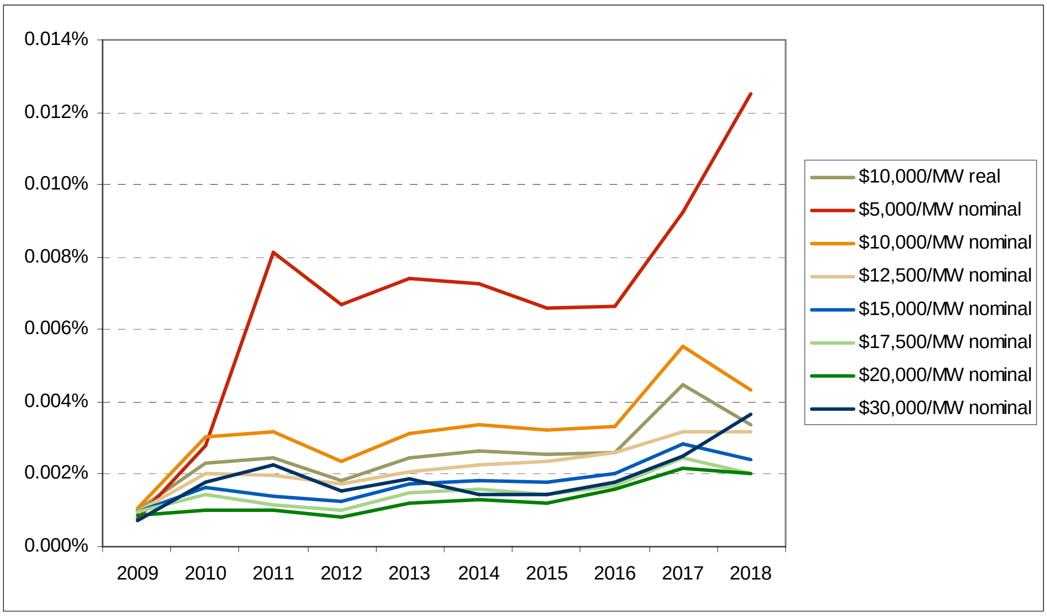
A.4.3 Relationship between VoLL and USE

The level of VoLL is a key setting in the NEM. If it is set too low, generally there will be less revenue for generators, particularly for generators that only operate at peak times. In the terms of the Panel's interim report, there is a risk of "missing money" if the level is set too low, and as a result less investment would be expected and hence the risk of the market not meeting demand will rise. On the other hand, higher VoLL generally leads to higher financial risks for market participants and creates pressures for them to enter into risk mitigation activities. The Panel's interim report discussed these matters in some detail.

The relationship between VoLL and USE for the range of levels of VoLL that can be derived from the results is shown in Figure 15.

2 At the end of the horizon reported here the $30,000/MWh case shows slightly higher USE than a lower VoLL. This can result from slightly misaligned profitability ratios in the modelling process and where the model looks forward over the long term and identifies a different mix of plant that results in short term that leads to perturbations in USE.

Figure 15: Relationship Between VoLL and USE



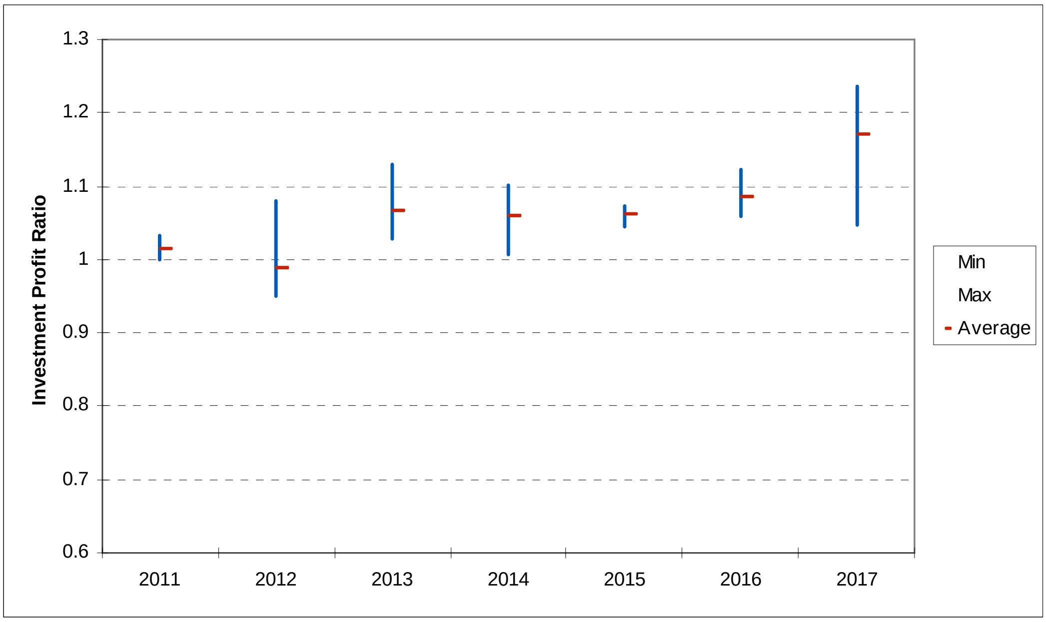
Significant trends evident in the results include that:

- there is considerable volatility from year to year;
- there is a general downward trend in USE as VoLL is increased; and
- there is a general upward trend in USE over time for any given fixed (nominal) level of VoLL but a much more gentle rise in USE when VoLL is indexed.

A.4.4 Profitability of Peaking Investment

A key element in our methodology (introduced in section A.1.1) was that in order to ensure like-for-like comparisons between different cases we retained a constant profitability for new generators. Figure 16 summarises the profitability for OCGT technology plant that will often be at the margin and hence most susceptible to market prices. A characteristic of markets such as the NEM is that there is significant volatility in returns to marginal generators and hence it is necessary to consider the return on investment over a number of years to assess the viability of an investment. It is also important to note that profitability can vary widely across different outage scenarios, with extremely high profitability in situations where deep outages occur relative to lower rates of outage. It is a matter for investors to consider how much volatility is acceptable to them and by implication what is the effective discount rate for such a volatile return. In this study we have applied the same discount rate to all plants and operating duties and our results are therefore somewhat optimistic in this regard. In addition as we noted in section A.4.2 we found that the results were highly sensitivity to minor variations in profitability.

Figure 16: Profitability Ratio for New OCGT Generators (NEM wide) across VoLL scenarios



Profitability is calculated as the weighted average of 10% and 50% POE cases using a 30% and 70% weight, respectively.

A.4.5 NEM Prices

Spot prices emerging from the analysis were consistent with the results for USE and profitability. Where VoLL is increased the potential peak price will rise and conversely, it falls with lower VoLL. The effect of increased VoLL on price is complex, however. Although the potential peak price might rise, the additional capacity that can eventuate may increase competition, particularly as reserves fall, and this tends to dampen prices before a shortfall occurs. On the other hand any opportunities for the exercise of market power can be accentuated with higher VoLL in the absence of competition, especially if network congestion is present. The model assesses the combined effect of incentives which tend to increase and decrease price outcomes. The methodology did not extend to consideration of the effect on contracting behaviour and hence on contract price.

It is also important to note that the manner in which model inputs are created can make a significant difference to the outcomes, for example how the high-priced bids are formed in the Cournot modules[3] and assumptions about relative costs of plant and transmission. In the results it was seen that prices increase when VOLL is increased, which in turn increases profitability for peaking generation.[4] This result suggests that when VoLL is increased the ability of generators to bid at least a portion of their capacity at the higher prices dominates the effect of greater competition in the peak generation segment due to increased peaking entry.

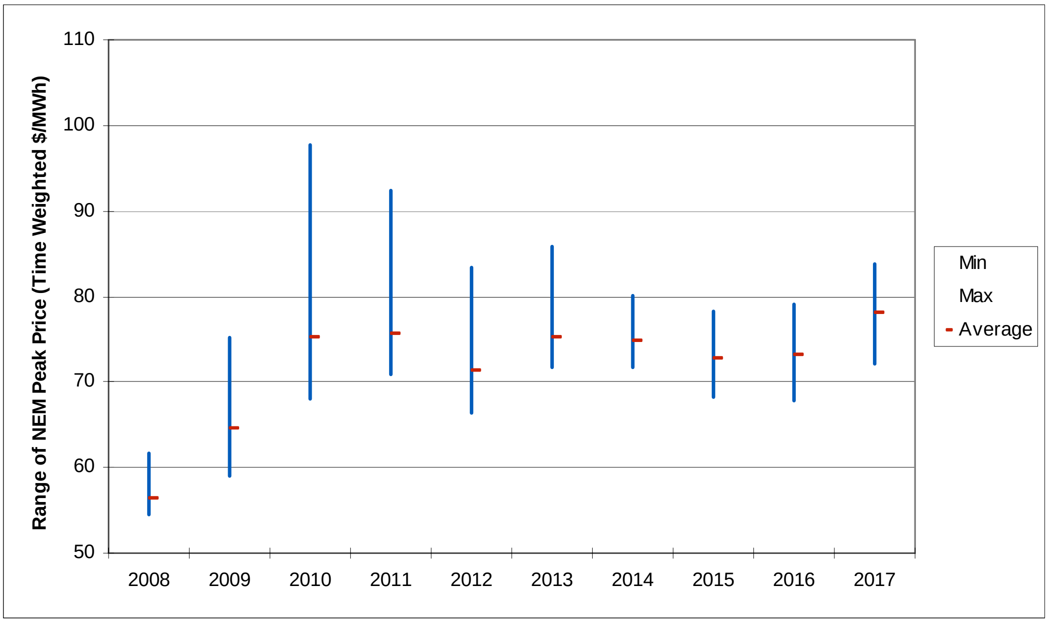
In reality however, none of these effects may be the dominant issue – as external policy factors that lead to investments that are driven by other than the electricity market price, such as greenhouse related policies, are likely to have a much greater impact on investment decisions.

3 All models employ some form of input dependant modelling in this regard. The most common is to benchmark against previous bidding patterns and assume that these apply into the future after changes to the settings have been made. This is the approach NEMMCO uses based on back-casting and contract optimisation prepared by Intelligent Energy Systems – http://www.nemmco.com.au/transmission_distribution/410-0069.pdf

4 See Figure 16 for profitability of new entrant OCGTs.

Base load generators that run for a large proportion of the year receive close to the time weighted average spot price in the market.[5] Other generators run only at times of higher demand and price (mid merit or intermediate and peak plants). It is therefore useful to assess peak and super peak groupings. Figure 17 and Figure 18 summarise these prices[6].

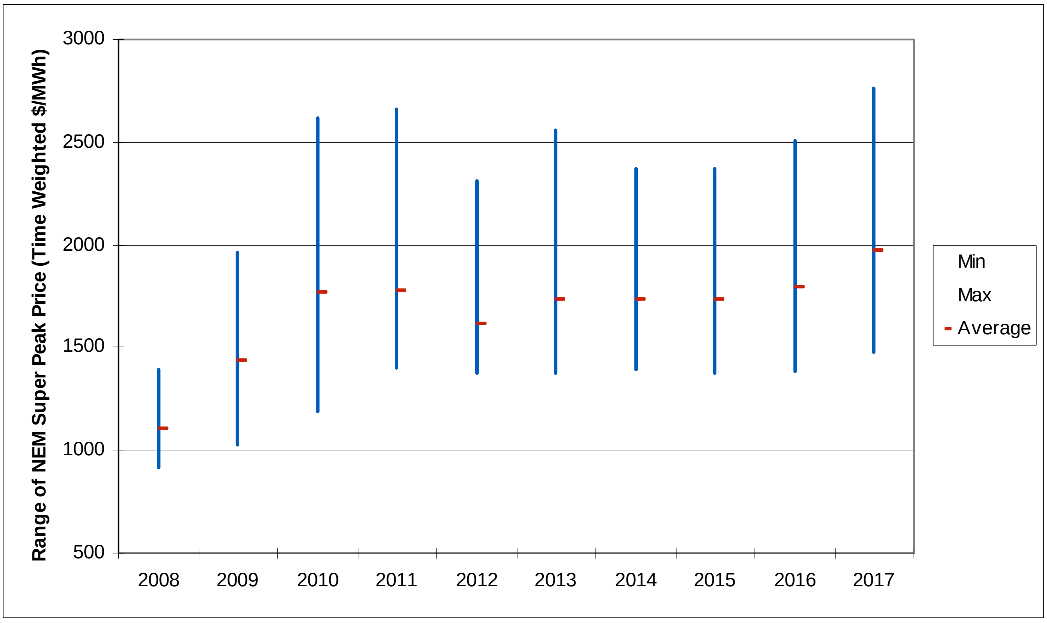
Figure 17: NEM Peak Prices – Range Across Scenarios ($/MWh)



5 This is true for generators exposed to spot price and where contract prices reflect spot price without a premium. In practice it is common for generators to enter into contracts and for contract prices to include a premium above the expected spot price and this will alter the net position of generators. For the purposes of analysing the fundamentals within the market, contract arrangements have been assumed to include no premium.

6 The definitions of Peak and Super Peak are taken from the conventions used by the Australian Financial Market Association (AFMA). The peak period covers all working hours during weekdays. Super-peak refers to the top 50 hour prices for all regions.

Figure 18: NEM Super Peak Prices – Range Across Scenarios ($/MWh)



The absolute level and range of super peak price settles down to a relatively steady level after an initial transition at the start of the period of analysis. A steady super peak price is consistent with a steady level of profitability for peak plant that was a central part of our methodology.

A.5 STANDING DEMAND SIDE RESERVE

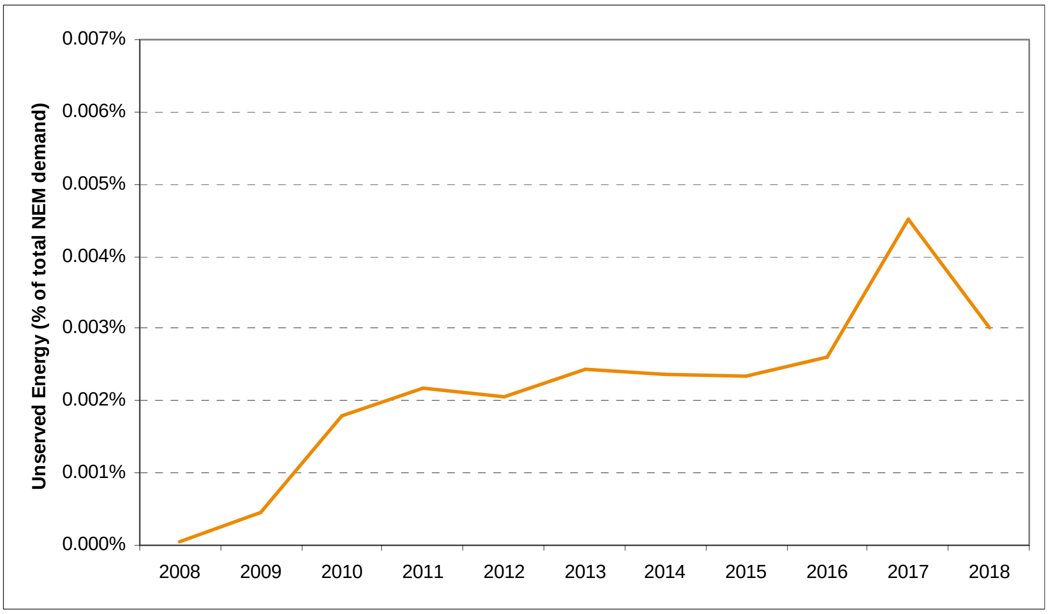
We also investigated the effect of employing standing demand side reserves. While the market rules allow scheduled demand side to be bid into the dispatch process there is negligible participation.

This scenario did not assess why or how additional demand side would participate, for example by a change in strategy of demand side participants or through a set of facilitated contracts, but assumed that of the order of 25% of the reserve normally required by NEMMCO to meet the capacity reserve margin would be provided by an assured level of demand side response. This amounts to approximately 2% of system peak being available as demand side. In order to minimise (but not avoid) distortion to the market outcomes we modelled the reserve as a demand side bid at VoLL-$1 and distributed the demand side response pro rata across the regions in accordance with peak demand. As there will be many factors that affect how much and where demand side might participate, for example in response to a standing offer this analysis is indicative.

The effect of the demand side is to reduce the amount of peaking generation that will be profitable. The analysis presumed the specified level of demand side would be presented and examined how much plant would enter the market for the same profitability that was achieved in the absence of the demand side participation. Based on projections of revenue the first order effect is simply to substitute demand side for the most marginal peaking generation. However, this does not take account of the higher utilisation of the remaining peaking generators and there is thus greater certainty of revenue to the remaining generators. An indication of the effect on certainty can be seen in the utilisation and distribution of revenues to peaking generators.

Figure 19 shows the USE achieved in the scenario and as expected illustrates little difference from the case without demand side. The difference in the distribution of revenues to peaking plant is indicative of greater certainty of revenue.

Figure 19: USE for the Standing Demand Side Reserve Scenario.



A.6 VARIABILITY

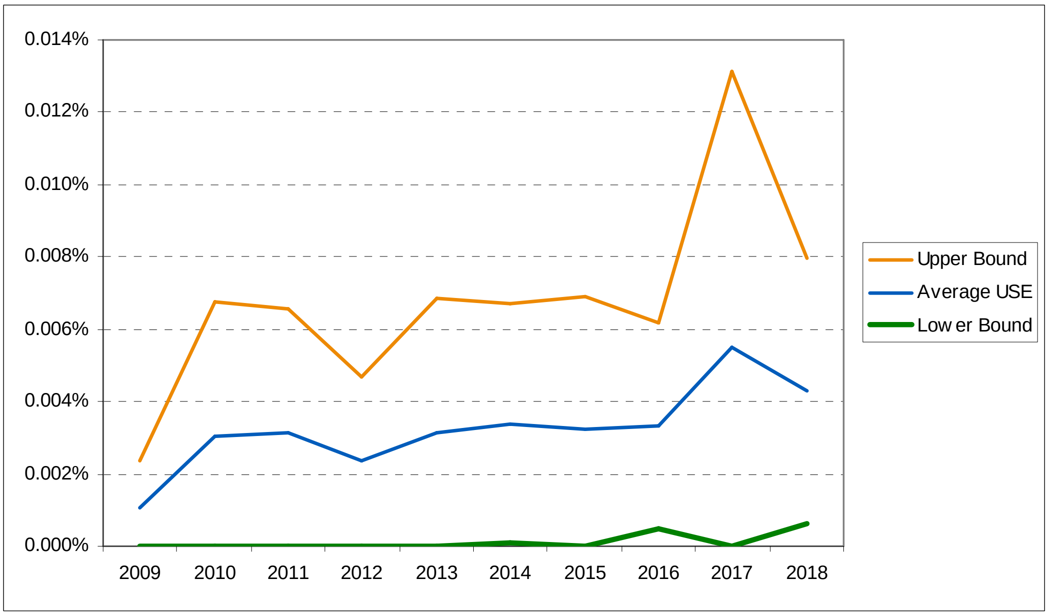
USE can vary due to inherent volatility of market conditions and differences in responses of different investors to the price signals.

Volatility

We observed a wide spread of USE outcomes for each level of investment. The spread is a consequence of the inherent volatility of demand, mainly due to temperature sensitivity, and net generating capacity available at any time. Net generating capacity is related to generator performance, in particular unplanned breakdowns, and unit size. All else being equal the larger unit sizes lead to greater the volatility from hour to hour.

As a result no matter what the level of VoLL or market design, USE outcomes for the NEM will be volatile. Figure 20 shows the band of USE outcomes for one standard deviation from the mean at the current setting for VoLL ($10,000/MWh) and shows results ranging from zero to well above the average. This highlights the position that results from year to year can vary markedly and that informed investors will be assess the commercial effect of the equivalent variability in revenue.

Figure 20: Band of USE outcomes



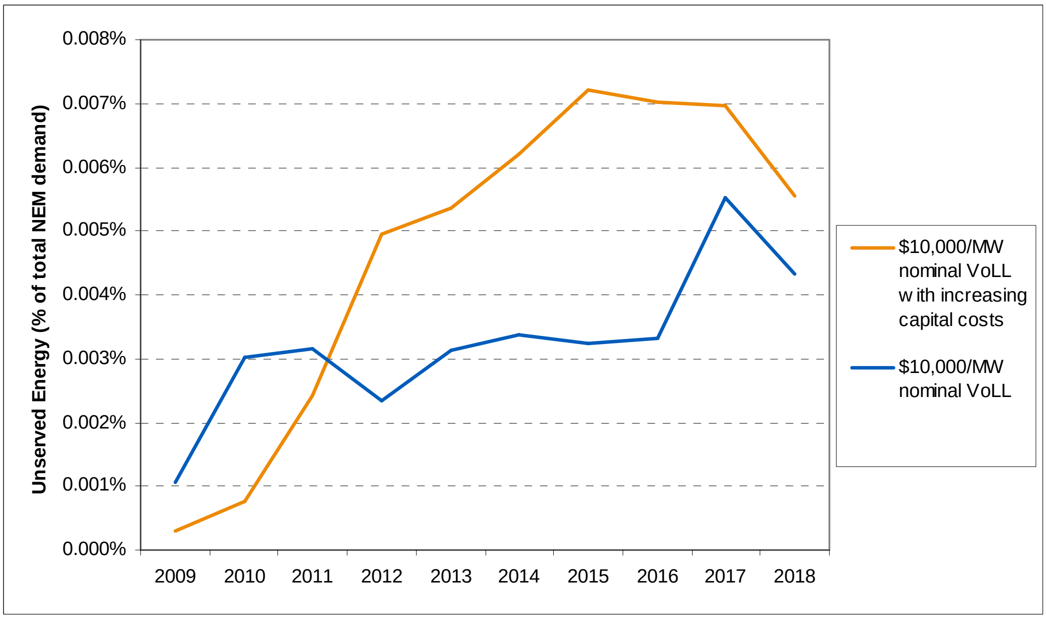
Investment uncertainty

Within an energy only market with limited demand side participation such as the NEM, the inherent volatility within the design leads to volatile revenues to generators and thus volatile investment signals and uncertainty about the level of investment for a given level of VoLL. Market participants are expected to mange this risk, for example by using financial contracts and thus stabilise the investment signal. This point has been noted as a criticism of energy only markets by commentators in the discussion in the main report.

A scenario was tested, whereby the annual capital cost ($/MW/year) for new generators increased at a nominal level of 8% per year (5.5% per year when accounting for inflation). Using the current level of VoLL ($10,000/MWh) and keeping all other market settings constant, there would be lower profitability for the new peak generators. In order to compare the USE outcome of the run with increasing capital costs to the run with the current level of capital costs, a stable level of profitability between these two scenarios was needed. As Figure 21 shows, for similar profitability of new peak generators, a higher level of USE will result in the market which has increasing capital costs.

Figure 21 shows the effect on USE if the level of VoLL is held at the current level but investors required a higher level of return for any reason for example to compensate for uncertainty of revenue streams.

Figure 21: NEM Annual USE comparison of Original and Increasing Capital Cost Scenarios



A key reason for investigating amendments to the design of the market during the course of the review was to assess the potential for those alternative designs to reduce the variability of revenue even though USE outcomes would remain volatile. Results of analysis of these results are shown in later sections of this appendix.

A.7 CUMULATIVE PRICE THRESHOLD

The cumulative price threshold (CPT) is a mechanism that triggers a reduction in the market price cap from VoLL to an Administered Price Cap (APC). The CPT was introduced into the NEM as a replacement for force majeure provisions that were intended to trap physical events that represented a major disturbance to normal market conditions and meant the normal market price was no longer likely to be an effective means to signal efficient behaviour. Market participants, particularly generators, were unable to quantify the extent of financial exposure and thus were unable to purchase cost-effective insurance against plant failure. The CPT was introduced as a pure price trigger for the APC based on extended (rolling 7 day period) high price regardless of the reason the price is high and considerably reduces the uncertainty about maximum exposure.

If the market breaches the CPT and the APC becomes the price cap and revenue to generators is clearly reduced while the APC is operative. The setting for the CPT (and the APC) can therefore have important consequences for reliability incentives in a similar way to the setting of VoLL. It is therefore important that settings for VoLL and CPT to be aligned and that a balance be struck between mitigating the adverse effects of high price against the adverse impacts of too low a price

This section quantifies the effect of different levels of CPT under the current setting for VoLL at $10,000/MWh nominal.

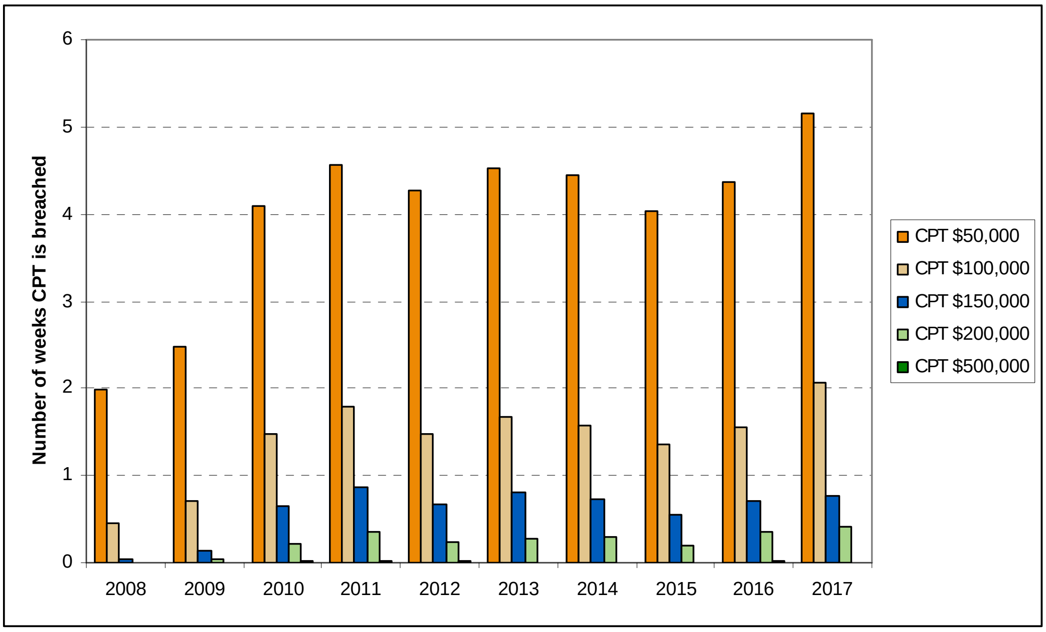
A.7.1 Analysis

Potentially, quantitative analysis of the effect of the CPT involves significant computational complexity because the threshold is based on a rolling 7 day accumulation of prices and once triggered means that participants may receive less than the price they offer to the market and secondly because the PEPPY module of CEMOS works on a load block approach common to many longer term models it does not directly examine sequential half hours on which the CPT is calculated. Further participant bids and offers cannot readily be formed as inputs to the modelling in the absence of knowledge of whether the CPT will be reached in each Monte Carlo simulation.

In light of these circumstances we have mapped the occurrences of high price within each Monte Carlo run onto a sequential load profile for each region and thus computed the number of times the different levels of CPT would be breached. The approach is an approximation in that if participants felt there was a risk of the CPT being reached within the next day (or so) then it is likely they would set bids and rebids to their commercial advantage in ways that are not assessed within the model and the resultant market prices would in principle affect returns to the marginal investor. However, the impact on investment and USE for any practical market settings is expected to be to be minimal. These approximations result in a higher number of incidences of breach of the CPT and for this reason should be viewed as indicative.

Figure 22 shows the number of weeks CPT is breached each year for different settings of CPT when VoLL is held at $10,000 nominal.

Figure 22: Number of weeks per year in which CPT is breached for one or more half hours (VoLL $10,000/MWh nominal)



As would be expected the number of breaches falls as the CPT is increased.

At the current market setting of $150,000 level with VoLL held at $10,000/MWh the modelling shows a negligible chance of breach at present and this is consistent with experience to date. However, the risk of breach rises over time so that CPT may be breached in one or two weeks per year in the next few years. It is important, however, to bear in mind that the input assumptions for this work deliberately excluded the effect of all government policy measures and as a result reserve margins in the study are at the minimum necessary to meet the reliability standard and that there are no mitigating influences such as contracts or demand side measures that may act to cap the price. Each of these effects is likely to reduce the risk of extended high price that would lead to the CPT being breached.

A.8 ALTERNATIVE MARKET DESIGN OPTIONS

A.8.1 Overview of Results

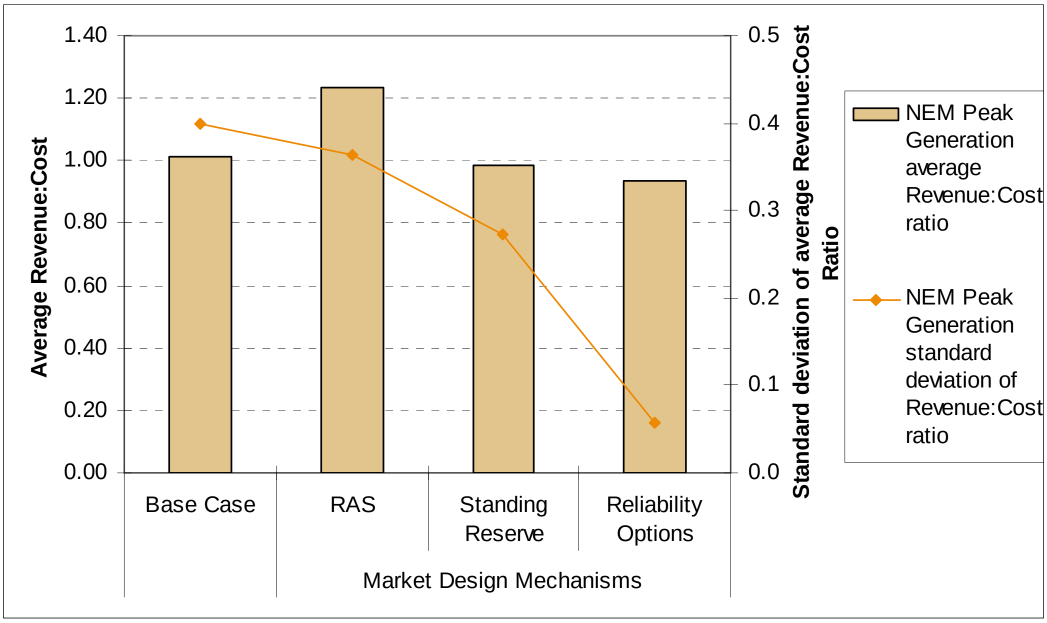
The discussion so far has considered variations in VoLL and CPT in the status quo design. This section discusses the outcomes from modelling of broader changes to the NEM design that were initially considered in the appendix to the interim report of the review and now updated with 2007 data. These options represent more significant departures from the current design, and hence may involve very different dispatch/pricing and reliability outcomes.

Consistent with the approach we adopted in the interim report, we designed the analysis to compare outcomes on the basis that VoLL remained at $10,000/MWh in real terms. Clearly if VoLL were maintained at the same level in absolute terms, as it has been in the NEM, then over time the ability of the market to attract new investment will fall and USE will progressively rise.

The RAS and standby contracts are designed primarily to provide additional revenue to new investment that provides reserve but not (in the main) to incumbents. These mechanisms can therefore reduce USE but lead to higher costs but discriminate between energy producing plant and reserve plant and hence value the contribution to capacity from different plants according to the role they play. Reliability Options represent the most significant change to the design and involve a contract fee for capacity which is intended to replace the payment generators receive from market prices in excess of SRMC in the energy market design. In assessing the Reliability Options the VoLL was set to $3,000/MWh (real) although it is useful to note that the level of VoLL under this option has less impact on reliability.

Figure 23 plots key cost ratios and standard deviation of profitability as an indicator of the change in certainty of revenue for the different options. The following sections provide additional detail on the results for each option.

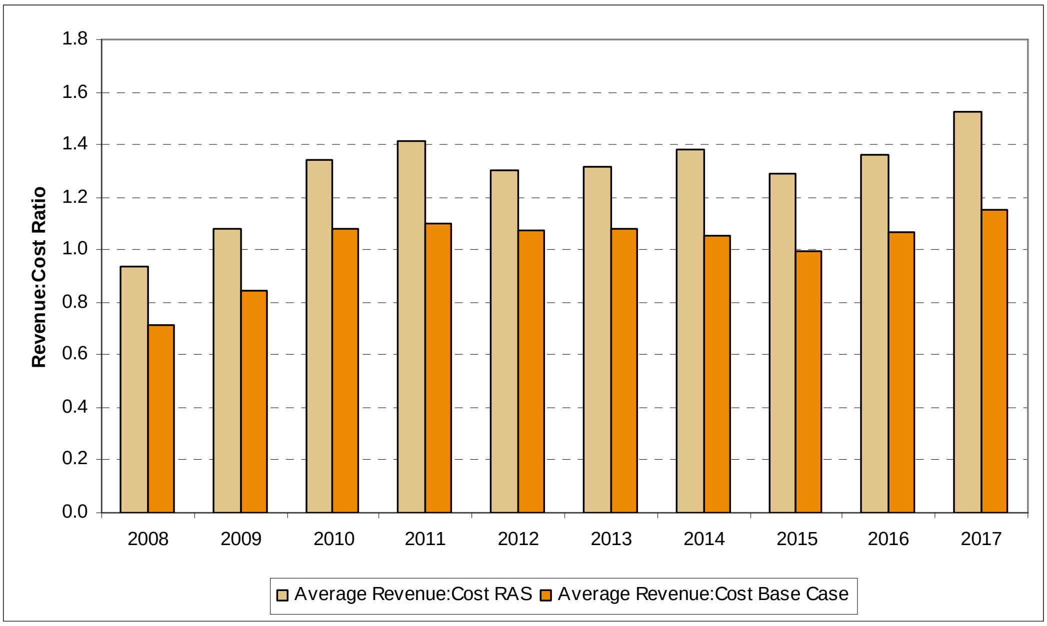
Figure 23: Revenue:Cost Ratio and Variability for new OCGT by Design Option



A.8.2 Option B: Reliability Ancillary Services (RAS)

A RAS would be expected to increase the certainty of revenue to plant providing reserve as shown in Figure 23. It will also increase the revenue to these plants. Figure 24 shows the relative increase in revenue as a result of a RAS set to achieve additional reserve equivalent to an increase in VoLL of $2,500.

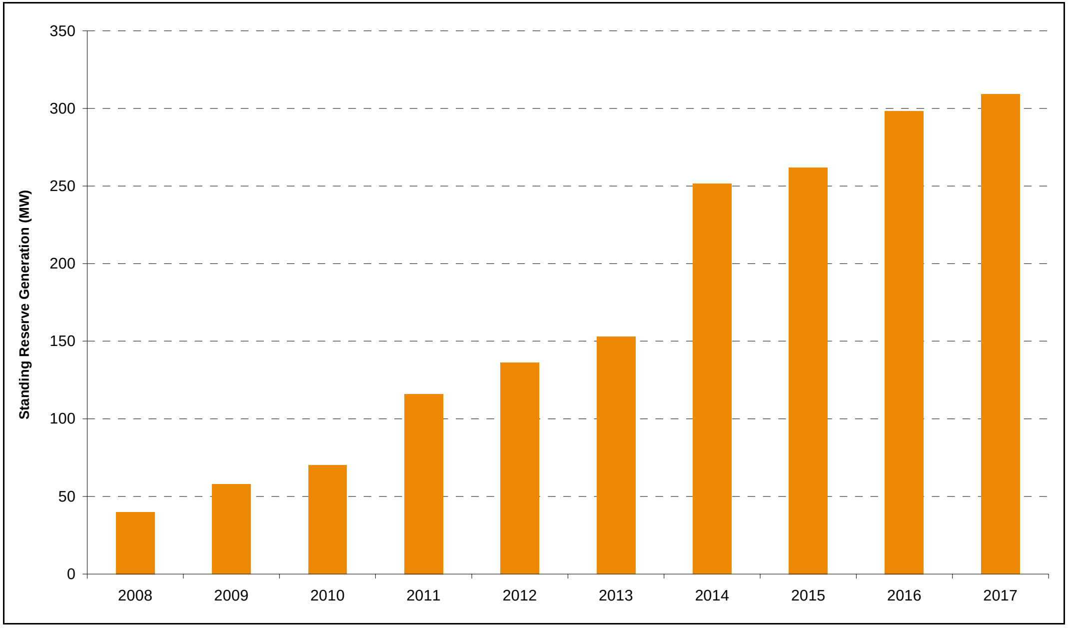
Figure 24: RAS Revenue:Cost ratio Comparison to Status Quo for new OCGT



A.8.3 Option C: Standing Reserve

Figure 25 shows the amount of centrally contracted reserve generation modelled in the standing reserve option.[7] The standby reserve generators are offered into the market at VoLL ($10,000/MWh). Figure 25 summarises the amount of standby reserve modelled and Figure 26 shows the ratio of profitability of OCGT plant as a whole. OCGT plant providing standing reserve would however achieve a highly stable revenue as it would be under contract.

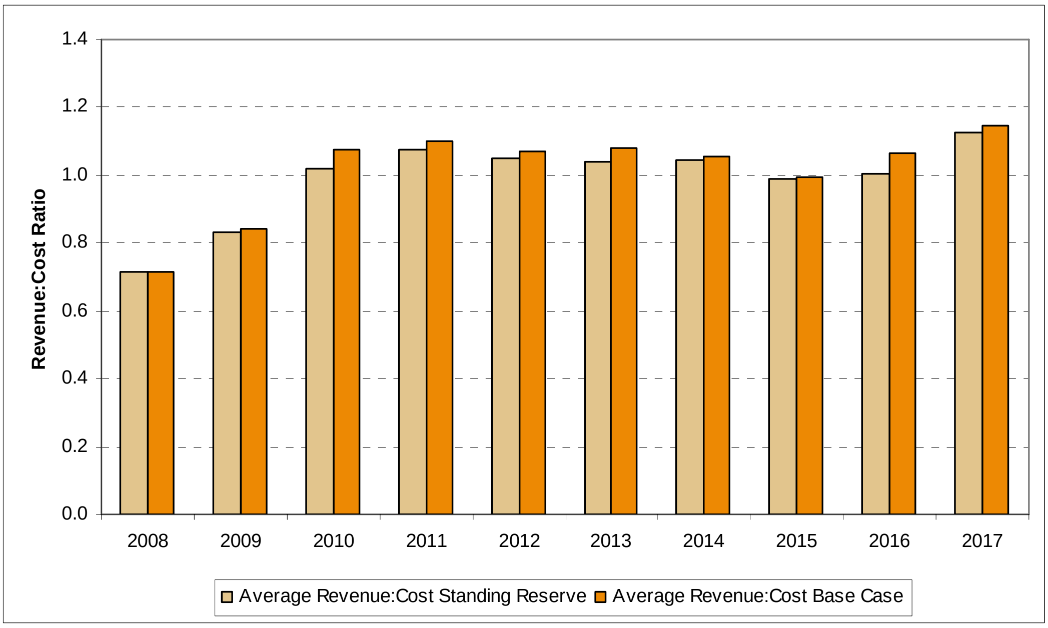
Figure 25: Centrally Contracted Standing Reserve Generation



7 For the purposes of the update to the analysis we used the same MW standing reserve levels and geographic distribution from the interim report. The amounts were based on the difference between the new OCGT capacity that was supported by the status quo VoLL $12,500/MWh and status quo VoLL $10,000/MWh cases in the interim report. These amounts will have shifted slightly in the light of revised plant costs but the methodology was a matter convenience in the interim report and illustrative of outcomes and thus remains a suitable and consistent distribution of reserve generation.

Figure 26 shows the profitability over the period from 2008 to 2017.

Figure 26: Standing Reserve Revenue:Cost ratio Comparison to Status Quo for new OCGT



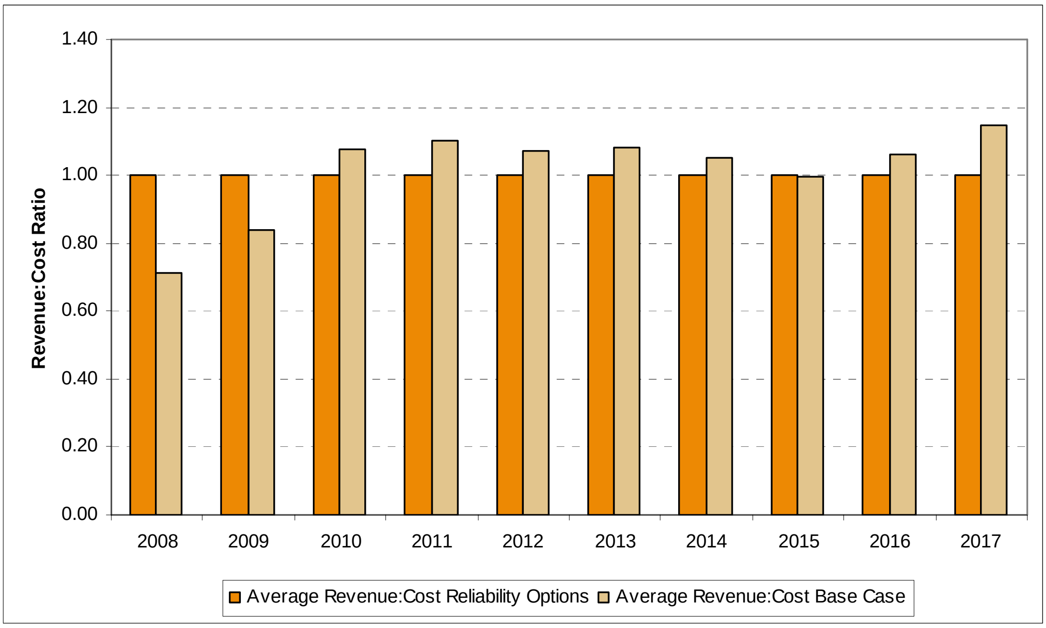
A.8.4 Option D: Financial Reliability Options

In the approach that uses "Reliability Options", a payment of $71,000/MW/year, equivalent to the capital costs of new OCGT entry, is assumed to be the option fee for the Reliability Option contract. In line with the design, VoLL is lowered to $3000/MWh (real).

Figure 27 shows the profitability over the period from 2008 to 2017.

From Table 6 it can be seen that the energy price under the Reliability option is significantly lower than in all other cases examined. However customer costs and generator revenue are each increased by the Reliability Option Fee that would be paid to generators. The certainty of revenue and costs is much higher (reflected in the lower standard deviation of revenue shown in Figure 23) with the Reliability Options and from a reliability perspective should offer greater certainty about meeting reliability standards but at the price of central control of participation levels.

Figure 27: Reliability Options Revenue:Cost ratio Comparison to Status Quo for new OCGT



A.9 MARKET FLOOR PRICE

The market floor price is the minimum price possible in the market. It is currently set at -$1000/MWh. Market prices can be negative for one of two reasons: a) when there is a potential surplus of generation bid into the market which cannot be used to meet total customer load; and b) where generators have bid negative prices when the network is constrained and cannot accommodate all generation from generators at a particular location and the generators compete for dispatch by lowering price.[8] Generally, neither of these conditions will affect long-term reliability but can indirectly affect short term reliability and security.

When a negative price occurs generators are in effect required to pay to stay on line and similarly customers receive payment for their consumption from the market. This situation can be economic for generators if the period of surplus and associated negative price lasts for only a short time and the particular generator would incur significant costs to stop and restart its unit. The risk of negative price is intended to provide an incentive for generators to manage the number of units that are online at any time and hence the risk of an uncontrolled surplus which would be technically dangerous and threaten system security. The level at which the market floor price is set therefore affects the incentive to both generation and load and the financial risk to generators.

8 Because of the regional pricing arrangements in the NEM the generators bidding negative prices are still however paid at the prevailing regional reference price.

If the market floor price is set too low generators have a stronger incentive to shut down and the risk of not being able to restart when loaded increases again. Setting the price too high (for example zero) reduces the incentive for generators to avoid surplus situations and leaves NEMMCO with little alternative but to use its power to direction generators to reduce output or shutdown. The actual cost to reduce output is very dependent on the circumstances at the time and can be reflected in bids for the lowest generation output block. The market floor price caps the minimum level.

However, the level at which it is set is unrelated to investment signals (ignoring the marginal incentive that might be seen for flexibility of response at low levels). Because In order to manage risks to security and short term reliability the main effect of the floor price is to affect the risk of NEMMCO needing to issue directions at low load times. The level can therefore be set pragmatically and subject to input from stakeholders there would seem to be little basis to change the current setting.