Carbon capture and storage projections to 2050

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ACIL Tasman
Economics Policy Strategy

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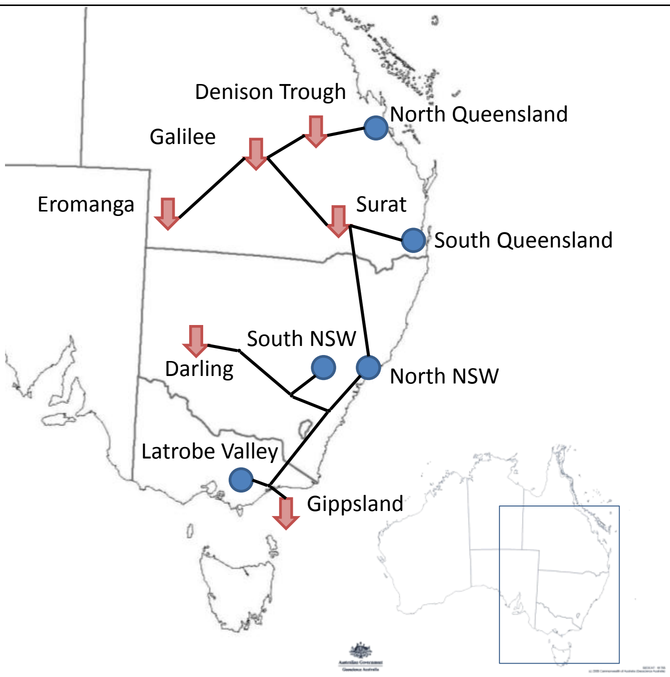
Executive summary

ACIL Tasman has been engaged by the Department of Energy, Resources and Tourism (DRET) to provide projections of the uptake of Carbon Capture and Storage (CCS) equipped plant over the period to 2050 in the National Electricity Market (NEM).

DRET have provided cost data for transport and storage of CO_2 for a number of generation site/reservoir pairs as shown in Figure ES 1. This cost data has been incorporated into ACIL Tasman's cost assumptions relating to CCS equipped generation.

Figure ES 1 **Notional generation sites, CO_2 pipelines and storage hubs**



Data source: UNSW, Costs of CO2 transport and storage in Australia, Draft, May 2009

Table ES 1 **Carbon transport and storage costs (\$/tonne CO_2)**

Generation location	Storage Location	Best Case	Mid Case	High Case
Latrobe Valley	Gippsland Basin	6	7	8
North NSW	Surat Basin	16	82	220
South NSW	Gippsland Basin	32	34	36
South QLD	Surat Basin	12	19	31
South QLD	Eromanga Basin	34	45	57
North QLD	Galilee Basin	37	80	115
North QLD	Eromanga Basin	28	45	55

Data source: Cost data provided by DRET

Long-term projections of the likely make-up of the generation fleet in the NEM to 2050 have been developed by ACIL Tasman using a simplified electricity market projection tool – PowerMark Long-Term (*PowerMark LT*). *PowerMark LT* is a dynamic least cost model, which optimises generation operation and investments over the period 2010 to 2050, given a range of input assumptions regarding demand growth, incumbent plant costs, interconnectors, new development costs and government policy settings.

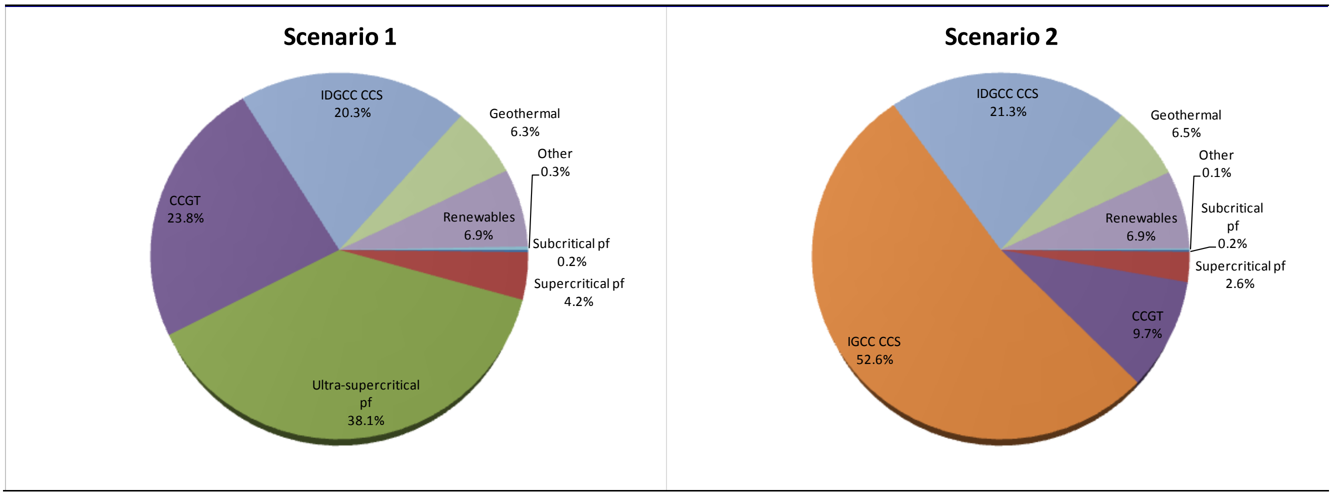
Using a number of assumptions regarding electricity demand growth, new entrant costs and assumptions relating to incumbent generation, ACIL Tasman projected the uptake of CCS equipped plant under two scenarios. These scenarios were as follows:

- **Scenario 1**: represents a low carbon price outlook which tracks permit prices under CPRS-5 scenario until 2030 and is held constant in real terms thereafter at around \$57/tonne CO_2. CCS equipped plant are available for deployment from 2020.
- **Scenario 2**: represents a higher carbon price outlook which tracks permit prices under CPRS-5 scenario until 2050. Permit prices reach \$127/tonne CO_2 in real terms by 2050. CCS equipped plant are available for deployment from 2020.

Figure ES 2 shows the projected generation mix (share of energy generated) by plant type under each of the scenarios. Scenario 1 sees the development of IDGCC CCS plant in Victoria, and high efficiency non-CCS equipped plant in both Queensland and NSW as a result of the capped emission permit price. Gas-fired CCGT also play a significant role in Queensland.

In Scenario 2, CCS plants are developed in Victoria (IDGCC), Queensland and NSW (IGCC) and account for over 73% of generation (roughly 343 TWh annually) by 2049-50.

Figure ES 2 **Projected NEM generation mix in 2049-50 under each scenario**

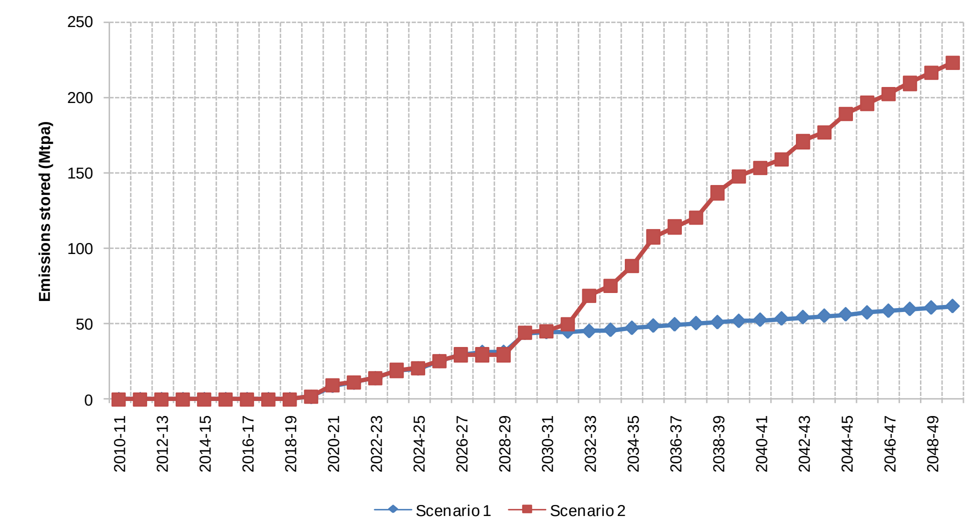


Data source: ACIL Tasman modelling

Figure ES 3 shows the resulting CO_2 volumes captured and stored under each scenario. In Scenario 1 the only volumes to be stored are from Latrobe Valley IDGCC plants which utilise the Gippsland Basin. Volumes under this scenario exceed 50 Mtpa by 2049-50.

In Scenario 2, additional IGCC CCS plant are developed in Queensland (stored in the Surat Basin) and NSW (stored in the Gippsland Basin), resulting in an aggregate transport and storage task of around 220 Mtpa by the end of the projection.

Figure ES 3 **Projected CO_2 emissions captured and stored**

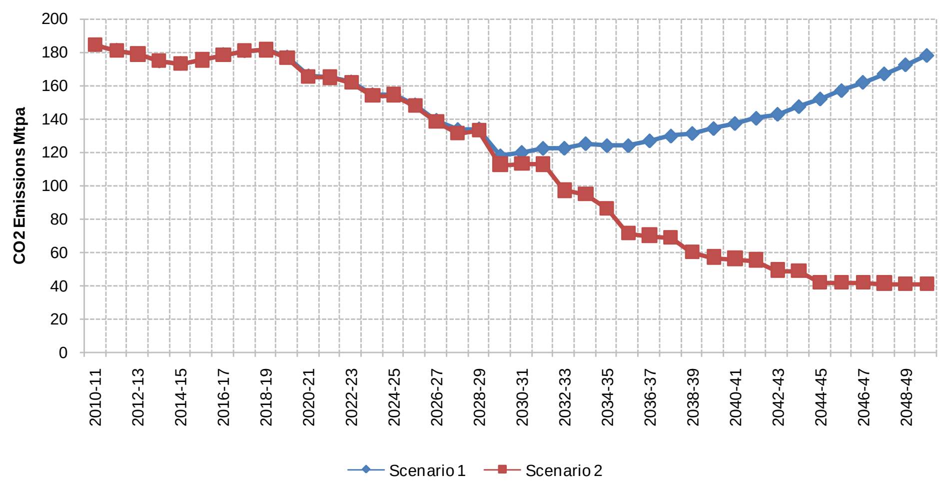


Data source: ACIL Tasman modelling

Figure ES 4 shows the resulting NEM emission profile under each scenario. Scenario 1 which involved the ongoing development of coal-fired plant without CCS results in emissions climbing from around 2030, indicating the emission permit price is not sufficient to offset the costs of CCS in these regions.

Significant abatement of emissions occurs under Scenario 2 relative to starting levels as a result of ongoing CCS development.

Figure ES 4 **Projected emission levels from NEM generation**



Data source: ACIL Tasman modelling

While acknowledging a number of limitations in the analysis undertaken for this exercise, opportunities for CCS in the Latrobe Valley appear to be the most significant across the east coast of Australia – given the abundant low cost coal supply and nearby storage potential offered by the Gippsland Basin. The modelling showed that in all scenarios that CCS became the lowest cost generation option from 2020 onwards. This result is significant given Victoria's large brown coal resource may become sterilised in the absence of CCS once emissions trading comes into force. For these reasons ACIL Tasman believe that the Latrobe Valley should become the primary focus for any commercial-scale demonstration efforts.

Development of CCS in Queensland and NSW appears more challenging given the potential competition from gas-fired CCGT in the former, and the costs involved in transporting CO_2 to Victoria in the latter. This suggests that commercial development of CCS is likely to be delayed until after 2030, based on the cost projections used in the analysis.

The timeframe for this study was very limited. It has been designed to provide a first-cut look at opportunities for CCS development in the NEM. Additional sensitivity analysis around each of the presented scenarios and a more refined specification of scenarios including CO_2 pipeline constraints or injection rates for storage sites is likely to provide further clarity, but is beyond the scope of this exercise.

1 Introduction and background

ACIL Tasman has been engaged by the Department of Energy, Resources and Tourism (DRET) to provide projections of the uptake of Carbon Capture and Storage (CCS) equipped plant over the period to 2050 in the National Electricity Market (NEM).

DRET have provided cost data for transport and storage of CO_2 for a number of generation site/reservoir pairs. This cost data has been incorporated into ACIL Tasman's cost assumptions relating to CCS equipped generation.

Long-term projections of the likely make-up of the generation fleet in the NEM to 2050 have been developed by ACIL Tasman using *PowerMark LT* – which utilises a long-term planning approach.

The timeframe for this study was very limited and is designed to provide a first-cut look at opportunities for CCS development in the NEM. Additional sensitivity analysis around each of the presented scenarios and a more refined specification of scenarios including CO_2 pipeline constraints or injection rates for storage sites is likely to provide further clarity, but is beyond the scope of this exercise.

2 Methodology

Long-term projections of the likely make-up of the generation fleet in the NEM to 2050 were developed using *PowerMark LT*.

The following sections provide an overview of the modelling approach and key input parameters used in deriving the projections.

2.1 PowerMark LT

PowerMark LT is a dynamic least cost model, which optimises generation operation and investments over the period 2010 to 2050, given a range of input assumptions regarding demand growth, incumbent plant costs, interconnectors, new development costs and government policy settings. *PowerMark LT* utilises a large scale commercial LP solver. The LP matrix is reasonably large with approximately 1 million variables, 1.4 million constraints and 2.5 million non-zero coefficients.

The model is not strictly a least cost Short-Run Marginal Cost (SRMC) model, in that each plant is represented by two offer bands – one at SRMC and another at a defined multiple of SRMC.[1] This is a crude approximation of the complex bidding behaviour observed in the NEM. The SRMC offer band represents a proxy for the plants level of contract cover, which owners are incentivised to offer to the market at their marginal cost of generation. The second, higher offer band reflects the uncontracted portion of the stations output that typically seeks higher priced opportunity sales.

PowerMark LT utilises a sampled 100 point sequential representation of demand in each year, with each point weighted such that it provides a realistic representation of the demand population. The sampling utilises a tree clustering process with a weighted pair-group centroid distance measure.

The NEM is modelled on a regional basis with interconnectors represented as bidirectional linkages between regions with defined capacity limits and linear (as opposed to quadratic) loss equations.

In relation to new entry, PowerMark LT provides an optimal expansion program which takes into account all generation costs, including carbon costs and constructs new generation facilities under the assumption of perfect foresight of future costs.

[1] Alternate modelling approaches could involve the use of additional offer bands and potentially fewer demand points to keep the problem tractable.

A range of new entrant technologies are available for deployment in each region, with defined fixed and variable costs. Fixed costs are in the form of an annual charge (specified in $/kW/year), covering capital, fixed O&M and tax. Variable costs (specified in $/MWh), represent fuel, variable O&M and carbon costs. For each technology constraints may be applied to construction limits in any one year or in aggregate.

The model is calibrated against the more detailed PowerMark simulation model for the initial 10-15 year period.

2.2 Key input assumptions

This section provides an overview of the key input assumptions used within the modelling.

2.2.1 Demand

Table 1 and Table 2 provide an overview of the annual energy and peak demand assumptions used within the modelling. These demand figures to 2030 are sourced from the NEMMCO 2008 SOO, with adjustments made for the anticipated impact of the Carbon Pollution Reduction Scheme (CPRS) and the Expanded Renewable Energy Target (eRET) upon demand levels. Growth in annual energy post 2030 has been extrapolated from the 2008 to 2030 projections. Long-term peak demand growth rates have been set to match growth in annual energy (i.e. constant load factor).

Table 1 **Annual energy and growth rates 2009-10 to 2049-50**

Energy (GWh generated)						
Year	NSW	QLD	SA	TAS	VIC	NEM
2009-10	80,132	53,130	13,775	10,431	53,782	211,250
2019-20	89,975	70,544	16,156	12,614	60,302	249,590
2029-30	105,690	96,878	19,786	14,435	71,917	308,707
2039-40	123,353	132,146	24,055	16,479	85,115	381,148
2049-50	143,967	180,253	29,245	18,811	100,735	473,012
CAGR						
Period to	NSW	QLD	SA	TAS	VIC	NEM
2019-20	1.17%	2.88%	1.61%	1.92%	1.15%	1.68%
2029-30	1.62%	3.22%	2.05%	1.36%	1.78%	2.15%
2039-40	1.56%	3.15%	1.97%	1.33%	1.70%	2.13%
2049-50	1.56%	3.15%	1.97%	1.33%	1.70%	2.18%

Data source: ACIL Tasman

Table 2 **Peak demand and growth rates 2009-10 to 2049-50**

Demand (MW generated)						
Year	NSW	QLD	SA	TAS	VIC	NEM
2009-10	14,230	9,020	3,161	1,819	10,049	14,230
2019-20	17,075	11,950	3,520	2,181	11,616	17,075
2029-30	20,793	15,984	4,138	2,533	13,988	20,793
2039-40	24,802	21,533	4,931	2,920	16,682	24,802
2049-50	28,947	29,371	5,994	3,333	19,744	28,947
CAGR						
Period to	NSW	QLD	SA	TAS	VIC	NEM
2019-20	1.84%	2.85%	1.08%	1.83%	1.46%	1.84%
2029-30	1.99%	2.95%	1.63%	1.51%	1.88%	1.99%
2039-40	1.78%	3.02%	1.77%	1.43%	1.78%	1.78%
2049-50	1.56%	3.15%	1.97%	1.33%	1.70%	1.56%

Data source: ACIL Tasman

2.2.2 Incumbent generation

Capacity and cost data for incumbent generators have been sourced from ACIL Tasman's 2009 generator cost report prepared for NEMMCO.[2] Contract cover levels and SRMC multiples have been calibrated out to 2020 with settings used within our fully detailed NEM simulator *PowerMark* and have been held constant thereafter.

2.2.3 Interconnectors

Table 3 details the interconnector assumptions used. It should be noted that in some scenarios significant price differentials between regions result. This may prompt expansion of interconnects to enable increased access to lower cost generation. Due to time constraints, the potential for interconnector augmentation was not examined within the analysis.

Increases in interconnectors would largely be expected to shift the location of CCS plant (source) closer to sinks, but would be unlikely to significantly change the volume of CO_2 generated and transported to each sink.

[2] ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM*, Final report, April 2009 (see http://www.nemmco.com.au/psplanning/nts.html).

Table 3 **Interconnector assumptions**

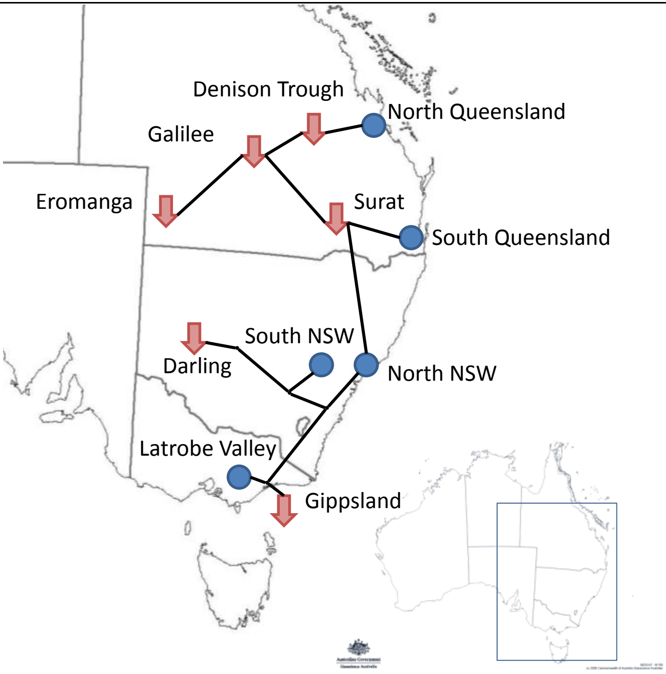
Interconnector	Send Region	Receive Region	Send capacity (MW)	Receive capacity (MW)	Average Losses
BassLink	TAS	VIC	594	478	7.0%
Terranora	NSW	QLD	175	135	5.0%
QNI	NSW	QLD	400	1,080	4.5%
VIC-NSW	VIC	NSW	1,500	1,300	5.0%
Murraylink	VIC	SA	220	120	3.5%
Heywood	VIC	SA	400	300	2.5%

Note: Average losses apply to all flow and losses are shared equally between the two connected regions.
Data source: ACIL Tasman

2.2.4 Carbon transport and storage costs

Figure 1 illustrates the notional generation sites, CO_2 pipelines and storage sinks evaluated by DRET. Estimated transport and storage costs were provided for a number of generation/sink pairs as detailed in Table 4. ACIL Tasman has adopted the Mid Case costs for all scenarios examined.

Figure 1 **Notional generation sites, CO_2 pipelines and storage hubs**



Data source: UNSW, Costs of CO2 transport and storage in Australia, Draft, May 2009

Table 4 **Carbon transport and storage costs ($/tonne CO_2)**

Generation location	Storage Location	Best Case	Mid Case	High Case
Latrobe Valley	Gippsland Basin	6	7	8
North NSW	Surat Basin	16	82	220
South NSW	Gippsland Basin	32	34	36
South QLD	Surat Basin	12	19	31
South QLD	Eromanga Basin	34	45	57
North QLD	Galilee Basin	37	80	115
North QLD	Eromanga Basin	28	45	55

Data source: Cost data provided by DRET

As the transport and storage costs were provided in $/tonne CO_2, these were converted to fixed and variable cost components (in $/kW/year and $/MWh respectively based on assumed emission intensities for IGCC and USC plant respectively). It was assumed 95% of transport and storage costs are fixed and do not vary with output.

ACIL Tasman employed two CCS generation technologies – Integrated Gasification Combined Cycle (IGCC) and Ultra-supercritical coal (USC) with post combustion capture.[3] The proportion of CO2 captured from IGCC and USC was assumed to be 95% and 85% respectively.

Transport and storage costs from Table 4 were converted into fixed and variable components as shown in Table 5.

[3] A variant of IGCC, IDGCC (Integrated Drying Gasification Combined Cycle) was used in Victoria where brown coal is the only available coal resource.

Table 5 **Transport and storage costs translated into fixed and variable components**

Technology_Location_Sink	Emission intensity (kg CO2/MWh)	Capture rate (%)	Emission intensity after capture (kg CO2/MWh)	Tonnes CO2 captured per MWh	Transport and storage cost per MWh	Variable transport and storage cost per MWh	Fixed transport and storage cost per MW/year
IDGCC_Latrobe Valley_Gippsland	962	95%	48	0.91	**6.40**	0.32	47,900
IGCC_North NSW_Surat	954	95%	48	0.91	**74.28**	3.71	556,333
IGCC_South NSW_Gippsland	954	95%	48	0.91	**30.80**	1.54	230,675
IGCC_South QLD_Surat	906	95%	45	0.86	**16.35**	0.82	122,461
IGCC_South QLD_Eromanga	906	95%	45	0.86	**38.72**	1.94	290,039
IGCC_North QLD_Galilee	906	95%	45	0.86	**68.84**	3.44	515,625
IGCC_North QLD_Eromanga	906	95%	45	0.86	**38.72**	1.94	290,039
USC_Latrobe Valley_Gippsland	1,020	85%	153	0.87	**6.07**	0.30	45,456
USC_North NSW_Surat	954	85%	143	0.81	**66.46**	3.32	497,771
USC_South NSW_Gippsland	954	85%	143	0.81	**27.56**	1.38	206,393
USC_South QLD_Surat	906	85%	136	0.77	**14.63**	0.73	109,570
USC_South QLD_Eromanga	906	85%	136	0.77	**34.65**	1.73	259,509
USC_North QLD_Galilee	906	85%	136	0.77	**61.60**	3.08	461,349
USC_North QLD_Eromanga	906	85%	136	0.77	**34.65**	1.73	259,509

Note: Assumed capacity factor for each technology of 90%

Data source: ACIL Tasman analysis

2.2.5 New entrant costs

As capital costs and thermal efficiencies are expected to change over time, new entrant assumptions are developed in 10 year blocks. Each subsequent 10 year block represents the next generation of technology.

Table 6 details the capital cost assumptions for each technology in each 20 year block. In general capital costs are anticipated to decline in real terms – particularly for new technologies as they mature. The capture rates for CCS equipped plant are 95% for IDGCC/IGCC and 85% for USC.

Geothermal Hot Dry Rock (HDR, also known as Hot Fractured Rock or HFR) plant were assumed only to be available in South Australia, however it should be noted that if proponents are successful in utilising lower quality thermal resources, geothermal plant could become available in other NEM regions. As current Australian Government policy does not support nuclear power as part of Australia's energy mix, nuclear has been excluded from the analysis.

It is important to note that accurate estimates of capital costs, particularly for long-term projections in relation to new or emerging technologies is extremely difficult because of the large uncertainties in input costs and technological developments. In this regard there is no 'one correct' assumption to use within analysis of this kind. Ideally, long-term projections should be undertaken across a range of potential cost assumptions, using sensitivity analysis to test the robustness of results. In this instance, as a result of time and budget constraints, the analysis has been limited to a single set of cost assumptions. It should be noted however that outcomes are highly dependent upon cost input assumptions given the nature of the modelling exercise.

Table 6 **New entrant capital costs (Real 2009 $/kW installed)**

Technology	2010-20	2020-30	2030-40	2040-50
CCGT (AC)	1,237	1,189	1,174	1,174
OCGT	889	851	839	839
SC BLACK (AC)	2,126	2,071	2,057	2,057
SC BROWN (AC)	2,338	2,278	2,262	2,262
USC BLACK (AC)	2,274	2,216	2,201	2,201
USC BROWN (AC)	2,502	2,438	2,421	2,421
Geothermal (HDR)	5,070	4,461	4,256	4,256
IGCC BLACK	2,934	2,506	2,489	2,489
IDGCC BROWN	3,227	2,757	2,738	2,738
CCS technologies				
IDGCC_CCS_Brown	4,139	3,465	3,394	3,394
IGCC_CCS_Black	3,763	3,150	3,085	3,085
USC_CCS_Brown	3,641	3,296	3,192	3,192
USC_CCS_Black	3,339	3,045	2,948	2,948

Note: Capital costs for CCS equipped plant exclude CO_2 transport and storage costs which are incorporated through fixed and variable O&M charges. CCS equipped plant not available for deployment until 2020.

Data source: ACIL Tasman analysis

Table 7 shows the capital cost premium applied to CCS equipped plant for capture of CO_2 over conventional non-CCS plant of the same type. Premiums are assumed to decline over time as the technology matures.

Table 7 **Capital cost premium for carbon capture**

CCS Plant	2010-20	2020-30	2030-40	2040-50
IDGCC Brown	28%	26%	24%	24%
IGCC Black	28%	26%	24%	24%
USC Brown	46%	35%	32%	32%
USC Black	47%	37%	34%	34%

Note: Represents the percentage increase in capital cost (in $/kW) over conventional non-CCS plant. CCS capital costs include capture component only (transport and storage costs accounted within O&M figures).

Data source: ACIL Tasman analysis

Along with capital costs, thermal efficiencies are also assumed to improve over time with each subsequent generation of plant as shown in Table 8.

Table 8 **New entrant thermal efficiencies (%)**

Technology	2010-20	2020-30	2030-40	2040-50
CCGT (AC)	52.0%	53.8%	54.0%	54.0%
OCGT	32.8%	35.2%	36.0%	36.0%
SC BLACK (AC)	40.8%	41.8%	42.0%	42.0%
SC BROWN (AC)	32.7%	33.4%	34.0%	34.0%
USC BLACK (AC)	44.8%	48.2%	49.0%	49.0%
USC BROWN (AC)	36.5%	39.2%	40.0%	40.0%
Geothermal (HDR)	70.0%	70.0%	70.0%	70.0%
IGCC BLACK	42.1%	44.1%	45.0%	45.0%
IDGCC BROWN	42.1%	44.1%	45.0%	45.0%
CCS technologies				
IDGCC_CCS_Brown	34.1%	38.5%	40.0%	40.0%
IGCC_CCS_Black	34.1%	38.5%	40.0%	40.0%
USC_CCS_Brown	30.1%	33.5%	35.0%	35.0%
USC_CCS_Black	33.1%	37.4%	39.0%	39.0%

Note: Expressed on a sent-out HHV basis. CCS equipped plant not available for deployment until 2020.
Data source: ACIL Tasman analysis

Table 9 shows the fuel cost assumptions used for coal and gas based plant for selected years in real terms. It should be noted that for this exercise fuel costs post 2030 are simple extrapolations of trends to 2030. ACIL Tasman has not assessed resource adequacy to support generation levels.

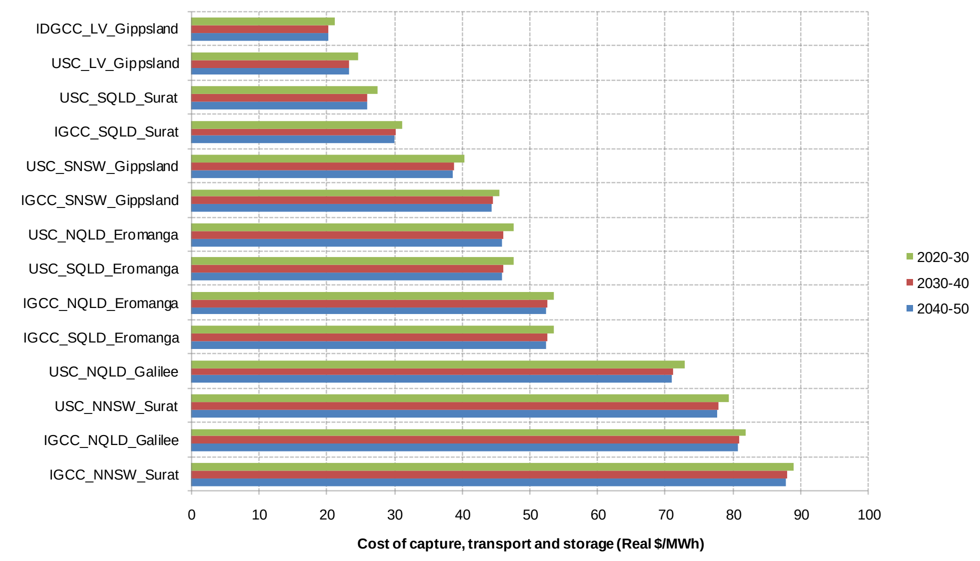
Table 9 **New entrant fuel cost assumptions (Real $/GJ)**

	2010-11	2019-20	2029-30	2039-40	2049-50
Black coal Central QLD	1.39	1.20	1.09	1.00	0.91
Black coal SW QLD	1.46	1.37	1.28	1.20	1.13
Black coal Central NSW	1.28	1.14	1.01	0.88	0.75
Brown coal VIC	0.57	0.56	0.54	0.53	0.52
Natural gas SW QLD	4.69	4.83	5.29	6.02	6.74
Natural gas Central NSW	5.54	5.78	6.71	7.91	9.10
Natural gas Latrobe VIC	4.47	5.30	6.62	8.59	10.56
Natural gas Adelaide SA	5.43	6.47	7.58	9.10	10.61
Natural gas Bell Bay TAS	5.28	6.11	7.40	9.28	11.15

Note: The figures show fuel prices for selected years only – they do not represent an average or mid-point for the ten year block.
Data source: ACIL Tasman analysis

Figure 2 displays the calculated cost of capture, transport and storage of CO_2 for each of the generation site/storage basin options for ultra-supercritical (USC) and IGCC technologies in $/MWh. This cost is calculated as the difference in LRMC (in $/MWh) between CCS equipped plant and non-CCS plant (plant with no carbon capture component included) at 90% capacity factor. The differential therefore includes the incremental capital for capture, additional auxiliary usage (loss of sent-out thermal efficiency) and incremental capital and operating costs associated with transport and storage. The chart presents three cost elements, representing three ten year blocks within the projection. The CCS premium declines slightly over time as a result of the assumptions regarding capital cost decline in real terms and also the reduction in efficiency penalty.

Figure 2 **Cost of capture, transport and storage of CO_2**



Data source: ACIL Tasman analysis

While the costs between IDGCC/IGCC and USC technologies appear relatively close within regions, the assumption that IDGCC/IGCC capture 95% of emissions, while USC plant – which utilises post combustion capture – only captures 85%, results in a larger LRMC differential between the two once the cost of carbon capture is included.

It should also be noted that the costs of CCS in Figure 2 do not equate directly to the emission permit price. That is, if the costs of CCS are $30/MWh, this does not mean that this technology would be economic with an emission permit price of $30/tonne CO_2. This is because:

- the level of 'pass-through' of emission permit prices (in $/tonne CO_2) through to wholesale electricity prices (in $/MWh) will be less than one as a result of incumbent and new entrant emission intensities. This is particularly the case for gas-fired CCGT which has emission intensity of around 0.4 tonnes CO_2/MWh.
- the underlying technology without CCS will generally have an emission intensity itself of less than one.

As a result of these two factors it is often difficult to say at what emission permit price each CCS technology option would become viable. For example, a CCS technology which has a $30/MWh cost of CCS may require permit prices in excess of $50/tonne CO_2, before it becomes commercially viable.

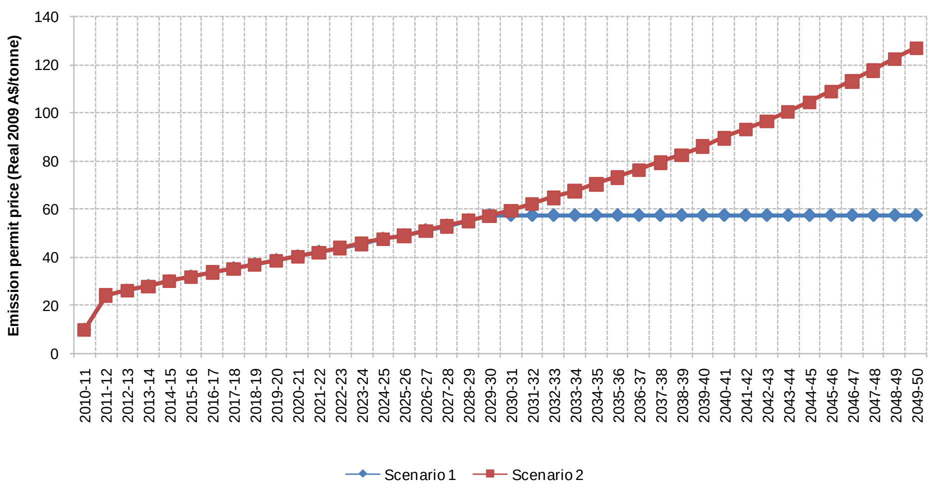
3 Scenario modelling

In projecting the potential uptake of CCS to 2050, ACIL Tasman has examined two scenarios:

- **Scenario 1**: represents a low carbon price outlook which tracks permit prices under CPRS-5 scenario until 2030 and held constant in real terms thereafter at around \$57/tonne CO_2. CCS equipped plant are available for deployment from 2020.
- **Scenario 2**: represents a higher carbon price outlook which tracks permit prices under CPRS-5 scenario until 2050. Permit prices reach \$127/tonne CO_2 in real terms by 2050. CCS equipped plant are available for deployment from 2020.

All cost inputs and electricity demand are held constant across both scenarios. The emission permit prices for Scenario 1 & 2 are shown in Figure 3.

Figure 3 **Emission permit prices assumed under each scenario**

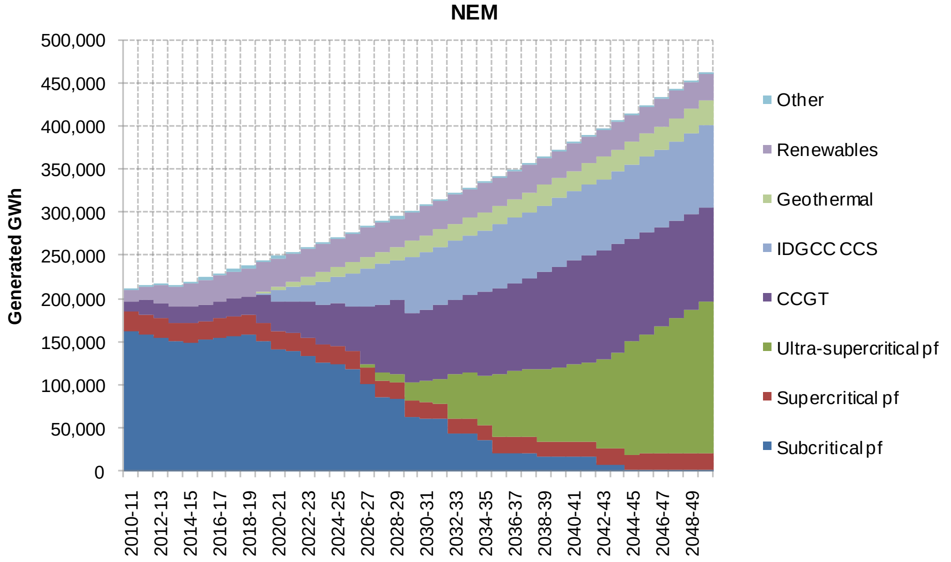


Data source: ACIL Tasman analysis based on Treasury modelling of CPRS-5 scenario

3.1 Scenario 1 results

Figure 4 shows NEM generation by plant-type over the 40 year period spanning 2010-11 through to 2049-50. The share of energy met by each generation technology for selected years is also shown in Figure 5.

Figure 4 **NEM generation by plant type: Scenario 1**



Data source: ACIL Tasman modelling

Figure 6 provides charts showing generation by plant-type for the four major NEM regions.

Scenario 1 results in the development of IDGCC plant equipped with CCS in Victoria from 2020 onward. Development of this technology replaces existing subcritical brown coal plant and meets energy growth in Victoria. As a result of the emission permit price being capped at $57/tonne from 2030 onward, the development of CCS equipped plant in other regions does not occur, indicating that costs of capture, transport and storage for other locations exceeds the permit price.

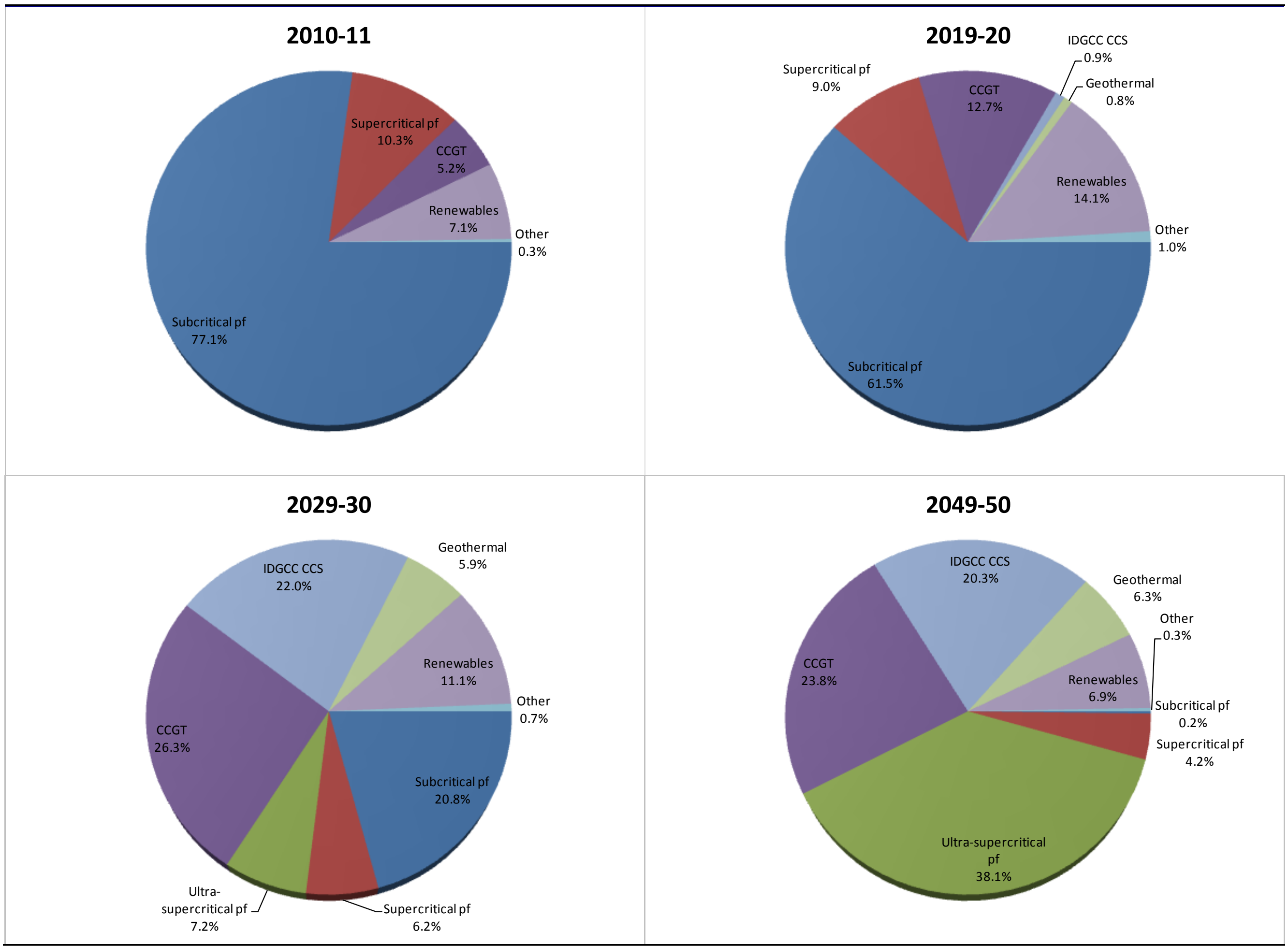
Gas-fired CCGT plays a significant role in Queensland, accounting for much of the growth in demand and replacement/displacement of existing coal-fired stations. However, late in the projection period, ultra-supercritical coal becomes a lower cost option as a result of increasing gas prices.

NSW sees ultra-supercritical coal enter much earlier as a result of higher gas prices and this continues to replace existing subcritical units as they retire.

South Australia's demand is largely met by geothermal developments, with installed capacity reaching 1,700 MW by 2025, and growing to 3,900 MW by 2050.

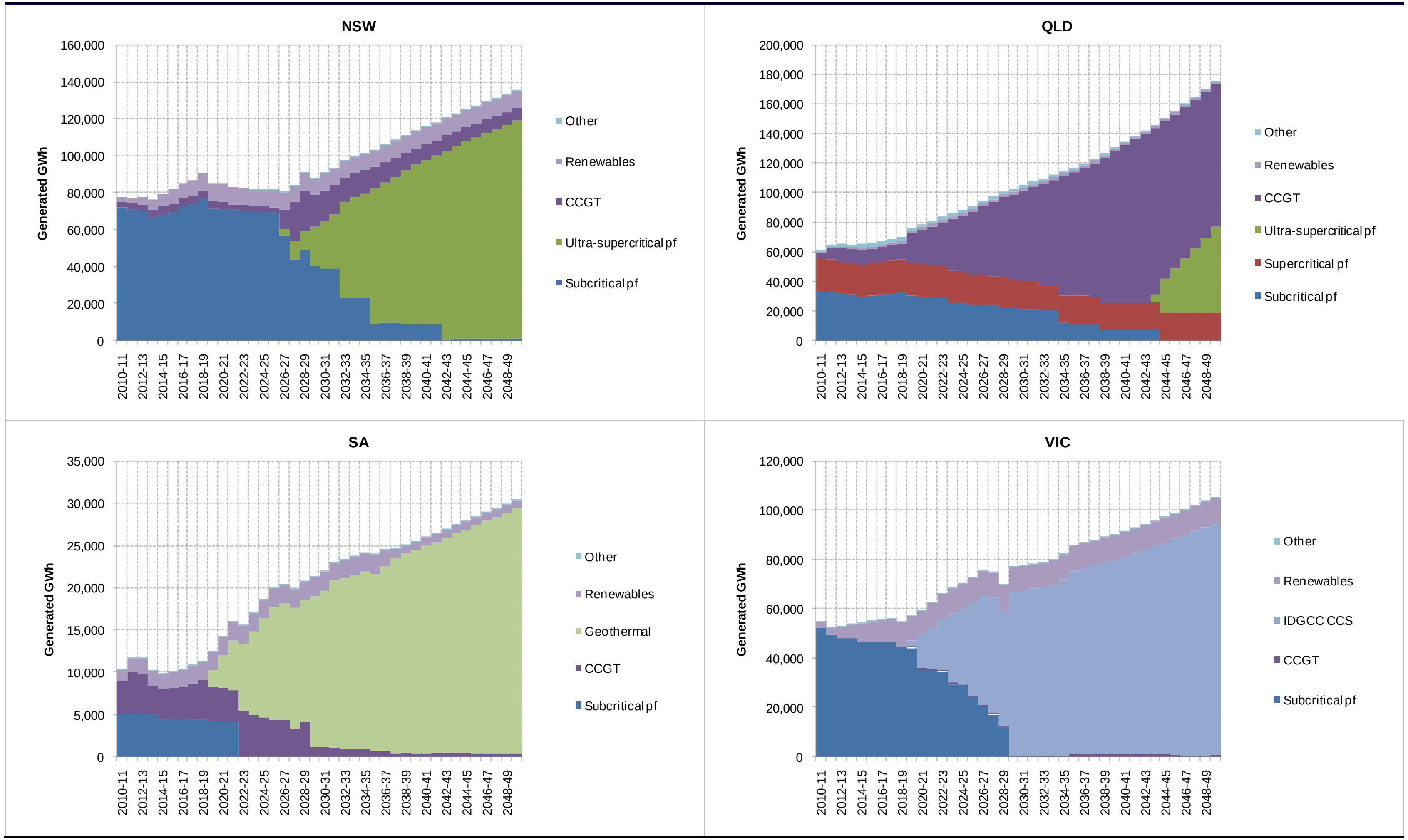
Tasmania, although not shown in Figure 6, sees demand met by a combination of existing hydro output, coupled with gas-fired CCGT being developed to meet demand growth over time. By 2050, the modelling projects an additional 700 MW of CCGT capacity (running at high capacity factor) would be required.

Figure 5 **Share of NEM generation by plant-type: Scenario 1**



Data source: ACIL Tasman modelling

Figure 6 **Generation by plant-type by region: Scenario 1**



Data source: ACIL Tasman modelling

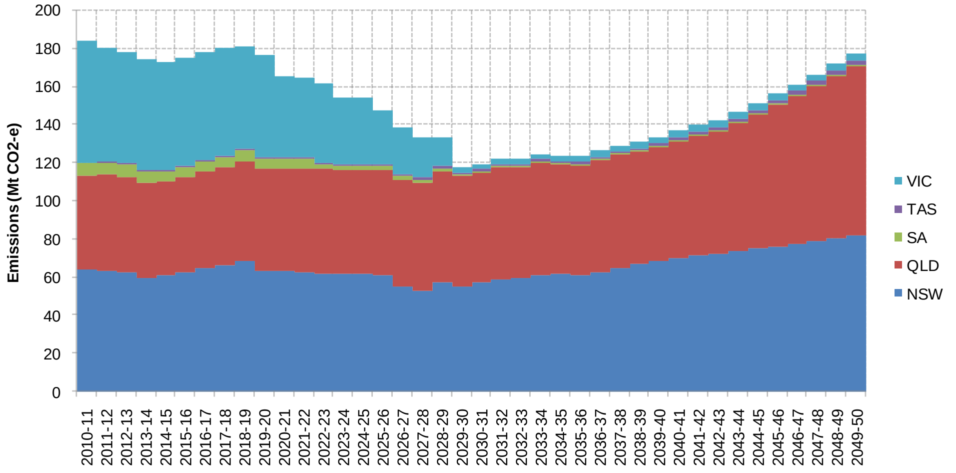
Figure 7 shows the aggregate NEM emissions by region in the period to 2050.

Emissions decline significantly in Victoria as a result of construction of IDGCC plant with CCS. With the last of the incumbent coal fleet retired in around 2030, Victorian emissions remain at low levels for the remainder of the period.

Emissions in NSW and Queensland are relatively flat in the first half of the period, before rising as a result of new ultra-supercritical coal-fired plant being constructed.

Aggregate emissions in 2020 are only around 4% below 2010-11 levels, however these drop to just under 120 Mtpa by 2029-30 (a 36% reduction from 2010-11 levels). Emissions climb back almost to the starting level by 2050 as a result of the capped emission permit price. This profile of emissions from the electricity sector implies that Australia would likely import permits to meet its global obligations. This situation could result if lower cost abatement opportunities existed in other counties relative to Australia.

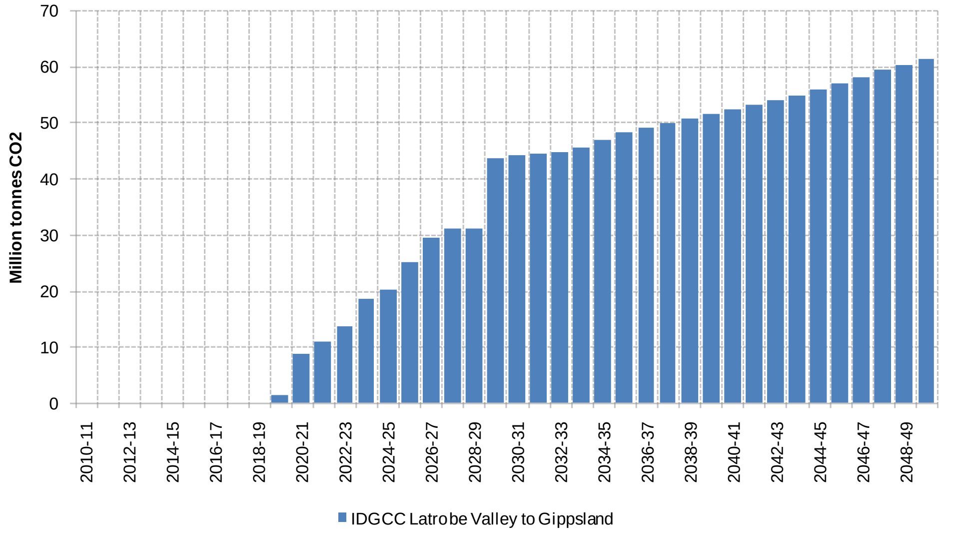
Figure 7 **Projected NEM emissions: Scenario 1**



Data source: ACIL Tasman modelling

Figure 8 shows the CO_2 volumes captured and stored under Scenario 1. Under this scenario CCS technology is only developed in the Latrobe Valley with CO_2 transported and stored in the Gippsland Basin. Volumes ramp up from 2020 up to around 45 Mtpa by 2030 and continue to grow throughout the remainder of the projection period, effectively matching the growth in energy in Victoria, with the only constraining factor to further development being limited interconnector capacity into adjoining regions. Volumes to be stored in the Gippsland Basin peak at just over 60 Mtpa by 2050.

Figure 8 **Volumes of CO_2 captured and stored: Scenario 1**



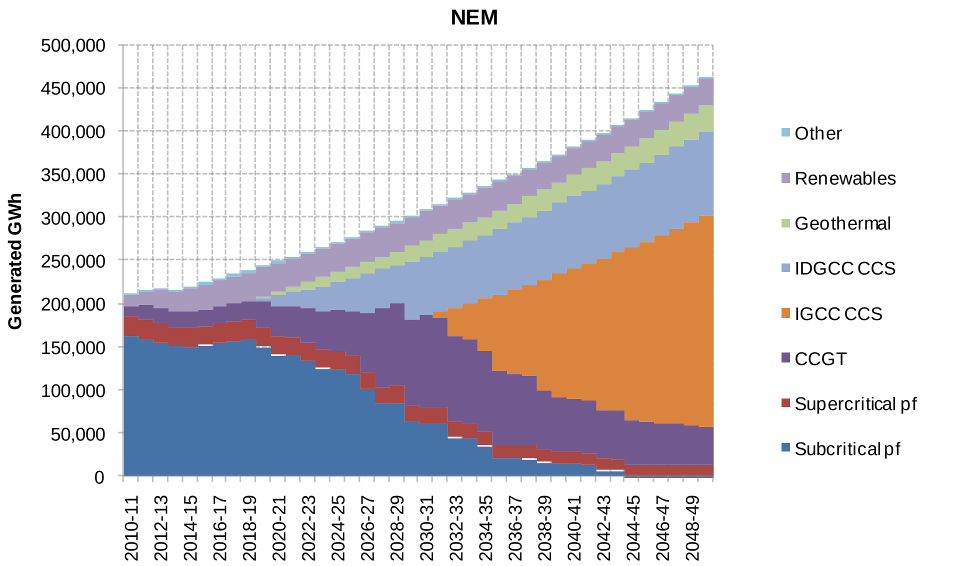
Data source: ACIL Tasman modelling

3.2 Scenario 2 results

Outcomes in Scenario 2 are radically different to those in Scenario 1 as a result of the ongoing increases to the emission permit price (rising at approximately 4% real throughout). The higher carbon costs results in a different plant mix, with CCS equipped stations being constructed in Victoria, NSW and Queensland.

Figure 9 shows NEM generation by plant-type over the projection period.

Figure 9 **NEM generation by plant type: Scenario 2**

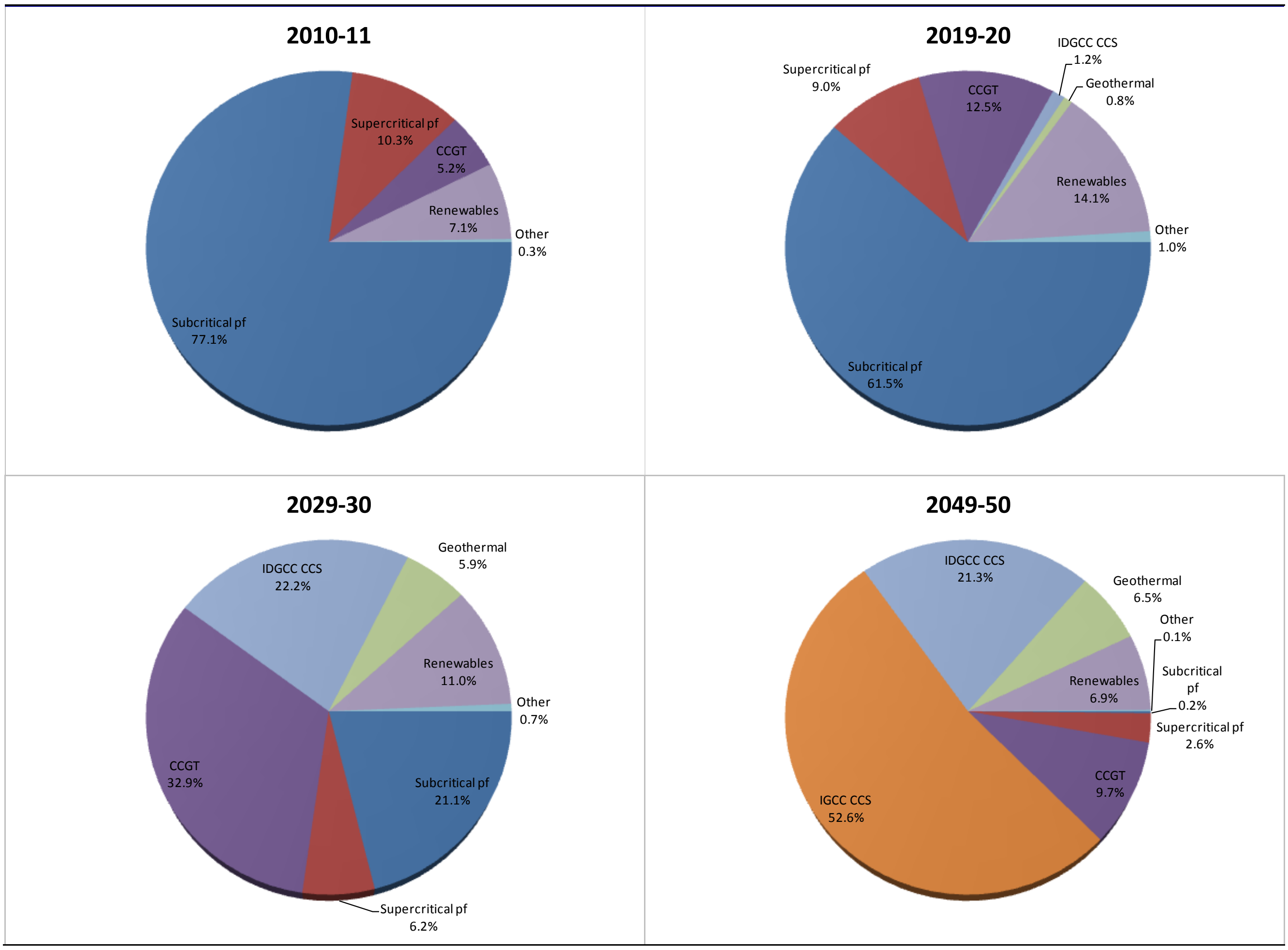


Data source: ACIL Tasman modelling

While IDGCC CCS plants are constructed from 2020 in Victoria, IGCC CCS plants are not built until after 2030 in Queensland and NSW.

The share of energy met by each generation technology for selected years is shown in Figure 10. Results for the period up to 2030 are broadly similar to Scenario 1 as emission permit prices are identical through this period. By the end of the projection, however IGCC CCS plant are contributing over 52% of the total energy supplied in the NEM, IDGCC CCS also contributing over 21%. In aggregate, CCS equipped coal plant are projected to supply around 73% of generation (roughly 343 TWh annually) by 2049-50.

Figure 10 **Share of NEM generation by plant-type: Scenario 2**



Data source: ACIL Tasman modelling

Figure 11 shows generation by fuel-type for each NEM region (except Tasmania). CCS equipped plant dominate the supply mix for all regions except South Australia where geothermal represents the lowest cost option.

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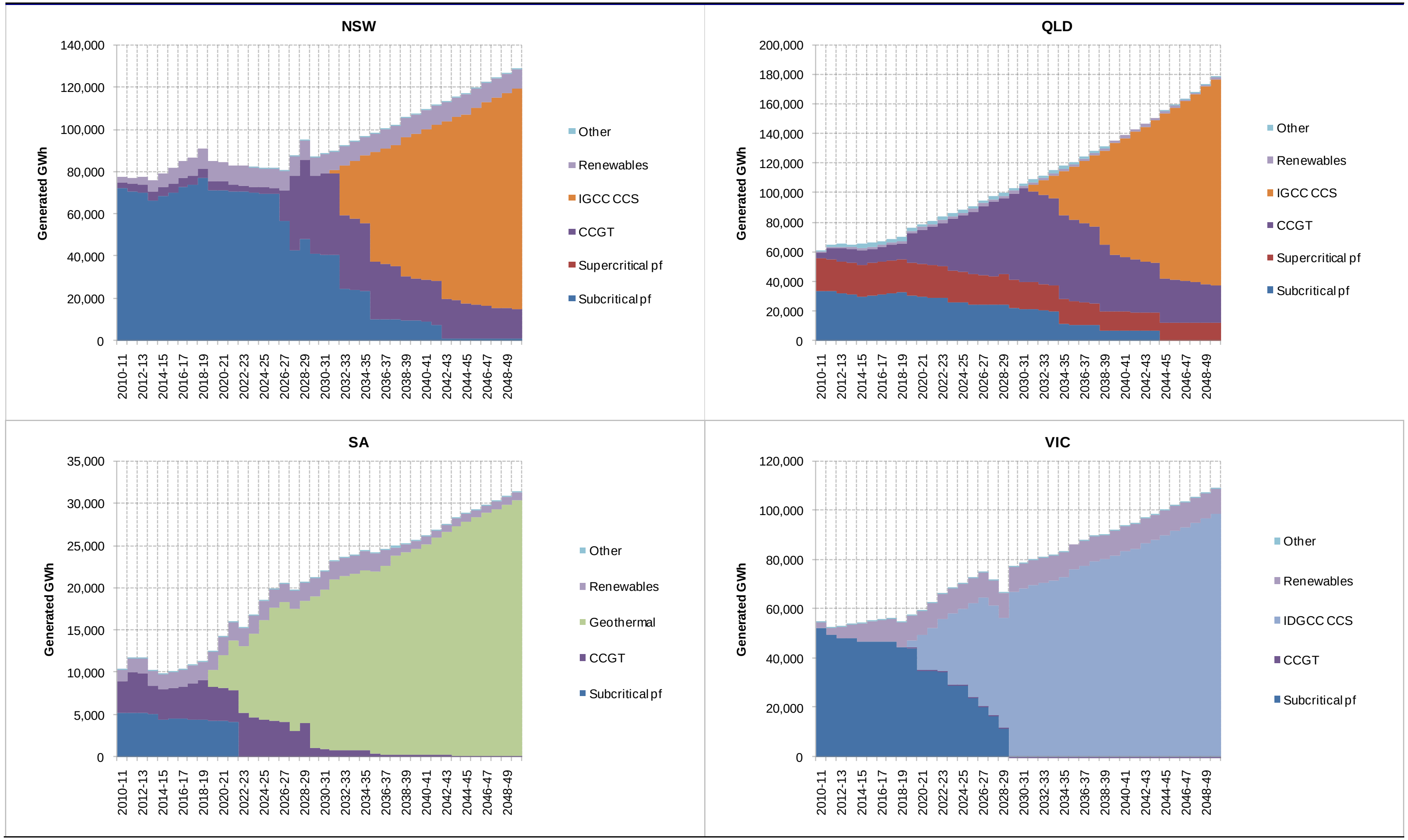
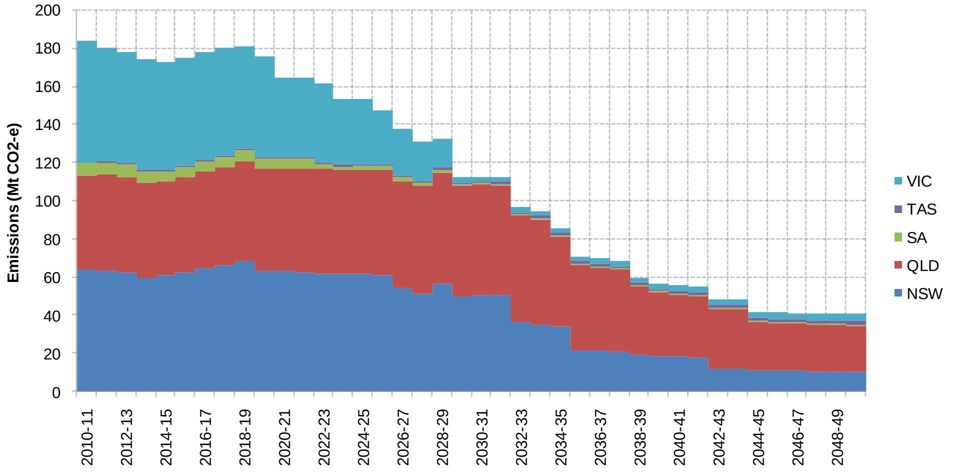
Figure 11 **Generation by plant-type by region: Scenario 2**



Data source: ACIL Tasman modelling

Emissions from the NEM are projected to fall over the period as CCS technologies are taken up. The reduction in emission levels is around 4% by 2020 and 78% by 2050 relative to 2010-11 levels.

Figure 12 **Projected NEM emissions: Scenario 2**



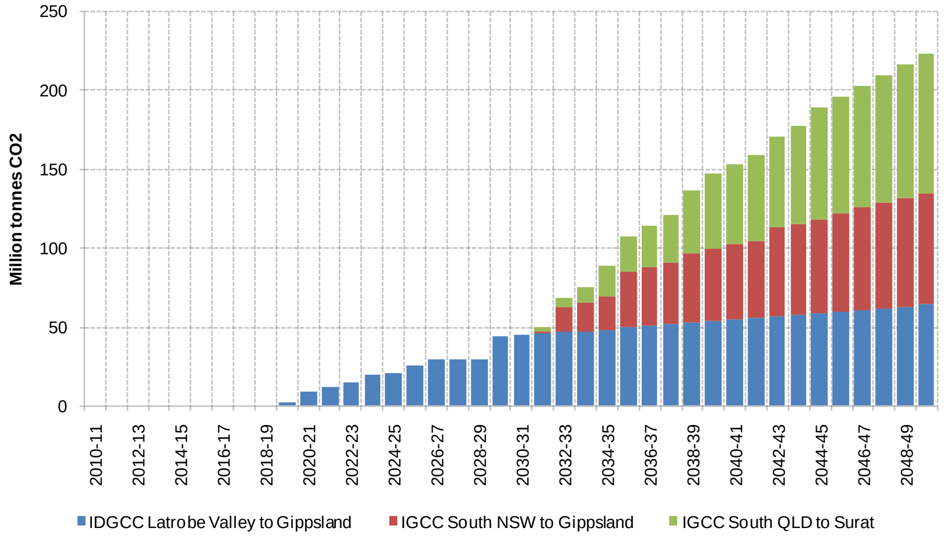
Data source: ACIL Tasman modelling

Volumes of CO_2 captured and stored under Scenario 2 are significant – in aggregate reaching 220 Mtpa/a by 2050 as shown in Figure 13. CCS plant developed in NSW export CO_2 to Gippsland, while Queensland plant store CO_2 locally in the Surat Basin. These outcomes are not particularly surprising given that these generation site/storage options represent the lowest cost alternatives provided by DRET. Different outcomes may result if constraints were applied to pipeline capacity or injection rates for Gippsland and Surat Basins.

Transport and storage costs are expected to be a key consideration for generation proponents and are likely to outweigh fuel cost differentials amongst regions in most circumstances. This may lead to the development of stations as close as possible to storage sites, with coal transported by rail to power station sites rather than siting stations at the mine-mouth as has largely been the case in recent years. The ideal generation site would have access to both suitable coal resource and CO_2 storage.

Another point to note in the projections is that the analysis has not considered opportunities for augmentation of interconnector capacity between regions. Additional interconnection may occur where the cost of augmentation is less than the price differentials between regions and may result in additional development of low cost CCS plant in Victoria, or further development of geothermal resources in South Australia.

Figure 13 **Volumes of CO_2 captured and stored: Scenario 2**



Data source: ACIL Tasman modelling