REPORT

Prepared for:

AEMC Reliability Panel

Updating the Comprehensive Reliability Review quantitative analysis to account for CPRS and MRET

Prepared by:

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EXECUTIVE SUMMARY

This document provides an update to our quantitative analysis of reliability in the National Electricity Market (NEM) that formed an Appendix to the report of the Comprehensive Reliability Review (CRR) by the Reliability Panel (Panel) published by the Commission in December 2007. The update is to inform the Panel's response to the Commission's request to assess the impact on reliability of the introduction of a Carbon Pollution Reduction Scheme (CPRS) and extension of the Mandatory Renewable Energy Target (MRET). The Commission's request is part of its broader assessment of the impact of CPRS and MRET on energy frameworks.

1.1. KEY CONCLUSIONS

The work has shown, subject to a number of important caveats and based on analysis of spot prices only, that:

- The theoretical design of an energy-only market should be able to accommodate and adapt to the changes that a CPRS and MRET will bring and ensure that there will be sufficient revenues to support investment to meet the long term reliability standard in the NEM. However, this requires that investors take a long term view of potential revenues and have good knowledge and confidence about a range of future conditions;

- For the NEM, in practice, the CPRS and MRET will lead to dramatic changes in the generation technology mix in a relatively short time. There is a risk that the uncertainty created by the rate of change may be too short or beyond the capacity of the overall NEM design to respond without significant short term fluctuations in national and regional unserved energy;

- Management of supply reliability within a day may also be affected. The characteristics of the future technology mix may invalidate the presumption that market participants will deliver sufficient "standby reserve" beyond the time for which NEMMCO directly manages system security (using ancillary services and mandatory technical standards). In particular, wind output is intermittent and requires that other controllable plant be installed and available in a "standby" mode to operate when needed. It is not clear that market incentives in the current design will ensure sufficient short term standby reserve will be present, especially during the transition to a CPRS regime. Further study is recommended and, if appropriate, consideration of alternative standby reserve mechanisms;

- Reliability outcomes were very sensitive to the level of VoLL. This result is consistent with previous analysis for the Reliability Panel. The results reaffirm that the current level of VoLL ($10,000/MWh without indexing) is unlikely to allow sufficient investment to meet the NEM reliability standard in the future. The studies also showed that (subject to the caveats concerning investor behaviours) the proposed level of $12,500/MWh if incremented over time at the assumed CPI, has the potential to support sufficient investment to meet the reliability standard. The Panel has previously noted that there are a number of factors that need to be taken into account in setting a final level of VoLL, including the effects on financial risk, and these remain; and

- If demand elasticity and the timing, availability and cost of new technologies can be forecast sufficiently far in advance, the market will adapt and offer revenue for new investment to meet reliability standard. These factors made little difference to results for reliability in the long run, but had significant effects on the technology mix and market prices.

1.2. POTENTIAL VS BEHAVIOURAL RESPONSE INCREASES UNCERTAINTY

A crucial caveat on the conclusion that the NEM will support sufficient investment to meet the reliability standard, is that analysis of the type undertaken here can only assess the potential response. It does not attempt to make judgements about the level of confidence investors will have about future conditions, for example about carbon prices, the timing of new technology and levels of demand elasticity. The analysis has perfect foresight of these factors. During the transition period to revised arrangements for the CPRS and MRET, there will be greater uncertainty about these factors.

The NEM energy-only design expects that investors will take a long term view. We would expect that, in the circumstances, some investors may seek a “first mover” advantage and discount the risk and make early investments, while others may act more conservatively and discount the potential revenues and delay investment. Therefore, there will be increased variability in outcomes and increased risk that market incentives will not be sufficient to drive investment in the locations and at the times needed to ensure the reliability standard is met.

While knowledge of the price for carbon is an important factor, it is not the sole source of uncertainty. For example the timing of availability of the technology to capture and sequester carbon dioxide and the timing of commercial availability of geothermal plant can be crucial. While the, emergence of these technologies is linked to carbon price it is also linked to basic technology development programs. While technology and demand risks are normal in a market, the potential magnitude will be amplified by the introduction of a CPRS and MRET.

1.3. Shorter term effects

Satisfactory operation of the long term reliability mechanism in the NEM is a necessary element of ensuring continuity of supply to customers. However, the introduction of a CPRS and RET scheme can also have significant effects on shorter term, within day, operations. The characteristics of some of the technologies likely to respond to the CPRS and RET schemes are different to the characteristics of existing technologies on which power systems and the NEM have been built. In particular, intermittency of wind is fundamentally different.

At the levels of wind plant expected to be present on the power system, the variability of output of wind can create situations requiring considerable amounts of what can be called "standby reserve" capacity. The NEM design presumes this reserve will be provided by commercial responses from traditional plant. This presumption may no longer be valid and is less certain during the transition period. In particular, the market relies on the provisions under which NEMMCO directly manages short term operation and system security in the central dispatch process. But the NEM also relies on commercial incentives for participants to provide "standby reserve" beyond the 5-minute boundary of the central dispatch process. Accordingly, an area for further examination over and above examination of longer term investment incentives is whether changes are needed to the design boundary between market based responses and central control of the management of security.

1.4. Reliability may be increased at times

Our assessments assumed only limited capacity from wind sources could be relied upon over critical peak times and additional thermal plant was found to be commercially viable to cover the peaks assuming low wind capacity. We note that at times this will mean reliability may in fact be better than our results show as wind capacity may be higher. On the other hand this would only add to the volatility and uncertainty. Investors may take the view that as wind may be present at higher levels in some years they should apply a discount to the returns they might receive and not invest in as much capacity.

1.5. INFLUENCE OF INPUT ASSUMPTIONS AND INPUTS

In common with other published work on the effect of climate change policies, our work has assumed a range of different costs and timing of new technologies. We found that providing the level of VoLL was sufficient, over the long term market prices could support adequate levels of investment to provide a reliable outcome. But we also found that only a limited number of new investments were being driven solely from market incentives. Therefore assumptions we adopted as part of the inputs had significant impact. For example, to ensure we had realistic levels of new plants being built in the analysis, we applied limits on the amount of new plant that could be built and set a time when new technologies would be available for commercial use. These limits were particularly important as displaced coal plant was assumed to shutdown and was replaced by new plant. We also found that market externalities such as MRET and minimum gas build policies were setting minimum levels of certain types of plant that had to be built, regardless of market returns. A similar situation must impact other studies with which this work may be compared.

We found that there was sometimes high volatility in levels of unserved energy in different regions that was driven by decisions we made about retirement of displaced generation and availability of replacement. In some cases we deliberately left these results stand rather than refine the retirement schedules or augment interconnectors. We were then able to highlight the potential range of impacts more clearly. We recognise that in reality investors may respond to the commercial incentives or interconnectors may be augmented. However, in the face of such rapidly changing conditions, there is also a risk that a range of decisions by incumbent generators about retirement, by new investors about new entrant plant and by network owners about network augmentation, may not be sequenced as closely as needed to avoid unacceptable short term dips in reliability. We highlight this risk as a matter for further consideration in the assessment of the broader framework.

Taken over the long term and with perfect knowledge of future conditions, results show that prices and the technology mix can adapt. However, as noted, this assumes investors will take a similar view on risks and forecasts of future conditions. Accordingly we caveat our view that market prices can provide sufficient revenue to support investment as a *necessary but not sufficient* condition for the market to meet reliability standards. These factors all serve to highlight the increased uncertainty about performance of the market and are highly relevant to an analysis of energy frameworks.

1.6. ASSESSING MRET

We found that assessment of MRET was difficult. In part this is because the effect of MRET is already factored into the energy forecast through reductions in NEMMCO's forecast of requirements for scheduled generation as significant levels of unscheduled generation is expected to emerge in response to MRET. We were not in a position during the course of the work to re-establish the energy profile assuming no MRET. As a result, our analysis of "no MRET" situation was in fact a study of the no MRET from scheduled generation and showed little difference to the cases reported.

1.7. SPECIFIC OUTPUTS VALID ONLY FOR SPECIFIC INPUTS

Modelling inputs considered a number of interlinked factors affecting the operation of the NEM in addition to the impact changes due to of the introduction of the CPRS and MRET including:

- The rapidly changing cost of new entrant generators;
- The expected long term sensitivity of demand for energy to carbon prices;
- The rate of increase in gas prices; and
- The emergence of new technologies especially those with low emissions – a number of these developments are being driven by the expected impact on price of a CPRS and MRET leading to material changes in mix of generation technologies and their development therefore is not independent of policy settings as other technological developments often are.

Some of the factors tend to degrade reliability while others improve it and the net effect on reliability at any time is determined by the relative magnitude and timing of each of the factors.

The work focussed on the key effects of the CPRS and RET on reliability and did not attempt a rigorous assessment of the effects of factors such as banking of permits and used a relatively simple treatment of demand elasticity at different electricity prices.

Accordingly, quantitative results reported here are valid only for the specific combination of factors used in the analysis and inherent approximations employed. The results therefore should not be read as predictions of expected outcomes but reporting of possible outcomes in the circumstances and possible response.

2. INTRODUCTION AND OBJECTIVES

This document provides an update to our quantitative analysis of reliability in the National Electricity Market (NEM) that formed an Appendix to the Comprehensive Reliability Review (CRR) by the Reliability Panel (Panel) published by the Commission in December 2007.

This update was requested as part of the Panel's input to the formation of a response to the Commission's request to assess the impact on reliability of the introduction of a Carbon Pollution Reduction Scheme (CPRS) and extension of the Mandatory Renewable Energy Target (MRET).scenarios and Comparisons to previous CRR modelling

The analysis is considering updated data on generation, energy, maximum demand and transmission interconnections and assessing a range of scenarios for carbon prices, MRET levels, rate of gas price increase and generator capital cost. The key differences in the assumptions underlying the new modelling and that undertaken for the 2007 CRR are outlined below

Table 1: Treatment of CEMOS parameters 2007 c.f. 2008 base cases*

Parameter(s)	2007 exercise	2008 update
VoLL	Range of scenarios including: • $10,000 nominal through to 2020 • $10,000 real from 2010 • $12,500 nominal from 2010	$10,000 nominal to June 2010 and then $12,500, indexed for inflation every 2nd year.
Energy and demand projections	*2007 Energy and Demand Projections*, NEMMCO (July 2007)	*2008 Energy and Demand Projections*, NEMMCO (July 2008) - updated
Generation capital costs	ACIL 2007[1]	Base case combination of: • assumptions underlying Treasury modelling of CPRS; and • CRA estimates [higher than ACiL 2007].
Regional structure	6 regions: Queensland, NSW, Snowy, Victoria, South Australia and Tasmania.	5 regions: Queensland, NSW, Victoria, South Australia and Tasmania.
Interconnector capacity	Interconnector capabilities as of July 2007	Interconnector capabilities as of July 2008 plus upgraded: • Vic-NSW from 2011; and • QNI from 2016

1 ACIL Tasman report incorporated in NEMMCO's Statement of Opportunities 2007.

Parameter(s)	2007 exercise	2008 update
MRET	Legislated state-based schemes as of mid-2007	Consolidated and enlarged MRET – NEM share of Australia-wide 45,000 GWh target by 2020
Drought	Energy capability associated with long-term average inflows for hydro-schemes	Energy capability as modified for 2008-09 and 2009-10 per NEMMCO assessment average inflow from Sept '08 drought report
Carbon prices	$0	$0
Gas prices	ACiL 2007[2]	CRA derived estimates that yield $6 / GJ commodity prices at Victorian and Queensland gas hubs by 2020

* All parameters expressed in real terms except where noted.

The models for this study were set up prior to the release of NEMMCO's *2008 Statement of Opportunities* and, therefore, there will be some (minor) discrepancies between some of the parameters used and the latest SOO benchmarks.

2 *Op. cit.*

3. ANALYTICAL APPROACH

3.1. BASIS FOR COMPARISON OF SCENARIOS

The analysis used essentially the same methodology we used in the CRR analysis in 2007, in that, where practicable, investment profitability was used as a benchmark parameter in modelling different market settings to ensure that comparisons between different cases were made on a like-for-like basis. For example, where the level of VoLL was altered or different carbon prices applied it was assumed that investors would invest until the same level of profitability was achieved. 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.

3.2. MARKET MODELLING IS ONLY PART OF THE STORY

In the CRR analysis we emphasised that, although modelling is a valuable tool to inform analysis, the results can be no better than the methodology, assumptions and data that are used. Like other models of the market, our work takes into account the technical and commercial characteristics of the NEM and simulates profit maximising behaviour of participants bidding in the spot market in the presence of hedge contracts. The modelling also assess investment decisions, but assumes investors will take a long term view of expected value of revenues from the spot market in making their decisions, and that the spot and contract markets work in tandem to the extent that decisions will be made on the basis of spot revenues alone.

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. It is also assumed that investors will require only the revenue needed to fund new investments underwritten by financing over an extended period. No attempt is made to assess the impact of a number of factors that create uncertainty from the perspective of investors, in particular those due to regulatory decisions, policy initiatives and technology uncertainty outside of the specific scenarios considered. While such limitations are also inherent in other analyses (e.g. by NEMMCO), they are particularly significant in this work because unserved energy is a relatively a small percentage of total energy. 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 and should be used to inform deeper analysis. It assesses the performance of the NEM under these assumptions and the effect of different settings on the market under the same assumptions.

4. KEY INPUT ASSUMPTIONS

4.1. 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 2009 to 2030 and have reported the results for the period up to (at least) 2020. In this way, the distortions due to "end-effects" for the period of interest are minimised.

4.2. SUPPLY CAPACITY

CEMOS uses the supply system characteristics including: existing generation shown in Table 2; 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 growing energy and demand requirements. The nature and timing of new entry will depend on a variety of factors, including the level of competition in the NEM. 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.

4.2.1. Existing generation capacity

Table 2: 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	49	9.15	10588
Anglesea	Sub_Cr_brownCoal	155	1.13	13235
Bairnsdale	OCGT	90	2.15	10286
Barcaldine	CCGT	49	2.28	7200
BarronGorge	Hydro	60	0.00	1000
Bayswater	Sub_Cr_BlkCoal	2760	1.13	10028
BellBay	Steam_Gas	240	7.54	11250
BellBayThree	OCGT	108	7.54	12414
Blowering	Hydro	50	0.00	1000

Station	Type	Capacity (MW)	Variable O&M ($/MWh)	Heat rate (MJ/MWh)
Bogong	Smallhydro	140	7.00	1000
Braemar	OCGT	450	7.54	10588
Braemar2	OCGT	516	7.50	11250
CallideA	Sub_Cr_BlkCoal	0	1.15	9972
CallideB	Sub_Cr_BlkCoal	700	1.15	9972
CallidePP	Sup_Cr_BlkCoal	900	1.15	9231
Collinsville	Sub_Cr_BlkCoal	187	1.26	12996
Colongra	OCGT	668	7.50	11250
Condamine	CCGT	138	4.85	6793
DarlingDowns	CCGT	621	4.85	6793
DartMouth	Hydro	153	0.00	1000
DryCreek	OCGT	148	9.15	13846
Eildon	Hydro	120	0.00	1000
Eraring	Sub_Cr_BlkCoal	2640	1.13	10170
Gladstone	Sub_Cr_BlkCoal	1680	1.13	10227
Guthega	Hydro	60	0.00	1000
HalletWind	Wind	95	0.00	1000
Hazelwood	Sub_Cr_brownCoal	1600	1.13	15000
HumeNSW	Hydro	0	0.00	1000
HumeV	Hydro	58	0.00	1000
HVGTS	OCGT_Oil	48	9.15	12000
JeeralangA	OCGT	232	8.62	12000
JeeralangB	OCGT	255	8.62	12000
Kareeya	Hydro	88	0.00	1000
KoganCreek	Sup_Cr_BlkCoal	744	1.19	9474
Ladbroke	OCGT	84	3.43	10588
LakeBonneyWind	Wind	159	0.00	1000
LavertonNorth	OCGT	340	7.54	12414
Liddell	Sub_Cr_BlkCoal	2090	1.13	10651
LoyYangA	Sub_Cr_brownCoal	2190	1.13	12500
LoyYangB	Sub_Cr_brownCoal	1030	1.13	13534
MackayGT	OCGT_Oil	34	8.62	12857
McKay	Hydro	150	0.00	1000
MillmerranPP	Sup_Cr_BlkCoal	860	1.13	9600
Mintaro	OCGT	90	9.15	12000
Morwell	Sub_Cr_brownCoal	148	1.13	15000
MtPiper	Sub_Cr_BlkCoal	1400	1.26	9704
MtStuart	OCGT_Oil	288	8.62	10588
Munmorah	Sub_Cr_BlkCoal	600	7.54	11613
Murray	Hydro	1500	0.00	1000
Newport	Steam_Gas	510	2.15	12000

Station	Type	Capacity (MW)	Variable O&M ($/MWh)	Heat rate (MJ/MWh)
NorthernPS	Sub_Cr_brownCoal	546	1.13	11429
NSWWind	Wind	17	0.00	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	0.00	1000
Quarantine	OCGT	219	4.84	6923
Redbank	Sub_Cr_BlkCoal	147	1.13	12040
RomaGT	OCGT	68	9.15	12000
SAWind	Wind	388	0.00	1000
Shoalhaven	Hydro	240	0.00	1000
Smithfield	Cogeneration	160	2.28	8781
SnowtownWind	Wind	88	0.00	1000
Snuggery	OCGT	42	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
TamarValleyCCGT	CCGT	203	4.85	6793
TamarValleyOCGT	OCGT	60	7.50	11250
Tarong	Sub_Cr_BlkCoal	1400	1.37	9945
TASHydro	Hydro	2173	0.00	1000
TasWind	Wind	142	0.00	1000
TNPS1	Sub_Cr_BlkCoal	443	1.37	9184
TorrensA	Steam_Gas	504	0.00	13044
TorrensB	Steam_Gas	824	0.00	12000
Tumut3	Hydro	1500	0.00	1000
Upptumut	Hydro	616	0.00	1000
Uranquinty	OCGT	696	7.50	11250
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	10876.1
WestKiewa	Hydro	72	0	1000
Wivenhoe	Hydro	500	0	1000
Yabulu	OCGT_Oil	243	8.9	11976
Yallourn	Sub_Cr_brownCoal	1487	1.13	13846.2
YarwunCoGen	Cogeneration	169	4.85	6793

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

Data source for capacity data: SOO 2007 aggregate scheduled generation capacity.

Data source for VOM and heat rate (calculated from thermal efficiency): ACIL, 2007[3]. We note that Torrens Island units are listed with zero VOM in this work.

4.2.2. Planned entry

The planned 'committed' entry assumptions (based on SOO 2007 announcements and subsequent updates) are as outlined in Table 3.

Table 3: Planned entry assumptions

Company	Unit name	Unit type	Rated capacity	Commissioning year
TRU Energy SA Generation Pty Ltd	Tallawarra	CCGT	434	2008
N P Power	LakeBonneyWind	Wind	159	2009
Trust Power	SnowtownWind	Wind	88	2009
ERM Power	Braemar2	OCGT	516	2010
Delta Electricty	Colongra	OCGT	668	2010
QLD Gas Co	Condamine	CCGT	138	2010
AGL Hydro Partnership	HalletWind	Wind	95	2010
Wambo Power Ventures	Uranquinty	OCGT	696	2010
AGL Hydro Partnership	Bogong	Small hydro	140	2011
Origin Energy Electricity Limited	DarlingDowns	CCGT	621	2011
Rio Tinto[a]	YarwunCoGen	Cogeneration	169	2011
Tamar Valley Power[b]	TamarValley	CCGT	203	2009
Tamar Valley Power[b]	TamarValley	OCGT	60	2009

[a] CRA is aware that the Yarwun CoGen plant is likely to only export approximately 65 MW to the grid, with the remainder of energy being used on-site. However, the plant will nevertheless be modelled as a 169 MW (winter rated) generator given that the energy and demand forecasts prepared by Powerlink Queensland would have taken account of the full load of the Yarwun refinery.

[b] The Tamar Valley CCGT is included on the basis that it is in an advanced stage of construction. Entry of Tamar Valley will coincide with retirement of BellBay thermal units.

The most economically viable renewable plant will enter modelled outcomes in accordance with the volume of renewable energy required to meet the NEM's share of a linear path to national target of an additional 45,000 GWh by 2020.

3 *Op. cit.*

4.2.3. New generation capacity

Assumptions regarding the addition of new generation technology over the time frame of interest (to 2020) are as follows:

- (as yet) uncommitted gas plant available for commercial production from 2011 and coal plant available from 2014; and
- CCS technologies – either new or retro-fit – will not be considered viable before 2020.

Although our 'central case' assumption is that CCS technologies would be available by 2020 and geothermal by 2015, there is some uncertainty around the development time frames for these technologies. To assess the impact of a delay in the date of commercial availability of new technologies we have included a study with availability of these technologies changed to 2025 for CCS and 2020 for geothermal.

Table 4: New generation characteristics

Station	Type	Low scenario annualised capital cost[1] ($/MW/yr)	High scenario annualised capital cost[1] ($/MW/yr)	Variable O&M ($/MWh)	Heat rate (MJ/MWh)
QLD_Biomass_2010	Biomass	249555	299466	3.13	9017
QLD_Biomass_2020	Biomass	237354	284825	3.13	8279
QLD_CCGT_2010	CCGT	142418	170901	4.85	6793
QLD_CCGT_2020	CCGT	135455	162546	4.85	6317
QLD_CCGT_CCS_ 2020	CCGT_CCS	193200	231840	10.30	7333
QLD_Geothermal_2010	Geothermal	480283	576339	0.00	37005
QLD_Geothermal_2020	Geothermal	412914	495496	0.00	33977
QLD_IGCC_2020	IGCC	243532	292238	4.85	7275
QLD_IGCC_CCS_2020	IGCC_CCS	336006	403207	18.96	8370
QLD_OCGT_2010	OCGT	89375	107250	7.50	11613
QLD_OCGT_2020	OCGT	83648	100378	7.50	10800
QLD_FutureFuel_2020	FutureFuel	408913	490695	0.00	1000
QLD_Smallhydro_2010	Smallhydro	309398	371278	7.00	1000
QLD_Smallhydro_2020	Smallhydro	309398	371278	7.00	1000
QLD_Sup_Cr_BlkCoal_ 2010	Sup_Cr_BlkCoal	199123	238947	1.20	8571
QLD_Sup_Cr_BlkCoal_ 2020	Sup_Cr_BlkCoal	189388	227265	1.20	8400
QLD_UltraSup_Cr_ BlkCoal_2010	UltraSup_Cr_BlkCoal	238969	286762	1.20	8000
QLD_UltraSup_Cr_ BlkCoal_2020	UltraSup_Cr_BlkCoal	227285	272742	1.20	7347
QLD_UltraSup_Cr_ BlkCoalCCS_2020	UltraSup_Cr_ BlkCoalCCS	287232	344678	1.20	7347
QLD_Wind_2010	Wind	204985	245982	0.00	1000

Station	Type	Low scenario annualised capital cost[1] ($/MW/yr)	High scenario annualised capital cost[1] ($/MW/yr)	Variable O&M ($/MWh)	Heat rate (MJ/MWh)
QLD_Wind_2020	Wind	194963	233956	0.00	1000
NSW_Biomass_2010	Biomass	249555	299466	3.13	9017
NSW_Biomass_2020	Biomass	237354	284825	3.13	8279
NSW_CCGT_2010	CCGT	142418	170901	4.85	6793
NSW_CCGT_2020	CCGT	135455	162546	4.85	6317
NSW_CCGT_CCS_ 2020	CCGT_CCS	193200	231840	10.18	7333
NSW_Geothermal_ 2010	Geothermal	480283	576339	0.00	37005
NSW_Geothermal_ 2020	Geothermal	412914	495496	0.00	33977
NSW_IGCC_2020	IGCC	243532	292238	4.85	7275
NSW_IGCC_CCS_2020	IGCC_CCS	336006	403207	18.96	8370
NSW_OCGT_2010	OCGT	89375	107250	7.50	11613
NSW_OCGT_2020	OCGT	83648	100378	7.50	10800
NSW_FutureFuel_2020	FutureFuel	408913	490695	0.00	1000
NSW_Smallhydro_2010	Smallhydro	309398	371278	7.00	1000
NSW_Smallhydro_2020	Smallhydro	309398	371278	7.00	1000
NSW_Sup_Cr_ BlkCoal_2010	Sup_Cr_BlkCoal	199123	238947	1.20	8571
NSW_Sup_Cr_ BlkCoal_2020	Sup_Cr_BlkCoal	189388	227265	1.20	8400
NSW_UltraSup_Cr_ BlkCoal_2010	UltraSup_Cr_BlkCoal	238969	286762	1.20	8000
NSW_UltraSup_Cr_ BlkCoal_2020	UltraSup_Cr_BlkCoal	227285	272742	1.20	7347
NSW_UltraSup_Cr_ BlkCoalCCS_2020	UltraSup_Cr_ BlkCoalCCS	287232	344678	1.20	7347
NSW_Wind_2010	Wind	204985	245982	0.00	1000
NSW_Wind_2020	Wind	194963	233956	0.00	1000
VIC_Biomass_2010	Biomass	249555	299466	3.13	9017
VIC_Biomass_2020	Biomass	237354	284825	3.13	8279
VIC_CCGT_2010	CCGT	142418	170901	4.85	6792.5
VIC_CCGT_2020	CCGT	135455	162546	4.85	6316.56
VIC_CCGT_CCS_2020	CCGT_CCS	193200	231840	10.2	7333
VIC_Geothermal_2010	Geothermal	480283	576339	0	37005
VIC_Geothermal_2020	Geothermal	412914	495496	0	33977
VIC_OCGT_2010	OCGT	89375	107250	7.5	11613
VIC_OCGT_2020	OCGT	83648	100378	7.5	10800.09
VIC_FutureFuel_2020	FutureFuel	408913	490695	0	1000
VIC_Smallhydro_2010	Smallhydro	309398	371278	7	1000
VIC_Smallhydro_2020	Smallhydro	309398	371278	7	1000

Station	Type	Low scenario annualised capital cost[1] ($/MW/yr)	High scenario annualised capital cost[1] ($/MW/yr)	Variable O&M ($/MWh)	Heat rate (MJ/MWh)
VIC_Sup_Cr_ brownCoal_2010	Sup_Cr_brownCoal	208978	250774	1.2	10588.2
VIC_Sup_Cr_ brownCoal_2020	Sup_Cr_brownCoal	198761	238514	1.2	10270.36
VIC_Wind_2010	Wind	204985	245982	0	1000
VIC_Wind_2020	Wind	194963	233956	0	1000
SA_Biomass_2010	Biomass	249555	299466	3.13	9017
SA_Biomass_2020	Biomass	237354	284825	3.13	8279
SA_CCGT_2010	CCGT	142418	170901	4.85	6793
SA_CCGT_2020	CCGT	135455	162546	4.85	6317
SA_CCGT_CCS_2020	CCGT_CCS	193200	231840	10.18	7333
SA_Geothermal_2010	Geothermal	480283	576339	0.00	37005
SA_Geothermal_2020	Geothermal	412914	495496	0.00	33977
SA_OCGT_2010	OCGT	89375	107250	7.50	11613
SA_OCGT_2020	OCGT	83648	100378	7.50	10800
SA_FutureFuel_2020	FutureFuel	408913	490695	0.00	1000
SA_Wind_2010	Wind	204985	245982	0.00	1000
SA_Wind_2020	Wind	194963	233956	0.00	1000
TAS_Biomass_2010	Biomass	249555	299466	3.13	9017
TAS_Biomass_2020	Biomass	237354	284825	3.13	8279
TAS_CCGT_2010	CCGT	142418	170901	4.85	6793
TAS_CCGT_2020	CCGT	135455	162546	4.85	6317
TAS_CCGT_CCS_2020	CCGT_CCS	193200	231840	10.20	7333
TAS_OCGT_2010	OCGT	89375	107250	7.50	11613
TAS_OCGT_2020	OCGT	83648	100378	7.50	10800
TAS_FutureFuel_2020	FutureFuel	408913	490695	0.00	1000
TAS_Smallhydro_2010	Smallhydro	309398	371278	7.00	1000
TAS_Smallhydro_2020	Smallhydro	309398	371278	7.00	1000
TAS_Wind_2010	Wind	204985	245982	0.00	1000
TAS_Wind_2020	Wind	194963	233956	0.00	1000

4.2.4. Retirement

Plant retirement was found to become an economic option as carbon prices increase. For the purposes of this work we have manually assessed utilisation of coal plant and retired brown coal plant to avoid utilisation less than approximately 50%. While this is very approximate we believe it is adequate for the purposes of assessing the effects on reliability.[4] We are aware that that there are adjustment mechanisms proposed in the Commonwealth Government's CPRS to reflect the effect of forced retirement of carbon intensive technologies but none of these has been included explicitly. In part, we have not included them because we would be speculating on the detailed design of the mechanisms and our assumptions would be yet another "modeller" influence on the outcomes and further complicate the interpretation of the results for limited strategic benefit.

4.3. INTERCONNECTOR CAPACITY

Transmission capability noted in the SOO/ANTS has been included, and interconnection limits from the SOO/ANTS have been applied; these are listed in Table 5.

4.3.1. Existing transmission

Table 5: Interconnector capabilities and average losses

Line	Flows from	Flows to	Maximum flow forward	Maximum flow backwards	Average loss[5]
Basslink (TAS to VIC)	TAS	VIC	594	469	0.09
Terranora (NSW to QLD)	NSW	QLD	155	285	0.075
QNI (NSW to QLD)	NSW	QLD	486	1078	0.05
NSW to VIC	NSW	VIC	1090	1361	0.12
Murraylink (VIC to SA)	VIC	SA	220	220	0.10
Heywood (VIC to SA)	VIC	SA	400	300	0.025

4 This is often reflected in modeling by increasing the fixed operating cost of generating units. In a commercial analysis detailed knowledge of the relevant costs would be needed on a unit by unit basis this is generally commercially sensitive information and varies with the circumstances.

5 In order to ensure the overall system energy balance is correct when scheduling transfers of energy between regions, CEMOS applies a loss factor based on a calculation of average losses implied by the inter-regional loss equations as published in NEMMCO's "List of Regional Boundaries and Marginal Loss Factors for the 2008/09 Financial Year".

4.3.2. New transmission

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. Economic opportunities to develop new interconnection capability are identified through NEMMCO's Annual National Transmission Statement (ANTS).[6] Earlier (2007 CRR) modelling manually assessed the case for interconnectors that were additional to those existing and committed – and found no strong case. As explained later in discussion of results, in this work we did identify some situations where augmentation was potentially viable. These situations were used to highlight some of the potential impacts and risks that might arise on a case by case basis.

6 Although there is no guarantee that opportunities so identified are necessarily taken up closer to the event when a formal investment test would need to be undertaken, nor is it necessary that an opportunity be identified in the ANTS before it can be constructed.

Table 6: Interconnector augmentations

Line	Proposed commission year	Flows from	Flows to	Maximum flow forward	Maximum flow backwards	Average loss
V_NSW2 [a]	2011	VIC	SNY	150	180	0.12
QLD_NSW2 [b]	20015-16	QLD	NSW	400	400	0.05

[a] The source of this project is the 2007 NEMMCO SOO / ANTS – a prioritised conceptual augmentation.

[b] Although the 2007 NEMMCO SOO / ANTS included a 400 MW upgrade of the NSW-Qld interconnector as a prioritised conceptual augmentation, Powerlink and TransGrid have since published a joint report that concludes "it is premature to recommend a QNI augmentation option at this time. As a network augmentation is not being recommended at this time, TransGrid and Powerlink Queensland are publishing this Final Report for the information of Registered Participants and interested parties." Initial modelling in CEMOS indicated that an upgrade to this interconnector would be justified from 2015-16 – timing that CRA understands to be consistent with preliminary analysis by Powerlink and TransGrid. Accordingly, CEMOS has modelled the QNI upgrade from 2015-16.

4.4. ENERGY AND DEMAND – SOO BASELINE

The energy and demand forecasts published by NEMMCO and used in the 2008 statement of opportunities have been developed by each JPB on an assumption of a carbon price path as follows:

- \$13.50/t CO2e in 2010;
- \$20/t CO2e in 2015;
- \$28/t CO2e in 2018;
- \$30/t CO2e in 2020;
- \$40/t CO2e in 2023;
- \$43/t CO2e in 2030; and
- \$45/t CO2e in 2035.

The long term analysis in CEMOS uses annual load duration curves developed using the peak and energy projections shown in Table 7. We have used the medium economic growth scenario to project regional energy requirements from the NEMMCO *2008 Energy and Demand Projections Summary Report* (updated)[7]. For modelling beyond 2018 (the point where NEMMCO forecasts stop) forecasts of electricity generation growth rates from ABARE will be used[8].

The NEM forecasts of energy and demand are expressed in terms of the requirement for generation scheduled in the wholesale market. A significant amount of small generation, in particular wind generators is entering the market as unscheduled generation which is effectively negative demand. This can be seen most vividly in the forecast for Victoria where scheduled generation is forecast to fall in the first years of the forecast[9], but this is only because of a very significant increase in the forecast level of unscheduled generation[10].

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.

7 Incorporating data updates advised after publication of the document. NEMMCO publication is available from: http://www.nemmco.com.au/about/410-0100.pdf

8 *Australian energy, national and state projections to 2029/2030*, ABARE Research Report 07.24. Available at: http://www.abareconomics.com/publications_html/energy/energy_07/auEnergy_proj07.pdf

9 See Table 13 of the NEMMCO reference above.

10 See Table 20 of the NEMMCO reference above.

Table 7: Regional energy and peak demand projections – SOO baseline

Year	Region	Annual energy (GWh)	Peak demand (10% POE)	Peak demand (50% POE)
2008	QLD	48134	9981	9461
2009	QLD	52194	10042	9493
2010	QLD	53943	10516	9930
2011	QLD	55909	10976	10355
2012	QLD	57826	11450	10777
2013	QLD	59465	11869	11143
2014	QLD	61364	12250	11474
2015	QLD	63173	12648	11821
2016	QLD	65139	13095	12209
2017	QLD	67211	13535	12592
2018	QLD	69422	13988	12987
2019	QLD	70854	14323	13298
2020	QLD	72623	14596	13552
2008	NSW	74310	15020	14070
2009	NSW	75480	14860	14040
2010	NSW	76120	15180	14290
2011	NSW	76280	15530	14620
2012	NSW	76760	16020	15070
2013	NSW	77820	16390	15410
2014	NSW	78420	16750	15730
2015	NSW	78900	17120	16070
2016	NSW	80020	17490	16400
2017	NSW	80450	17840	16720
2018	NSW	81260	18230	17080
2019	NSW	82936	18606	17432
2020	NSW	85007	19071	17868

Year	Region	Annual energy (GWh)	Peak demand (10% POE)	Peak demand (50% POE)
2008	VIC	47819	10026	9198
2009		47449	10525	9937
2010		44393	10592	9962
2011		43941	10753	10094
2012		43667	10940	10246
2013		42574	11151	10382
2014		43115	11354	10561
2015		43939	11552	10842
2016		44843	11809	11009
2017		45833	12054	11265
2018		46696	12320	11507
2019		47659	12578	11748
2020		48849	12697	11859
2008	SA	12704	3311	2990
2009		13140	3408	3091
2010		13255	3470	3143
2011		13218	3510	3169
2012		13348	3467	3136
2013		13762	3562	3221
2014		14045	3624	3273
2015		14391	3694	3342
2016		14570	3766	3404
2017		14951	3851	3460
2018		15296	3927	3525
2019		15611	3982	3575
2020		16001	4063	3647

Year	Region	Annual energy (GWh)	Peak demand (10% POE)	Peak demand (50% POE)
2008	TAS	10020	1805	1781
2009		10202	1854	1830
2010		10483	1896	1871
2011		10179	2022	1997
2012		10440	2039	2013
2013		10592	2061	2034
2014		10493	2111	2084
2015		10409	2147	2119
2016		10103	2176	2148
2017		10218	2205	2176
2018		10362	2228	2199
2019		10435	2252	2222
2020		10508	2268	2238

Sources: NEMMCO *2008 Energy and Demand Projections Summary Report*, July 2008 (updated); and CRA estimates.

Table 8: Total NEM-wide energy – SOO baseline

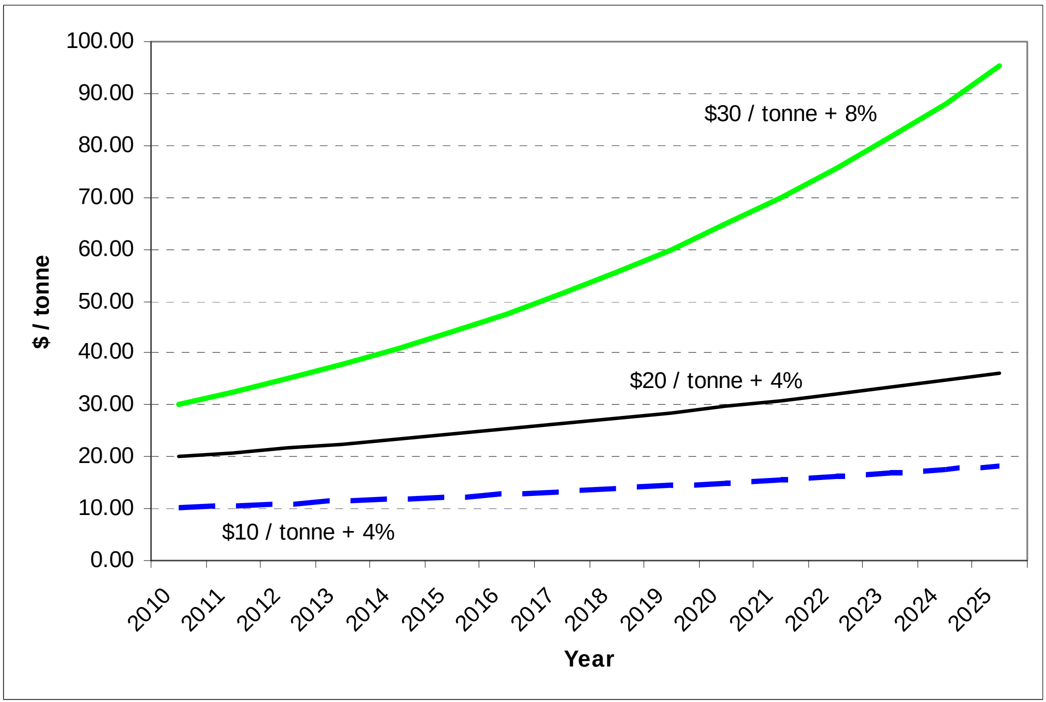
Year	Annual energy (scheduled) (GWh)	Wind energy (non-scheduled) (GWh)	Significant non-wind energy (non-scheduled) (GWh)	Total energy (scheduled + non-scheduled) (GWh)
2008	192,987	1,848	4,256	199,091
2009	198,465	2,773	4,487	205,725
2010	198,194	6,395	5,094	209,683
2011	199,527	8,167	5,221	212,915
2012	202,041	10,802	5,432	218,275
2013	204,213	12,345	5,631	222,189
2014	207,437	12,591	6,025	226,053
2015	210,812	14,180	6,259	231,251
2016	214,675	15,645	6,440	236,760
2017	218,663	16,565	6,709	241,937
2018	223,036	16,565	6,800	246,401

Data source: NEMMCO, *2008 Statement of Opportunities*.

4.5. CARBON PRICES AND THEIR EFFECT ON MODELLED DEMAND

To capture the price paths followed by Garnaut and avoid extreme step changes at the start of the CPRS, carbon prices as shown in Figure 1 are proposed[11]. We note Garnaut anticipates market prices rising at 4% real, potentially starting at $20/t in 2010. We expect the step change that starts at $30/t in the first year would be impractical, but have included it for the purposes of "stress testing" reliability outcomes.

Figure 1: CRR carbon price scenarios



For simplicity we have not considered "banking" of carbon permits on the assumption it will not greatly affect reliability outcomes and may overly complicate interpretation of the results.

In order to model carbon price paths as agreed with the Reliability Panel, and in the absence of (true) BAU projections from each Joint Planning Body (JPB), it was necessary to decompose the effects of carbon prices on energy and demand forecasts. With the time and information available, this can only be done approximately, making assumptions regarding:

- elasticity of demand for each region;
- average retail price for energy in each region;
- the degree to which carbon prices are translated into changes in retail prices.

11 For numbers underlying these paths see Table 19.

Given the above, we have used elasticities and retail prices as described in Table 9. The elasticities are taken from the NIEIR report and the average retail prices are a first approximation for the purposes of interim modelling.

Table 9: Initial assumptions on regional elasticities and average prices

	Own price elasticity of demand[12]	Average retail price (c/kWh)
New South Wales	-0.37	14
Queensland	-0.29	13
Victoria	-0.38	14
South Australia	-0.32	16
Tasmania	-0.23	12

A crucial assumption is the level of pass through of carbon prices to retail prices. For the purposes of our modelling, and consistent with the NIEIR Report published with the 2008 SOO[13], it will be initially assumed that carbon price will translate through to regional references prices on the basis that $1.00 / tonne of carbon equals a $0.70 / MWh of electricity.

The approach taken to develop energy and demand forecasts for each carbon price scenario that we model is to calculate, for each modelled carbon price path, a variation of energy and peak demand from SOO baseline projection in accordance with the above stated assumptions regarding:

- elasticity of demand for each region;
- average retail price for energy in each region; and
- the degree to which carbon prices are translated into changes in retail prices.

Arising from the application of this methodology for each modelled carbon price path, scheduled energy projections for the NEM are outlined in Table 10

Table 10: NEM scheduled energy under various carbon price paths

	Carbon price path: $0	Carbon price path: $10+4%	Carbon price path: $20+4%	Carbon price path: $30+8%
2009	198,465	198,465	198,465	198,465
2010	202,225	199,178	196,130	193,083
2011	203,972	200,778	197,584	194,021

12 Garnaut references NIEIR elasticity estimates and MMA capex; Treasury assumptions and Green Paper do not quote any elasticity number; and ACIL / ESAA is not precise, with 14% reduction in demand associated with a $55 carbon price and a 12% reduction in demand associated with a $45 carbon price.

13 NIEIR, *Climate change policies: international and Australian trends and impacts on the National Electricity Market*, Section 8, p.46.

	Carbon price path: $0	Carbon price path: $10+4%	Carbon price path: $20+4%	Carbon price path: $30+8%
2012	206,931	203,565	200,200	196,043
2013	209,547	206,007	202,468	197,656
2014	213,257	209,513	205,768	200,194
2015	217,135	213,172	209,209	202,776
2016	221,973	217,759	213,545	206,117
2017	226,966	222,487	218,009	209,467
2018	232,390	227,624	222,858	213,052
2019	236,723	231,674	226,624	215,447
2020	241,144	235,794	230,444	217,735
2021	246,473	240,786	235,098	220,631
2022	251,922	245,876	239,829	223,392
2023	257,493	251,065	244,637	225,996
2024	262,114	255,308	248,502	227,484
2025	266,824	259,618	252,413	228,749

Source: CRA estimates.

It is expected that CPRS will have an effect on the volume of energy that is sold, but may not impact peak demand to the same extent – the exact impact will be dependant on the nature of response to high prices. Sustained high prices that are likely to emerge from a CPRS scheme and drive energy efficiency and substitution will affect peak, potentially more than total energy if the effect is to flatten load shapes but, on the other hand, high prices may also drive increased price sensitive demand that may not impact peak demand on extreme days as much as total energy. On individual days with low reserves or unserved energy, the level of peak demand is crucial and the level of capacity is a “sunk decision” by that time. In a longer term study of this nature the energy to be supplied is also crucial as it affects the returns to new investors and therefore the level of capacity that will be present. Given the above, we model sensitivities in two ways:

- % change in peak demand = % change in energy; and
- % change in peak demand = 0.5 x % change in energy.

Table 11 outlines the resultant peak demands that would arise in 2020 for each region, each carbon price path and each sensitivity of change in peak demand to change in energy.

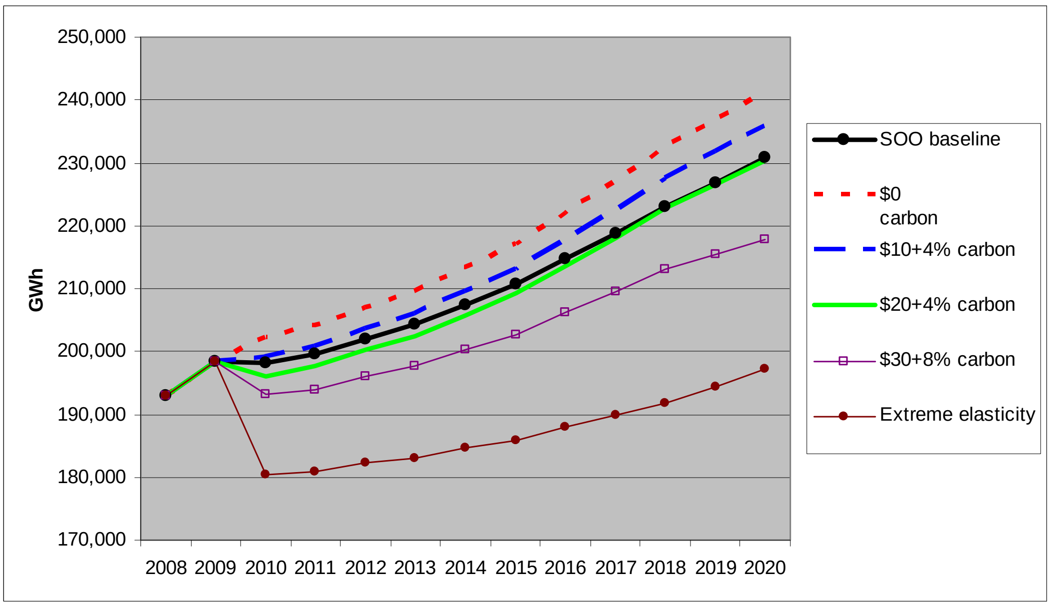
Table 11: Regional (scheduled) energy and 10% PoE peak demand projections for 2020

		NSW	Qld	Vic	SA	Tas
Energy						
	SOO	84,958	71,887	47,550	15,870	10,508
Carbon price path:	$10 + 4%	84,958	71,887	47,550	15,870	10,508
Carbon price path:	$20 + 4%	86,949	73,307	48,693	16,160	10,685
Carbon price path:	$30 + 8%	84,814	71,809	47,464	15,856	10,500
SOO baseline peak demand		19,060	14,485	12,545	4,074	2,259
Proportional change in peak demand and energy						
Carbon price path:	$10 + 4%	19,506	14,771	12,847	4,149	2,297
Carbon price path:	$20 + 4%	19,027	14,469	12,523	4,071	2,258
Carbon price path:	$30 + 8%	17,890	13,752	11,753	3,886	2,163
Half proportional change in peak demand and change in energy						
Carbon price path:	$10 + 4%	19,746	14,922	13,009	4,188	2,317
Carbon price path:	$20 + 4%	19,506	14,771	12,847	4,149	2,297
Carbon price path:	$30 + 8%	18,938	14,412	12,462	4,056	2,250

Source: CRA estimates.

A summary of key reference demand traces are shown in Figure 2. In addition to the demands associated with the escalating $10, $20 and $30 carbon price paths, we have also modelled reliability effects under what could be seen as an extreme elasticity demand scenario.

Figure 2: Modelled NEM scheduled demand traces



The extreme elasticity case arose from initial studies which inadvertently double counted the effect of carbon price on demand by adding elasticity to the demand and energy projections issued by NEMMCO before it became apparent to us that these values already included an allowance for carbon price effects. The results have been retained to illustrate the effect of an extreme sensitivity.

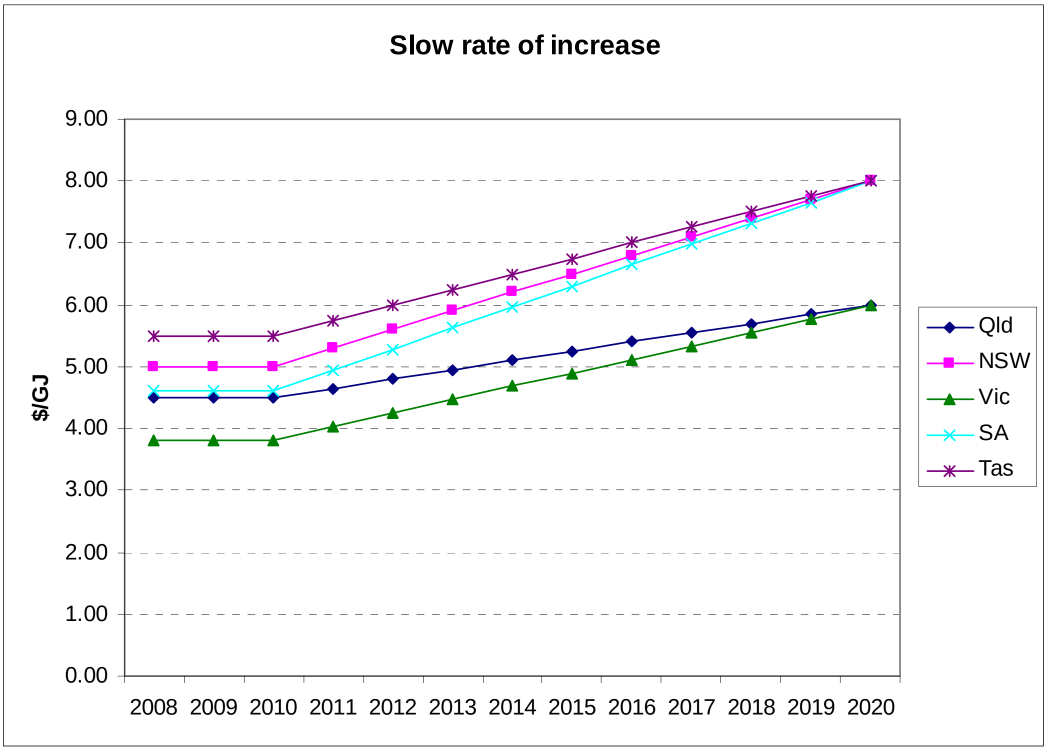
4.6. FUEL PRICES

4.6.1. Gas

East coast gas prices and availability are changing rapidly – not unlike west coast prices. By international standards, prices have been relatively low (AU$3-4/GJ) until the last few years but have begun to move recently as CSG supply (and reserves) increase, proposals for LNG emerge, and demand for gas for power generation rises. As a result, the environment for both supply and demand is dynamic and LNG options are introducing an international factor in pricing.

There is uncertainty about how fast and how high gas prices will rise. For the purposes of the update of the CRR, we initially ran scenarios with fast and slow rates of increase, expecting the most onerous condition to be the faster rate of gas price increase as the higher the gas price the harder it will be for new entrant gas plant to recover costs. In practice we found little difference in reliability outcomes because the market adapted to both the price trajectories. We therefore focussed only on the slower rate which the Panel felt was the morel likely trajectory. Figure 3 shows the trajectory used.

Figure 3: Gas price scenario



4.6.2. Coal

To ensure consistency with other studies of the market, coal price projections are based on the estimates reported in ACIL 2007[14]. Indicative real coal prices as reported by ACIL for respective regions are:

- for Queensland (black coal) – starting around $0.95 / GJ in 2008 and moving to around $0.90 / GJ in 2020

- for NSW (black coal) – starting around $1.07 / GJ in 2008 and moving to around $1.03 / GJ in 2020

- for Victoria (brown coal) – starting around $0.55 / GJ in 2008 and moving to around $0.52 / GJ in 2020

14 *Op. cit.*

5. SCENARIO ANALYSIS RESULTS

5.1. SCENARIO DESIGN

The final set of scenarios was chosen to capture the effects of carbon price, timing of new technologies, demand elasticity and the market price cap. The $20/t case was used as a central case and thus examined in more detail than cases with higher and lower carbon prices. The scenarios modelled are outlined in Table 12.

Table 12: Key to scenarios

	Carbon $10 + 4% p.a.	Carbon $20 + 4% p.a.	Carbon $30 + 8% p.a.
Proportional change in peak demand energy			
$12.5k real (indexed) VoLL Earlier geothermal and CCS	P4	P1	P5
$12.5k real (indexed) VoLL Later geothermal and CCS		P2	
$10k nominal VoLL Earlier geothermal and CCS		P3	
Half proportional change in peak demand and energy			
$12.5k real (indexed) VoLL Earlier geothermal and CCS	H4	H1	H5
$12.5k real (indexed) VoLL Later geothermal and CCS		H2	
$10k nominal VoLL Earlier geothermal and CCS		H3	

5.2. SUMMARY OF KEY RESULTS

There are a number of ways the results can be compared. This section provides a high level summary of selected comparisons with references to the detailed case results which are provided in Appendix A.

5.2.1. Effect of VoLL/timing of new technology/demand elasticity

The majority of the studies were undertaken with the market price cap, VoLL, set at $12,500/MWh in real terms (i.e. indexed at CPI) consistent with the Panel's recommended increase and assuming that CPI indexation will be required in future years.

Checks on the sensitivity of the results if the level of VoLL were to be left at its current level of $10,000/MWh nominal (i.e. not indexed) were also undertaken. It is instructive to review the results of this sensitivity before reviewing other results.

The level of VoLL had a significant effect on the outcomes, larger than the effects of the CPRS or MRET or of other factors analysed. The significance of the level of VoLL is consistent with the Panel's previous conclusions that led to its recommendation that VoLL should be increased. It is also useful to reiterate our note that, the absolute levels of unserved energy in the results are subject to the same caveats about assumptions of investor responses to uncertainty and acceptance of long term returns as the basis for decision making, that were expressed our Appendix to the CRR.

The significant issue for this current work is that the relative impact of the level of VoLL is large and underscores the volatility of results to factors that impact marginal returns in the few hours of low reserve each year from the spot market alone. This result also indirectly highlights the importance of energy hedge contracting activity within the market (either directly or indirectly through vertical integration). Within this caveat, the results show that with VoLL at its current un-indexed level of $10,000/MWh, unserved energy is well above the 0.002% reliability standard across the NEM as a whole, but with VoLL indexed from $12,5000/MWh, unserved energy is well within the standard on average across the NEM.

However, there is the potential for marked differences between regions – see discussion in Section 5.2.4

The effect of delayed entry of geothermal and CCS based technology is also shown as it was at first thought this would have a significant bearing on the results prior to 2020 as it entered at such a high rate from when it was assumed to be available. In practice a delay in commercial availability of these new technologies was picked up by other plant and had a small effect. However, again it needs to be emphasised that the "decision" for the replacement plant to enter was made by the model with perfect foresight of future conditions and thus shows the potential for entry to fill the gap left by later entry of the new technology.

The following summarises our results using the central carbon case of $20/t for the different levels of demand elasticity, level of VoLL and date of entry of new technology. We will draw on these summaries in later discussion.

Figure 4 and Figure 5 show the results where demand elasticity was assumed to affect the peak demand in the same proportion as the annual energy (the "P" series scenarios).[15]

- Scenario **P1** ($**12,5000**/MWh VoLL, entry of geothermal in **2015,** entry of CCS in **2020** and proportional reductions in peak and energy)
- Scenario **P2** ($**12,500**/MWh VoLL, entry of geothermal in **2020,** entry of CCS in **2025** and proportional reductions in peak and energy)
- Scenario **P3** ($**10,0000**/MWh VoLL, entry of geothermal in **2015,** entry of CCS in **2020** and proportional reductions in peak and energy)

15 For example: if annual energy was reduced by 8% the peak demand would be reduced by 8%.

And in Figure 6 and Figure 7 for the same situation but with the demand elasticity of peak demand set to half the effect on energy (the "H" series scenarios)[16] shown in Figure 6 and Figure 7:

- Scenario **H1** ($**12,5000**/MWh VoLL, entry of geothermal in **2015,** entry of CCS in **2020** and proportional reductions in peak and energy)
- Scenario **H2** ($**12,500**/MWh VoLL, entry of geothermal in **2020,** entry of CCS in **2025** and proportional reductions in peak and energy)
- Scenario **H3** ($**10,0000**/MWh VoLL, entry of geothermal in **2015,** entry of CCS in **2020** and proportional reductions in peak and energy)

The results show the high impact of the level of VoLL, but relatively muted effects of the level of demand sensitivity and timing of new technology. Although peak demand is different there are corresponding differences in the level of capacity that enters the mix in each case. In the particular combination of costs and timing in the scenarios, there is a small effect of delayed entry of new technology but still well within the reliability standard. When the new technologies are delayed reliability is marginally better at first but worse later.

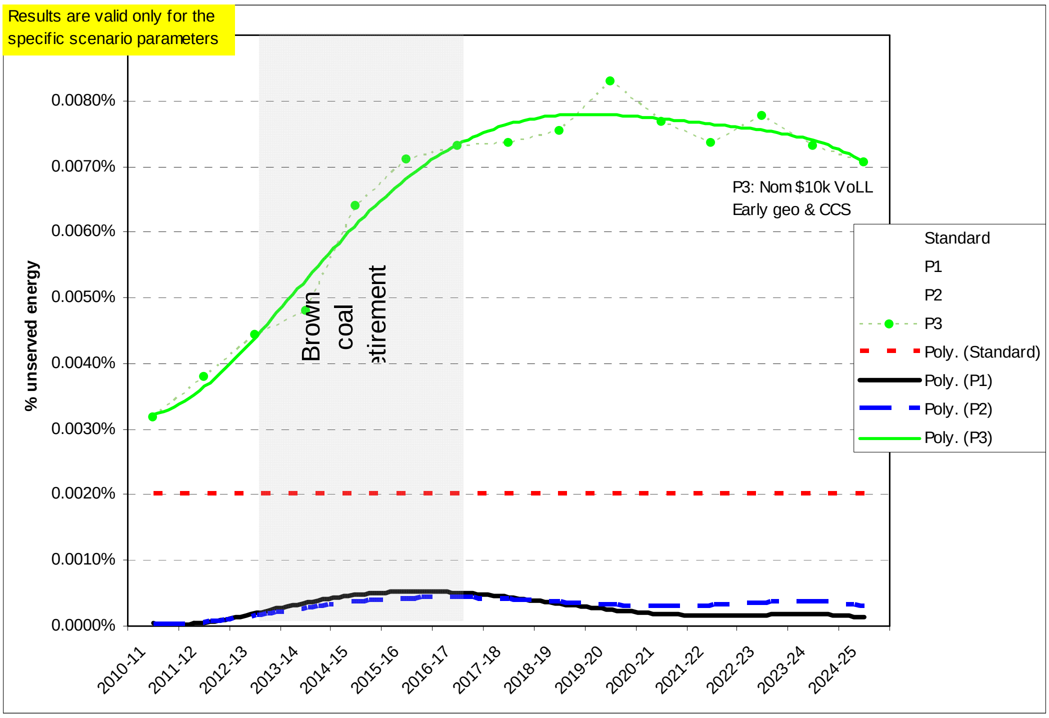
This small difference can be explained by the complex interactions between the rapidly changing technologies as the amount of gas plant that enters in the few years ahead of the first availability of a new technology. In the case with earlier entry of geothermal, entry of gas plant is constrained to the amount that can profitably enter after retirement of coal plant, but before geothermal. Reliability improves further when CCS technology becomes available in 2020. But, when geothermal is made available from 2020 and CCS from 2025, more gas plant enters before 2020 resulting in initially (marginally) better reliability, but new entry is then constrained ahead of the availability firstly of geothermal plants in 2020 and then CCS in 2025. These are very small differences, but nevertheless serve to highlight the complex interactions at play.

Presentation format: Detailed results are shown in Appendix A. In the sections immediately below it is important to note the scale of Unserved Energy plots. To highlight where the scale data plotted is of the order of the current standard for reliability (0.002%) the plots have a white background. Many of the plots show much smaller levels of unserved energy, including enlargements of portions of companion plots that generally immediately precede them, and these plots have a grey shaded border to the charts.

16 For example if annual energy was reduced by 8% the peak demand would be reduced by 4%.

Figure 4: NEM wide USE trends – Proportional sensitivity peak; carbon $20+4%pa [comparing VoLL and new entrant timing]

(Panel A)



(Panel B – same information as Panel A, but different scale)

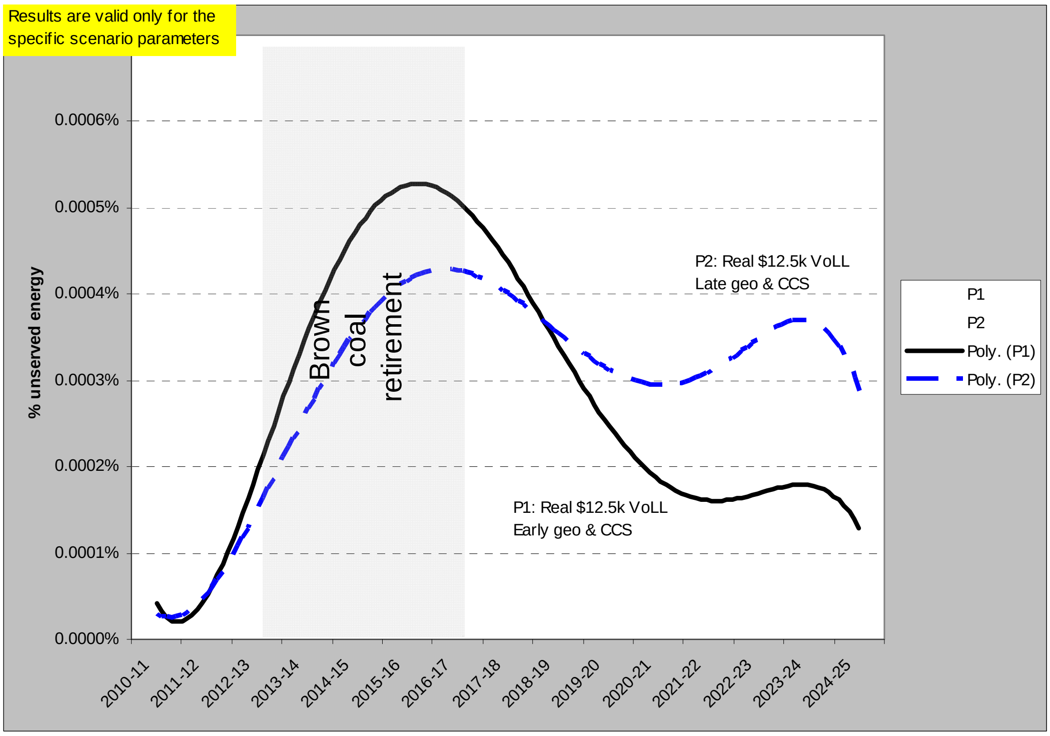


Figure 5: NEM prices – Proportional sensitivity peak; carbon $20+4%pa. Comparing VoLL and new entrant timing

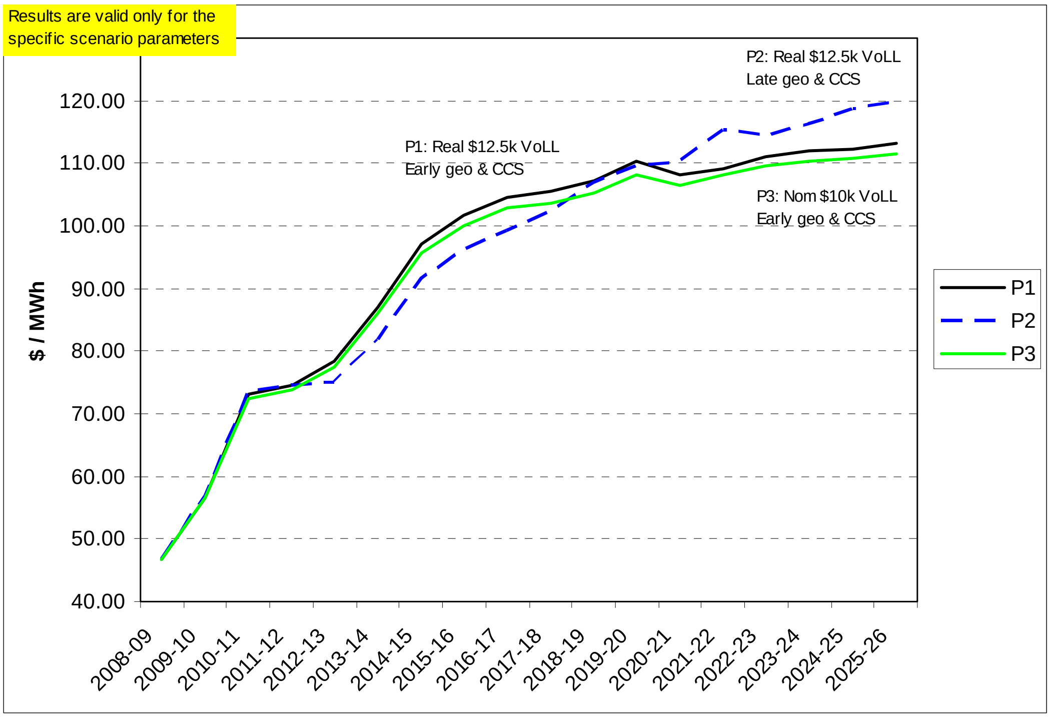
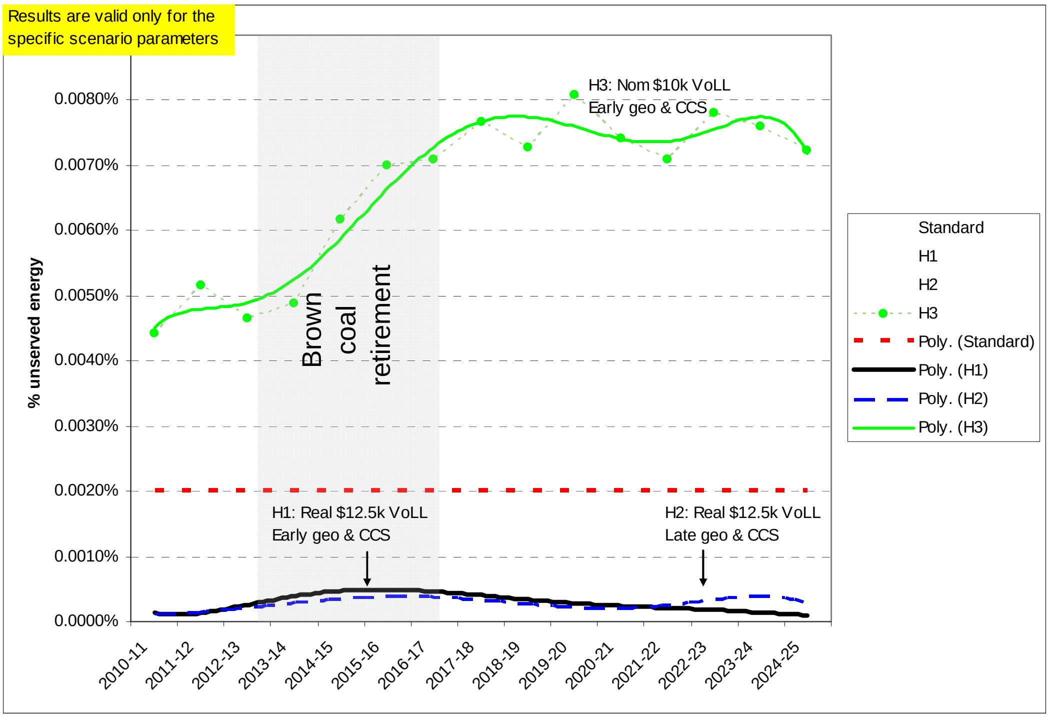


Figure 6: NEW wide USE trends – Half proportional sensitivity peak; carbon $20+4%pa. Comparing VoLL and new entrant timing

(Panel A)



(Panel B – same information as Panel A, but different scale)

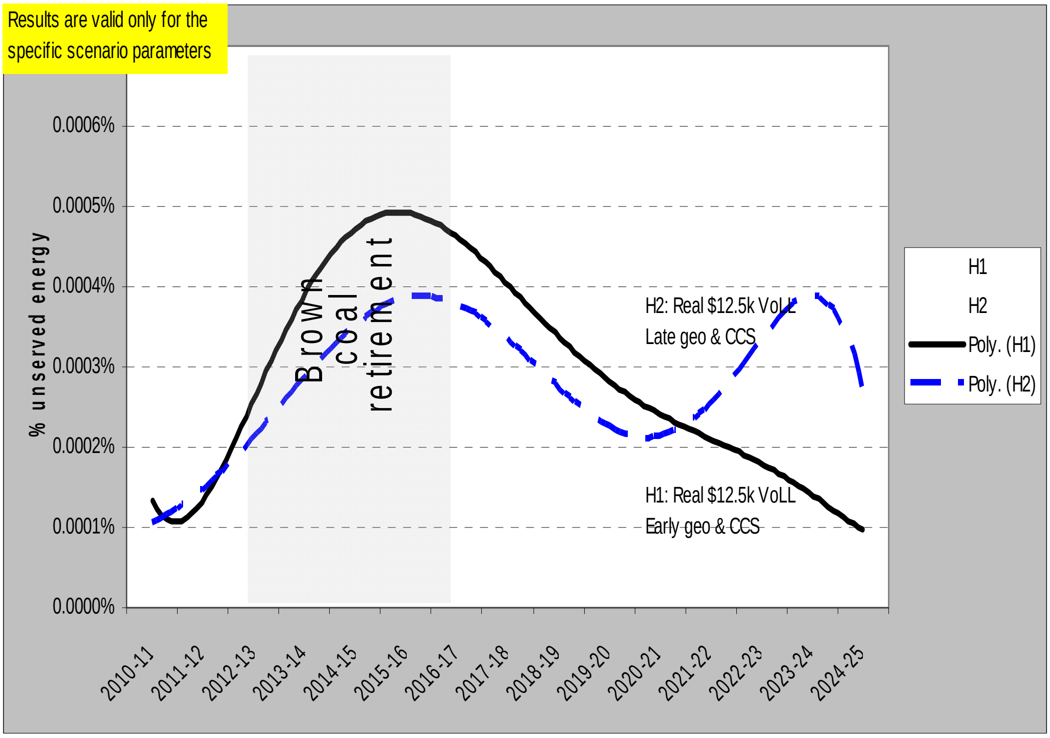
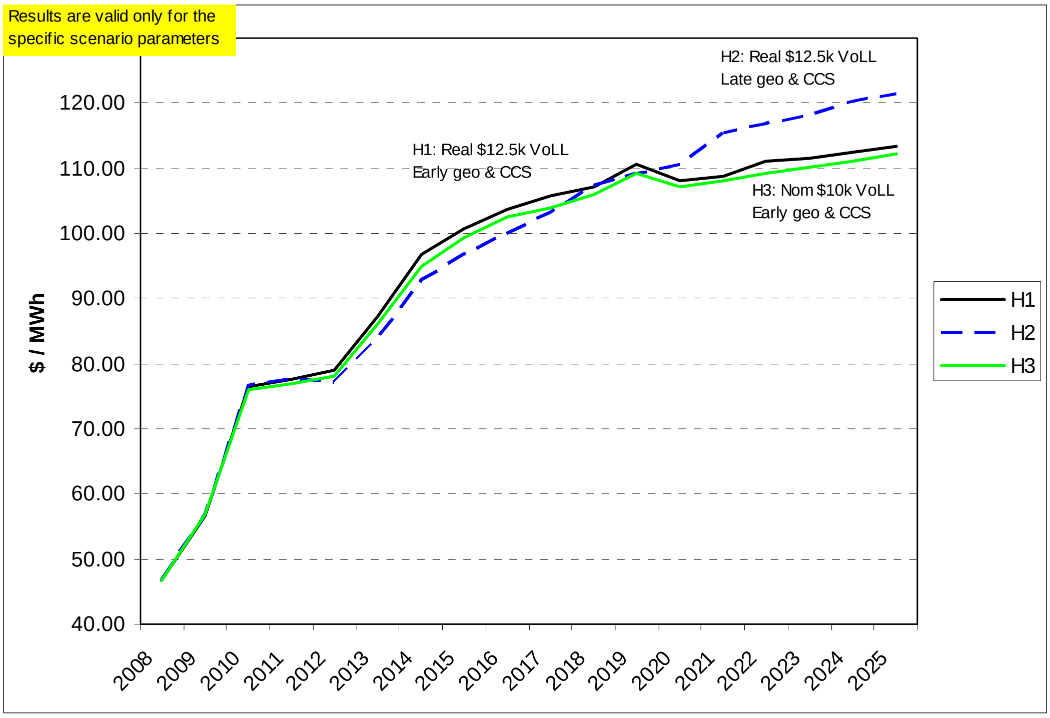


Figure 7: NEM prices – Half proportional sensitivity peak; carbon $20+4%pa. Comparing VoLL and new entrant timing



5.2.2. Sensitivity to carbon price

A key aspect of the work was to investigate the effect of different levels of carbon price on reliability. A majority of results show USE within the reliability standard – we again emphasise that this is on the basis that investors will make investment decisions based on long term spot market revenue forecasts based on known carbon prices and technology costs and timing similar to the conditions we studied.

As noted in section 5.2.2 we used a simple representation of carbon price to minimise the impact of assumptions about banking and other details of possible trading arrangements. In practice, the results showed that unavoidable modelling inputs were a major factor in the results and interpretation of the results would have been even further complicated if we had assumed elements of the CPRS that have not yet been announced.

The results are summarised Figure 8 through Figure 11 and show that USE was generally low and well within the reliability standard as carbon price was increased, particularly on the $30/t trajectory. However, the market prices and technology mix differed substantially. The technology mix for each case is plotted in the relevant sections of Appendix A. Market price rises as carbon price is increased, exceeding $100/MWh for most of the study period in the $30/t trajectory. Coal plant utilisation fell as carbon price increased and retirement of existing brown coal plant was assumed. The retired capacity was replaced, with a combination of combined cycle and open cycle gas plant initially, plus geothermal and CCS based plant from the time they were made available to the analysis.

Only slightly more wind plant was built in the high carbon cases as the majority of the available wind resources was needed to meet the MRET target, even in the low carbon prices cases, and there was little scope to add more – highlighting another input driven constraint on the results.

Figure 8: USE trends – Proportional sensitivity peak; real $12.5k VoLL; earlier technology availability [comparing carbon price trajectories]

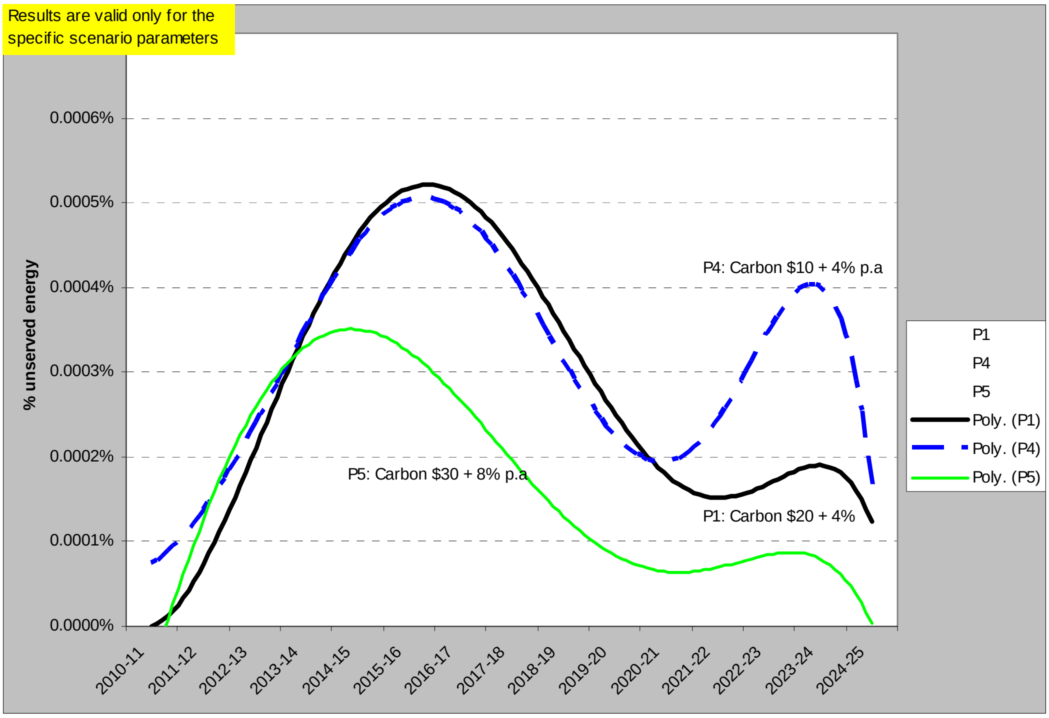


Figure 9: NEM prices – Proportional sensitivity peak; real $12.5k VoLL; earlier technology availability [comparing carbon price trajectories]

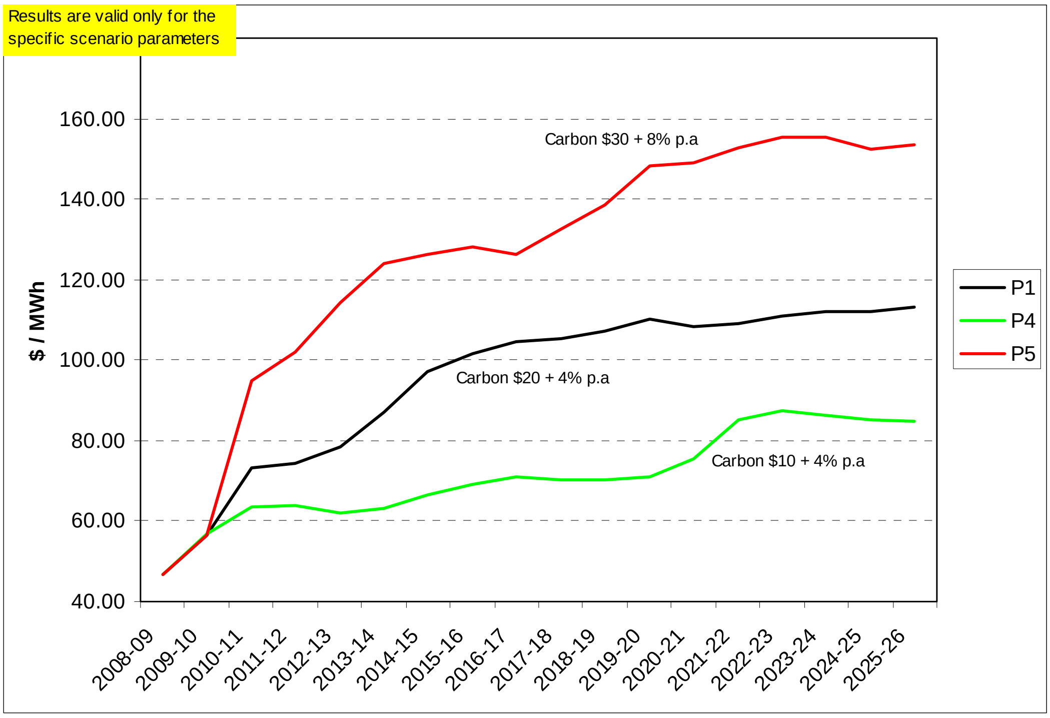


Figure 10: USE trends – Half proportional sensitivity peak; real $12.5k VoLL; earlier technology availability [comparing carbon price trajectories]

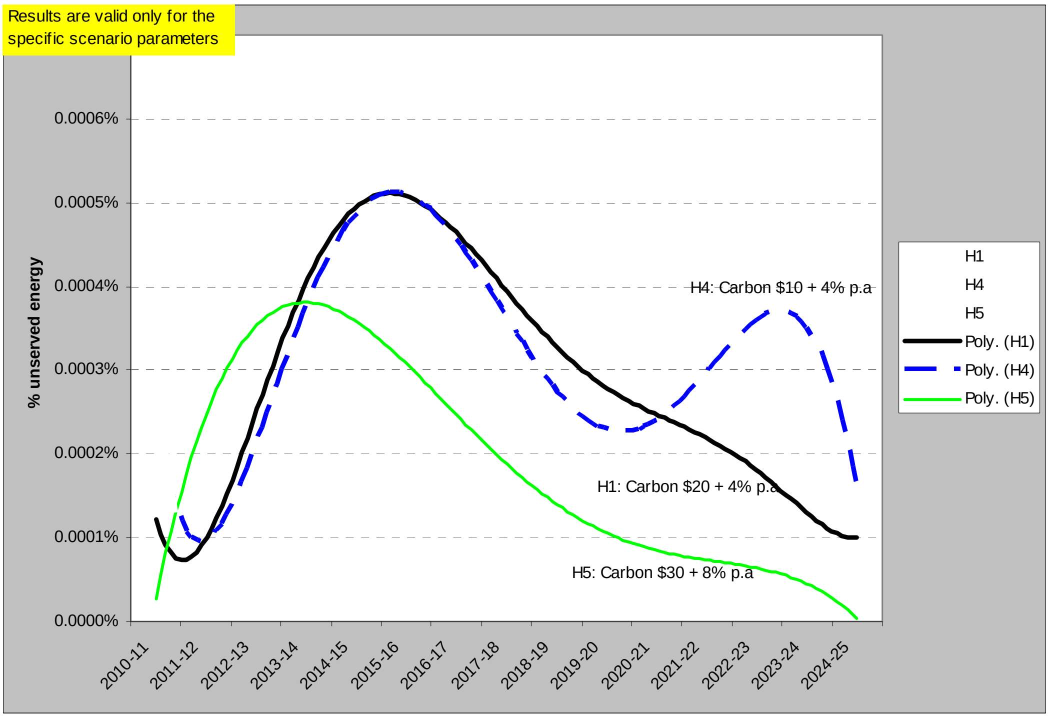
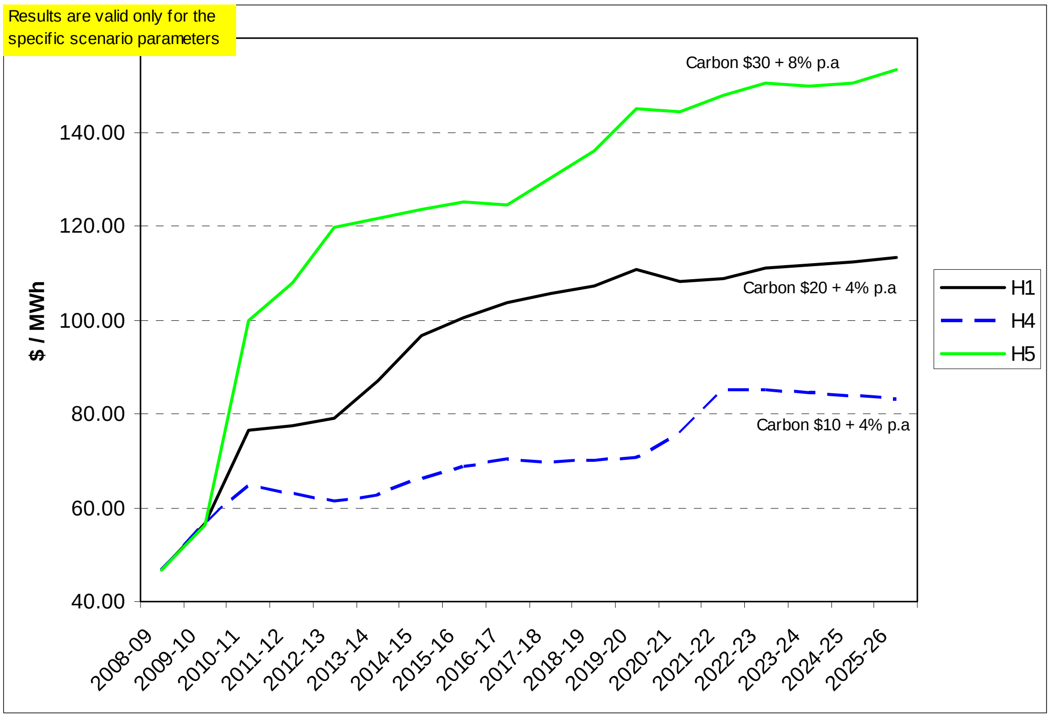


Figure 11: NEM prices – Half proportional sensitivity peak; real $12.5k VoLL; early technology availability [comparing carbon price trajectories]



5.2.3. Sensitivity to elasticity of peak demand

This section elaborates on the effect of elasticity of demand using the same base results presented in section 5.2.1 and shows it had little effect on reliability as the lower demand in the fully proportional case relative to the Half proportional case led to less peaking plant. Figure 12 shows this effect for the central $20/t case and it is seen again in Figure 14 which overlays the results for delayed entry of new technologies. Differences between the cases are seen across time due to different horizons for recovery of investment capital but remain well below the reliability standard.

Figure 12: USE trends – Carbon $20+4%pa; real $12.5k VoLL; earlier technology availability

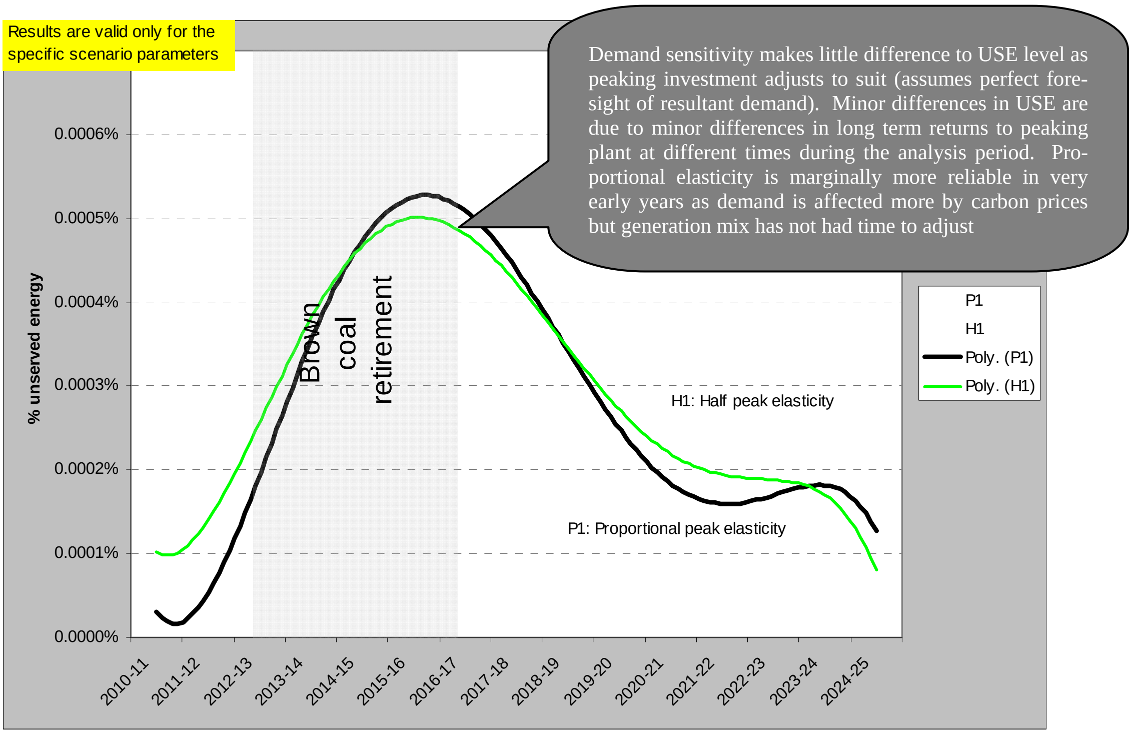
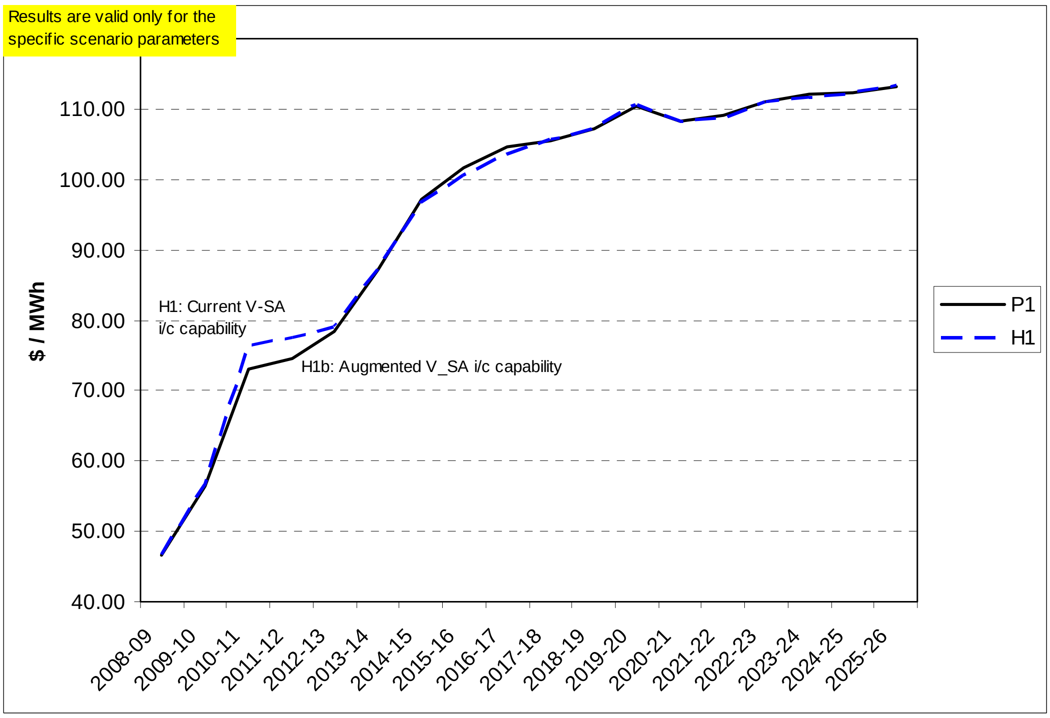


Figure 13: NEM prices – Carbon $20+4%pa; real $12.5k VoLL; earlier technology availability



Comparison of proportional and Half proportional sensitivity of peak demand

Figure 14: USE trends – Comparison of proportional and Half proportional sensitivity of peak demand – Indexed $12,500/MWh VoLL cases

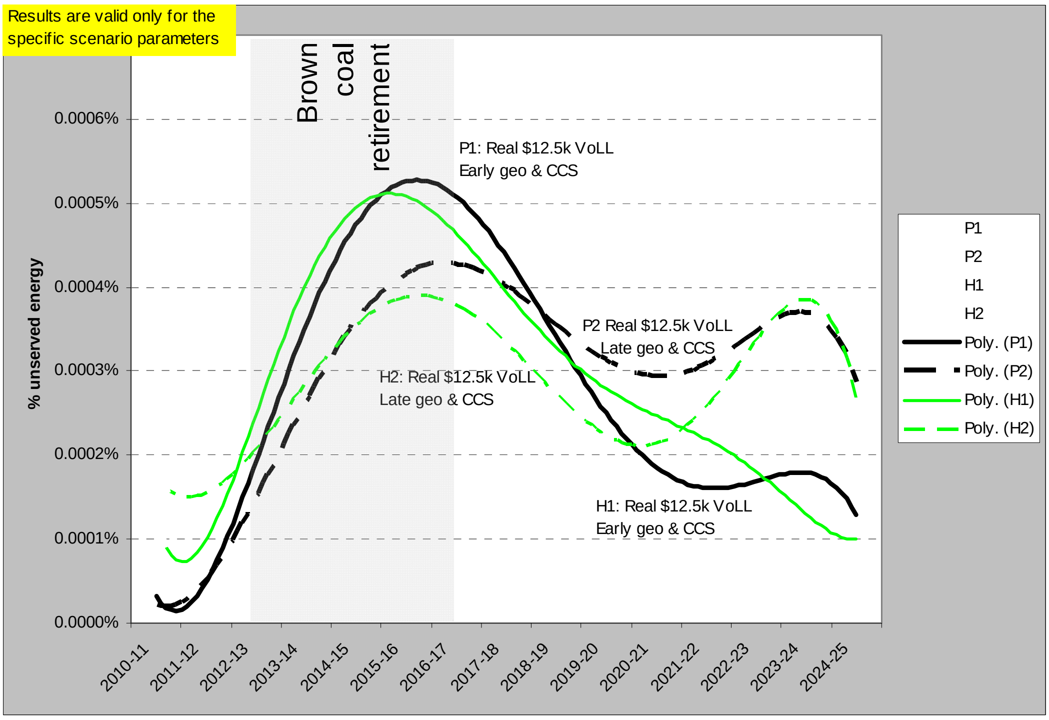
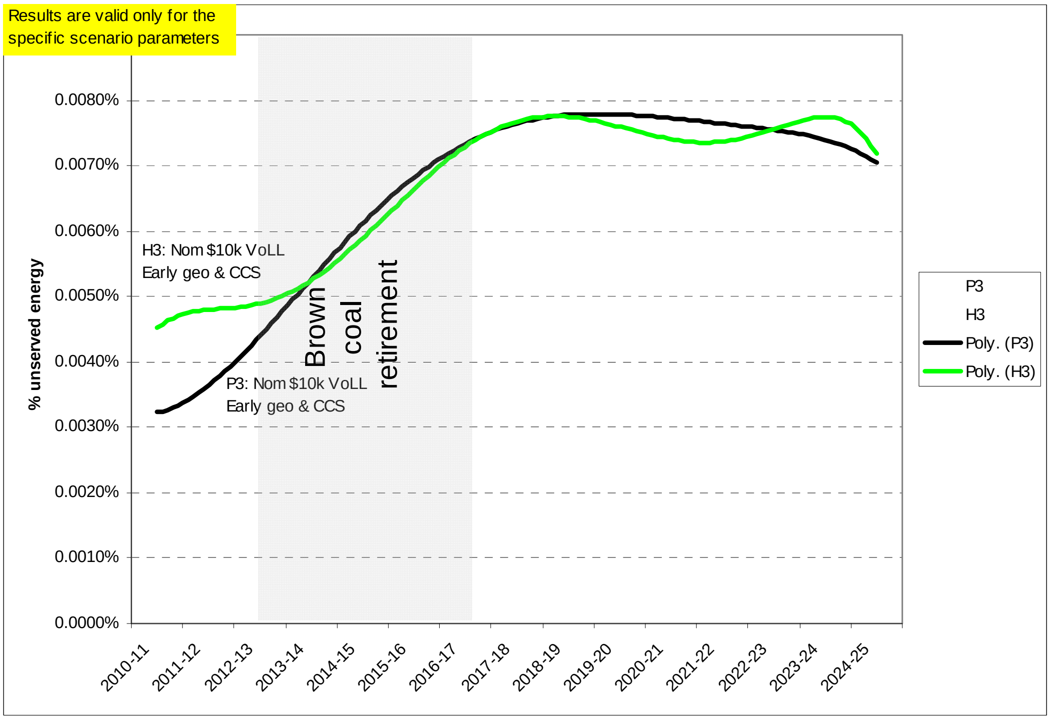


Figure 15: USE trends – Comparison of proportional and Half proportional sensitivity of peak demand – Flat $10,0000/MWh VoLL case



5.2.4. Regional Comparisons

In a number of cases there were significant differences between the regional levels of unserved energy. Regional results are presented for each case in the relevant parts of Appendix A. Short lived minor differences are to be expected, especially given the different lead times and investment decision making processes for networks and generation (and demand side). However, the energy only market design anticipates that market incentives will lead to rational decisions for new investment that will tend to reduce such differences. This does not mean there will be no regional differences, but that any that do exist will be economically justified.

The relevant point for this work is that the transition period as the CPRS and MRET arrangements are being phased-in will be a period of major change – for example a technology that is not economic currently may be well “in the money” within a just a few years. Investments will be made on the basis of expectations of long term revenue sufficiency. A number of cases highlighted the potential for short term gaps in available capacity in some regions as one group of plant retires due to low utilisation, but prior to the time when new and more cost effective technologies expected in service a short time later are available. The modelling made purely rational decisions that unless there was sufficient revenue available over a number of years, investments would not occur. In some cases this meant that plant that did enter were very profitable for the first few years.

This led to a number of cases with transitionary spikes in unserved energy in different regions: primarily in South Australia but in preliminary results that we subsequently did not pursue we also found spikes in Victoria under slightly different conditions. Similar situations could occur in any region given different combinations of input assumptions. These spikes may be at some point become unacceptable: especially as they may be readily avoidable.

In principle we could have re-run the cases to remove the spikes by presuming the operation of an adjustment mechanism to retain retiring plant in service or augment relevant interconnectors. However, this would reduce the ability to report on the potential risk that arises from such a rapid transition within a market that normally evolves much slower. It would also have required us to presume the design of a mechanism that government is yet to announce. For the purposes of demonstrating the ability to avoid the spikes in unserved energy that were seen in South Australia, we have shown the effect of augmenting the interconnector to Victoria, and the resultant dramatic improvement in reliability this had. Augmenting the interconnector is just one of the responses that can be made: if in due course it appears that an unacceptable spike will actually eventuate. Accordingly the results shown here should not be taken as forecasts of future outcomes – rather they are advance notice of a risk that can be prepared for.

Figure 16 and Figure 17 respectively show the unserved energy in the pre and post SA-Victoria interconnector augmentation in South Australia that emerged in one of the central cases. South Australian reliability was well below that of other regions at the same time in Figure 16 and this prompted us to investigate the reasons and the potential mitigants.

The key point to note is that the introduction of the CPRS and MRET creates the conditions where there is a risk of unacceptable transition effects across all regions for a number of years. Accordingly the ability to monitor if, where and when a risk is materialising and the flexibility to respond as appropriate should be considered.

Figure 16 Regional USE trends – Carbon $20+4%pa; real $12.5k VoLL; earlier technology availability (current SA- Victoria interconnector capability)

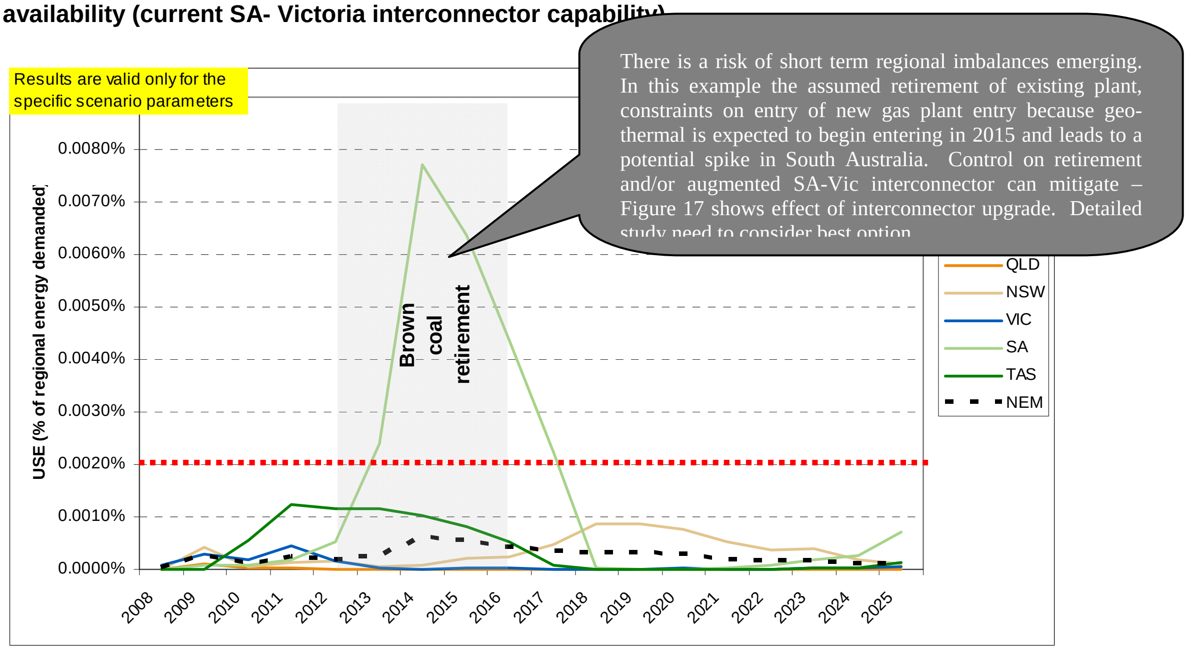
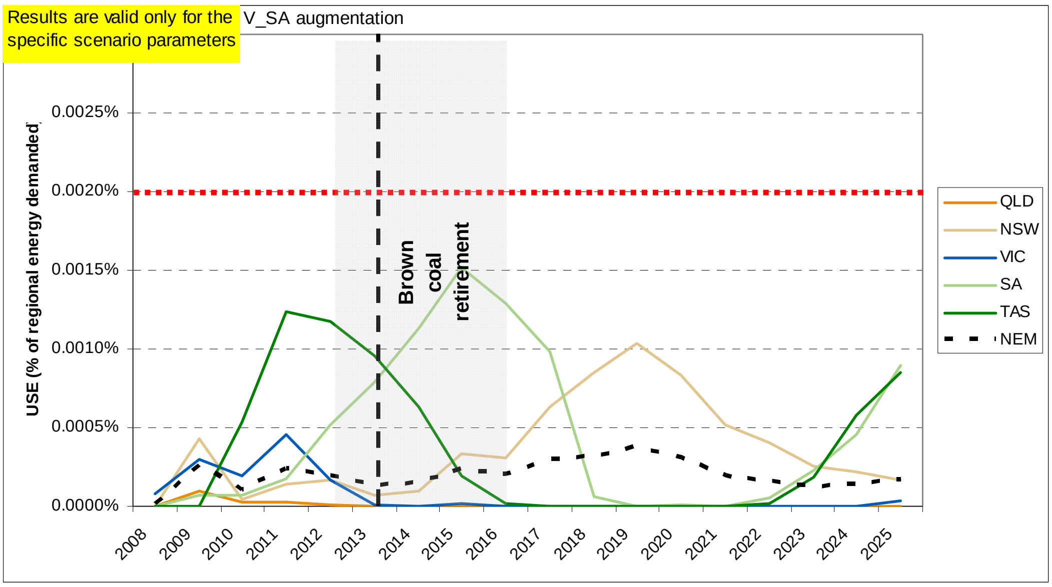


Figure 17 Regional USE trends – Carbon $20+4%pa; real $12.5k VoLL; earlier technology availability (augmented SA-Victoria interconnector capability)



5.3. TECHNOLOGY MIX

Many other studies[17] have developed forecasts of changes in the generation mix as a carbon price and MRET are introduced. We found the technology mix was very sensitive to input assumptions about timing of availability of new technologies and limits on annual and total capacity of the new technologies. Details for each of the cases are presented in the relevant sections of Appendix A. For example, our technology slate allows for ultra-supercritical coal with CCS to become available for service from 2020. On the data used for this study[18] the cost of this technology is well under the market price that prevails at the time the technology available, even with a moderate carbon price. As a result it enters up to the build limit we have assumed and dramatically lowers unserved energy. The effect of assumptions of this nature are strategically important for two reasons:

- In the years immediately preceding new technology entry, the model finds that it is more cost effective to not invest and thus to allow unserved energy and price to rise because the model has perfect foresight of future conditions. As a result some plants make windfall gains for a short period; and
- There is no risk factor to account for the technology failing to become available or that CCS will also be technically and commercially successful. As a result there is a risk of unexpected shortfall in capacity and a spike in unserved energy as the technologies that are available rush to fill the gap.

There is considerable uncertainty, however, about the final timing of commercial service for both geothermal and CCS based technologies. Accordingly we have run cases with later entry of geothermal and CCS technology on the $20/t carbon price results. The results showed relatively little effect of timing on outturn reliability because additional gas plant entered the market. Although the differences were minor the results in fact showed the case with delayed entry of these technologies was better than the early entry prior to 2020. This occurs because there is an opportunity for additional peaking gas plant to recover costs when the geothermal plant is delayed. It is important to note that this conclusion that there will be little effect because the market will adapt is based on perfect foresight. There is clearly a risk that the timing will not be known that a particular plant or technology will not be coming into service until it is too late for other plant to (fully) respond. This is another risk that needs to be monitored and responded to.

17 For example for the federal government Green Paper and the Garnaut report.

18 Where practicable, we used the capital cost assumptions underlying the modelling undertaken by the Commonwealth Treasury.

5.3.1. The effect of MRET

All else being equal, MRET suppresses price but leads to an increase in volatility. If the volume of plant introduced under MRET can match both capacity and energy requirements, it follows that reliability can be maintained. However, if plant entering in response to MRET is unable to meet demand, and other plant that rely on market revenue alone is required, then reliability will suffer as the suppressed prices will not provide sufficient return without much higher level of volatility and higher VoLL.

However, if MRET is introduced in conjunction with a carbon price, then gas plant is advantaged. This is because although gas plant is facing a carbon price, market price increases sufficiently to counteract the effect of the suppression of price, with reliability being less affected. In conjunction with scenario assumptions about the level of MRET and operation of jurisdictional schemes including the Queensland gas scheme, the technology mix was often dominated by external non-market factors. As a result it was difficult to assess the affect of MRET alone.

5.4. Discussion

Conceptually, the impact of the proposed CPRS and the MRET can be analysed by the effect on the ability of the market to provide revenue to cover fixed and operating costs of incumbent and new plant. In an energy-only market, operating costs are generally able to be reflected in bid prices and recovered. On the other hand, recovery of fixed costs depends (to varying degrees) on the occurrence of occasional high prices.

Reliability is crucially dependent on investors believing that they will be able to recover fixed costs. The Comprehensive Reliability Review discussed this point in considering the level of VoLL and included an analysis of “missing money” to recover fixed costs due to a low price cap.

A carbon price or a faster rate of increase in gas prices will increase the effective operating cost of plant and thus result in higher average prices. This will occur because plant operators will seek to increase bid prices in line with the increase in fuel costs and, subject to competitive pressures, the increases will be recovered. However, for larger increases where it is (potentially) economic for new higher capital cost new technology plant to be built, unless the duration, frequency and magnitude of price excursions is sufficient, the higher capital cost of new technology plant may not be recovered. As result reliability will be compromised. The modelling has shown that this the situation if the level of VoLL is held at its current level.

All else being equal, the price of carbon at which reliability may be threatened is determined by:

- the relative operating and “stay in business” costs of existing plant; and
- the LRMC of potential new plant.

New plant with higher capital costs will enter economically in preference to additional units of current technologies, provided the higher capital cost can be recovered. Higher capital cost plant may “required” either because existing plant has been displaced in the merit order, to the point where it is no longer viable. Alternatively, that existing technologies are more costly than newer technologies with lower carbon emissions. The carbon price at which this occurs is dependent on the relativity between the stay in business costs[19], operating costs, new entrant capital cost and demand profile. The relevant carbon price can be identified for a particular set of operating costs and demand profiles.

However, the investment environment in the NEM is currently very fluid and there is considerable overlap between different factors and this masks the effect of individual factors. Capital costs are changing rapidly. Fuel costs are also changing, in particular for gas. New technologies are emerging, some in response to current and expected climate change policies. The new technologies have different operating characteristics (especially wind), and key technologies expected to play a large part in the future are not yet commercial, giving rise to uncertainty about technical and commercial viability and timing. With energy prices subject to step change, demand elasticity is likely to increase to levels not previously seen and this adds more uncertainty.

Further, policy jurisdictional initiatives are neither static nor integrated and are operated by different bodies and apply to different parts of the NEM. While some policies may be merged into the CPRS and MRET in the medium term, they currently exert separate influences. As a result, there is considerable uncertainty around the costs and demand profiles on which investment decisions must be made.

The effects of MRET and capital cost are the most difficult to see in the modelling. MRET is “hidden” because much of the effect appears in the market as a reduction in scheduled demand requirements due to the presence of unscheduled (wind) generation – to the extent that NEMMCO’s energy forecasts show an initial fall in scheduled energy requirements because so much will be produced from wind generation. The effect of different levels of capital cost has also been difficult to see. There are minor changes in reliability evident from the results that are consistent with what would be expected from higher capex but the results are overshadowed by other factors including the availability of new technologies.

Our work has assessed the effects of a number of these factors. However, we caution readers that while we have developed quantitative measures for the scenarios, they represent only a small sample of the possible combinations. We have confirmed that there are factors with both positive and negative impacts on reliability. The net effect is due to the combination of factors and, as each factor can shift in time and relative cost, the net effect may be positive or negative at different times.

19 Which may be reflected in a fixed operating and maintenance cost.

The high carbon price scenarios, where ultra-supercritical coal with CCS becomes available from 2020, illustrate the interaction of the factors. On the costs assumed for this plant it has a long run marginal cost (LRMC) well under the market price by 2020. Likewise, geothermal technology (with LRMC around $90 / MWh) is profitable without having to rely on income from renewable energy certificates. As a result, geothermal and CCS technologies enter the model at a rate up to the annual build limits we have imposed. Unserved energy rises in the years preceding 2020 but then falls sharply as the newly available technology is built to the limit.

In addition to the effects we have modelled in this work, it is important to also consider that a linear optimisation over the investment horizon will assess the expected value of revenue but, in the form assessed here, does not account for uncertainty of revenue. At higher prices there is potentially greater value at risk as a result of plant outages. Also important is the range of factors at play that can lead to very significant changes in timing and levels of revenue. In principle, uncertainty can be accounted for by different discount rates in the assessments but, where the uncertainty relates to the timing of a new technology, there is a an element of judgement to assign appropriate values. Decision making under uncertainty is a complex area and techniques exist to manage it, although in current circumstances the range of factors and materiality of the overlapping effects means considerable uncertainty is unavoidable.

Is the current boundary between market incentive and central management viable?

While satisfactory operation of the reliability mechanisms are necessary element of ensuring continuity of supply to customers,[20] the introduction of a CPRS and RET scheme can also have significant effects on shorter term operations that also impact continuity of supply. In this respect it is worth noting that events that have led to major interruptions to supply in the power systems of developed countries are dominated by operational events.[21] The characteristics of some of the technologies that are likely to respond to the CPRS and RET schemes (and in the case of wind technology already is responding) are different to the characteristics of existing technologies and on which power systems have been built. In particular, intermittency and variability of operation of wind is fundamentally different. At low levels of penetration variability of wind plant is similar to variability of customer load and does not create an operational concern. At the levels of wind plant now being seen, variability of wind can create situations that the underlying market design presumes will be covered by commercial responses from traditional plant.

20 Within relevant performance standards – e.g. the NEM standard for no more than 0.002% of potential customer load to not be supplied.

21 For example, interruptions across Europe due to network overloading following routine outage of a transmission across a river for ship access in late-2003 and the major shutdown in the north east of the US in August 2003.

In particular, the NEM design presumes that commercial incentives will not be able to deliver coordinated responses from generation and controllable loads necessary to manage power system security within 5-minute dispatch periods and accordingly includes a range of ancillary services and mandatory performance standards. However, the design does presume commercial responses will be adequate beyond the 5-minute boundary – but also includes safety nets in the form of powers of direction and the RERT. It is presumed that market participants will be able to predict major trends in customer load within seasons and within a day and that generating plant will present to the market in order to meet this level of volatility. In the case of wind – and, in the future, potentially other intermittent technologies such as wave energy – the current state of the art for predicting wind variability is unable to match the level of variability (which can run to more than a 1000MW variation in availability in a matter of hours). Forecasting capability can predict short term (minute-to-minute) variability and long term (annual) variability within reasonable levels, but there is a gap in the hour-to-daily forecasting capability. This variability requires what would traditionally have been called standby plant to be ready to respond to the cycles of wind availability.

In principle, the mechanics of the current design of the NEM could accommodate the large amounts of standby plant that will be required if there was sufficient commercial incentive in contracts to underwrite the investment in such plant. However two factors work against this occurring. The first is that wind generating plant is supported by mandatory obligations through the RET scheme and thus has less (or no) incentive to find its own standby arrangements. The second is that security or reliability of supply is a central obligation (on NEMMCO) and retailers cannot rationally incur the additional costs that would be necessary to support standby plant. The Reliability Panel considered an option for centrally administered 30-minute reserve ancillary service during the CRR as a means to increase revenue certainty to reserve plant, but found it had limited economic benefit in the circumstances and was unable to find a practical means to implement it within the current NEM framework. Accordingly the option was not pursued.

Our analysis did not quantitatively examine these questions as the current NEM reliability mechanisms are premised on participants responding to market incentives to provide what we are labelling as standby reserve. However, we consider that key presumptions underpinning the current design may no longer be valid for maintenance of continuity of supply in the shorter term. Accordingly an area for further examination is whether the framework may need to be re-assessed. In particular to consider the boundary between market incentive and central management that is currently set at 5 minutes or accountability for security of supply shifted to drive different contracting outcomes that could support “standby reserve”.

APPENDIX A: TECHNOLOGY MIX, REGIONAL USE & REGIONAL PRICES

TABLE OF FIGURES FOR APPENDIX A

A.1 HALF PEAK ELASTICITY SCENARIOS

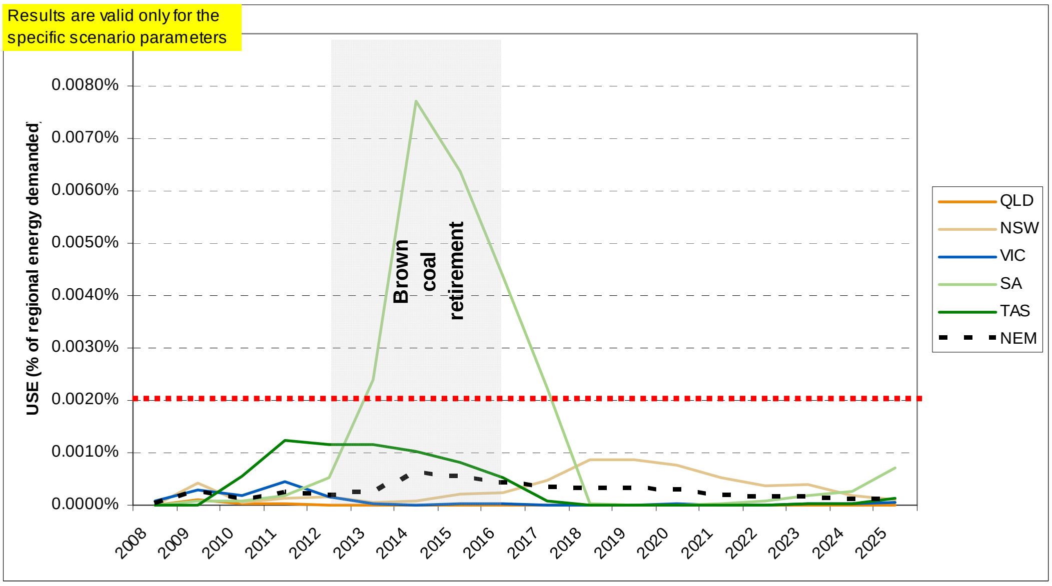
The "H" series of scenarios is based on demand elasticity at peak being half the ratio of annual energy, for example if annual energy demand is reduced by 8% the peak demand will be reduced by 4%. The scenarios within the series consider different levels of carbon price, VoLL and timing of availability of new technologies.

Modelling results are shown for:

- Unserved energy expressed as the percentage of national/regional demand that would not be supplied and where practicable on the scale of the plot the reliability standard of 0.002% is also shown;
- Technology mix by installed capacity of each technology (NEM wide);
- Technology mix by energy shares for each technology (NEM wide);
- Load weighted spot price – average; and
- Load weighted spot price - "super peak" (i.e. the top 50 hours of the year).

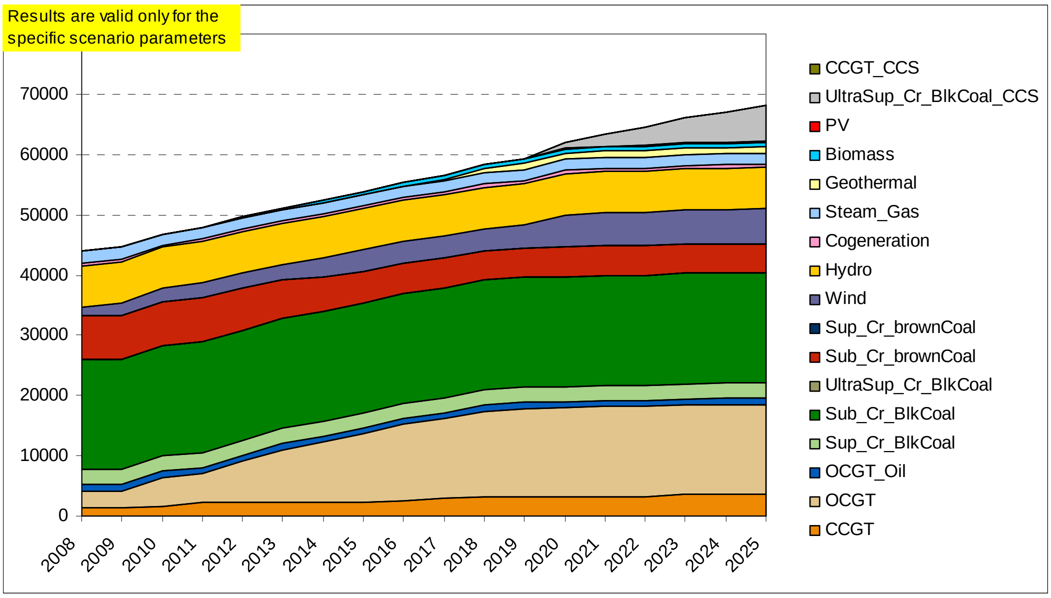
A.1.1 H1: Carbon price $20/t indexed at 4%p.a, VoLL: $12,500/MWh indexed, Geothermal available from 2015, CCS available from 2020.

Figure 18: Regional unserved energy – scenario H1



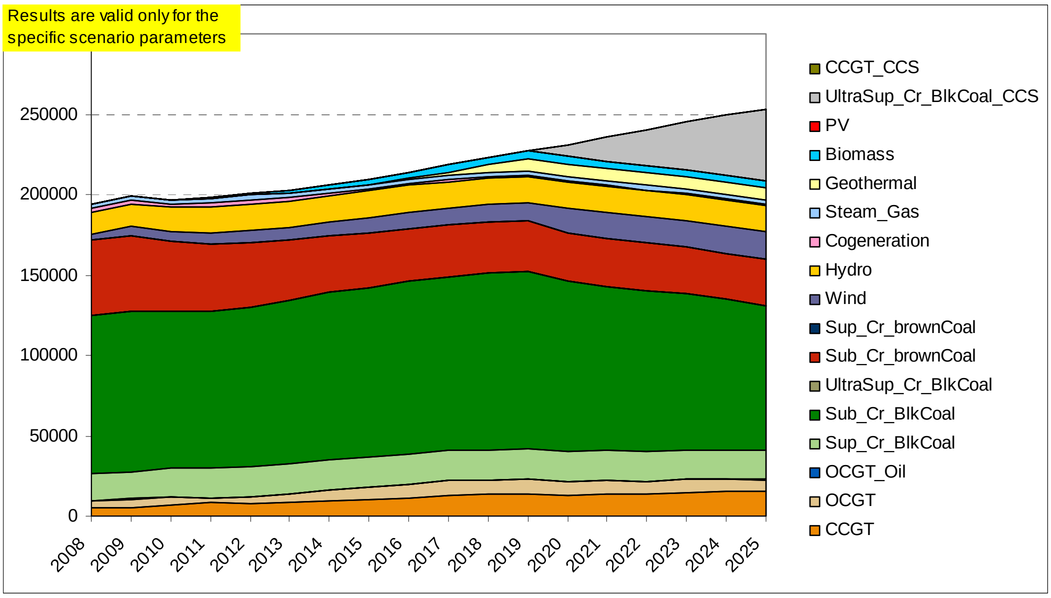
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 19: Technology mix by MW of capacity – scenario H1

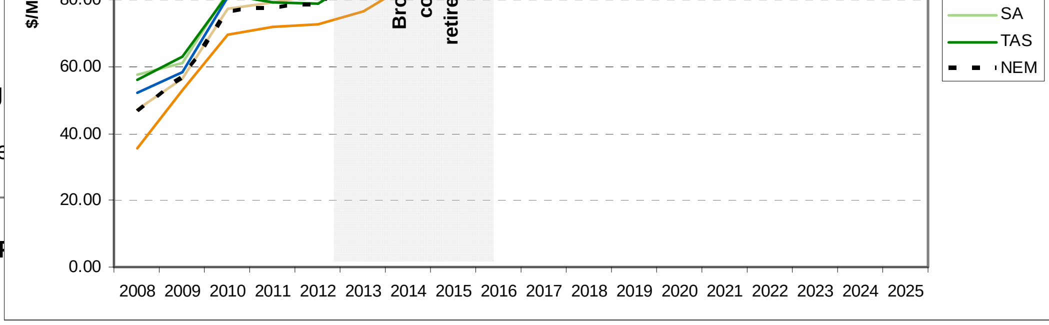


QNI augmentation 2016; Geothermal available 2015; CCS available 2020

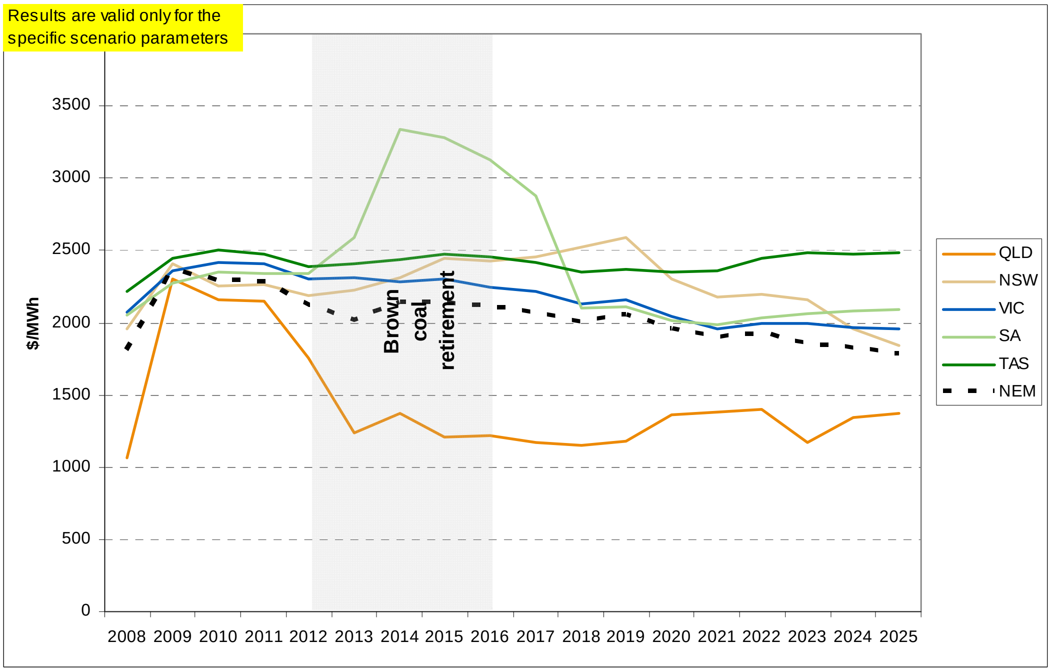
Figure 20: Technology mix by GWh of generation – scenario H1



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

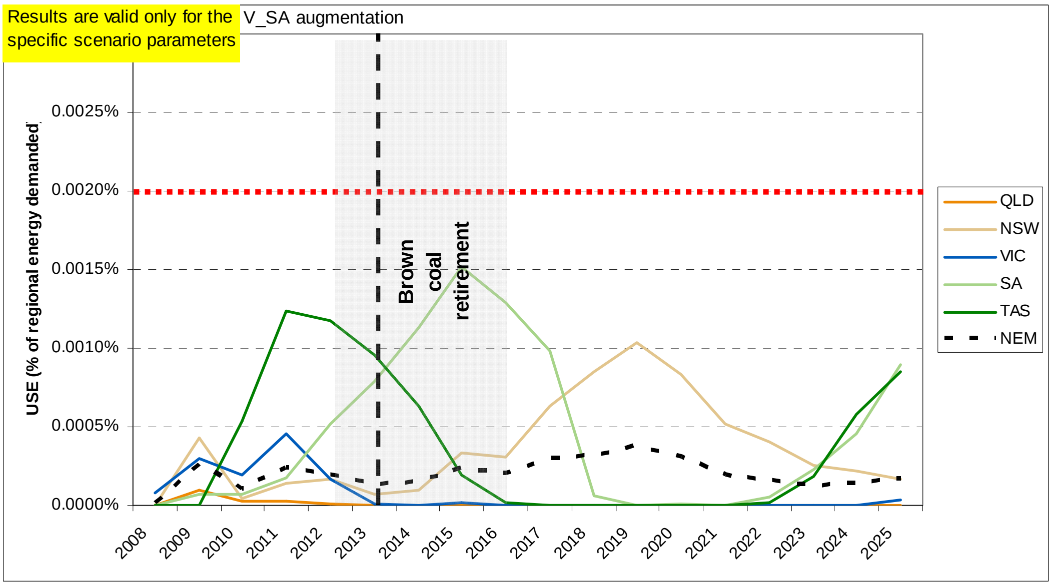


QNI augmentation 2016; Geothermal available 2015; CCS available 2020Figure 22: Regional average super peak price – scenario H1



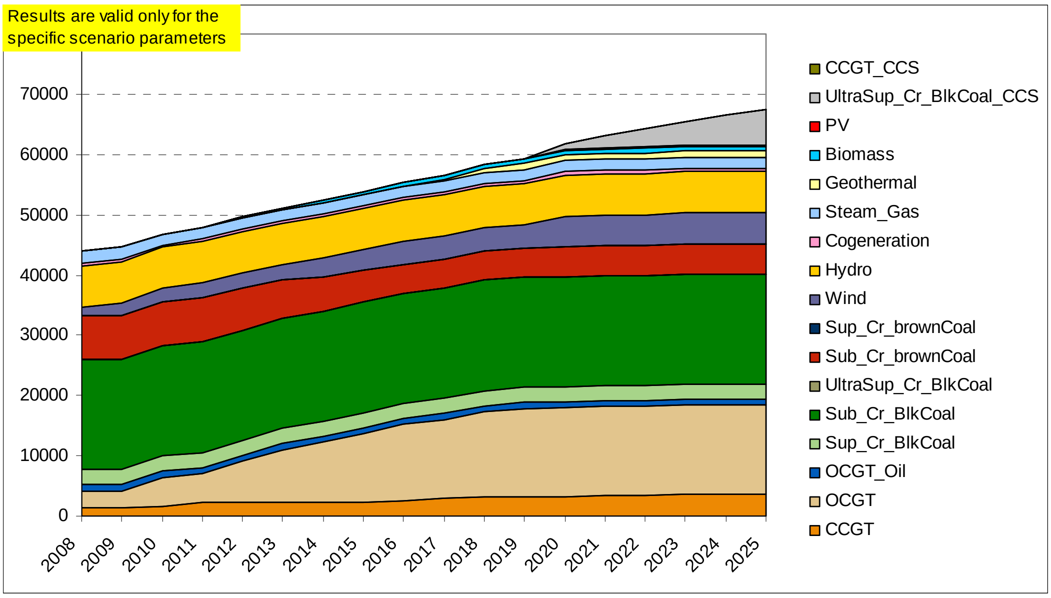
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 23: Regional unserved energy – scenario H1b



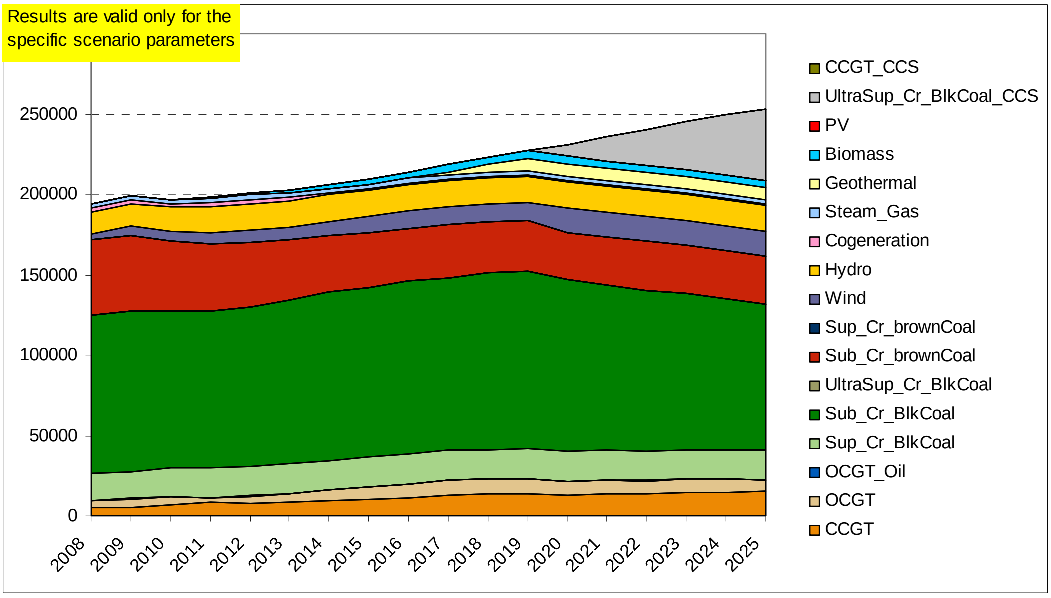
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 24: Technology mix by MW of capacity – scenario H1b



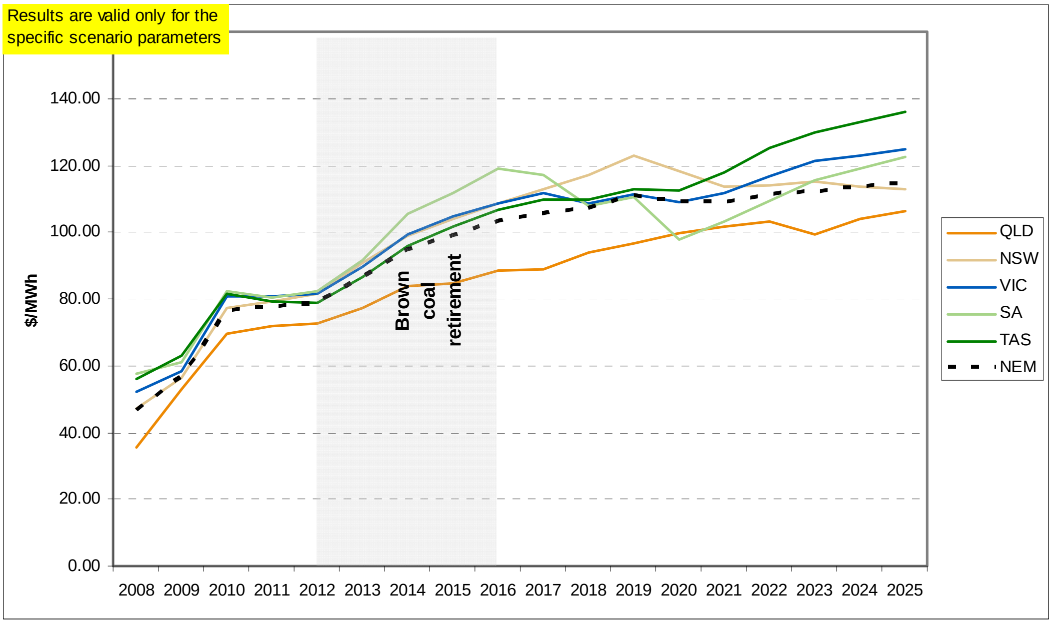
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 25: Technology mix by GWh of generation – scenario H1b



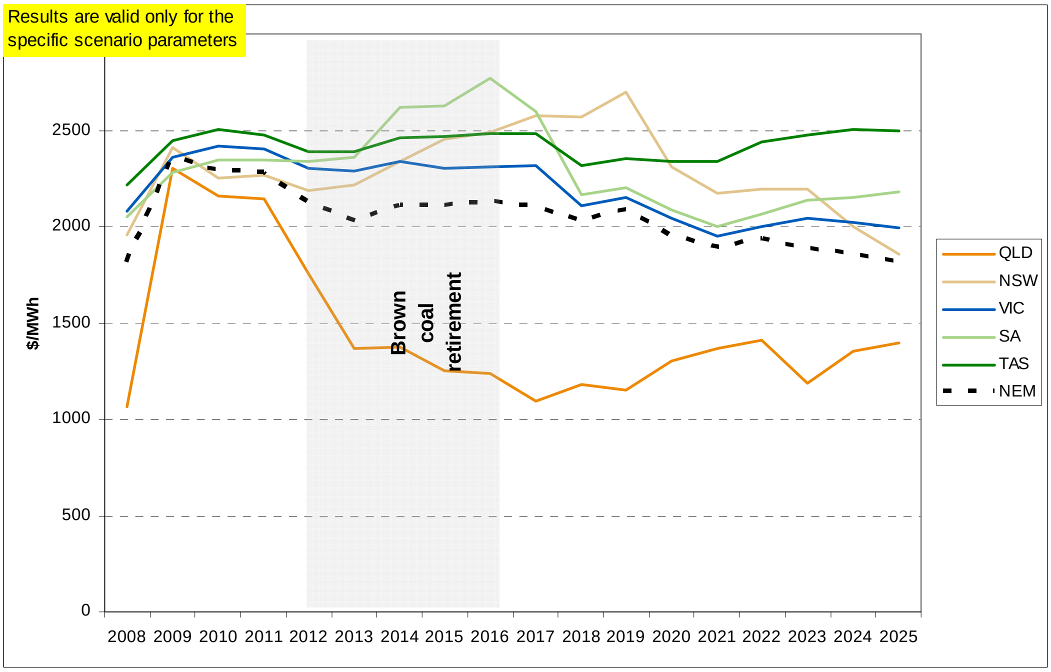
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 26: Regional load weighted average spot price – scenario H1b



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

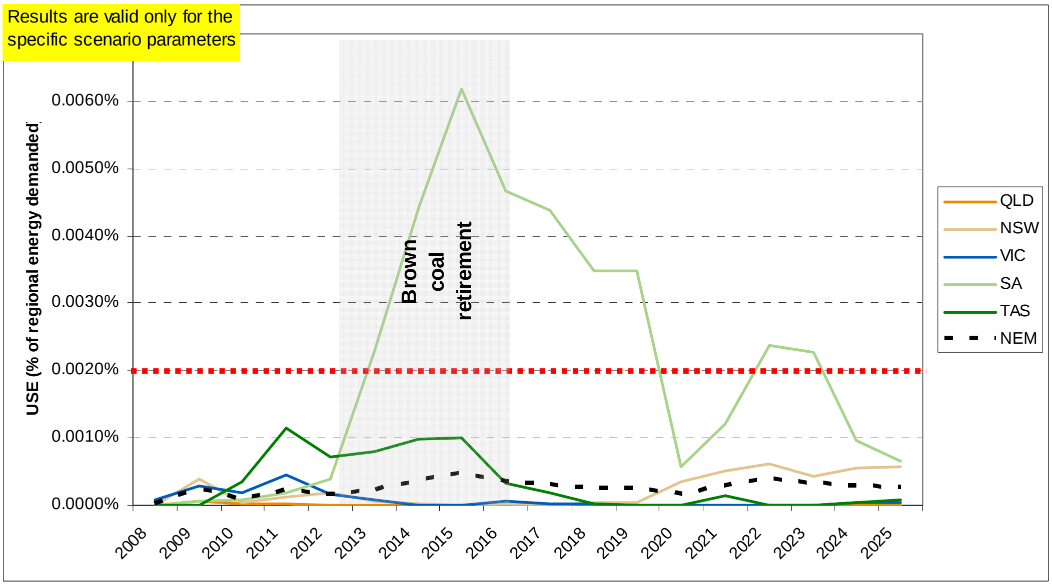
Figure 27: Regional average super peak price – scenario H1b



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

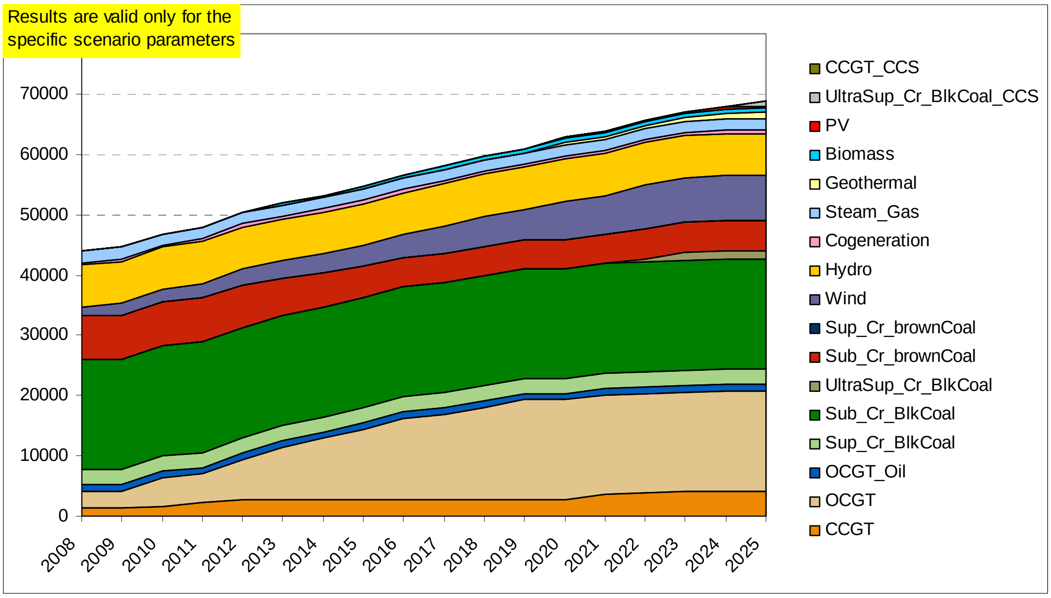
A.1.2 H2: Carbon price $20/t indexed at 4%p.a, VoLL: $12,500/MWh indexed, Geothermal available from 2020, CCS available from 2025.

Figure 28: Regional unserved energy – scenario H2



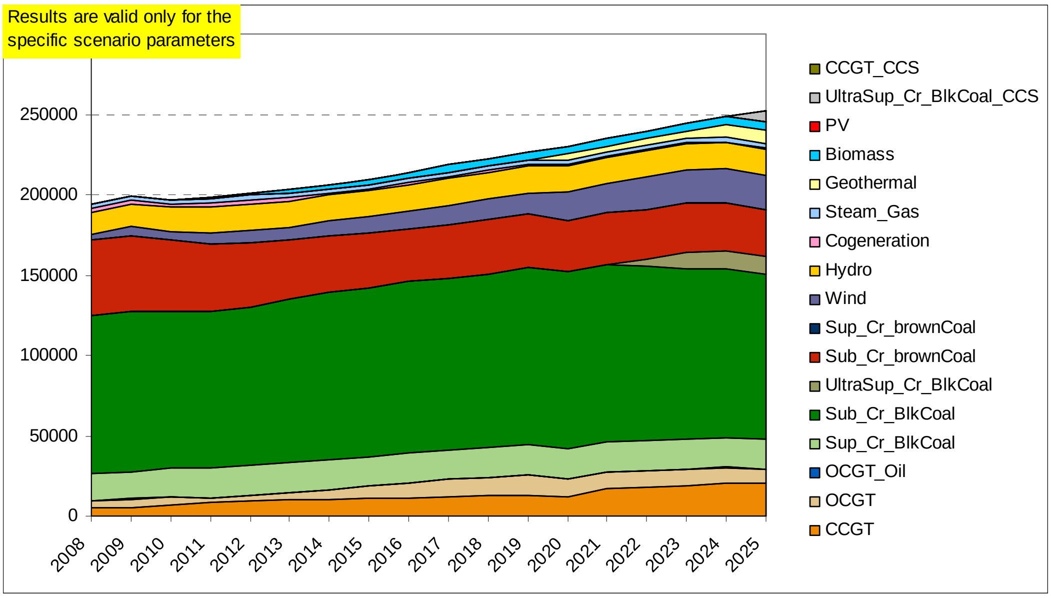
QNI augmentation 2016; Geothermal available 2020; CCS available 2025

Figure 29: Technology mix by MW of capacity – scenario H2



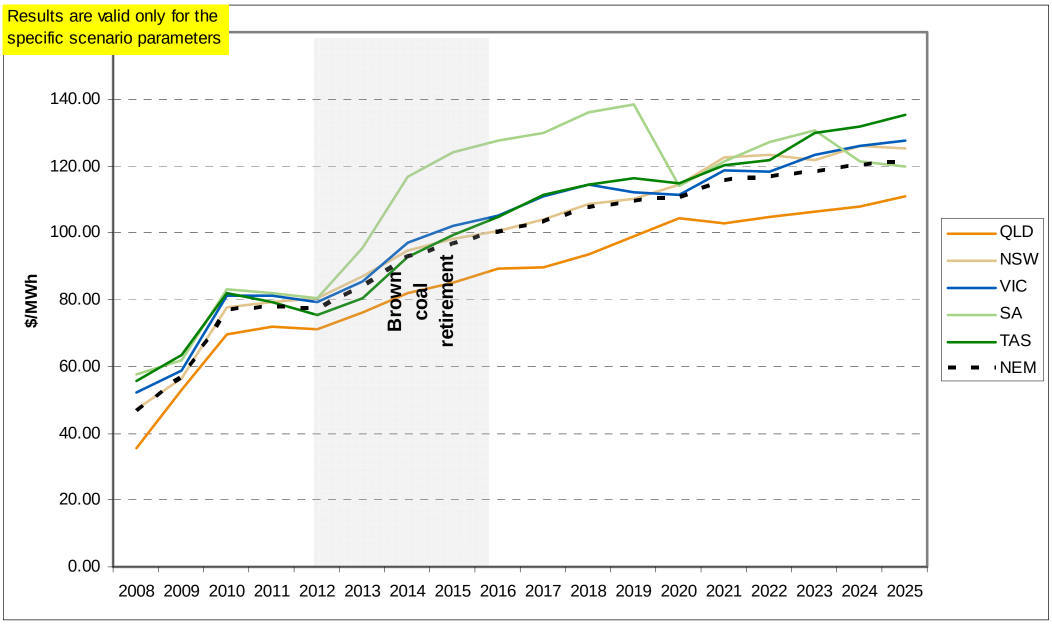
QNI augmentation 2016; Geothermal available 2020; CCS available 2025

Figure 30: Technology mix by GWh of generation – scenario H2



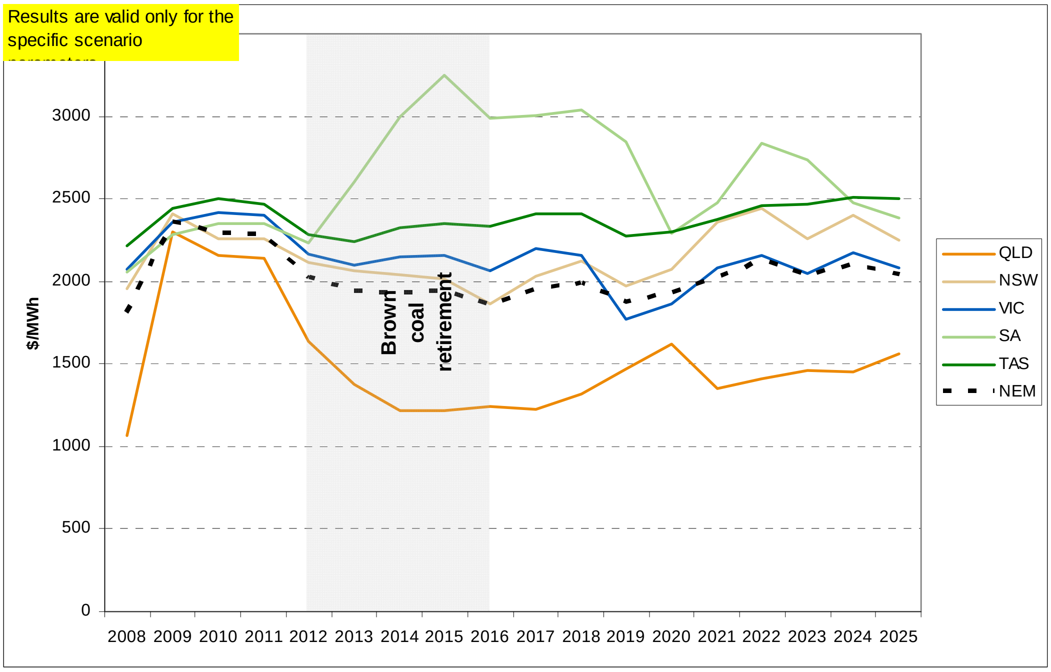
QNI augmentation 2016; Geothermal available 2020; CCS available 2025

Figure 31: Regional load weighted average spot price – scenario H2



QNI augmentation 2016; Geothermal available 2020; CCS available 2025

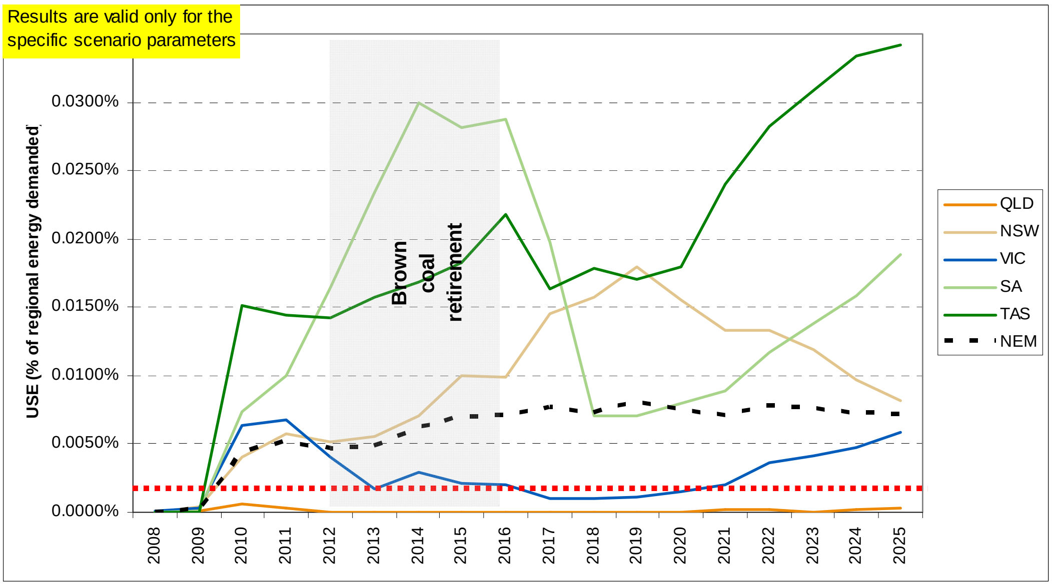
Figure 32: Regional average super peak price – scenario H2



QNI augmentation 2016; Geothermal available 2020; CCS available 2025

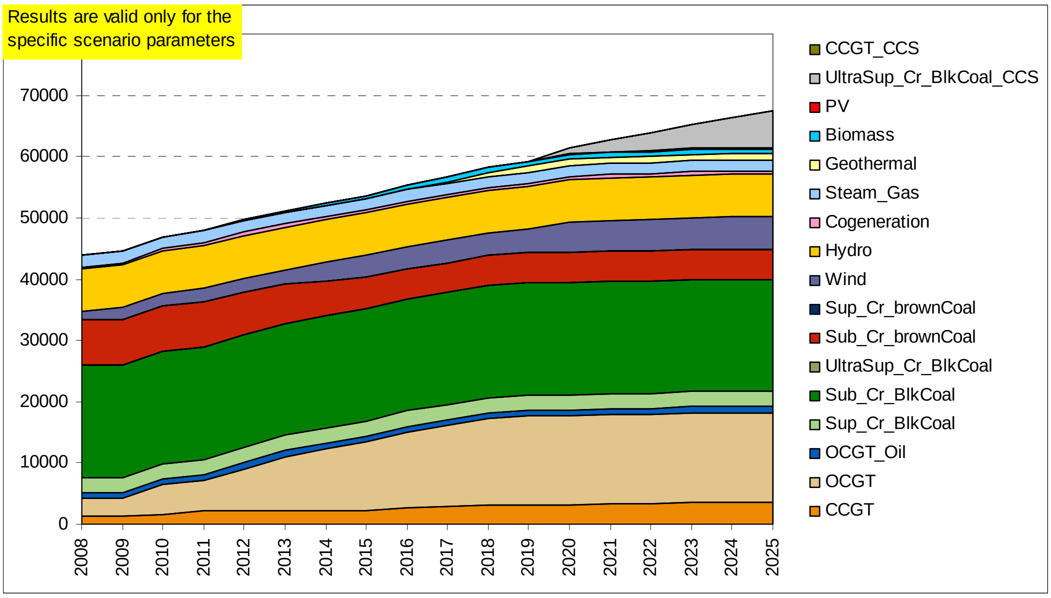
A.1.3 H3: Carbon price $20/t indexed at 4%p.a, VoLL: $10,000/MWh not indexed, Geothermal available from 2015, CCS available from 2020.

Figure 33: Regional unserved energy – scenario H3



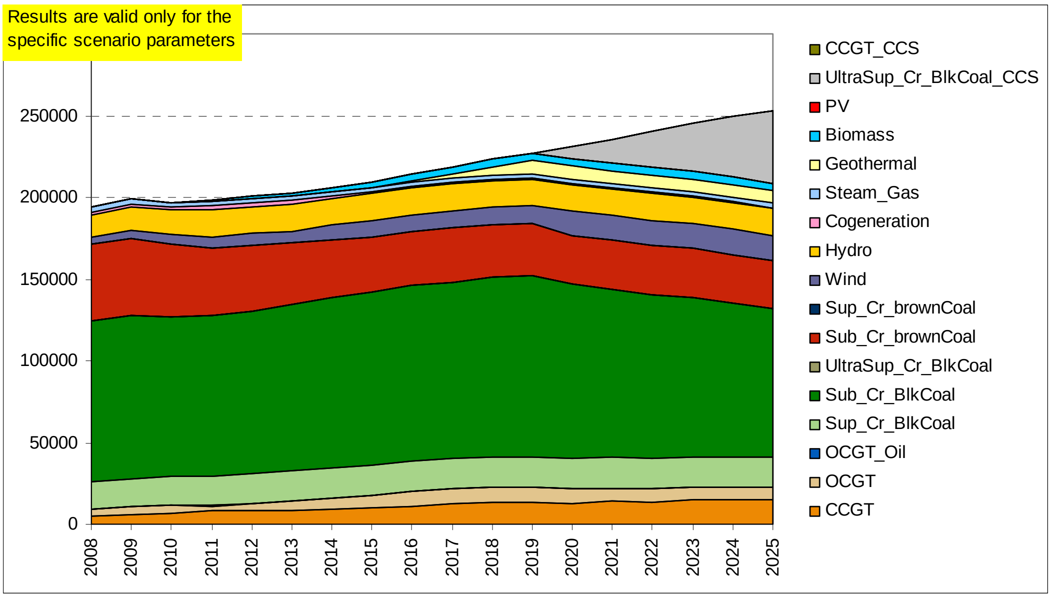
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 34: Technology mix by MW of capacity – scenario H3



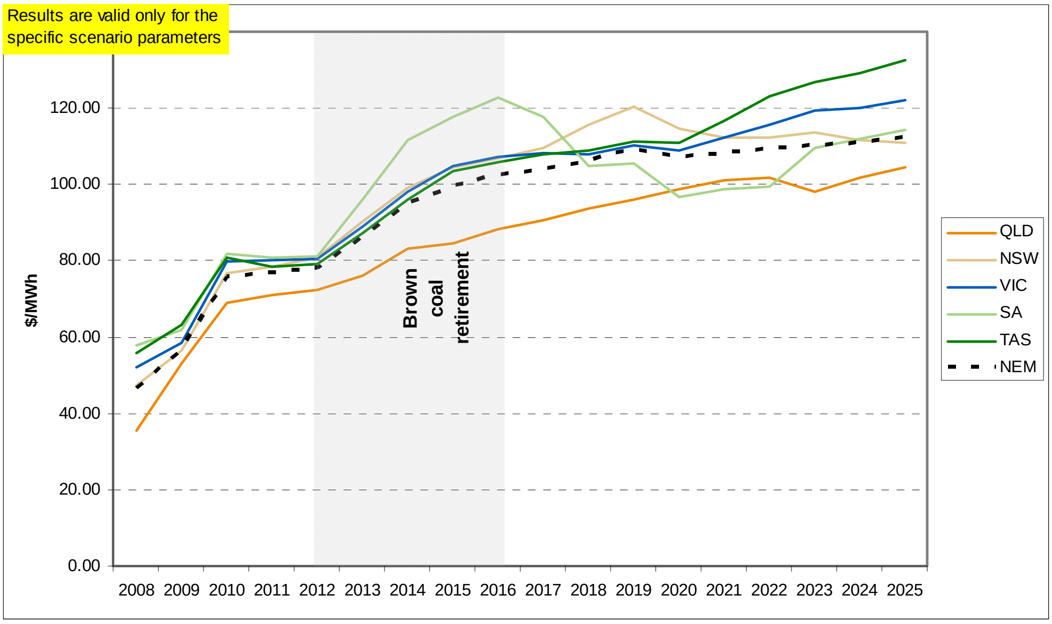
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 35: Technology mix by GWh of generation – scenario H3



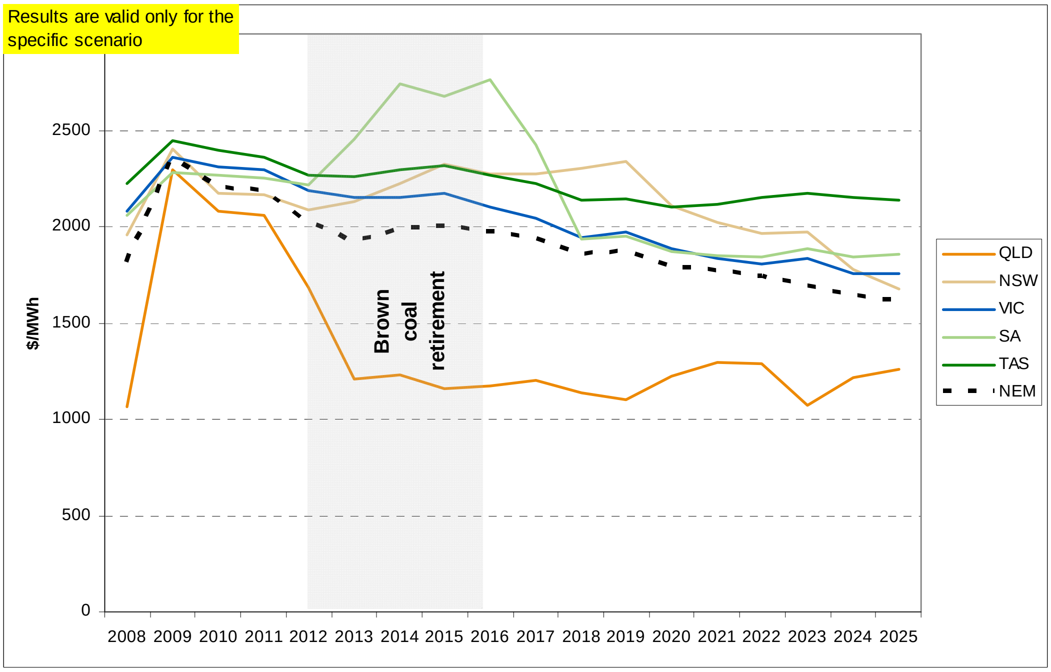
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 36: Regional load weighted average spot price – scenario H3



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

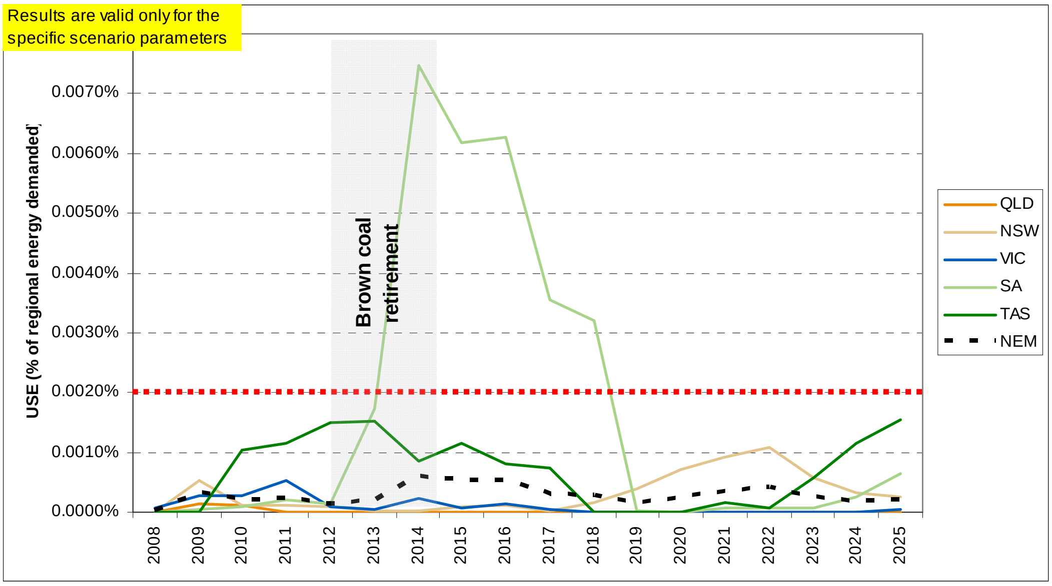
Figure 37: Regional average super peak price – scenario H3



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

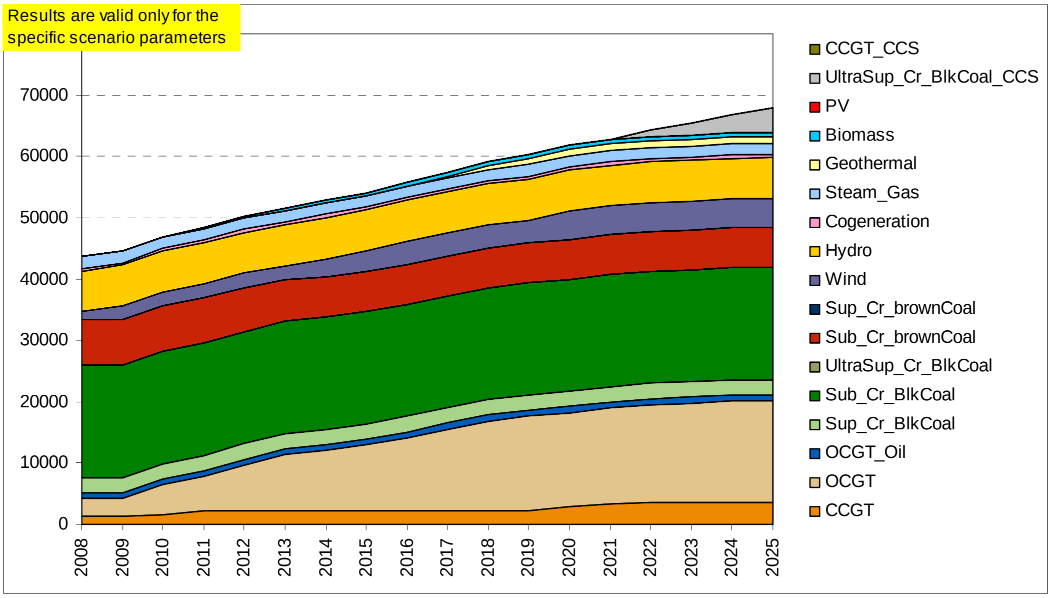
A.1.4 H4: Carbon price $10/t indexed at 4%p.a, VoLL: $12,500/MWh indexed, Geothermal available from 2015, CCS available from 2020.

Figure 38: Regional unserved energy – scenario H4



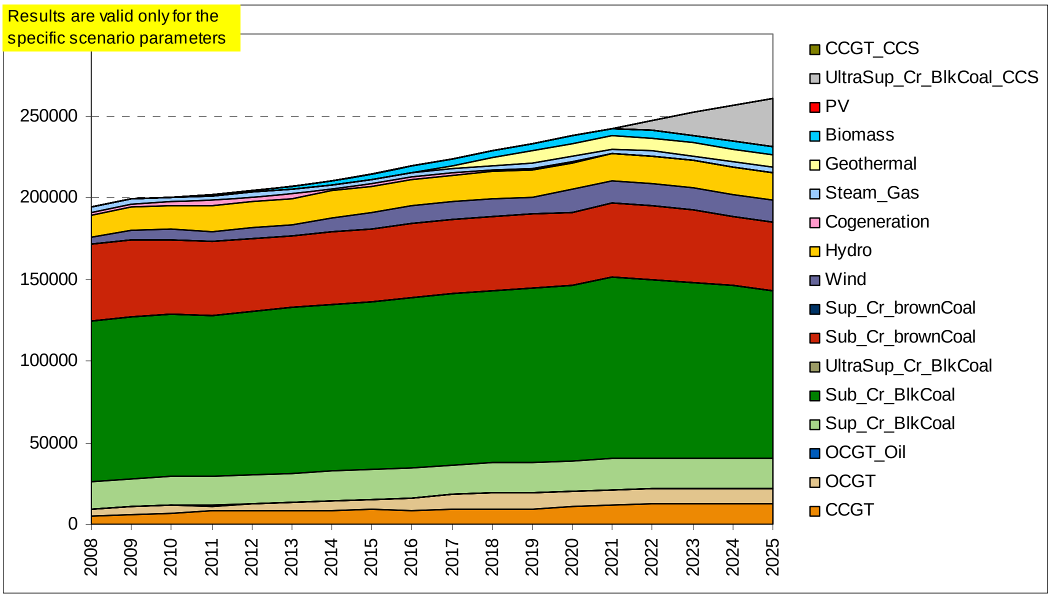
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 39: Technology mix by MW of capacity – scenario H4



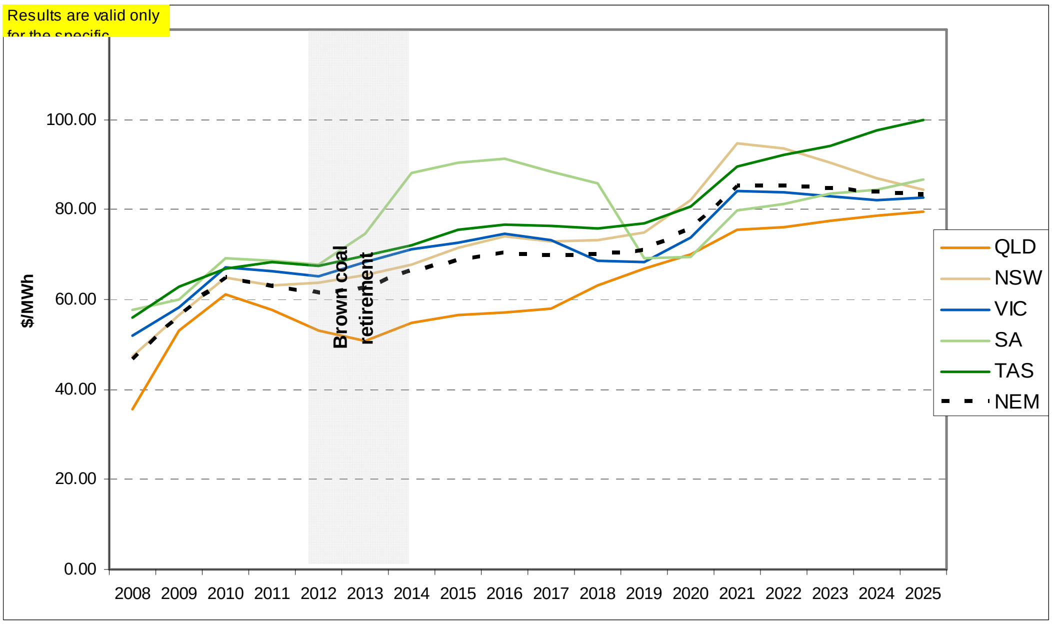
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 40: Technology mix by GWh of generation – scenario H4



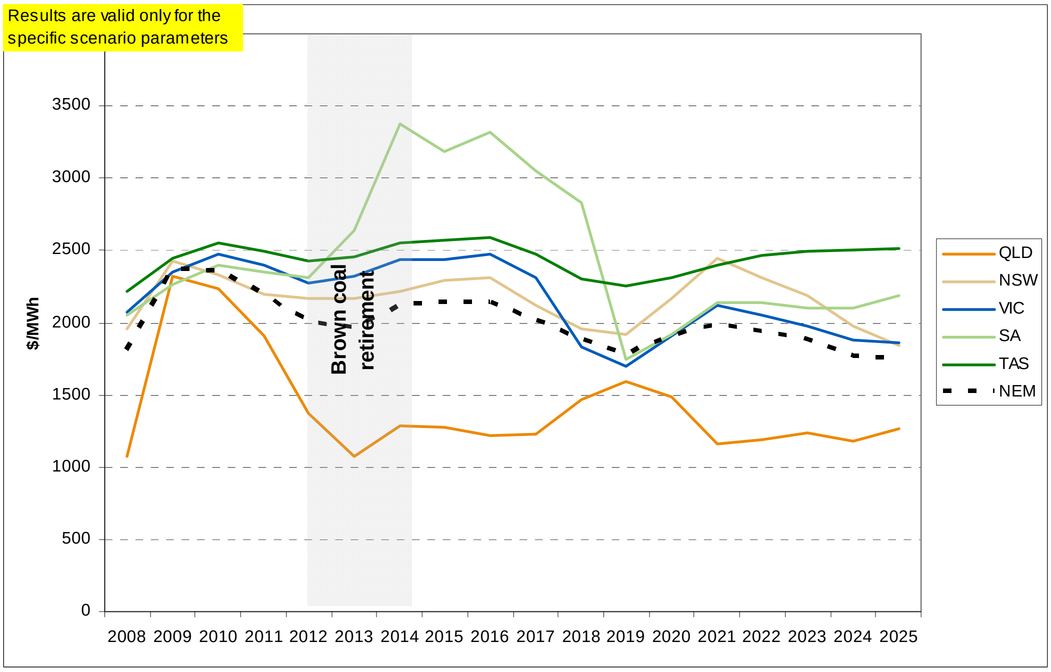
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 41: Regional load weighted average spot price – scenario H4



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

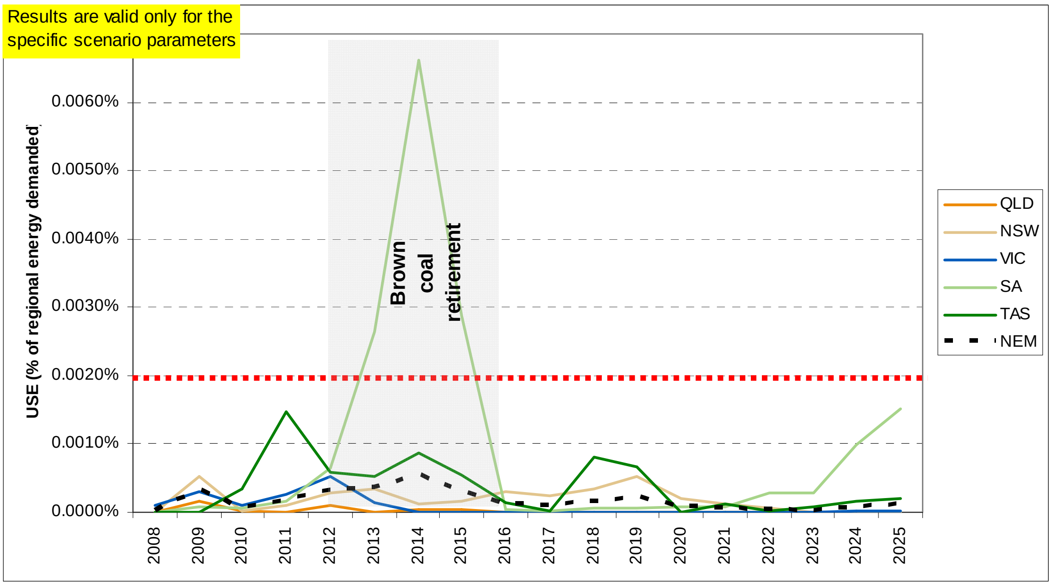
Figure 42: Regional average super peak price – scenario H4



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

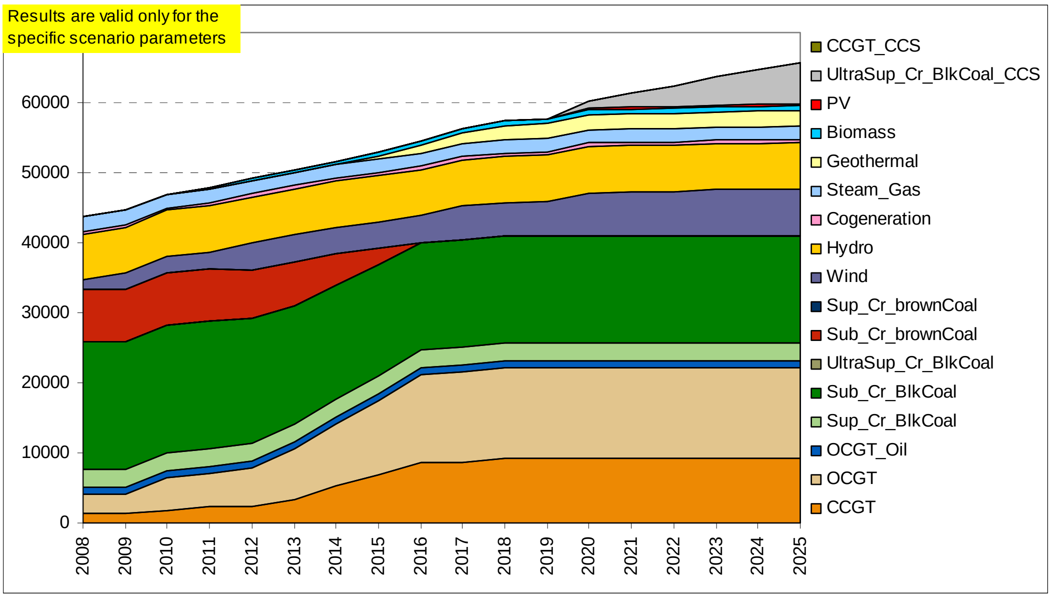
A.1.5 H5: Carbon price $30/t indexed at 8%p.a, VoLL: $12,500/MWh indexed, Geothermal available from 2015, CCS available from 2020.

Figure 43: Regional unserved energy – scenario H5



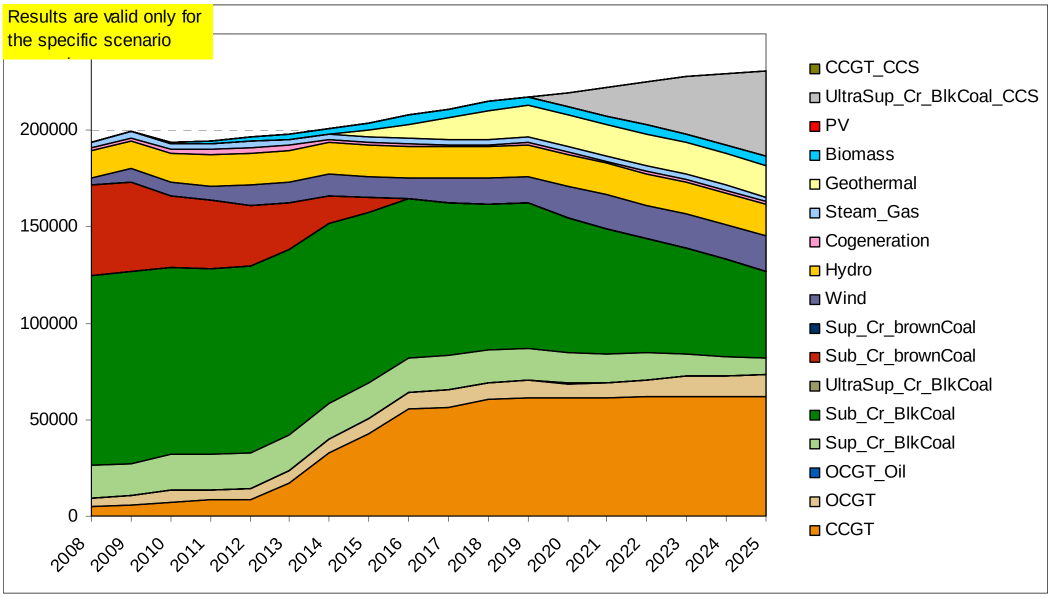
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 44: Technology mix by MW of capacity – scenario H5



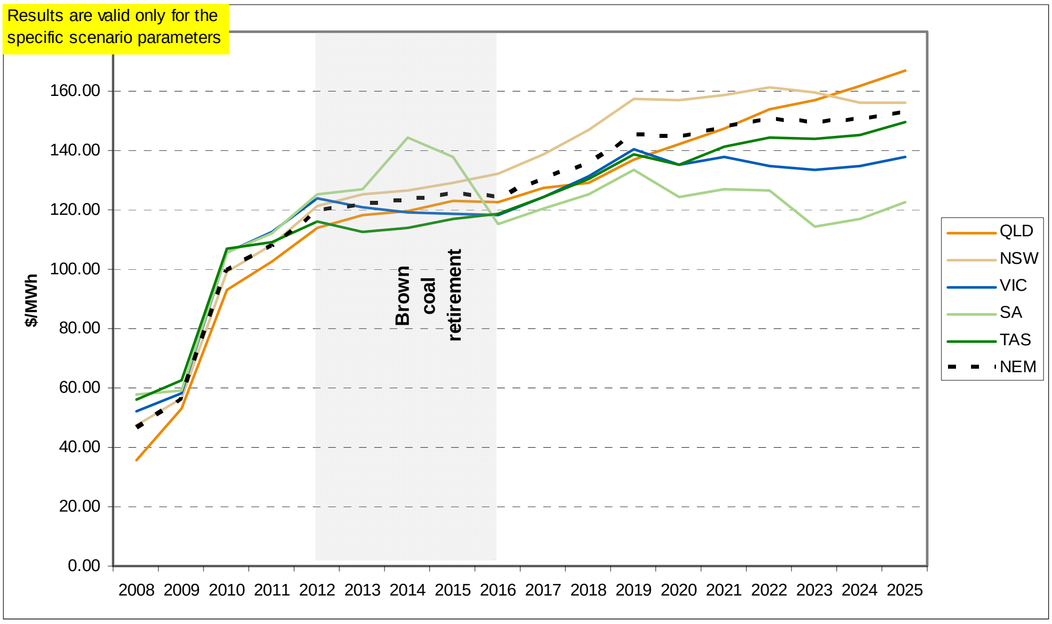
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 45: Technology mix by GWh of generation – scenario H5



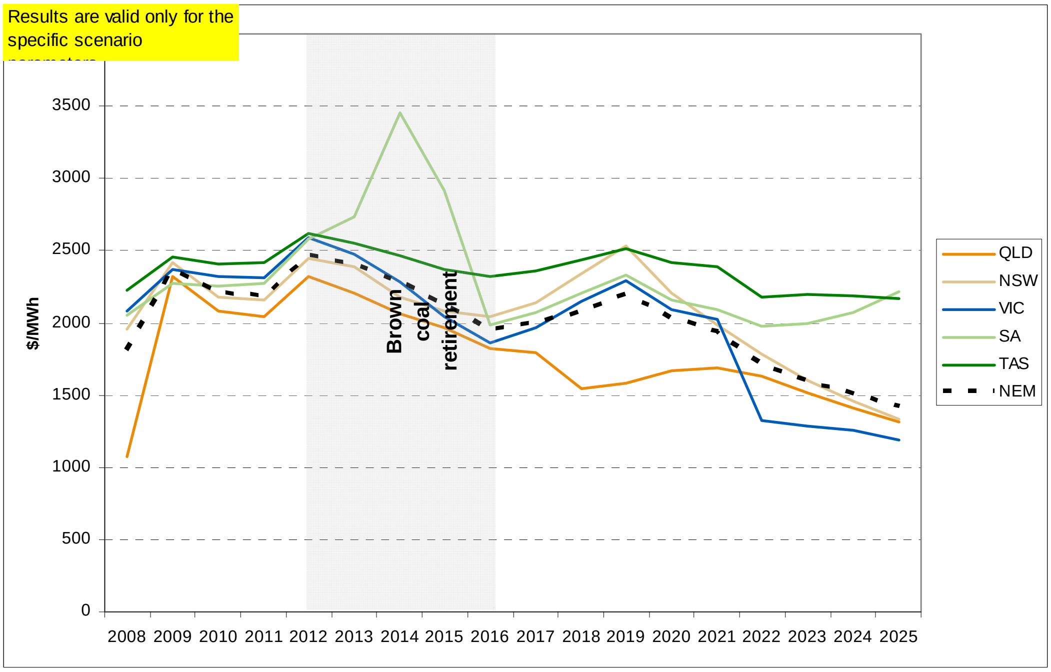
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 46: Regional load weighted average spot price – scenario H5



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 47: Regional average super peak price – scenario H5



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

A.2 PROPORTIONAL PEAK SCENARIOS

The “P” series of scenarios is based on demand elasticity at peak being in the same ratio as that for annual energy, for example if annual energy demand is reduced by 8% the peak demand will be reduced by 8% also. The scenarios within the series consider different levels of carbon price, VoLL and timing of availability of new technologies.

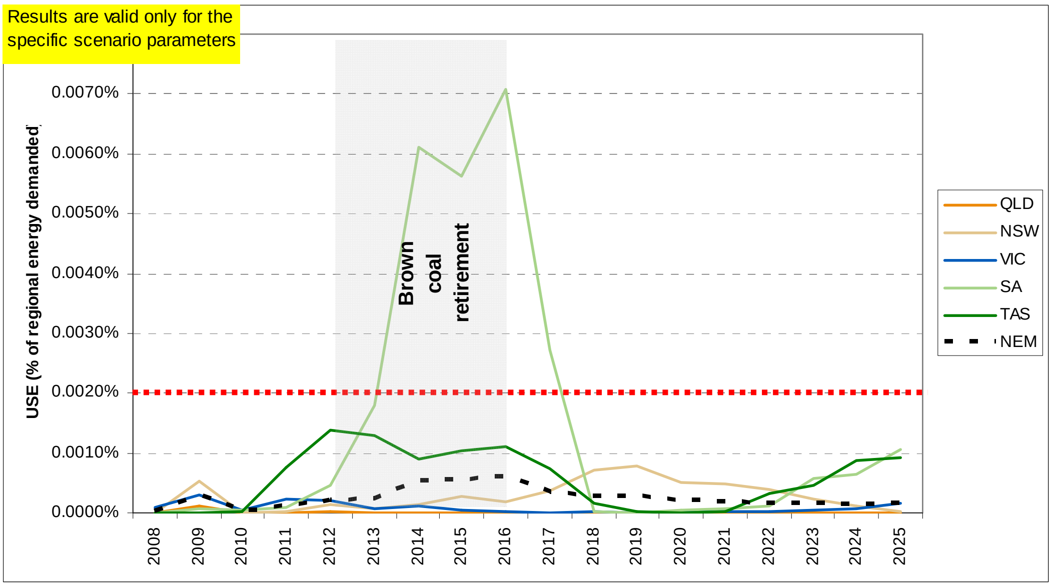
Modelling results are shown for:

- Unserved energy expressed as the percentage of national/regional demand that would not be supplied and where practicable on the scale of the plot the reliability standard of 0.002% is also shown;
- Technology mix by installed capacity of each technology (NEM wide);
- Technology mix by energy shares for each technology (NEM wide);
- Load weighted spot price – average; and

Load weighted spot price - "super peak" (i.e. the top 50 hours of the year).

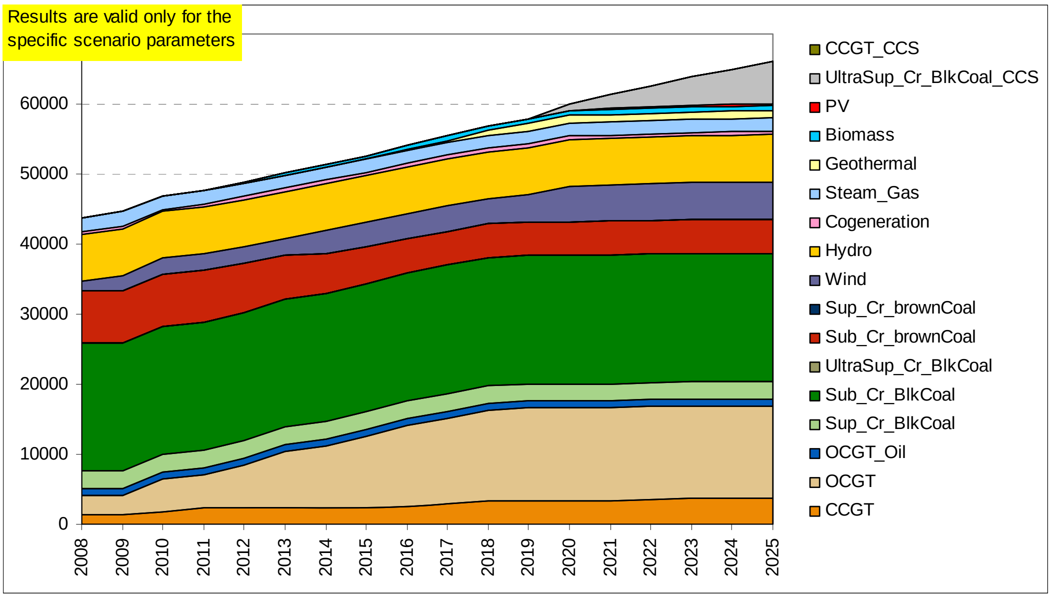
A.2.1 P1: Carbon price \$20/t indexed at 4%p.a, VoLL: \$12,500/MWh indexed, Geothermal available from 2015, CCS available from 2020.

Figure 48: Regional unserved energy – scenario P1



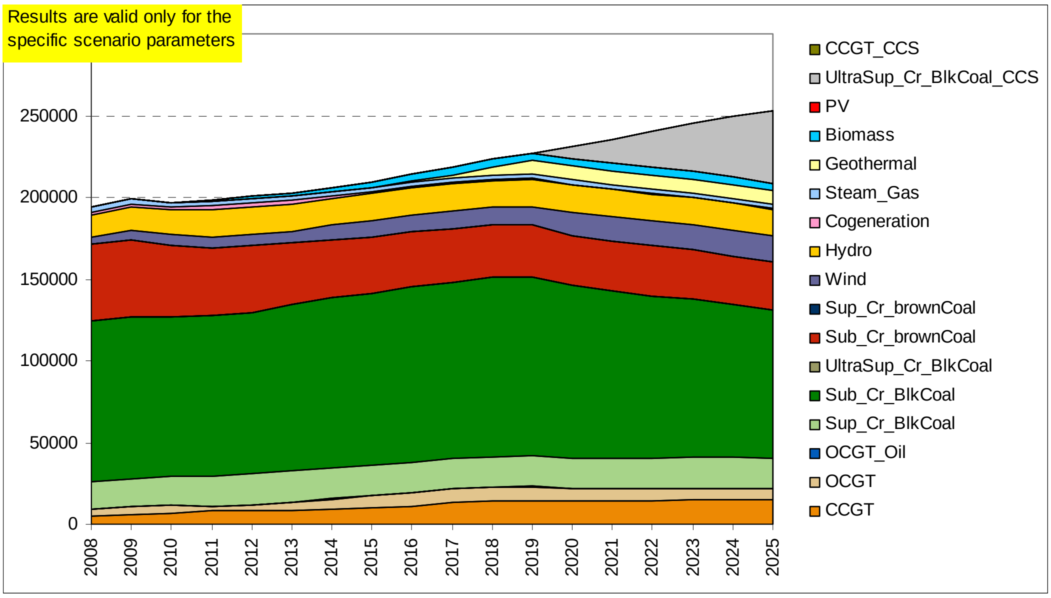
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 49: Technology mix by MW of capacity – scenario P1



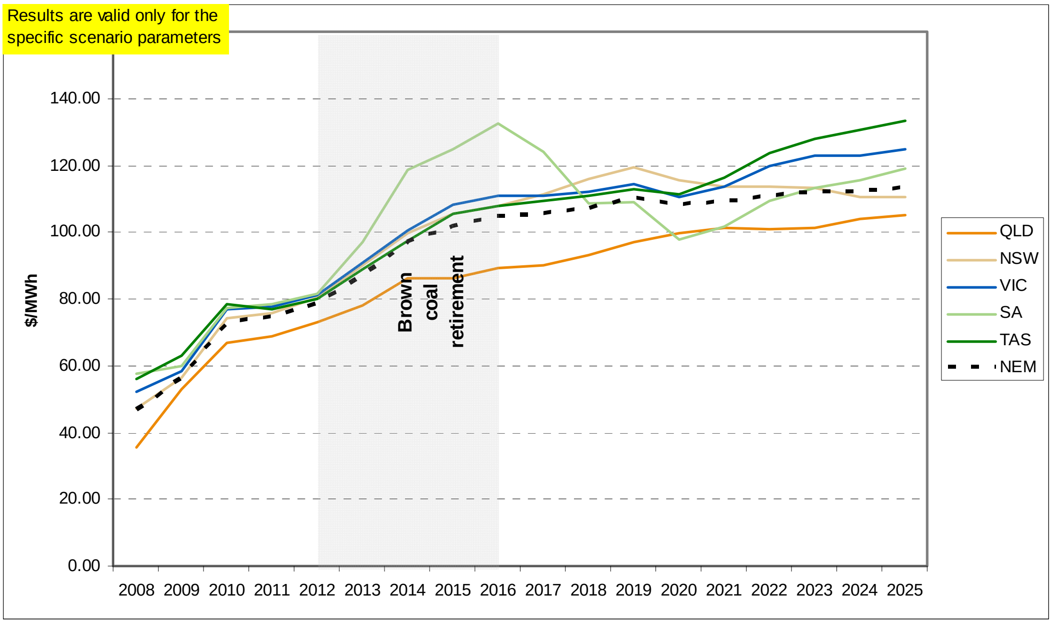
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 50: Technology mix by GWh of generation – scenario P1



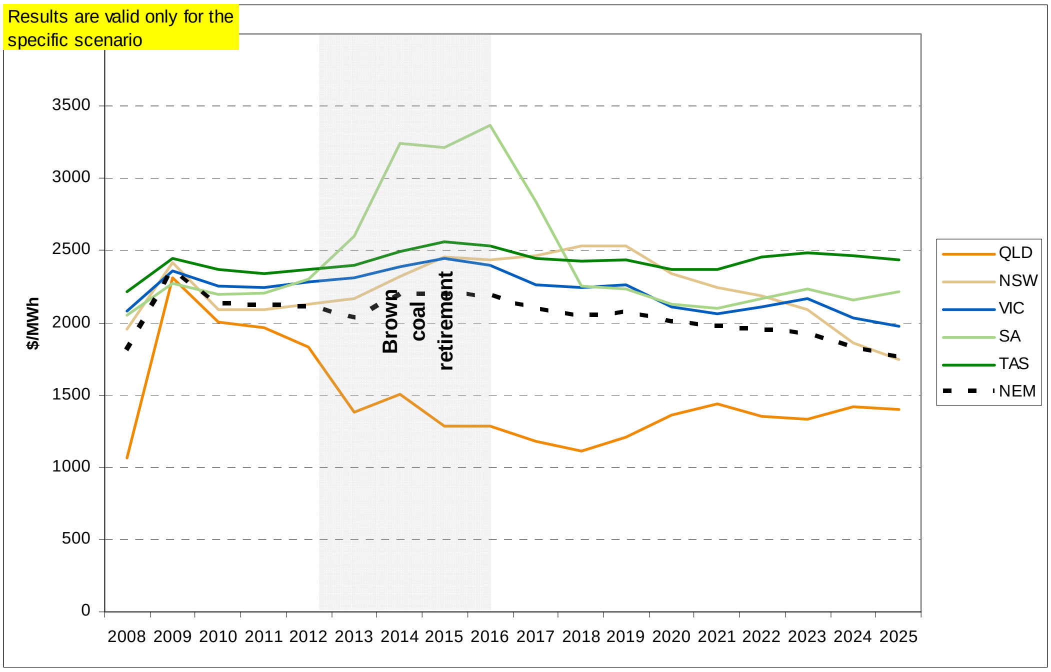
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 51: Regional load weighted average spot price – scenario P1



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

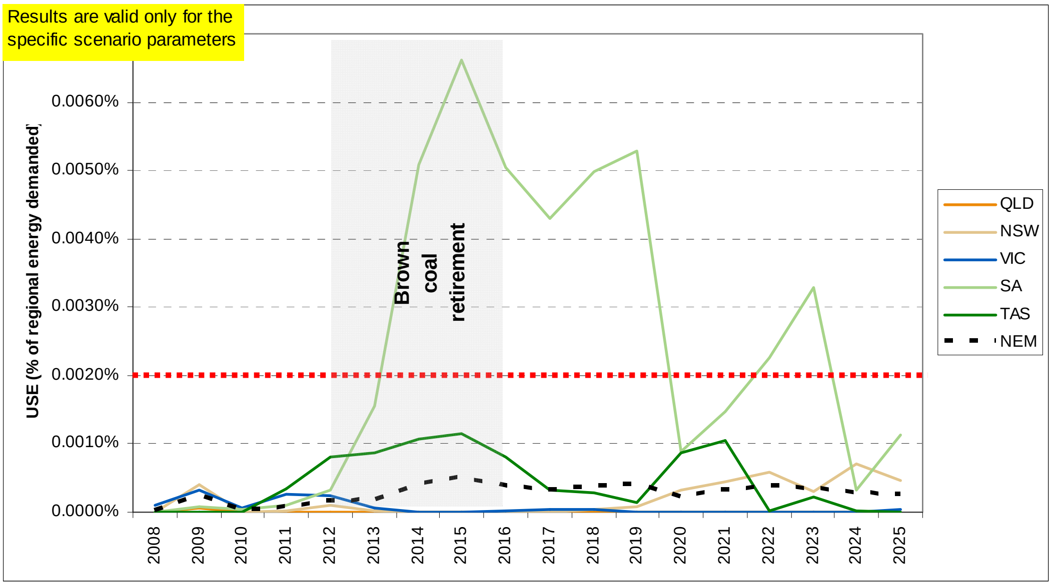
Figure 52: Regional average super peak price – scenario P1



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

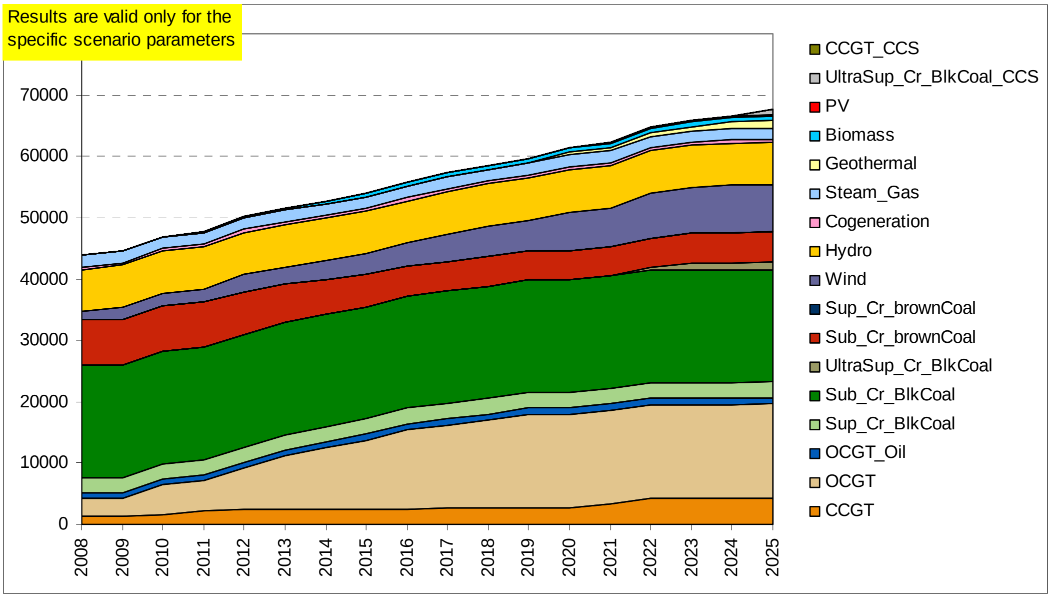
A.2.2 P2: Carbon price $20/t indexed at 4%p.a, VoLL: $12,500/MWh indexed, Geothermal available from 2020, CCS available from 2025.

Figure 53: Regional unserved energy – scenario P2



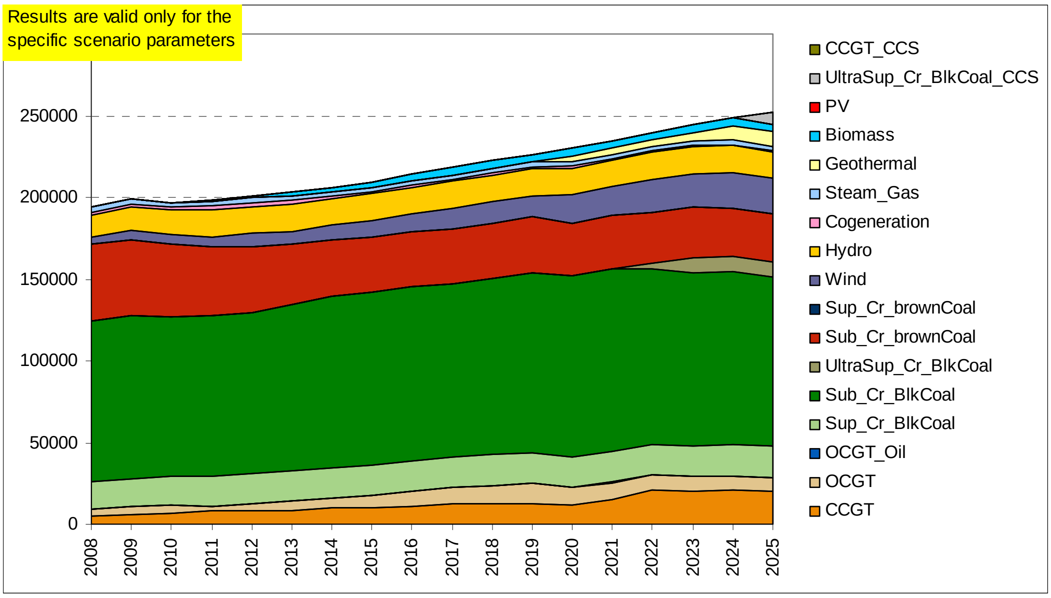
QNI augmentation 2016; Geothermal available 2020; CCS available 2025

Figure 54: Technology mix by MW of capacity – scenario P2



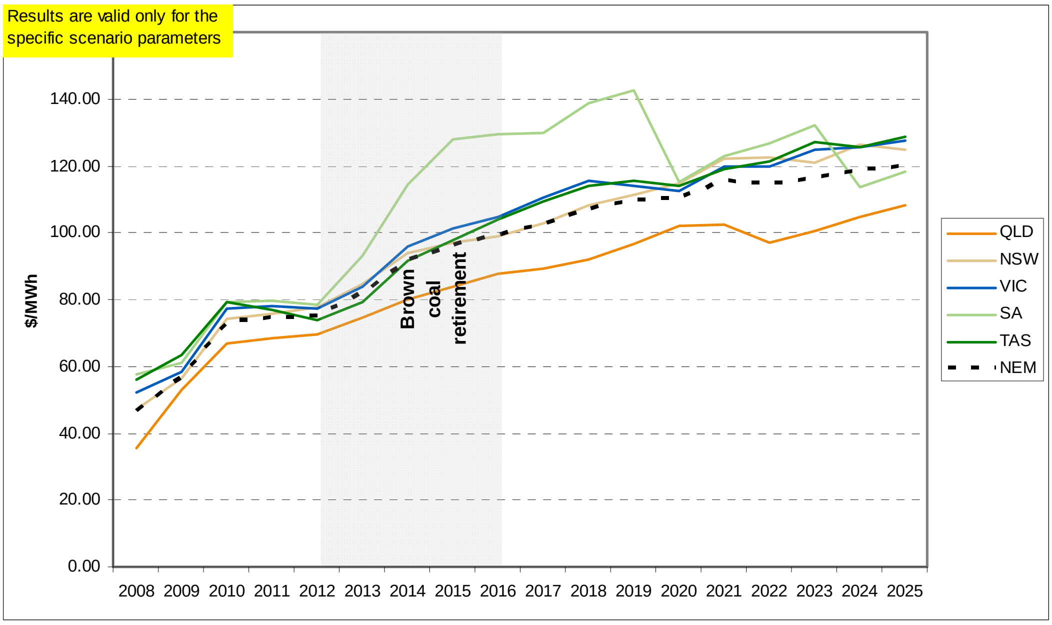
QNI augmentation 2016; Geothermal available 2020; CCS available 2025

Figure 55: Technology mix by GWh of generation – scenario P2



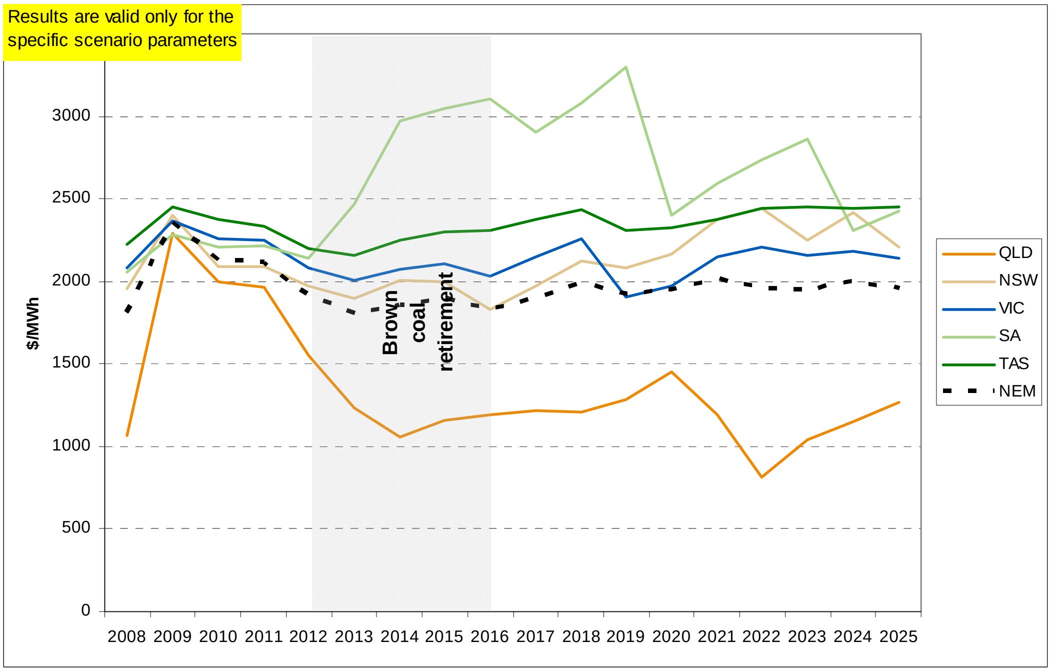
QNI augmentation 2016; Geothermal available 2020; CCS available 2025

Figure 56: Regional load weighted average spot price – scenario P2



QNI augmentation 2016; Geothermal available 2020; CCS available 2025

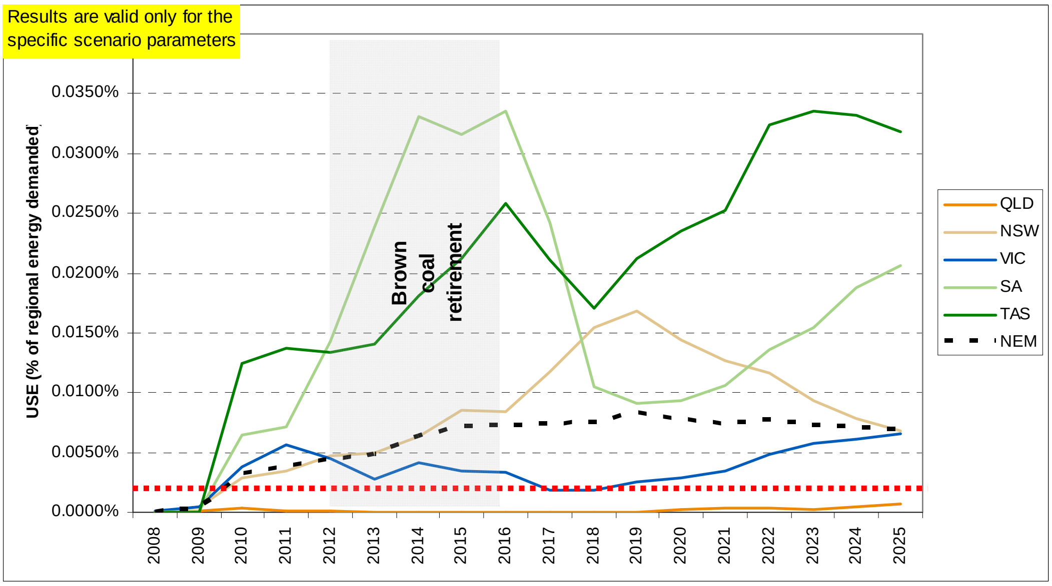
Figure 57: Regional average super peak price – scenario P2



QNI augmentation 2016; Geothermal available 2020; CCS available 2025

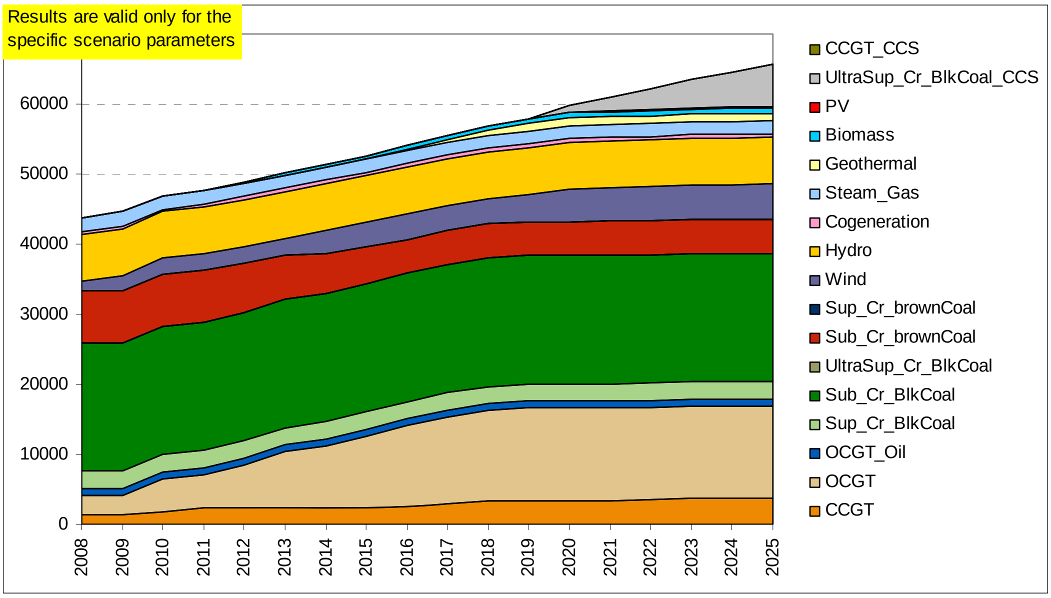
A.2.3 P3: Carbon price $20/t indexed at 4%p.a, VoLL: $10,000/MWh not indexed, Geothermal available from 2015, CCS available from 2020.

Figure 58: Regional unserved energy – scenario P3



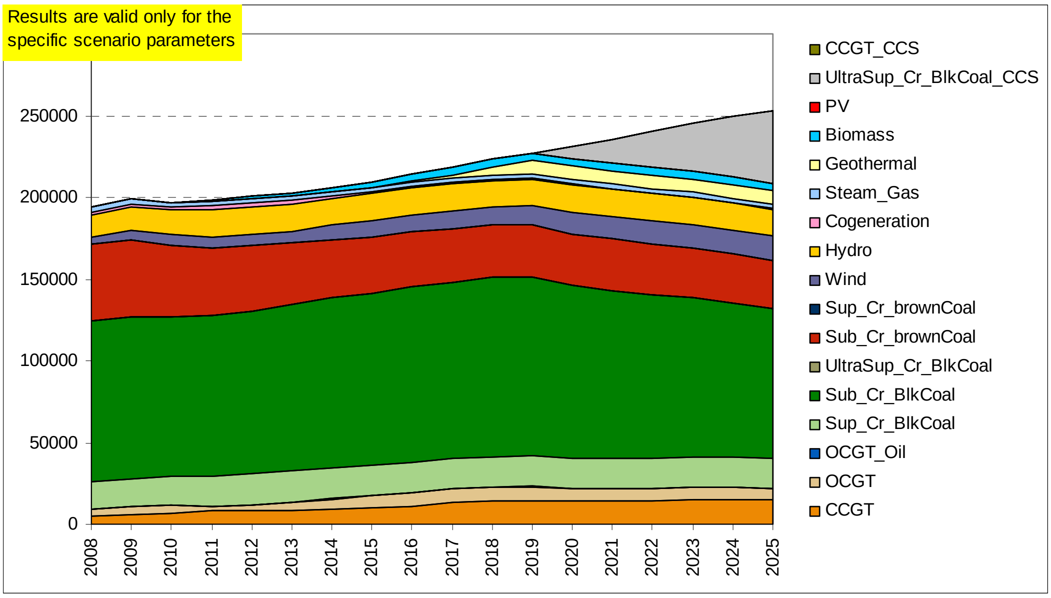
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 59: Technology mix by MW of capacity – scenario P3



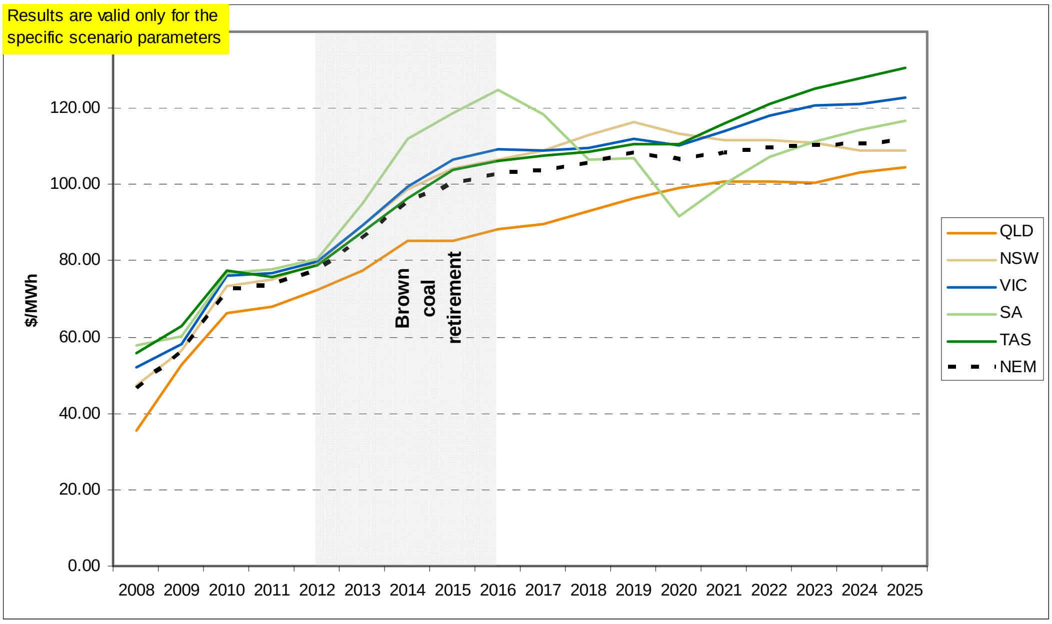
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 60: Technology mix by GWh of generation – scenario P3



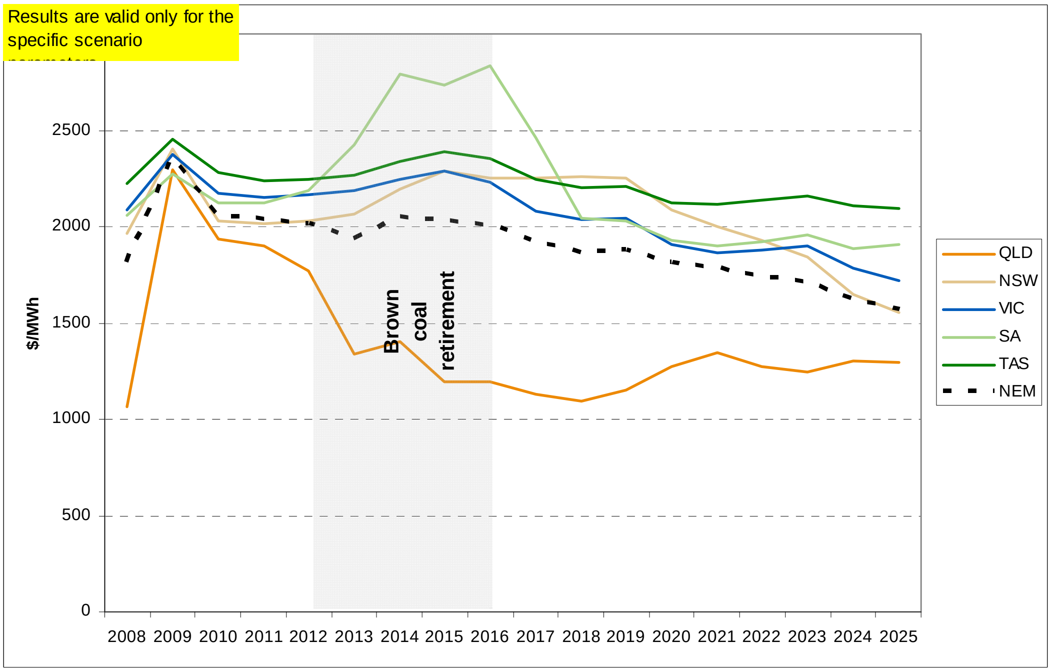
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 61: Regional load weighted average spot price – scenario P3



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

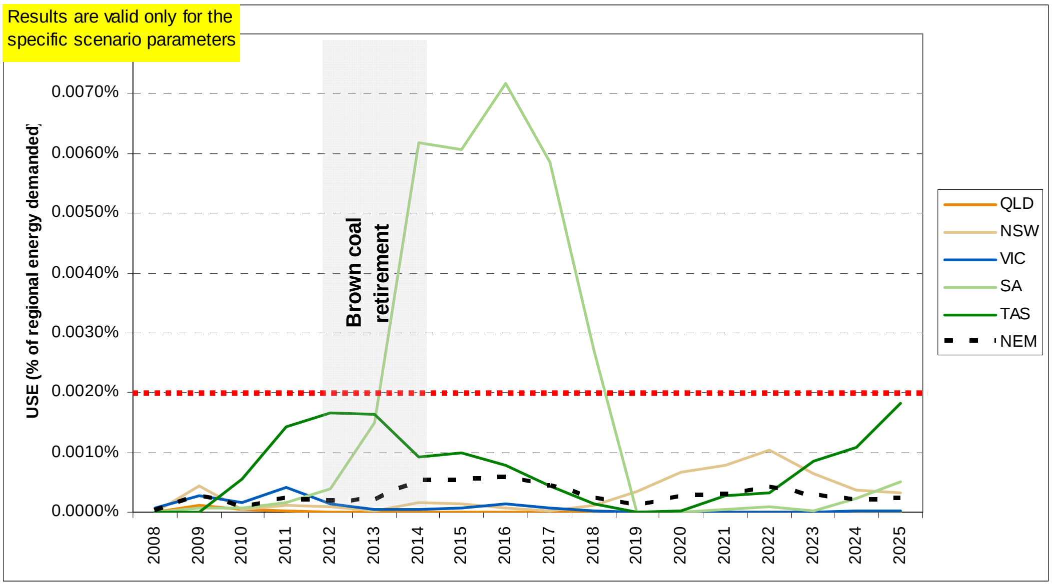
Figure 62: Regional average super peak price – scenario P3



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

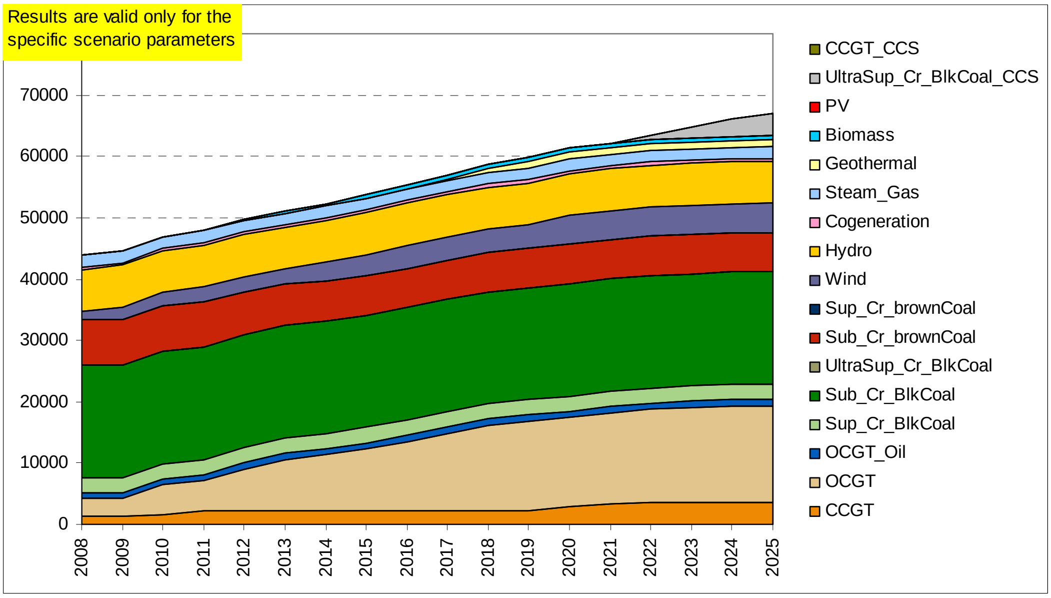
A.2.4 P4: Carbon price $10/t indexed at 4%p.a, VoLL: $12,500/MWh indexed, Geothermal available from 2015, CCS available from 2020.

Figure 63: Regional unserved energy – scenario P4



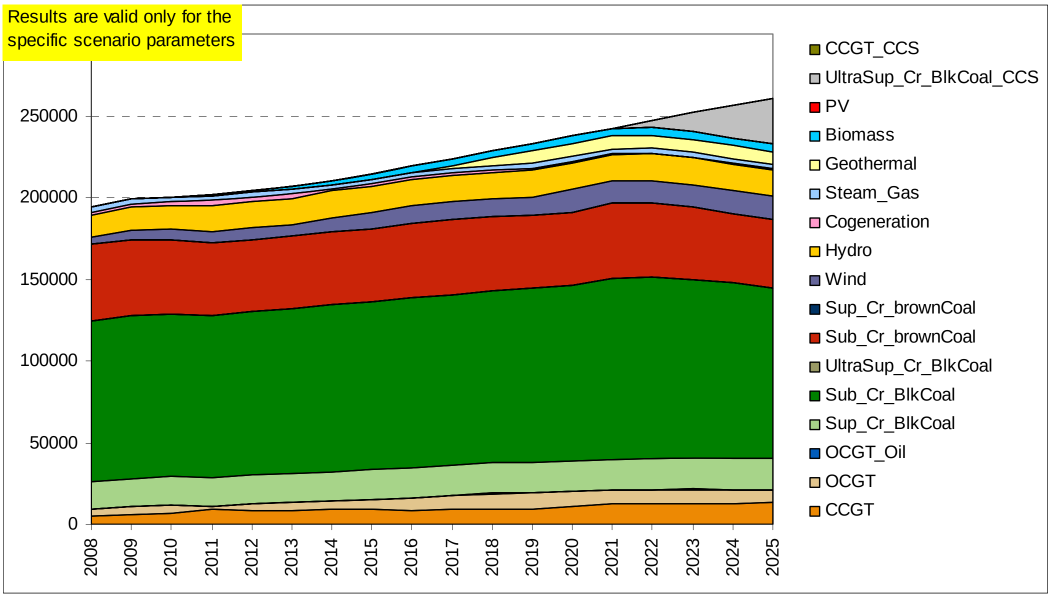
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 64: Technology mix by MW of capacity – scenario P4



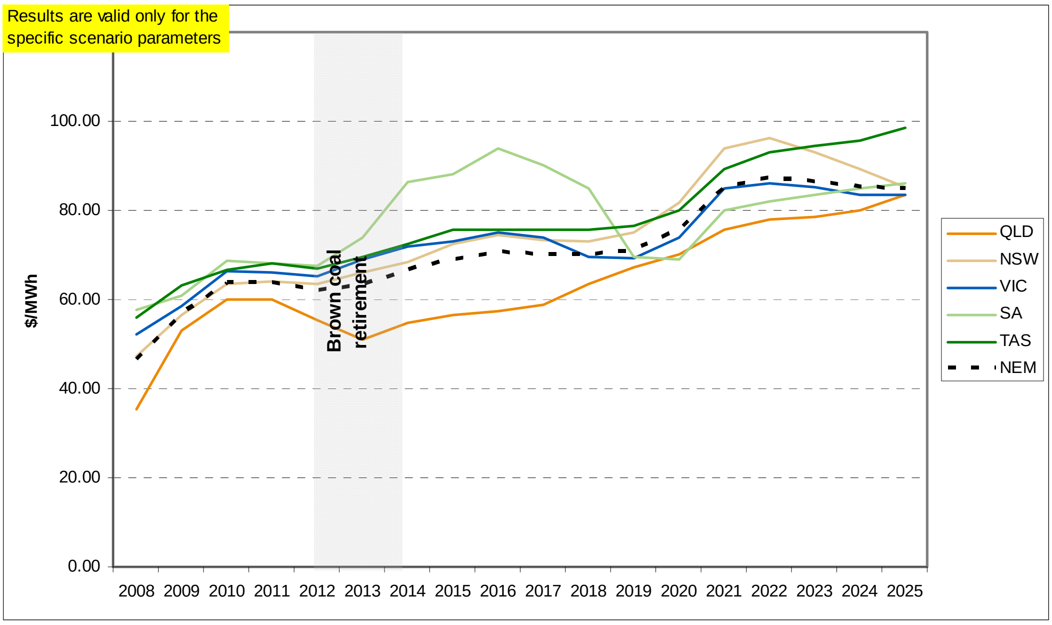
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 65: Technology mix by GWh of generation – scenario P4



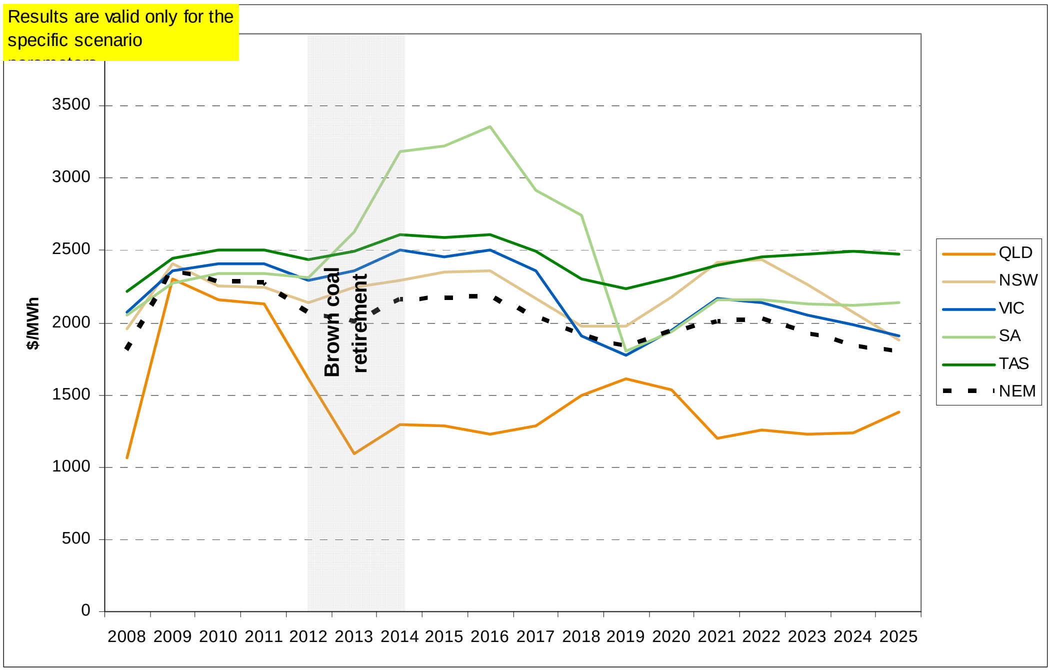
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 66: Regional load weighted average spot price – scenario P4



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

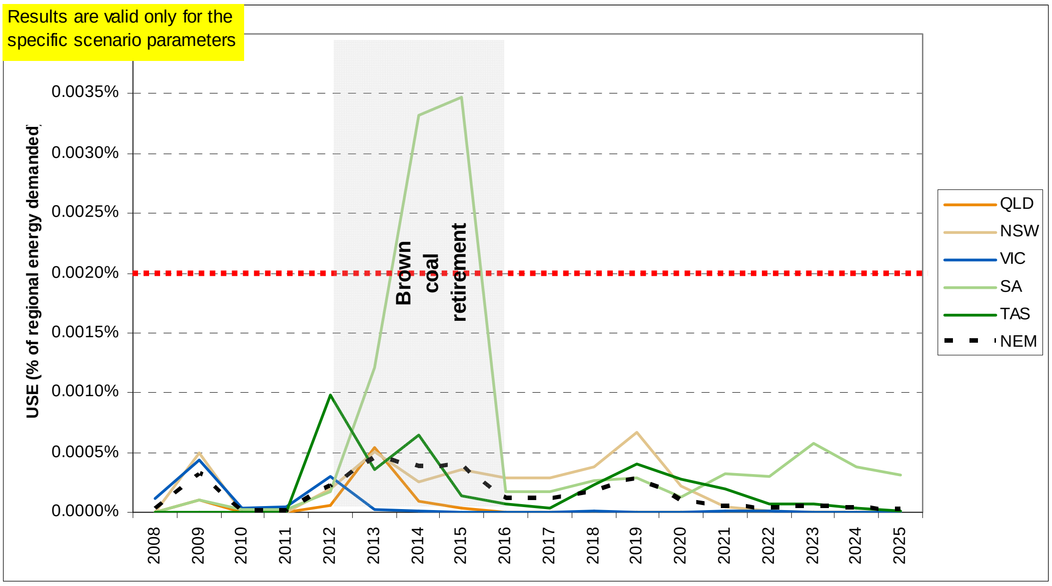
Figure 67: Regional average super peak price – scenario P4



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

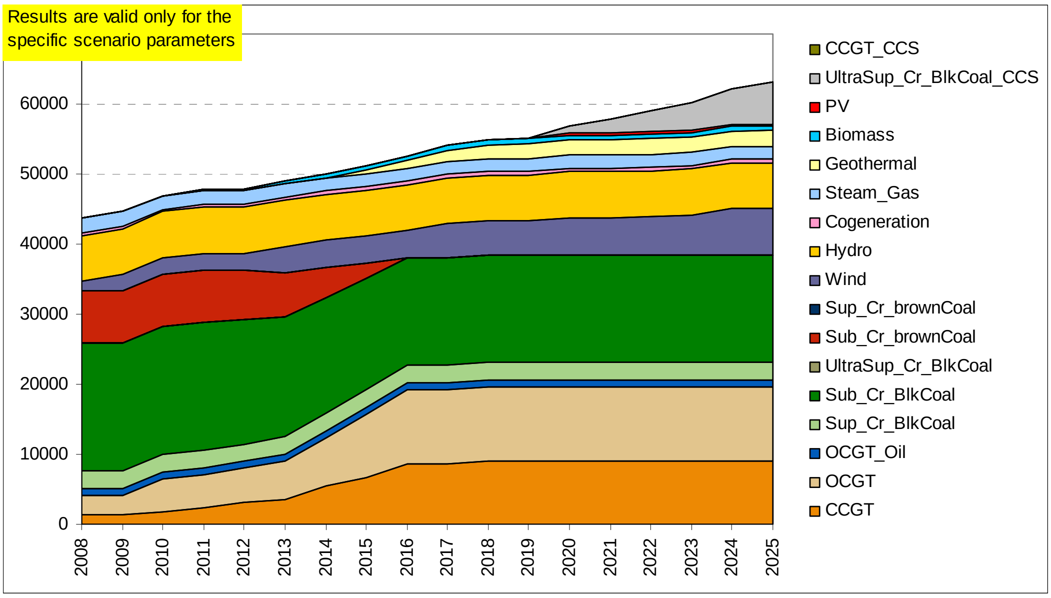
A.2.5 P5: Carbon price $30/t indexed at 8%p.a, VoLL: $12,500/MWh indexed, Geothermal available from 2015, CCS available from 2020

Figure 68: Regional unserved energy – scenario P5



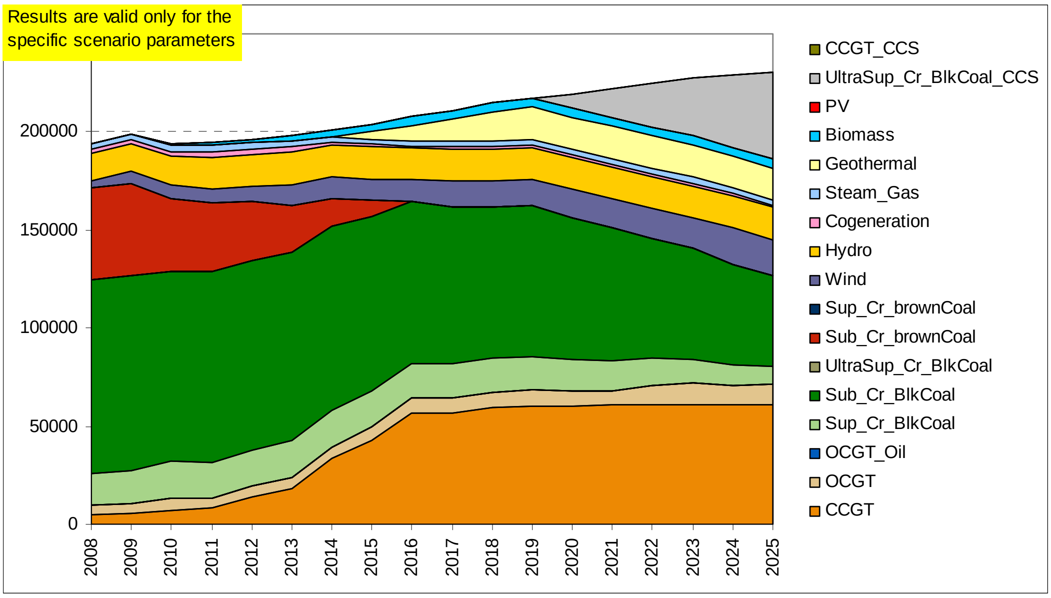
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 69: Technology mix by MW of capacity – scenario P5



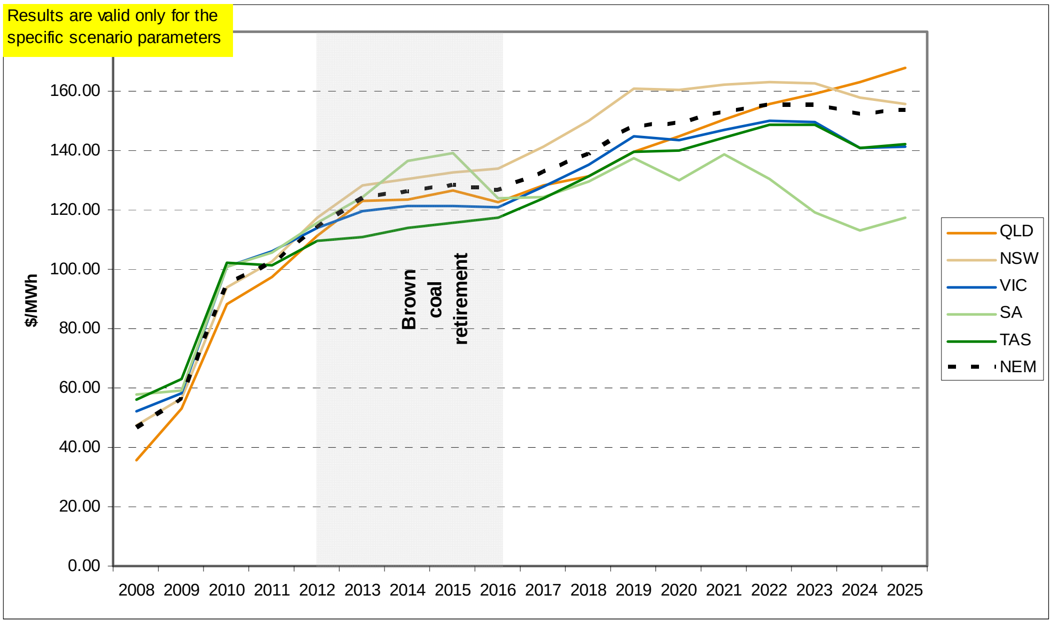
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 70: Technology mix by GWh of generation – scenario P5



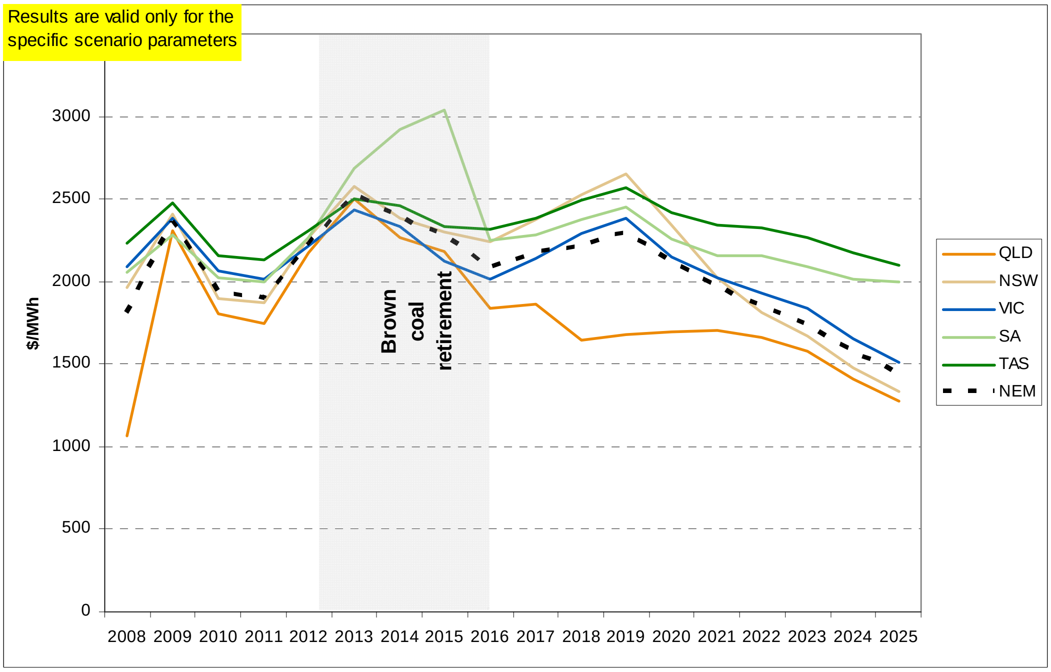
QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 71: Regional load weighted average spot price – scenario P5



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

Figure 72: Regional average super peak price – scenario P5



QNI augmentation 2016; Geothermal available 2015; CCS available 2020

APPENDIX B: TECHNICAL ASSUMPTIONS

B.1 GENERATOR UNIT CHARACTERISTICS

Table 13: Key data sources – existing units

Data	Source
Capacity (MW)	NEMMCO 2007 (October) “Statement of Opportunities for the National Electricity Market”, Update to the 2007 SOO (November 2007)
Retirement year [a]	NEMMCO 2007 “Statement of Opportunities for the National Electricity Market”
Variable O&M (VOM) A$/MWh	Various sources
Fixed O&M (FOM) A$/MW/Year	Various sources
Average heat rate, HHV (GJ/MWh)	Various sources
Emissions Rate (t/MWh)	ACIL 2007 "Fuel resource, new entry and generation costs in the NEM"
Intra-Regional Loss Factors	NEMMCO "List of Regional Boundaries and Marginal Loss Factors for the 2008/09 Financial Year". See http://www.nemmco.com.au/psplanning/172-0067.pdf For new generators, average of existing generators in their state.

[a] In modelling market performance, existing generation plant may be forced out of service (retired) if the carbon price or other costs make plant non-viable on an economic basis.

B.1.1 Capital costs

Table 14 lists the capital cost used. The capital cost is annualised for the purpose of modelling assuming long term financing (see Table 4).

Table 14: New entrant costs by technology[22]

Technology	Capital cost A$2007/08 per kW
Sub critical black coal (assumed superseded)	
Super critical black coal -dry cooling	1,879 [a]
Ultra super critical black coal	2,255 [a]

22 New entry capital costs are consistent (where possible) with those reported in the Commonwealth Treasury’s *Climate change mitigation policy modelling: Summary of assumptions and data sources* (October 2008). Available from: http://www.treasurer.gov.au/Ministers/wms/Content/pressreleases/2008/attachments/108/Treasury%20climate%20change%20mitigation%20policy%20modelling%20assumptions.pdf

Technology	Capital cost A$2007/08 per kW
Ultra super critical black coal with carbon capture and storage	2,997 [a]
Sub critical brown coal (assumed superseded)	
Super critical brown coal	1,972 [a]
OCGT	900 [b]
CCGT	1,334 [a]
CCGT with carbon capture and storage	2,001 [a]
IGCC	2,673 [a]
IGCC with carbon capture and storage	3,688 [a]
Nuclear (not available in Australia)	
Small hydro	3,221 [b]
Wind	2,134 [a]
Geothermal – hot dry rocks	5,000 [b]
Solar thermal	4,176 [a]
Photovoltaics	4,640 [a]
Biomass – steam	2,598 [a]

[a] See Footnote 22.

[b] CRA estimate. Note large capital cost penalty for geothermal to reflect the cost of drilling

Capex and heat rate learning rates applied as per Treasury assumptions [published 3 October] – exceptions being for:

- OCGT, where capex and heat rate learning rates sources from AEO 2008; and
- small hydro where capex and heat rate learning rates assumed = 0.

In modelling sensitivities against capital costs, we will adopt a uniform 20% increase in the above estimates for an alternative scenario.

B.1.2 Renewable build limits and capacity factors

Wind

Capacity factors for each region are as follows:

- Queensland – 20%
- NSW – 25%
- Victoria – 35%
- South Australia – 40%
- Tasmania – 35%

At peak demand capacity factor assumed to be 8% in all regions.

Table 15: Non-scheduled wind incorporated in jurisdictional APRs (installed MW)

	QLD	NSW	VIC	SA	TAS
2008	11	11	449	389	195
2009	11	11	449	389	195
2010	11	240	1599	389	195
2011	11	384	1877	455	381
2012	11	837	2175	455	632
2013	11	837	2762	455	632
2014	25	837	2762	455	712
2015	25	1309	2762	455	845
2016	25	1594	2849	455	1030
2017	25	1944	2849	455	1030
2018	25	1944	2849	455	1030
2019	25	1944	2849	455	1030

Geothermal

- Capacity
  - Data sources from a report indicating that under current greenhouse policy there could be up to 2200MW geothermal installed by 2020.

    http://www.austconserv.com/index.php?option=com_content&view=article&catid=45:alternative-energy&id=199:1-of-australias-geothermal-power-potential--26000-years-of-energy&Itemid=63

    The above source refers to the Australian Geothermal Energy Association as the original source.

- Capacity factor

  ESIPC 2008 APR reports capacity factor of geothermal at 85%.

- Location and build limits

  The most prospective site for geothermal is NE SA and SE Qld. Build limits proposed as follows:

  - 1000 MW in Queensland;
  - 800 in SA;
  - 400 in NSW.

  Maximum construction of 500 MW / year.

- Capital costs including transmission

  Geothermal energy generating plant that sits above ground is likely to represent a relatively small proportion of the total capital cost of delivering geothermal energy to the market. The costs of drilling and transmission will add substantially to the total cost. The LRMC of geothermal energy is expected to be in the region of $100 / MWh, with transmission costs representing (potentially) around $10 / MWh of that total[23].

Biomass

- Capacity factor

  Capacity factor of 75% reported by International Sugarcane Biomass Utilization Consortium (ISBUC) – see:

  http://issct.intnet.mu/ISBUCresprop1.HTM

- Arbitrary build limits (100MW / year), with totals as follows:

  - Qld: 400MW
  - NSW: 400MW
  - Vic: 200MW
  - Tas: 200MW

B.2 PROJECTIONS OF ENERGY REQUIREMENTS

For modelling beyond 2018 (the point where NEMMCO forecasts stop forecasts from ABARE's *Australian energy, national and state projections to 2029/2030* will be used – see Table 16. CRR modelling will be reported to 2020 but analysis goes beyond the end date of interest to ensure rational new entrant decisions are made in the final years of interest.

23 Transmission costs can only be expressed in approximate terms while the total distance to be covered by transmission lines and the total volume of geothermal plant over which the transmission cost is to be amortised are each unknown. Total transmission costs in the region of $1 billion (or more) to facilitate the connection of remote geothermal plant cannot be ruled out.

Table 16: Electricity generation in Australia, by State

	2010-20 (TWh)	2029-30 (TWh)	Average annual growth rate
NSW	92.5	115.6	2.25%
Vic	80.2	87.8	0.91%
Qld	104.4	124.3	1.76%
WA	40.5	51.4	2.42%
SA	12.8	15.40	1.86%
Tas	14	15.00	0.70%
NT	5	5.90	1.67%
Aust	349.4	415.4	1.74%

Source: *Energy projections to 2029-30*, ABARE research report 07.24, Table 12, p.29. Available from: http://www.abare.gov.au/publications_html/energy/energy_07/auEnergy_proj07.pdf

The base forecasts are for "business as usual" and do not account for the effect of emission trading that is proposed to commence in 2010.

B.3 On-going effect of drought

In CEMOS modelling, energy limitations are be placed on hydro plant to reflect NEMMCO expectations of aggregate energy reductions under short-term average rainfall scenarios. It will be assumed that inflows return to long-term averages after 2009-10 and that energy limitations after that point will not be appropriate.

B.4 Gas price paths

B.4.1 Transport costs

Existing fuel prices to be decomposed into transport and commodity charge in accordance with the following methodology:

- The cheapest ACIL price for gas plant in each region are to be identified and nominated as the "home node" with zero transport charge – for example, cheapest fuel price is $3.00/GJ – assume transport charge is $0 for that 'node' and gas commodity cost is $3.00/GJ for all nodes, with transport cost at other nodes deemed to be reported fuel price less $3.00.

- Having determined the transport charge at each node, an updated commodity cost is then applied to each node in addition to the transport charge to yield a fuel price that then enters the model.

B.4.2 Commodity prices

Table 17: Slow rate of increase in gas (commodity) price scenario ($/GJ)

	Qld	NSW	Vic	SA	Tas
2008	4.50	5.00	3.80	4.60	5.50
2009	4.50	5.00	3.80	4.60	5.50
2010	4.50	5.00	3.80	4.60	5.50
2011	4.65	5.30	4.02	4.94	5.75
2012	4.80	5.60	4.24	5.28	6.00
2013	4.95	5.90	4.46	5.62	6.25
2014	5.10	6.20	4.68	5.96	6.50
2015	5.25	6.50	4.90	6.30	6.75
2016	5.40	6.80	5.12	6.64	7.00
2017	5.55	7.10	5.34	6.98	7.25
2018	5.70	7.40	5.56	7.32	7.50
2019	5.85	7.70	5.78	7.66	7.75
2020	6.00	8.00	6.00	8.00	8.00
2021	6.15	8.30	6.22	8.34	8.25
2022	6.30	8.60	6.44	8.68	8.50
2023	6.45	8.90	6.66	9.02	8.75
2024	6.60	9.20	6.88	9.36	9.00
2025	6.75	9.50	7.10	9.70	9.25
2026	6.90	9.80	7.32	10.04	9.50
2027	7.05	10.10	7.54	10.38	9.75
2028	7.20	10.40	7.76	10.72	10.00
2029	7.35	10.70	7.98	11.06	10.25
2030	7.50	11.00	8.20	11.40	10.50

Table 18: Fast rate of increase in gas (commodity) price scenario ($/GJ)

	Qld	NSW	Vic	SA	Tas
2008	4.50	5.00	3.80	4.60	5.50
2009	4.50	5.00	3.80	4.60	5.50
2010	4.50	5.00	3.80	4.60	5.50
2011	4.95	5.60	4.32	5.24	6.05
2012	5.40	6.20	4.84	5.88	6.60
2013	5.85	6.80	5.36	6.52	7.15
2014	6.30	7.40	5.88	7.16	7.70
2015	6.75	8.00	6.40	7.80	8.25
2016	7.20	8.60	6.92	8.44	8.80
2017	7.65	9.20	7.44	9.08	9.35
2018	8.10	9.80	7.96	9.72	9.90

	Qld	NSW	Vic	SA	Tas
2019	8.55	10.40	8.48	10.36	10.45
2020	9.00	11.00	9.00	11.00	11.00
2021	9.30	11.30	9.30	11.30	11.30
2022	9.60	11.60	9.60	11.60	11.60
2023	9.90	11.90	9.90	11.90	11.90
2024	10.20	12.20	10.20	12.20	12.20
2025	10.50	12.50	10.50	12.50	12.50
2026	10.80	12.80	10.80	12.80	12.80
2027	11.10	13.10	11.10	13.10	13.10
2028	11.40	13.40	11.40	13.40	13.40
2029	11.70	13.70	11.70	13.70	13.70
2030	12.00	14.00	12.00	14.00	14.00

B.5 CARBON PRICE PATHS

Table 19: Carbon price escalation

	Carb 10 / 4 $10 start 4% p.a. growth	Carb 10 / 8 $10 start 8% p.a. growth	Carb 20 / 4 $20 start 4% p.a. growth	Carb 20 / 8 $20 start 8% p.a. growth	Carb 30 / 4 $30 start 4% p.a. growth	Carb 30 / 8 $30 start 8% p.a. growth
2010	10.00	10.00	20.00	20.00	30.00	30.00
2011	10.40	10.80	20.80	21.60	31.20	32.40
2012	10.82	11.66	21.63	23.33	32.45	34.99
2013	11.25	12.60	22.50	25.19	33.75	37.79
2014	11.70	13.60	23.40	27.21	35.10	40.81
2015	12.17	14.69	24.33	29.39	36.50	44.08
2016	12.65	15.87	25.31	31.74	37.96	47.61
2017	13.16	17.14	26.32	34.28	39.48	51.41
2018	13.69	18.51	27.37	37.02	41.06	55.53
2019	14.23	19.99	28.47	39.98	42.70	59.97
2020	14.80	21.59	29.60	43.18	44.41	64.77
2021	15.39	23.32	30.79	46.63	46.18	69.95
2022	16.01	25.18	32.02	50.36	48.03	75.55
2023	16.65	27.20	33.30	54.39	49.95	81.59
2024	17.32	29.37	34.63	58.74	51.95	88.12
2025	18.01	31.72	36.02	63.44	54.03	95.17
2026	18.73	34.26	37.46	68.52	56.19	102.78
2027	19.48	37.00	38.96	74.00	58.44	111.00
2028	20.26	39.96	40.52	79.92	60.77	119.88
2029	21.07	43.16	42.14	86.31	63.21	129.47
2030	25.63	63.41	51.27	126.82	76.90	190.24

	Carb 10 / 4 $10 start 4% p.a. growth	Carb 10 / 8 $10 start 8% p.a. growth	Carb 20 / 4 $20 start 4% p.a. growth	Carb 20 / 8 $20 start 8% p.a. growth	Carb 30 / 4 $30 start 4% p.a. growth	Carb 30 / 8 $30 start 8% p.a. growth
2035	31.19	93.17	62.37	186.35	93.56	279.52
2040	37.94	136.90	75.89	273.80	113.83	410.70
2045	46.16	201.15	92.33	402.31	138.49	603.46
2050	56.17	295.56	112.33	591.12	168.50	886.68

B.6 FINANCIAL PARAMETERS

- All prices expressed in $2007-08