

Net Zero Emission Electricity

A Total Systems Cost Approach for Queensland



Gamma Energy Technology
EXPERIENCE THINKING INNOVATION

REDvector

Executive Summary

Key Messages

- For deep decarbonisation, CCS is essential and needs to be part of a diverse power generation portfolio:
 - The need for CCS to enable deep decarbonisation beyond approximately 70% is essential, and while its cost remain important, it was secondary to the requirement for CCS.
 - A diverse mix of solar PV, wind, energy storage, hydro, gas and coal with CCS will be required to deliver deep decarbonisation at a lowest total systems cost. Removing any one of these technologies will increase cost to consumer.
- CCS development must commence early to enable adequate deployment:
 - It is expected that Queensland would host at least 6GW of CCS plant and would need to be able to sequester 30-35Mt of CO₂ annually.
 - Large or commercial scale CCS would need to commence in the late 2020's.
 - Large sustained rates of CO₂ storage are required for deep decarbonisation. More storage options (including enhanced oil recovery) are required than the current estimated storage potential of the Surat Basin and Carbon Net projects. All options need to be characterised by drilling new wells.

There is gradual uptake of renewable power plants and more recently, battery storage plants, facilitated by both Federal and State^{a,b} based incentives and a general uncertainty around Federal and State energy and climate policies. The Department of the Environment and Energy state that the shift away from *unabated* coal fired energy generation as the predominant source of supply resources in the National Energy Market (the NEM) has been set in motion, as no new black or brown coal plants have been built to replace retiring plants.^c Internationally, the IEA emphasise that a mixed portfolio of technologies will be required to bring down emissions, including CCS.^d

^a Department of Energy and Water Supply (2017). *Queensland Government response to the Renewable Energy Expert Panel inquiry into credible pathways to a 50 per cent renewable energy target in Queensland by 2030*. Queensland Government, Australia.

^b Stock, P., Alexander, D., Andrew Stock, A. and Bourne, G. (2017). *Renewables Ready: States Leading the Charge*. Climate Change Council, Victoria, Australia, ISBN: 978-1-925573-28-2.

^c Department of the Environment and Energy, (2018). *Australian Energy Update 2018*, August, Canberra.

^d International Energy Agency (2016). *20 Years of Carbon Capture and Storage Accelerating Future Deployment*. Paris, France.

The NEM has experienced increasing contributions from natural gas, both base-load combined cycle (CCGT) and flexible, open cycle plant (OCGT), and wind in today's generation mix, in addition to more utility scale solar PV. The initial introduction of battery (and other energy) storage is also forcing the power generation industry to think differently about how the power system operates and what metrics are best to measure the effectiveness of future changes aimed at decarbonising the electricity sector.

As the requirements for decarbonisation increase, a number of technology options and pathways are being proposed. However, the transition must be considered within some constraints; the system needs to be secure, *reliable and affordable* throughout this transformation to a low emission future.

The Modelling

For this report, MEGS (the Modelling of Energy Grid Services) was used for the modelling of technology scenarios to explore the contribution of different technologies to decarbonising the power system. MEGS is a unique electricity system model that not only ensures demand is met but also that there are sufficient grid services for the system to be secure and operable at all points in time while seeking to model the most effective methods of decarbonising the NEM. The previous report on the "*Managing Flexibility Whilst Decarbonising Electricity, the Australian NEM is changing*" was the first time the MEGS methodology focusing on optimising a total systems cost approach was applied in the Australian context.^e

It is assumed that to meet the various State targets of net zero emissions by 2050 only 90% can be achieved by the technologies modelled (fossil CCS, renewables, energy storage and unabated gas). Nuclear could bring emissions lower but is assumed not to be an option for Australia. Biomass was considered as a costed fuel switching option for coal CCS in order to achieve a net zero emissions reduction target; 'negative emissions' from BECCS plant were used to counteract the remaining emissions of the 90% reduction target.

The Optimum Scenario for Deep Decarbonisation

The transformation from the current generation mix to a system of lowest total system cost for a deep decarbonisation scenario in 2050 is detailed in both Table A and illustrated in Figure A. The total system capacity is significantly higher than the installed capacity today, and as such will likely need commercial / market incentives to achieve such a generation mix.

^e Boston, A., Bongers, G. Byrom, S. and Staffell, I. (2017). *Managing Flexibility Whilst Decarbonising Electricity – the Australian NEM is Changing*. Gamma Energy Technology P/L, Brisbane, Australia.

Table A Lowest total system cost 2050 optimum generation mix

Technology	Generation		Capacity (GW)	
	(TWh)	%	GW	%
Biomass and waste	5	2	1	1
Solar PV	55	21	34	28
Wind	75	28	34	28
Storage	10	4	6	5
Hydro	12	4	7	6
OCGT	2	1	8	7
CCGT/CHP	6	2	10	8
Coal CCS	85	32	18	15
Retrofit Coal CCS	18	7	3	3
Total	268	100%	121	100%

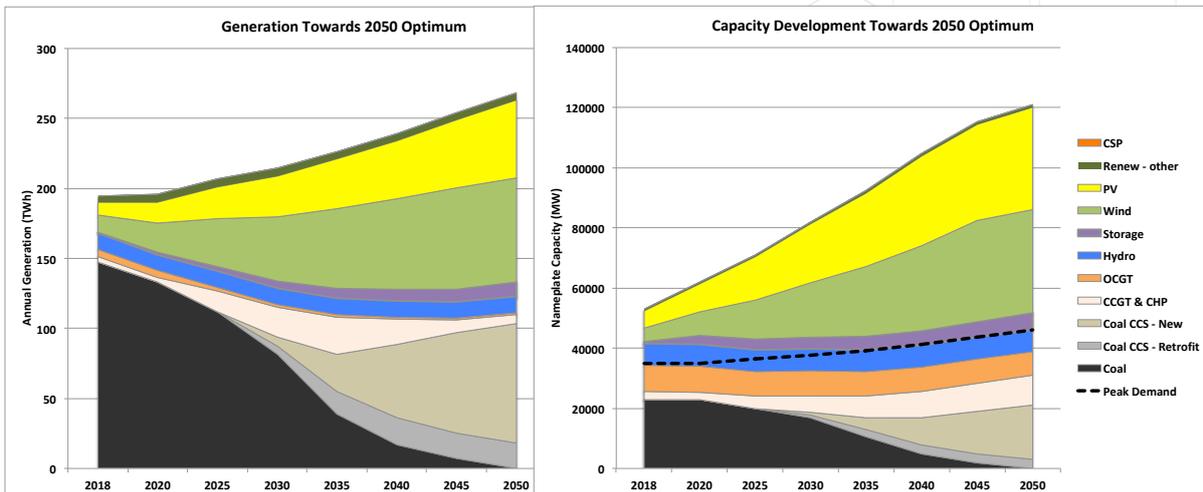


Figure A Lowest total system cost 2050 optimum generation mix

It is important to note that the amount of CCS within the optimum 2050 solution was modelled with no constraints on CO₂ storage. The major storage work with the NEM regions centres around Victoria (Carbon Net) and Queensland (the Surat Basin and Enhanced Oil Recovery). Large sustained rates of CO₂ storage are required and so more storage options (including enhanced oil recovery) beyond current known storage potential of the Surat Basin and Carbon Net projects will be needed for deep decarbonisation. The current understanding is that an approximate limit for storage within the proposed Surat Basin hub is approximately 15Mtpa and for the whole of the NEM a rate of approximately 50Mtpa of CO₂ injection might be assumed^f.

^f Sustained rate is defined as sustainable for a useful, uncertain but finite duration of 30+ years

Queensland’s Fossil Fleet Transformation Pathway

Figure B shows the transformation of the fossil plant in Queensland from now until 2050 for the optimum, deep decarbonisation scenario. The supercritical plants at Tarong North, Callide C, Kogan Creek and Millmerran are retrofitted with CCS, probably starting with one commercial scale unit in the late 2020’s followed by the remaining plant in the 2030’s. Storage from these three plants can likely be accommodated in the Surat Basin⁸. Storage from these three plants can likely be accommodated in the Surat Basin⁸.

By the end of the 2030’s, new CSS-abated coal would be required, and a building programme will be needed to deliver 350MW of new coal with CCS each year of the late 2030’s. Throughout the period to 2050, unabated gas plant is added at the rate of about 1GW per decade, being the most cost effective firm capacity able to meet peak demand. By 2050 there would need to be nearly 6GW of CCS equipped plant operating in Queensland. The amount of CO₂ storage required in this scenario is well above current Queensland estimates and significant additional work is required to quantify this potential constraint.

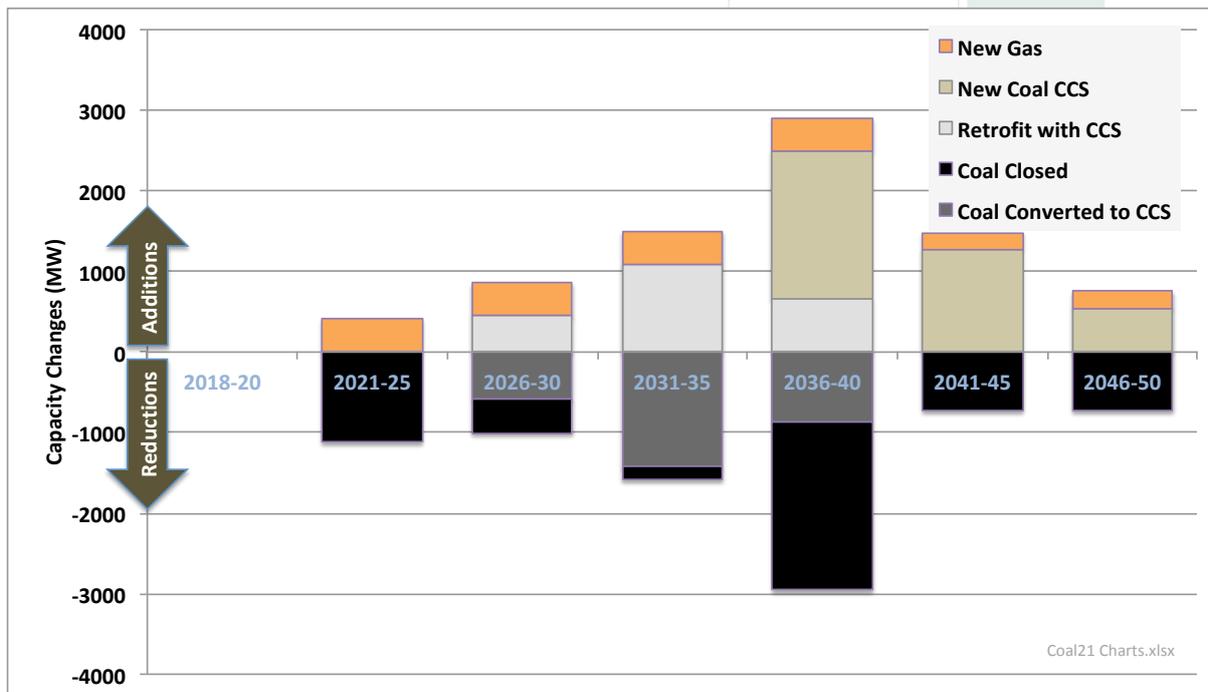


Figure B Development of Fossil Capacity in Queensland

⁸ University of Queensland Surat Deep Aquifer Appraisal Project (2019). *Carbon Capture and Storage Research Design and Development*. To be published.

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Introduction

In attempting to resolve the trilemma of providing reliable, affordable and sustainable electricity within the context of climate change, governments, industry and society are looking for solutions. A transformation of the electricity sector is required to deliver the outcomes the world needs.

Internationally many jurisdictions have set ambitious, long term goals and target with the aim of reducing the potential impacts of global climate change. Queensland, along with other States, has set itself a zero emissions target by 2050. This is in line with a global movement towards achieving the climate aspirations agreed at Paris. This is a significant challenge, as its current electricity system is heavily based on unabated coal generation. However, there have been some small steps towards emission reduction with a gradual uptake of renewable power plants and small scale solar PV, facilitated by Federal and State^{1,2} based renewable energy incentives.

Queensland, as the “Sunshine State” might indicate that solar technologies in particular, could play a significant role in progressing further reductions in emissions. Queensland also benefits from a very large natural gas resource, which could be used to displace coal generation via fuel switching to reduce emissions. Furthermore, Queensland also has the most modern Australian fleet of coal powered electricity fleet, along with abundant coal reserves.

Queensland also benefits from favourable geology, such as the Surat Basin, that could hold significant volumes of carbon dioxide if capture plant were added to existing or new power stations to deliver low carbon firm and dispatchable generation. The Queensland Government’s Climate Transition Plan³ considers the development of carbon sequestration capacity as “a low risk no-regrets action that Queensland can take”.

This study examines the role that this suite of power generation technologies, renewables, gas and Carbon Capture and Storage (CCS), could play in achieving Queensland’s target of zero emissions by 2050. It has been conducted in conjunction with the University of Queensland as part of their Surat Deep Aquifer Appraisal Project (UQ-SDAAP), and funded by Australian Coal Association Low Emissions Technologies Limited (ACALET) via the COAL21 Fund.

¹ Department of Energy and Water Supply (2017). *Queensland Government response to the Renewable Energy Expert Panel inquiry into credible pathways to a 50 per cent renewable energy target in Queensland by 2030*. Queensland Government, Brisbane, Australia.

² Stock, P., Alexander, D., Andrew Stock, A. and Bourne, G. (2017) *Renewables Ready: States Leading the Charge*. Climate Change Council, Victoria, Australia, ISBN: 978-1-925573-28-2.

³ Department of Environment and Heritage Protection (2017). *Pathways to a clean growth economy Queensland Climate Transition Strategy*. Queensland Government, Brisbane, Australia.

Previous modelling of the NEM

The Managing Flexibility Whilst Decarbonising Electricity, The Australian NEM is Changing⁴ report was the first time the MEGS methodology was used in the Australian context. The report concluded that the Australian grid needs to transform itself over the next decades to satisfy the energy trilemma, and that the NEM is still early in its evolution. The transformation of the grid should not be considered a sprint race between technologies. Rather, technology assets should be assembled as in a team sport, where they are chosen to play their most effective role via the services they provide to the system as a whole.

The four primary considerations from this report where:

- A secure grid requires a range of essential services, they are not just about the provision of electricity.
 - As traditional grid service providers are disappearing these services need to be replaced with new suppliers
 - In relation to existing coal and gas plants, increasingly they will need to be more flexible to both provide the electricity when required, and the grid services that are essential.
- It is important to consider the whole electricity system across all timescales to 2050 and beyond.
 - Aiming for intermediate reduction targets without considering long term goals may lead to a sub-optimal generation portfolio.
- The generation technology solution will be diverse to resolve the trilemma.
 - Different technologies offer a range of different attributes and services to the grid. Given the diversity of the NEM, the modelling showed a range of technologies will be required to meet decarbonisation targets.
- The provision of reliable low carbon electricity comes at an increased cost.
 - It is important that a total system optimisation is used to determine future generation technologies at the lowest total system cost with the highest reliability outcomes.
 - All low carbon energy forms are more expensive than existing assets.

The Australian grid has delivered reliable and secure energy for decades. With the majority of electricity generation provided by coal-fired power generation, this technology has also delivered the services required for grid stability such as inertia, frequency control etc. Fossil-fuel technologies have, to date, underpinned the energy competitiveness of the Australian economy, but, the grid is changing. With increasing penetration of renewable energy, it is becoming important to plan for and manage generation asset investment to track the least cost and highest reliability path to a low emissions future.

⁴ Boston, A., Bongers, G. Byrom, S. and Staffell, I. (2017). *Managing Flexibility Whilst Decarbonising Electricity – the Australian NEM is changing*. Gamma Energy Technology P/L, Brisbane, Australia.

Summary of the MEGS Methodology

Using MEGS (a Model of Energy and the Grid Services), this work generates and interrogates many different scenarios which use different combinations of the low carbon technologies to meet demand. However, generating scenarios simplistically by matching the annual energy generation of renewable technologies to demand will overlook the need to maintain a secure and operable system. To ensure that “the lights stay on” in these low carbon scenarios, Red Vector (RV) and Gamma Energy Technologies (GET) have developed MEGS, a Model of Energy and the Grid Services, essential to a secure the electricity system.

Like many models, MEGS balances energy for each calculated point in time for a grid of interconnected regions, but what makes it unique is its attention to the engineering constraints and ancillary services that ensure a grid is operable. In MEGS, these boil down to ensuring:

- Sufficient fast acting reserve is available to each region,
- A minimum level of inertia is connected in each region, and
- New plant only displaces firm capacity if it is not essential for meeting peak demand.

MEGS has been calibrated against the current electricity systems in Australia and used to examine decarbonisation pathways for the NEM as a whole, and for detailed studies of NSW and WA. It is therefore ideally placed to model scenarios for Queensland in the context of the NEM as a whole.

In order to determine the optimum energy mix for 2050, based on the lowest total system cost, the following 4 steps were undertaken using MEGS. The fifth step of the modelling methodology involved examining a range of sensitivities using MEGS.

- Step 1: Find the optimum mix of renewables
- Step 2: Find the optimum scenario for 2050
- Step 3: An examination of the optimum 2050 scenario
- Step 4: Composing the Pathway to 2050
- Step 5: Sensitivities

Refer to Appendix: MEGS – Modelling Energy and Grid Services for detail on the MEGS methodology in general, and how it was applied to this study in particular. Input assumptions are also detailed in this Appendix.

Optimum 2050 Generation Scenario

A number of different generation technologies and technology mixes have long been proposed as future generation scenarios. Solutions including a 100% renewable⁵ based grid, the addition of Snowy 2.0⁶ to the NEM, the introduction of nuclear power generation⁷ into Australia, the development of CCS hubs in Victorian⁸ and Queensland⁹ and the possible ‘options’ developed within the Finkel Review¹⁰, to name just a few.

Using the total system cost minimisation strategy described previously in the Summary of the MEGS Methodology section, an optimum scenario for a 90% reduction in emissions by 2050 across the NEM was determined.

Figure 1 shows the details of the optimum solution determined by MEGS using the lowest total system costs approach. The generation capacity stack on the left shows that total system capacity is around three times the peak demand. The central chart is the generation in load duration format, with each point in time sorted so that maximum values are on the left and minimum on the right. The right hand chart shows at the scheduled output across a ‘typical week’ in late autumn, which initially has only a little wind but ends up very windy.

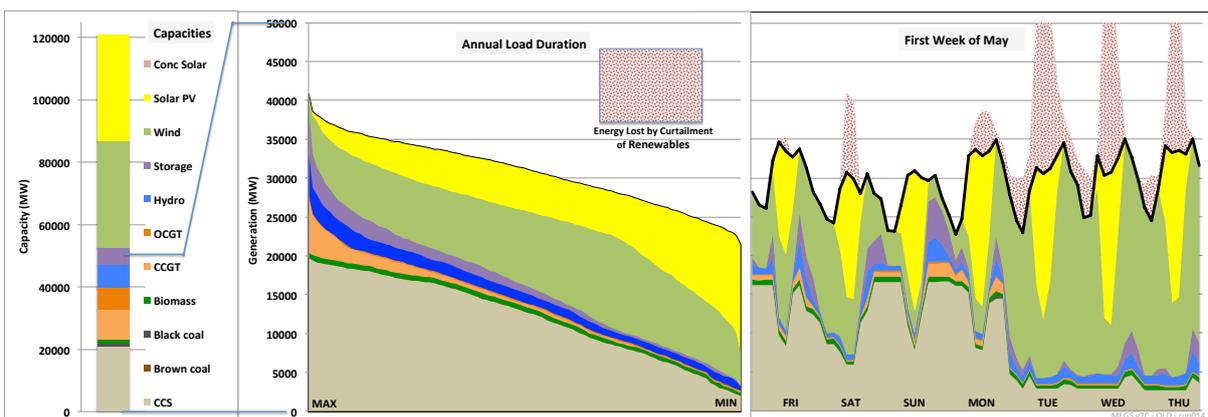


Figure 1 Examination of the Optimum 2050 Lowest Total System Cost Solution

The need for a seemingly large capacity overbuild (3x peak demand) is demonstrated on the load duration curve and also on the right hand chart where during periods of low wind and solar PV output, dispatchable generation is required. The areas on the load duration chart shows where the energy over the whole year comes from: 50% comes from wind and solar PV and 40% comes from the coal CCS. Note that a significant proportion of renewable output (about 12%) is lost through curtailment, as represented by the red box.

⁵ James, G and Hayward, J. (2012) *AEMO 100% renewable energy study: energy storage*. CSIRO; 2012.

⁶ Snowy Hydro Limited (2017). *Snowy 2.0 Short Feasibility Study Report*.

<https://www.snowyhydro.com.au/our-scheme/snowy20/snowy-2-0-feasibility-study/> [Accessed Mar. 2019].

⁷ Nuclear for Climate Australia. (2019). *Chapter 2 - Nuclear Energy replaces Coal Plants in Australia*. nuclearforclimate.com.au/2019/03/01/chapter-2-nuclear-energy-replaces-coal-plants [Accessed Mar. 2019].

⁸ Earth Resources. (2019). *The CarbonNet Project - Earth Resources*. earthresources.vic.gov.au/earth-resources/victorias-earth-resources/carbon-storage/the-carbonnet-project. [Accessed Mar. 2019].

⁹ Bongers, G., Byrom, S., Malss, S. and Constable, T. (2017). *Surat Basin CCS Hub – Helping secure a low carbon future*. ACA Low Emissions Technologies, Brisbane, Queensland.

¹⁰ Finkel, A. (2017). *Independent Review into the Future Security of the National Electricity Market: Blueprint for the future*. Commonwealth of Australia.

The right hand chart shows how this might play out over a typical 7 day period. In the first half of the period which has only a low wind output, the CCS plant is running close to its maximum output, supported by combined and open cycle gas and storage. As wind increases later in the week, CCS drops to minimum output (and in some cases shuts down completely). However, sufficient CCS remains online to provide essential grid services such as frequency response and inertia. A significant amount of wind and solar is curtailed, particularly around mid-day, due to the extensive renewable capacity additions. As the previous section has shown, MEGS found it sub-optimal to build more storage to capture this lost energy, as the costs outweighed the benefits.

To achieve this generation mix, the following plant mix will be required to be constructed:

- New Renewables: 71.3GW
- New CCGT: 7.4GW
- New Coal CCS¹¹: 18.3GW
- Retrofit Coal CCS: 2.9GW (net capacity after conversion)
- New OCGT 0.6GW

Achieving Zero emissions within the Electricity Generation Sector

Queensland, along with other Australian States, has set itself a zero emissions target by 2050. This is in line with a global movement towards achieving the climate aspirations agreed at Paris. This is a significant challenge, as the current electricity system is heavily based on unabated coal and gas generation.

To achieve a zero emissions power grid, any CO₂ emissions that are emitted need to be accounted for or offset in some manner. An open cycle gas turbine, while it only may be used infrequently, emits CO₂, most CCS plants also emits CO₂. Bio-energy CCS (BECCS) is one of the few technical options which allows for CO₂ to be offset.

Currently, combustion based BECCS is the most developed BECCS technology. Using this technology will require burning biomass at a very large scale; this is not the small scale agricultural and domestic waste streams that are already in the data set. The best example of biomass combustion is Drax in the UK which has 2.6GW of capacity to burn pelletised wood and is the largest biomass power station in the world. However, it does not currently have CCS integrated into the plant. Using the quoted cost for generation of £75/MWh without CCS,¹² a BECCS plant in Australia (with its lower efficiency) would generate at approximately \$184/MWh. To abate the remaining 16.3Mt CO₂ to achieve a net zero emissions grid would require production of 17.6TWh of electricity from 3.3GW of BECCS plant, causing an uplift to TSC of \$10.4/MWh.

¹¹ Note that CO₂ injection and storage constraints have not been taken into account in this scenario

¹² Twidale, S. (2018). *Drax plans to cut cost of biomass electricity by a third*. Reuters - Business News U.K. uk.reuters.com/article/uk-drax-biomass-costs/drax-plans-to-cut-cost-of-biomass-electricity-by-a-third-idUKKBN1HR1IG [Accessed Mar. 2019].

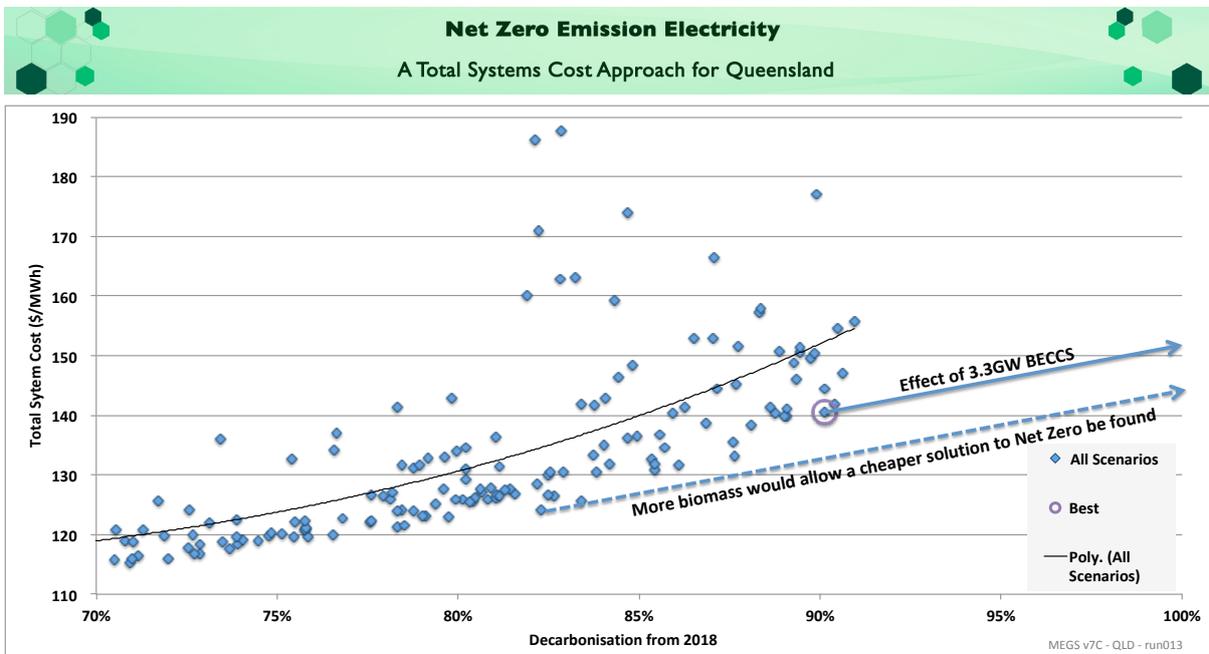


Figure 2 Effect of Using BECCS to bridge the gap from 90% to 100% Decarbonisation

Figure 2 shows the S-MEGS deeper carbonisation results from a 250 scenario run. Each scenario is made up of different amounts of an optimised renewables mix,¹³ natural gas and coal CCS generation options (refer also to Figure 16).

The conversion of some of the coal-CCS plant to biomass with CCS is illustrated in Figure 2. Starting with the lowest total system cost scenario above 90% decarbonisation (highlighted as ‘best’) an additional \$10/MWh on a TSC basis is needed for the BECCS to complete the last 10 percentage points of decarbonisation and attain zero emissions from the grid. The lower dashed arrow shows that if almost twice as much biomass were available (enough to generate 31TWh), a cheaper solution could probably be found by starting with a lower level of decarbonisation and bridging a larger gap with BECCS.

Generation Build Pathway to 2050

Achieving a 2050 optimum solution requires a transformation of the current power generation mix. New generation plant will be required to add to the generation mix and replace existing plants that will be closed (typically these are closed at the end of their technical life).

The change in generation and capacity on the system over time is illustrated in Figure 3. The growth of CCS would need to commence in the late 2020’s and accelerates through the 2030’s. Also shown is how peak demand growth is mostly covered by the firm capacity at the bottom of the stack fossil plant, as storage and renewables can provide very little dependable capacity. It can be seen that the decline in coal output on the left is faster than the closure of capacity on the right as it runs at increasingly lower load factors around the growing renewables output. It can also be seen how a much larger growth in renewable capacity is required to achieve similar output levels to CCS.

¹³ Refer to MEGS Study Methodology: Detailed, page 23.

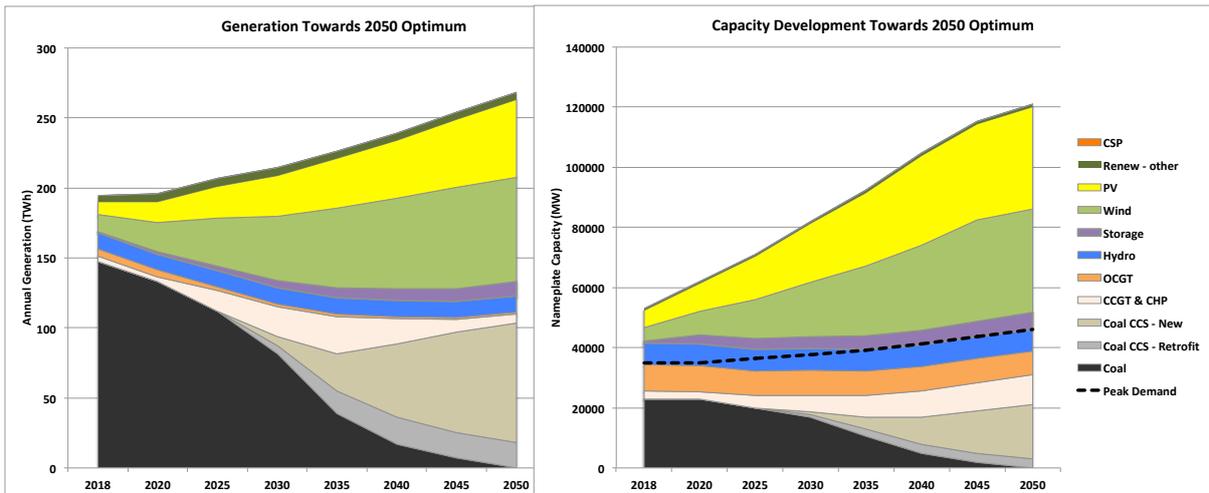


Figure 3 Development of Capacity Along the Pathway

The development of CCS in and around the Surat Basin is of particular interest to this study. MEGS does not divide States into smaller regions, so the development within the whole of Queensland is illustrated in Figure 4. The supercritical plants at Tarong North, Callide C, Kogan Creek and Millmerran are retrofitted with CCS, which is assumed to start with one industrial-scale pilot unit in the late 2020's followed by the remaining plant in the 2030's.¹⁴ By the end of the 2030's new abated coal would be required, and a building programme will be needed to deliver 350MW of new coal with CCS each year of the late 2030's. Storage from three plants can likely be accommodated in the Surat Basin.¹⁵ Throughout the period to 2050, gas plant is added at the rate of approximately 1GW per decade. By 2050, there will be nearly 6GW of CCS-equipped plant operating in Queensland. The amount of CO₂ storage required in this scenario is well above current Queensland estimates and significant additional work is required to investigate and quantify this potential constraint.

¹⁴ The use of an industrial-scale pilot plant is not an outcome of the MEGS modelling, but rather a comment on the steps likely required to establish a CCS industry in Australia, and the likely location based on current research and understanding.

¹⁵ University of Queensland Surat Deep Aquifer Appraisal Project (2019). *Carbon Capture and Storage Research Design and Development*. To be published.

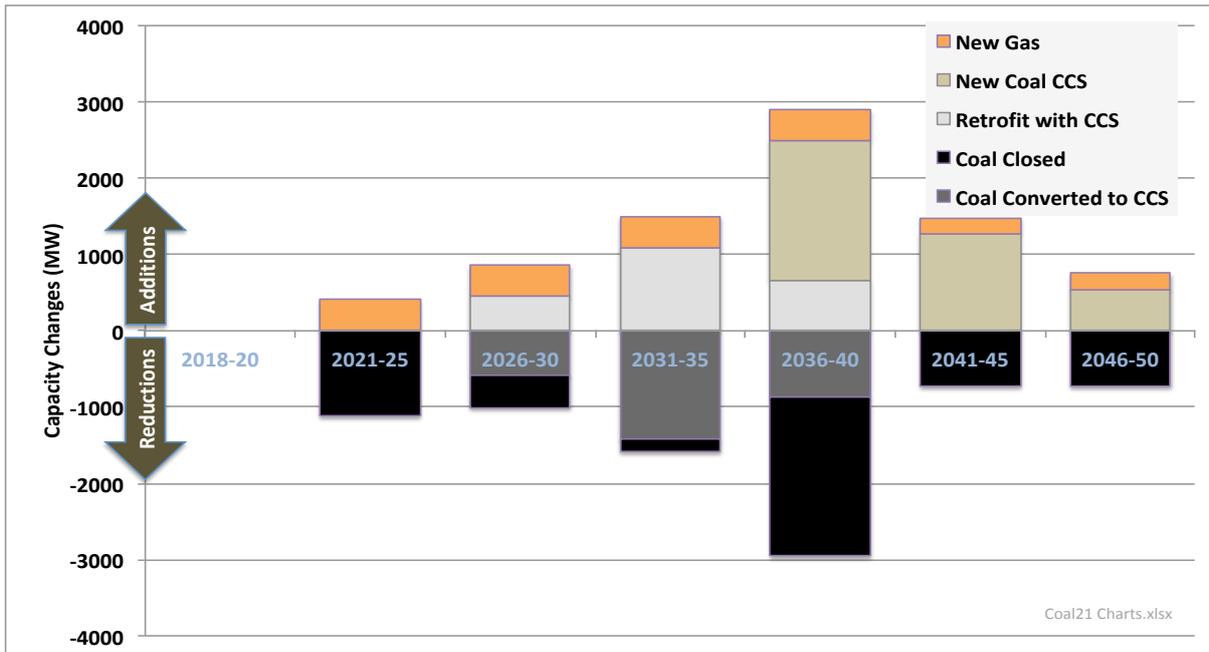


Figure 4 Changes to Fossil Capacity within Queensland

The cost of decarbonisation of the optimum lowest total system cost generation build pathway by 2050 is illustrated in Figure 5. Note the bigger leap in progress in reducing emissions between 2030 and 2035, as this is when CCS is assumed to be available commercially and retrofits are undertaken. It can also be seen that as the system approaches high levels of decarbonisation the progress slows, even though costs are still rising significantly. This is because technologies that are added towards the end of the decarbonisation period inevitably run at lower load factors (or force other low carbon technologies to lower their output). Hence the high capex of these additions is not recovered as effectively as the early builds.

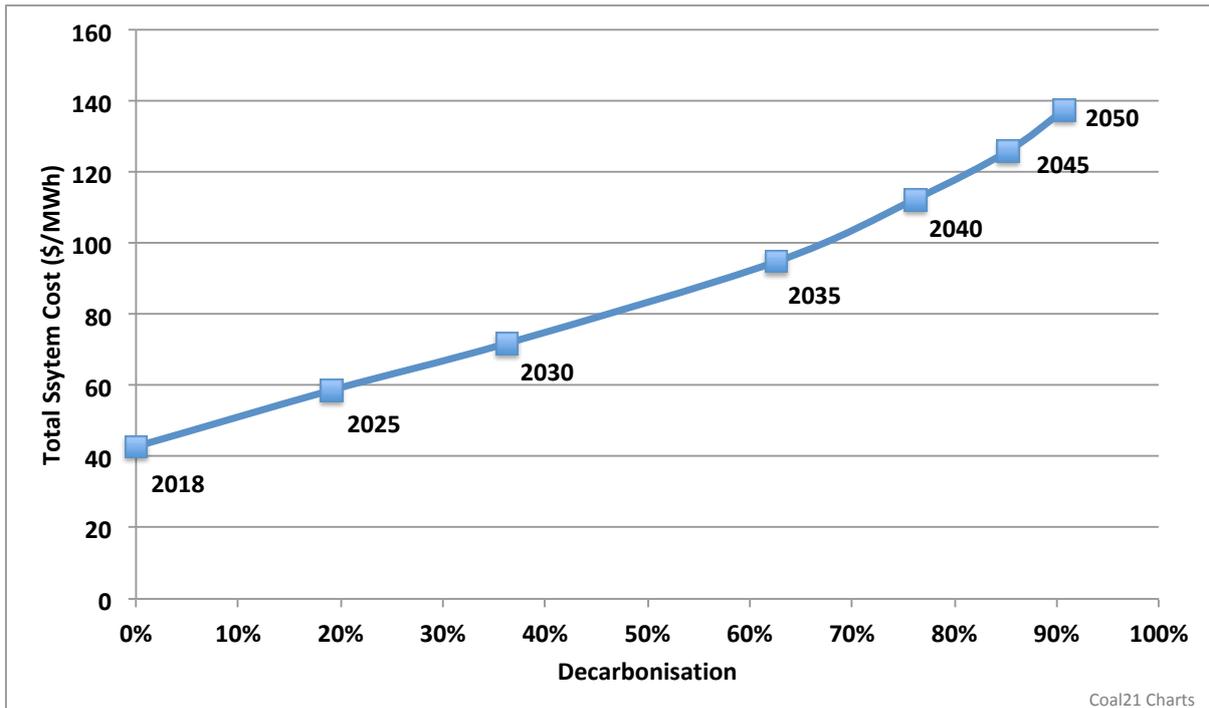


Figure 5 Cost-Decarbonisation Pathway to 2050

CCS injection constraint

The amount of CCS within the optimum 2050 solution was modelled in an unconstrained manner.¹⁶ The major storage work with the NEM regions centres around Victoria (Carbon Net⁸) and Queensland (the Surat Basin⁹ and Enhanced Oil Recovery¹⁷). The current UQSDAAP study¹⁵ shows that an approximate limit for storage within the proposed Surat Basin hub is approximately 15Mtpa, sustainable across approximately 40 years. A working estimate for a likely whole-of-NEM rate of approximately 50Mtpa has been used to illustrate the impact (sustainable for 40 years is assumed).

The impact of applying a CCS constraint to the currently estimated storage is shown in Figure 6. The remaining CCS requires that additional storage options are found, and/or alternatively a different generation mix is required. Gas with CCS would allow for more generation capacity to be achieved, albeit at a higher total system cost. The other technology opportunity to be explored is nuclear.

¹⁶ Refer to Appendix: MEGS – Modelling Energy and Grid Services, specifically the sub section: Generation capacity constraints on page 22.

¹⁷ Bridgeport.net.au. (2019). *Bridgeport Energy | A New Hope Group Company*. bridgeport.net.au [Accessed Mar. 2019].

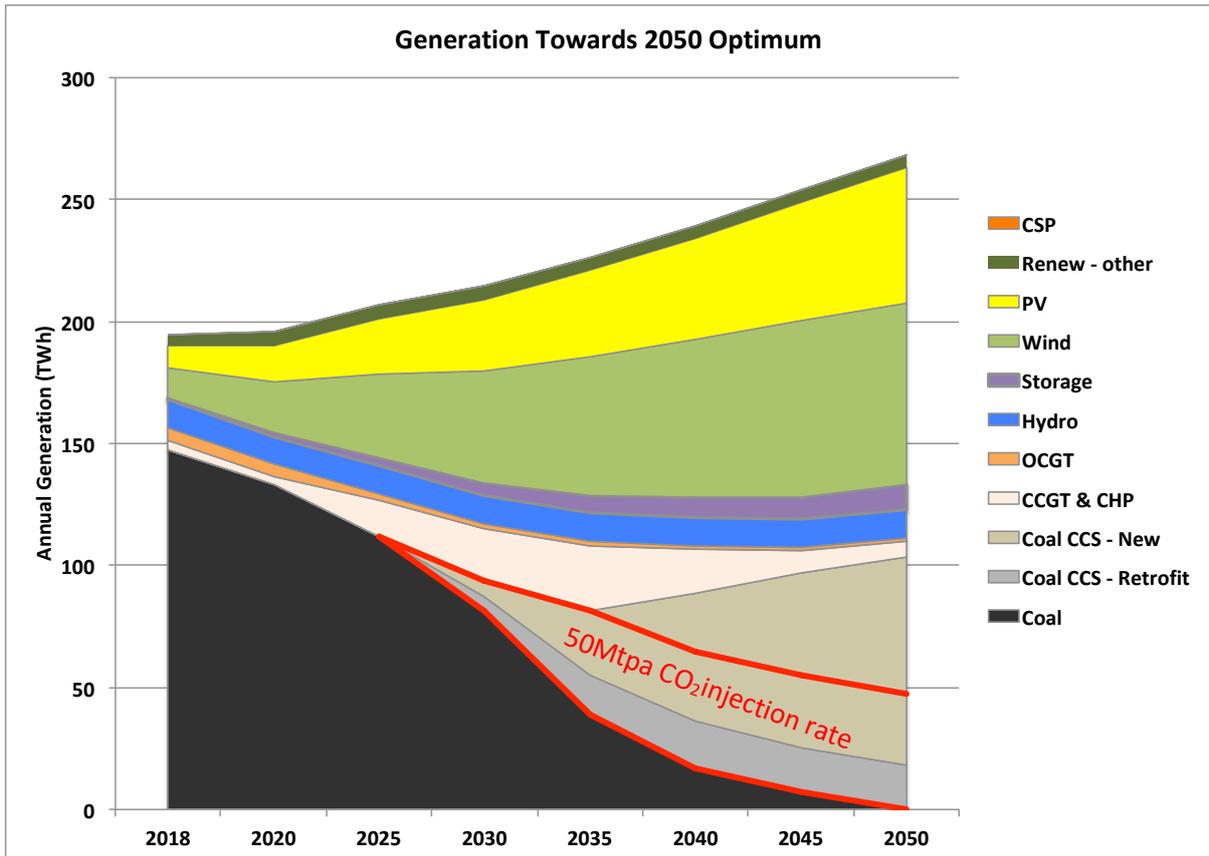


Figure 6 CCS injection rate constraint

In order for the current 2050 optimum scenario to be realised, additional storage locations would be required to be identified, characterised and costed into the CCS opportunity. This requires significant efforts in drilling wells in the short term.

Sensitivity Studies

Key sensitivities were investigated to establish the impact on the 2050 optimum generation technology mix. The following were investigated:

- Gas price is an important parameter in determining whether coal or gas with CCS is built. Gas price uncertainty remains a key risk in technology selection
- CCS capital cost estimates in Australia have a high degree of uncertainty due to the lack of CCS plants built here.
- Concentrated Solar Power (CSP) is an 'up-coming' technology which has a high degree of cost uncertainty in the latest Gen Cost 2018 discussions. Given its storage and generation characteristics, it's an important technology to explore.

Gas price sensitivity

The best 5 scenarios that represent 90% decarbonisation for each of the three modelled gas prices are illustrated in Figure 7. Note that the x-axis is zoomed in comparison with previous charts showing just scenarios within 3 percentage points of 90% decarbonisation. The main point to note is that all three gas prices lie on the same optimal curve (within the scatter expected from a random scenario selection process). The higher gas prices achieve slightly higher decarbonisation (albeit at higher cost) as the optimisation is less favourable to gas (the highest emitting technology). However, the effect is small, with just a couple of percentage points difference.

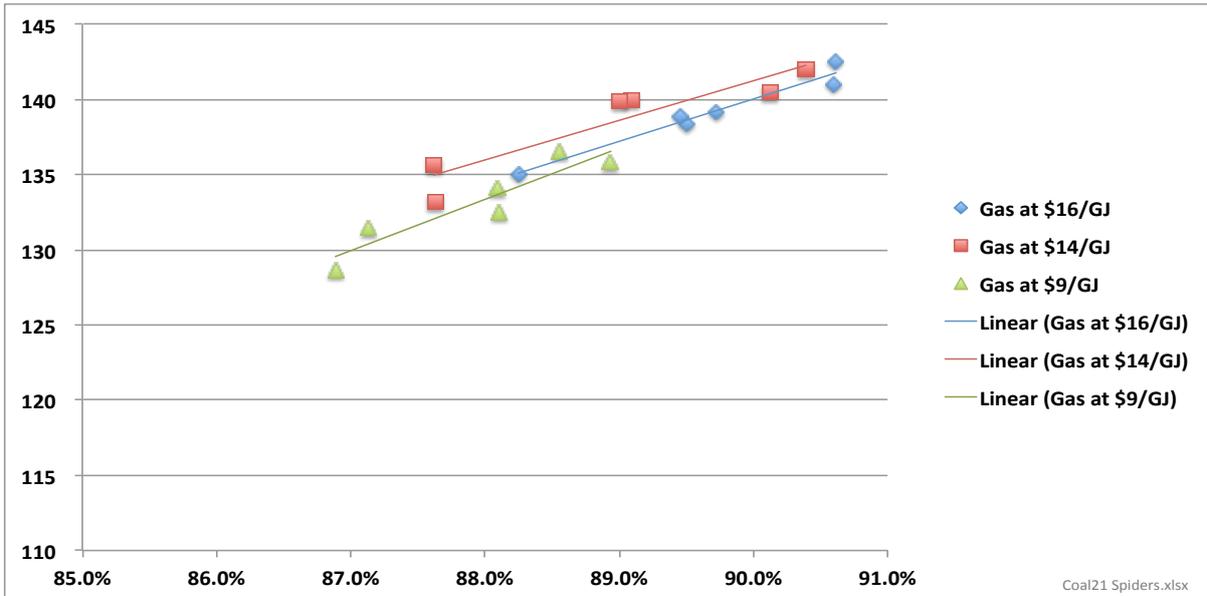


Figure 7 Optimal Scenarios at Different Gas Prices

To investigate any material difference between the optimal portfolios chosen by MEGS, the capacities of the main technologies were plotted. The box and whisker plot in Figure 8 below shows the best 5 scenarios of Figure 7, with the minimum and maximum build at the end of the whiskers and the inter-quartile range as the box. Renewables build is illustrated by the first three on the left, one for each gas price. There is significant scatter of 25GW within each set, but there is not significant difference between one gas price and the next, as the results are mostly within the scatter. The variation for CCS build in the middle 3 plots is much less, in fact it can be said that whatever the gas price, the optimum CCS build is remains between 15 and 25GW, and is likely to be close to 20GW. There is a small build of gas plant, around 6-8GW, and this too is not dependent on gas price.

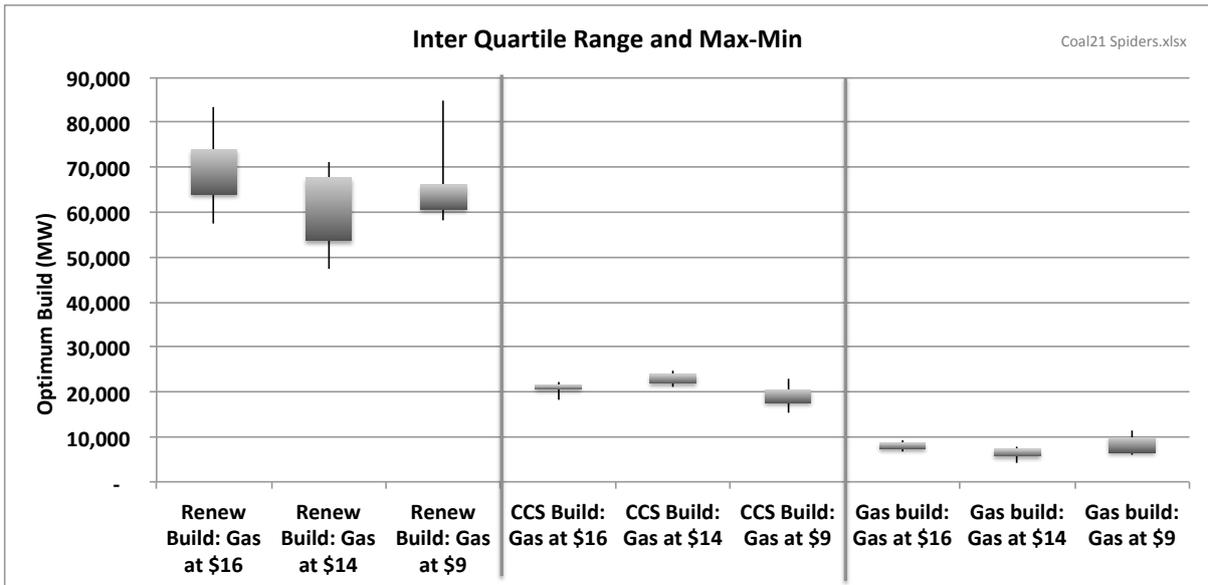


Figure 8 Range of Renewable, CCS & Gas Capacities Chosen by MEGS for the 3 Gas Prices

It can be concluded that there is a clear need for coal CCS plant for any gas price between 9 and \$16/GJ. The amount required does not depend on gas price within this range, so, notwithstanding CO₂ storage constraints above, this should provide confidence for developers and investors in coal CCS that their asset is unlikely to be stranded.

An examination of the long run costs of gas and coal CCS suggest that the swap over point occurs around \$8/GJ, which is just outside of the range considered credible by this study. This means that should gas price fall to, and remain at this level then MEGS would be indifferent to whether coal or gas CCS is built, but if gas prices were to fall below \$8/GJ then gas CCS would be more economic than coal CCS.

CCS Cost Sensitivity

Figure 9 shows the effect on TSC of reducing CCS costs. Note that the x-axis is zoomed in comparison with previous charts showing just scenarios within 5 percentage points of 90% decarbonisation. The 5 scenarios with both the Capex and Opex of the capture plant halved lie on a line that is \$12-13/MWh lower than for the whole system, i.e. reducing capture costs by half reduces TSC by 10%.

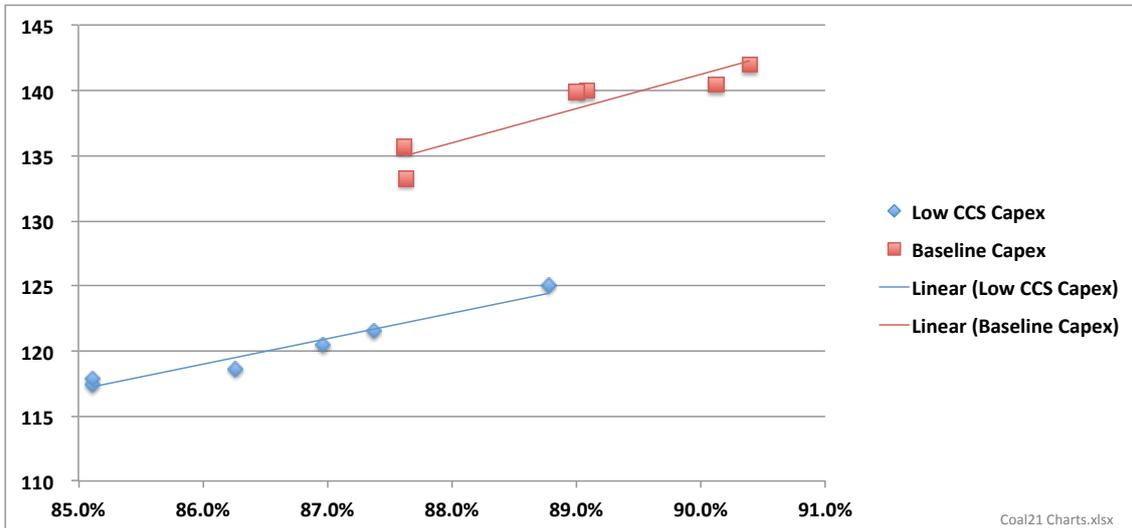


Figure 9 Effects on TSC of a much lower cost for CCS

Even though the effect on TSC is significant Figure 10 shows there is little effect on the choice of plant for the optimum solution. Although it seems that the renewables build is reduced with a lower CCS cost the two distributions overlap significantly and the difference is less than the scatter of results. Furthermore it would be expected that the primary effect of reducing CCS costs would be to increase the amount built, which in turn might reduce the amount of renewables built, but the central plots show this not to be the case.

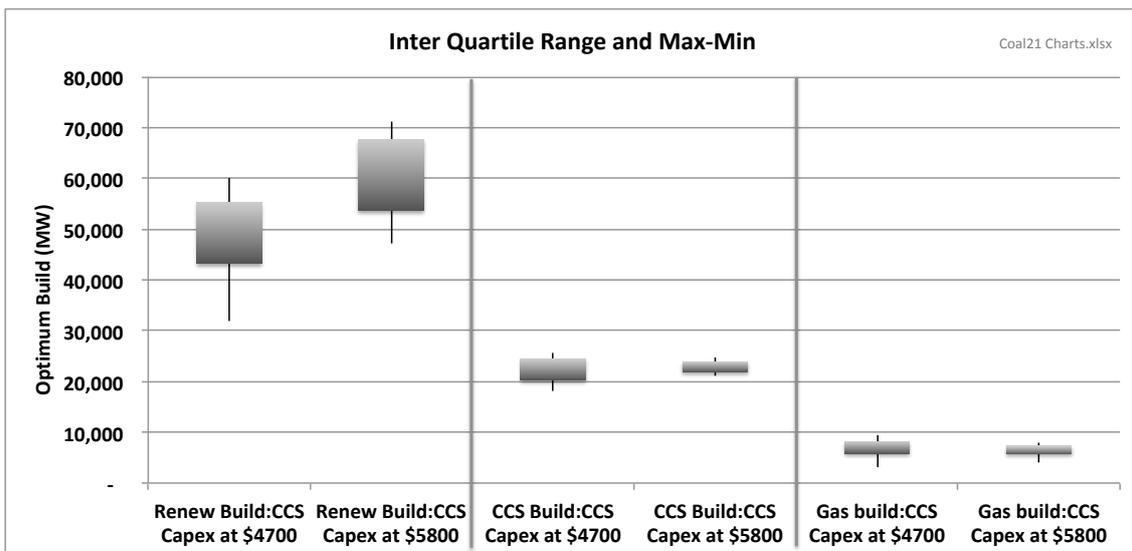


Figure 10 Effect of lower CCS cost on optimum technology mix

In conclusion, reducing CCS costs has a significant effect on reducing overall costs, but does not change the optimum generation solution.

Concentrating Solar Power Cost Sensitivity

Figure 11 shows the effect of adding CSP as an option after 2030 at two different capex, GHD at \$6,800/kW and CSIRO at \$2,800/kW. No other costs are changed so the latter scenario is particularly favourable to CSP as capex of other plant isn't reduced in line with CSIRO's lower estimates for most new build. This then is a most conservative examination of the role CSP might have and its impact on other plant, notably CCS.

Each step is 5.6GW spread across the five states of the NEM and a new desert region according to solar potential and demand in each region. If CSP costs are consistent with the GHD estimated capex, it would clearly be an expensive addition to the system. The solid red line is much more costly than the optimum line for the same decarbonisation.

However, if CSP could be delivered at the CSIRO estimated cost, then it is slightly cheaper than the optimum pathway we have previously examined. This only lasts for two steps after which the CSP dashed line is steeper than the pathway to the optimum. Therefore, it is possible that about 11GW of solar thermal could be part of the solution if costs could be reduced. At this level of penetration, CSP would generate 40TWh. However, the effect it has on CCS is minimal, as it only loses 3% of its output to CSP.

In conclusion, if everything was favourable for CSP to reduce its costs, and other technologies failed to reduce their costs in line with CSIRO's estimates, CSP could play a role in the optimum solution. However, its impact on CCS is likely to be minimal, i.e. CCS is still needed to provide firm low carbon power. If CSP costs were in line with the GHD cost estimates, it is a very expensive addition to the system so should not be deployed on the pathway to the optimum.

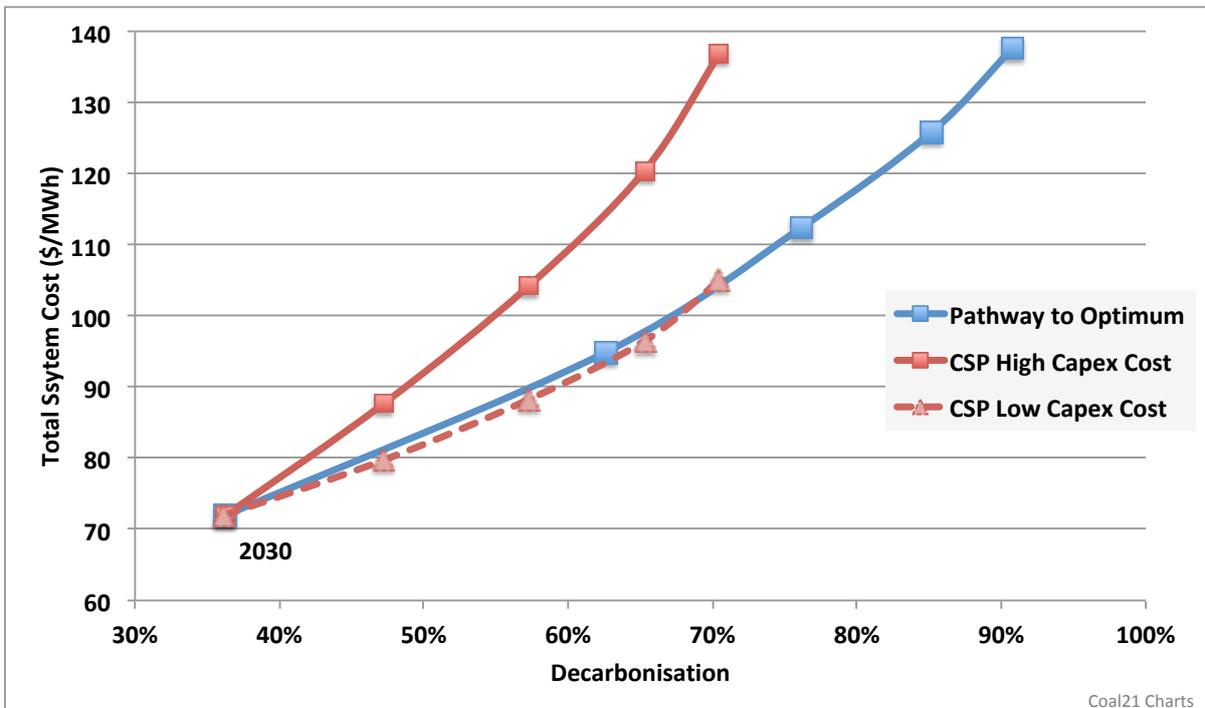


Figure 11 Effect of Adding CSP after 2030

Conclusions

The transformation from the current generation mix to a system of lowest total system cost for a deep decarbonisation scenario in 2050 is detailed in both Table 1 and illustrated in Figure 12. The total system capacity is significantly higher than the installed capacity today, and as such will likely need commercial incentives / market to achieve such a generation mix. It also should be noted that the fossil fuel plants plus hydro are able to meet peak capacity, though will not always be called on to do so.

Table 1 Lowest total system cost 2050 optimum generation mix

Technology	Generation		Capacity (GW)	
	(TWh)	%	GW	%
Biomass and waste	5	2	1	1
Solar PV	55	21	34	28
Wind	75	28	34	28
Storage	10	4	6	5
Hydro	12	4	7	6
OCGT	2	1	8	7
CCGT/CHP	6	2	10	8
Coal CCS	85	32	18	15
Retrofit Coal CCS	18	7	3	3
Total	268	100%	121	100%

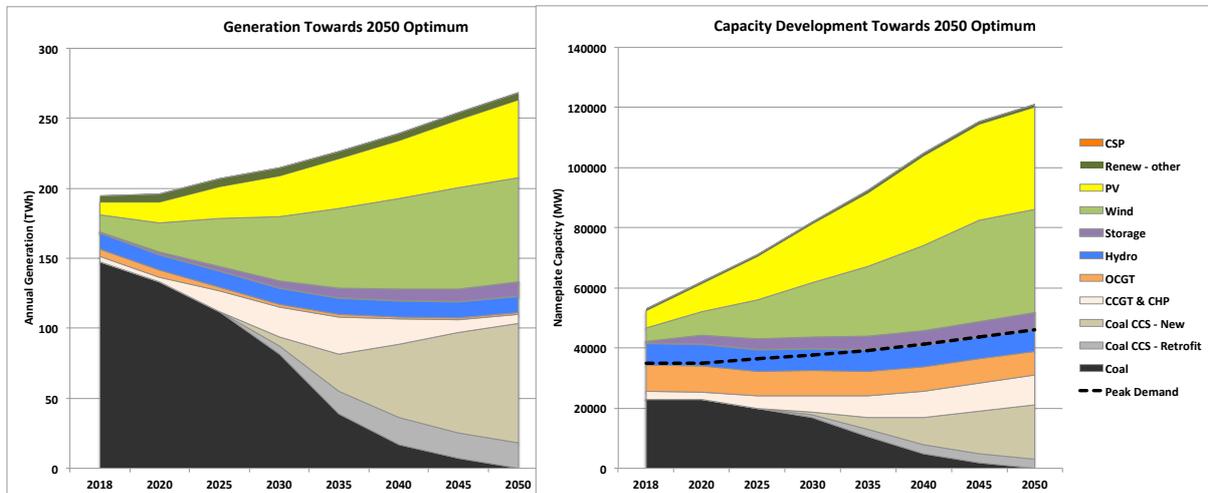


Figure 12 Lowest total system cost 2050 optimum generation mix

The key conclusions of the MEGS analysis of decarbonising the NEM raises a number of important points for stakeholders.

For deep decarbonisation a diverse portfolio is essential

- A diverse mix of solar PV, wind, energy storage, hydro, gas and low emissions coal will be required to deliver deep decarbonisation at a lowest total systems cost.
- CCS is essential for deep decarbonisation beyond approximately 70% reduction.
- All of the economically efficient (and hence more affordable) scenarios with deep decarbonisation of >85% included at least 21 GW of (mostly new-build) Coal-CCS plant by 2050.

CCS development must commence early to enable adequate deployment

- If targeting low levels of decarbonisation by 2050, CCS becomes less important and while unabated coal remains in the mix, it is possible to rely on renewables alone to bring emissions down. However, if CCS is not developed by this point, the option of deeper decarbonisation, as envisaged by most State targets and Paris by 2050, is lost.
- It is expected that Queensland would host at least 6GW of CCS plant and would need to be able to sequester / remove 30-35Mt of CO₂ annually. NSW would be expected to have half as much again.
 - Commercial CCS would need to commence in the late 2020's.
 - Large sustained injection rates for CO₂ storage are required for deep decarbonisation. More storage options are required than the current known storage potential of the Surat Basin and Carbon Net projects for deep decarbonisation.¹⁸ All options need to be characterised by drilling new wells.

Possible variations on the 2050 generation mix

- Sensitivity of 2050 generation mix as a result to gas price, capex of CCS plant and capex of CSP is very low. Exploring these over a factor of 2 showed no discernible change to need for 21GW CCS.
 - The need for CCS to enable deep decarbonisation is essential, and while its cost remain important, it was secondary to the requirement for CCS.
 - As the emissions targets become greater, the emissions from OCGT as a peaking technology become critical and OCGT is replaced by more expensive batteries or other fast acting low emissions technologies.
- CCS plant and downstream CO₂ transportation and storage would have to operate flexibly. Fossil generation (and hence CO₂ production) will vary significantly on a daily cycle and across the year as it operates flexibly around variable renewable output.
- Constraints on the availability of high, sustained injection rates for CO₂ storage could lead to higher total system costs, greater use of gas with CCS and may indicate a role for nuclear.

¹⁸ Enhanced oil recovery in the Surat and Gippsland Basins will likely be required in addition to further exploration in other areas such as the Galilee and Eromanga Basins.

Appendix: MEGS – Modelling Energy and Grid Services

MEGS – Modelling Energy and Grid Services, sits between the broad models that account for energy, economics and emissions across the whole energy system, and detailed electrical engineering tools. It brings together the key features of both types of model for the electricity system. It is built on firm economic principles and gives the user an overview of system parameters such as total system cost and carbon emissions. At the same time it is ensuring that key engineering considerations are observed, modelling only systems which are operable and provide a given level of security to ensure the lights stay on.

How MEGS Works

Like many models, MEGS balances energy for each calculated point in time for a grid of interconnected regions, but what makes it unique is its attention to the engineering constraints and ancillary services that ensure a grid is operable. This leads to the four key principles of MEGS:

1. For every modelled time period energy is conserved
2. For every modelled time period there is sufficient fast acting reserve / frequency response available (simply called 'FCAS' here)
3. A minimum level of inertia is connected in each region at all times
4. The grid is reliable and operable by ensuring sufficient generation to cover higher demand in each region

The conservation of energy

Nearly all models balance energy supply and demand over a relevant timescale. In the crudest form this is ensuring that annual energy demand for electricity (TWh delivered to customers) is exactly matched by generation from various sources. However, the electricity grid is much more exacting than this and in reality, supply and demand have to be balanced hour by hour, even down to second by second. MEGS ensures that for each modelled point in time, the energy generated in each region (and energy imported) matches the energy consumed. This is the first step to ensuring lights stay on during dark, windless periods when renewable output is very low. A model that only balances energy on an annual basis will not necessarily ensure there is sufficient power at all times.

In summary, MEGS results will always satisfy the following expression for balancing MW in each region:

$$\textit{Generation + imports = demand + exports}$$

All reserve requirements are satisfied

Ensuring energy balances alone will not “keep the lights on”. Grid operators need the flexibility to adjust generation or demand to keep the system in balance during disturbances. For example, if a power station “trips” and ceases generation, the grid frequency will start to decline. To halt this and prevent a blackout, extra power will need to be brought onto the grid in a matter of seconds. This is provided by generation or responsive demand that automatically responds to frequency deviations from 50Hz. This cannot be sustained so shortly afterwards (in a matter of minutes) fast acting reserve generation will have to increase output and allow the first generators to respond to return to their normal output level. These grid services, known as frequency control ancillary services (FCAS), are mostly provided by generation or storage that leaves sufficient headroom to increase its output.

MEGS ensures there is enough FCAS at all times in each region, some of which can be provided by allocating some interconnector capacity to bring power into a region from neighbouring reserve providers. Mathematically:

$$\textit{Reserve from storage + generation headroom + imported reserve} \geq \textit{Reserve required + reserve exported}$$

Minimum inertia requirements

The fact that frequency doesn’t immediately fall when a generator trips is due to system inertia. The mass of rotating machinery holds enough kinetic energy to keep the system in balance for a few seconds, although as the system draws upon this, its rate of rotation (and hence the grid frequency) starts to fall. However, this is only effective if the generator is synchronous (i.e. is tied exactly to grid frequency) and has sufficient mass. Most renewable generators have little or no rotating mass, and are connected asynchronously to the grid, hence do not provide any inertia. The greater the inertia on the system the slower the drop in frequency and the longer it gives FCAS to act. AEMO work to a minimum level of inertia in each region that ensures that the rate of change of frequency (RoCoF) will be slow enough to avoid further losses of generation, in the event it becomes islanded and the system out of balance, allowing enough time for FCAS services to act.

MEGS is one of the few models to ensure that this condition is met at all points in time for every region:

$$\textit{Inertia from spinning generators} \geq \textit{minimum inertia for region}$$

Ensuring adequate capacity margins

The capacity margin is the excess of firm capacity over the peak demand in each region. Grid operators like to maintain a capacity margin of around 10-15% to ensure that demand can always be met with a little spare capacity to cover unusually high demand or larger than average failures. The capacity credit that can be given to each technology type depends on its availability at times of greatest need. A thermal unit might be available 95% of the time, so can contribute nearly all of its capacity to the total of firm capacity. On the other hand, wind output is highly correlated across a state, and it is not unusual for wind farms across a large region to all drop to low levels of output. Solar output is very likely to be zero at times of peak demand, which often occur around sunset on a hot day. Therefore, the capacity credit of renewables will be much lower, and approach zero as more renewables are added to the system.

MEGS has calculated capacity credit of all technologies as a function of the penetration of each, which is used to inform the user so they can ensure there is always sufficient firm capacity to meet demand in each region:

$$\text{Total capacity credit from generation \& storage} \geq (1 + \text{margin}) \times \text{Peak demand}$$

Total system cost minimisation / optimisation

The economics of a well-functioning, competitive market will drive the system towards a state that minimises short-run costs. Short-run costs are those that are avoidable in the day to day operation of the plant. For example, increasing output will increase the cost of some wear and tear, fuel burn and / or the volume of CO₂ going to storage (paid for on a tonne by tonne basis). Turning a plant on may well incur extra costs, hence an operator will only incur these costs if the market provides remuneration, which the operator can ensure by setting the offer price for each plant at the its short-run cost. The market should then pick only sufficient generation from the cheapest plant to meet demand, therefore naturally minimising short-run costs.

MEGS embodies these economics for each modelled point in time (typically 2-3 hours apart). The solver at the heart of MEGS determines generation, reserve and inertia provision from plant (to satisfy constraints 1-3 above) whilst minimising system short-run costs. These costs are derived from input data on fuel cost, efficiency, carbon sequestration costs, non-fuel variable costs and start-up costs, such as damage and warming costs.

Generation plant engineering constraints

Generating plant is characterised by a number of features such as capacity, minimum stable generation level, spinning reserve level, must-run level and an efficiency which varies with load. MEGS takes account of all of these parameters when choosing which power plant to use to meet demand.

Weather impacts

An important feature of MEGS is its ability to use a database of historic load factors for wind, solar PV, CSP and hydro alongside demand which can stretch back ten or more years. It is possible to call up particular weather years to explore droughts or periods of surplus, knowing that hour by hour the data will be consistent. This data is called upon by the storage algorithm described above to simulate a particular weather pattern and to calculate long term averages.

Modelling storage

MEGS takes special care of storage, and technology such as CSP which may have inherent storage. Within-day, a perfect foresight algorithm is used to allocate generation and filling in a way that minimises total short-run costs for the day. In essence MEGS is assumed to have a perfect weather forecast for the next 24 hours.

However, storage with a capacity of more than a few hours is optimised over a time horizon commensurate with its time scale for a full empty-refill cycle. The algorithm allocates an energy drawdown or storage target for each day according to limited foresight of the likely weather dependent generation and demand over that time horizon. The current day is optimised to satisfy that daily target with perfect foresight of the weather. For example, the current day scheduled takes the current simulated weather to determine renewable output and demand. Those days beyond the weather forecasting horizon are assumed to be a typical day for that season, and those in between see a mixture of the known weather and the seasonal average. Figure 13 shows how MEGS’ knowledge of the wind (red) varies from the actual weather being used (blue) and the long term average (green) over 10 days.

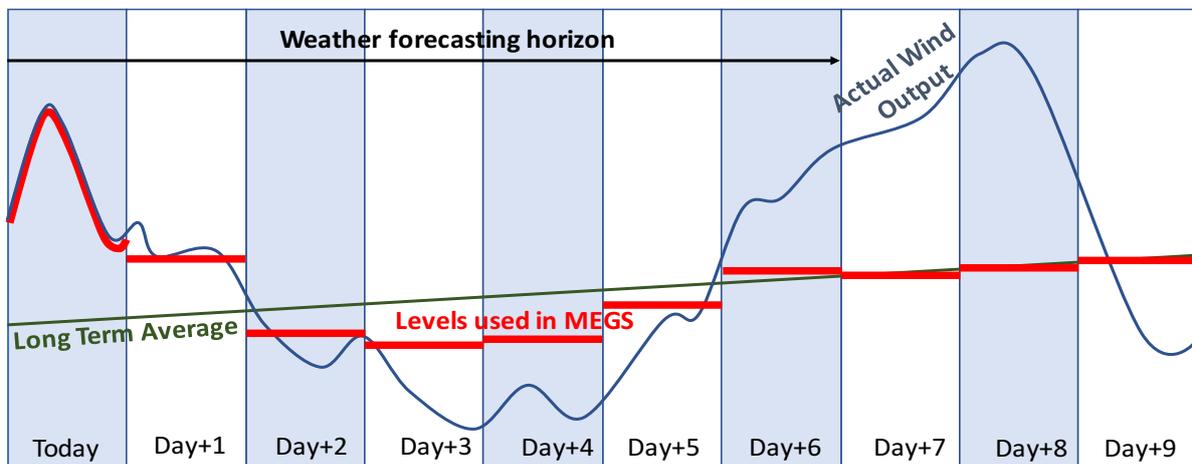


Figure 13 How MEGS uses actual weather data for storage forecasting

Stochastic Simulations (S-MEGS)

Forecasting into long term futures is inherently speculative. The ability to explore large uncertainties in future scenarios is an additional MEGS capability. When configured in this format, the model is denoted as **S-MEGS**. S-MEGS can model up to five key uncertainties via a Monte Carlo analysis. For this study, only its ability to vary the amount of new capacity was used. S-MEGS chose the level of a renewables mix, CCGT and coal-CCS from a uniform distribution of each, and built sufficient OCGT if required to maintain a set capacity margin in each region.

Key Modelling Metrics

An important distinction of MEGS is the focus on the Total System Cost (TSC), which takes into account all the costs incurred from the base year (2018) onwards. This is arguably the most important metric for policy makers, as it is the amount that needs to be funded by the consumer (and possibly the taxpayer) and is directly determined by the decision makers.

The second important output is the level of decarbonisation achieved. This measures the progress of the chosen pathway and ultimately success vis a vis the target (in this study, 100% by 2050). As with TSC, 2018 is chosen as the base year.¹⁹

The installed capacities of the plant built for the scenarios studied are also reported. However, no targets are placed on any particular technology build rate or capacity. MEGS is not forced to include a certain level of renewables, CCS or any other technology as this may well drive the solution away from the TSC optimum that is being sought.

Modelling Assumptions

Electricity demand

Electricity demand was assumed to grow according to AEMO Integrated System Plan (ISP) 2018 neutral scenario.²⁰ Demand to 2050 is extrapolated from 2040 demand using final growth rates. By 2050, demand is predicted to be about 30% higher than 2018 as illustrated in Figure 14.

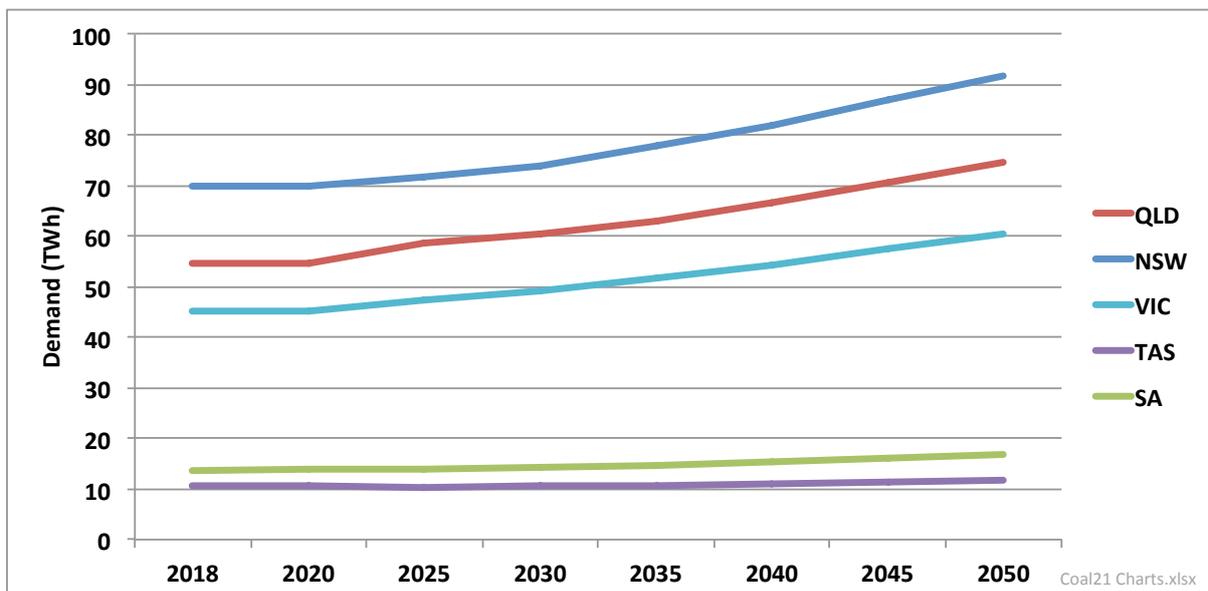


Figure 14 Electricity demand for each State over the modelled period

¹⁹ It is worth noting that Australia’s commitments at Paris were based on 2005. There has been a small reduction in emissions from 2005 to 2018 of about 7% which means the Paris commitment of 26-28% reduction in CO₂ translates to 21-23% on all the charts in this report.

²⁰ Australian Energy Market Operator. (2019). *Integrated System Plan*. www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan [Accessed Mar. 2019].

Power station retirements

Power stations were retired according to Generation Information published by AEMO,²¹ although this is only a guide, as MEGS may choose to close plant early/before its technical life is completed. Supercritical coal in Queensland with a lifespan beyond 2050 is made available to MEGS for retrofitting of CCS. All other CCS in the model is new build (potentially built on existing coal station sites as a brown field development).

Power generation costs

Cost information was taken from the database put together by GHD for AEMO.²² This gave information on current technology costs but did not include future projections. The projected changes in cost (learning rates) were taken from CSIRO.²³

Decarbonisation targets

The whole NEM decarbonises together, with each State reducing emissions at a similar pace, albeit with a different mix of technologies according to the resources in that State. It was assumed that no more than 10% of current emissions can be met by carbon trading or the use of biomass, which means 90% decarbonisation of the electricity system must be achieved through fuel and technology choices for generation. Although short of the target, achieving a zero emissions target will need to involve BECCS, nuclear or the purchase of credits, none of which is modelled directly, although estimates are made of achieving that final step.

Generation capacity constraints

The MEGS modelling was configured so that most generation technologies were not constrained by resource limitations, assuming that constraints such as build out rates are achievable and that resource availability (e.g. quality wind sites, CO₂ storage options and natural gas availability) is adequate. The major exception is hydrogeneration, where no additional capacity is available, other than Snowy 2.0.

Weather impacts

An important feature of MEGS is its ability to use a database of historic load factors for wind, solar PV, CSP and hydro alongside demand which can stretch back ten or more years. For this study, demand and hydro production is taken from NEM-Review,²⁴ solar PV and wind from Renewables Ninja²⁵, and CSP from the Bureau of Meteorology's Direct Normal Irradiance (DNI) reanalysis data.²⁶

²¹ AEM Australian Energy Market Operator. (2019). *Generator Information*.

www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information [Accessed Jan. 2019].

²² GHD. (2018). *Report for AEMO - AEMO Costs and Technical Parameter Review: Report Final Rev4*. GHD, Australia.

²³ Graham, P.W., Hayward, J, Foster, J., Story, O.1 and Havas, L. (2018) *GenCost 2018*. CSIRO, Australia.

²⁴ NEM-Review™, Data download from 2005-2017. <http://v6.nem-review.info>

²⁵ Pfenninger, S. and Staffell, I. (2016). *Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data*. Energy 114, pp. 1251-1265.

²⁶ Solar radiation data derived from satellite imagery processed by the [Bureau of Meteorology](http://www.bom.gov.au) from the Geostationary Meteorological Satellite, MTSAT and Himawari-8 series operated by Japan Meteorological Agency and from GOES-9 operated by the National Oceanographic & Atmospheric Administration (NOAA) for the Japan Meteorological Agency

MEGS Study Methodology: Detailed

Step 1: Find the optimum mix of renewables

An initial series of 100 scenarios for the NEM in 2050 was generated and modelled by S-MEGS. Although each scenario had the same expected plant closures, fuel prices and demand patterns each had a different mix of wind, solar PV and batteries added to the system to meet the requirements in 2050. The amount added was chosen randomly (by S-MEGS) from a range of 0-100GW installed capacity for each of wind and solar PV, and 0-20GW of batteries. They were distributed around NEM states according to demand in each, with a bias towards the most favourable renewable in each state. The results of Step 1 are shown in Figure 15.

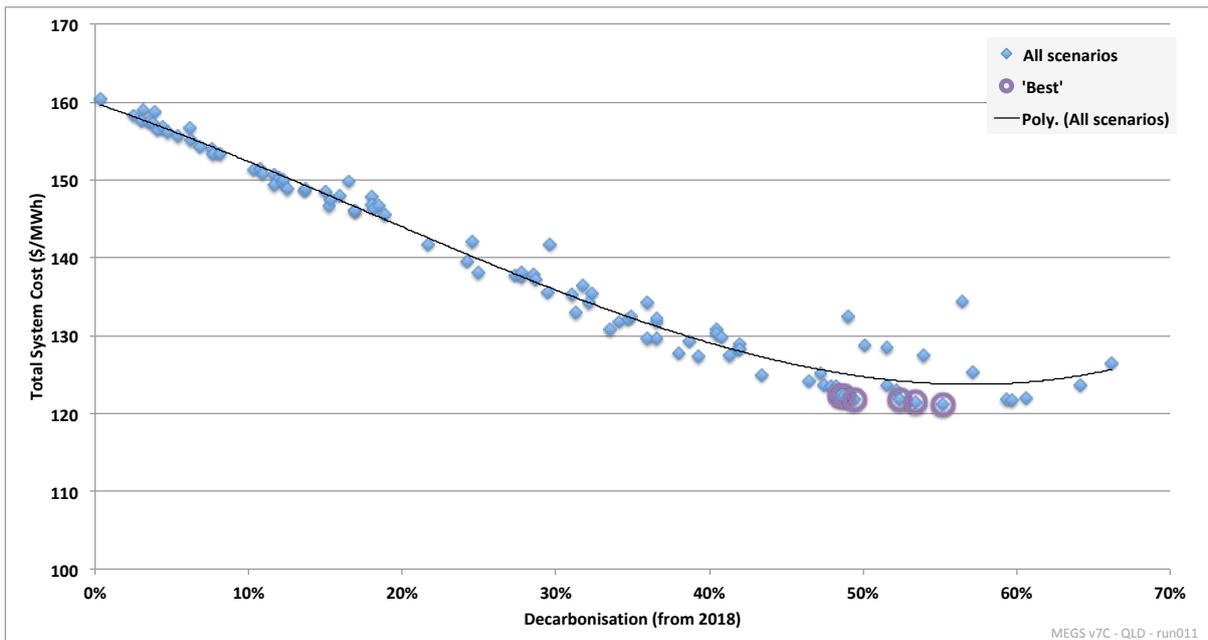


Figure 15 One hundred scenarios with different mixes of renewables

These initial scenarios were examined to find the optimum ratio of the 3 main components to achieve maximum effect (decarbonisation) for minimum total system cost. These were defined as the 5 scenarios (refer to Figure 15, with 5 points highlighted) with lowest total system cost that achieved 45%-55% decarbonisation (it is known from previous modelling⁴ that this is the maximum renewables penetration before costs become unreasonably large).

These are shown on the TSC vs Decarbonisation chart in Figure 15, which shows scenarios running from a high cost, high gas world on the left through the optimum to a high renewables world on the right. Averaging these 5 optimal scenarios resulted in a 48:48:4 ratio for solar PV, wind and battery capacity which established the optimum renewables mix.

Step 2: Find the optimum scenario for 2050

Step 1 was repeated but this time the 250 scenarios tested differing amounts of the three main options for decarbonisation: renewables, gas and CCS.

- Renewables comprised wind, PV and batteries in the optimum mix determined from Step 1.
- Gas was combined cycle gas turbine (CCGT)
- CCS was coal with post-combustion CCS, which is significantly cheaper than gas. Plant with closure dates of 2050 or beyond were deemed suitable for retrofit and formed the vanguard of the CCS fleet.

Any shortfall in firm capacity was covered by building OCGT peaking plant, as it is the most cost effective plant with the required technical attributes to fill the capacity short fall. The option of building unabated coal plant has not been considered as this will be of no help in reducing emissions, and will either be retrofitted with CCS or become stranded well before 2050.

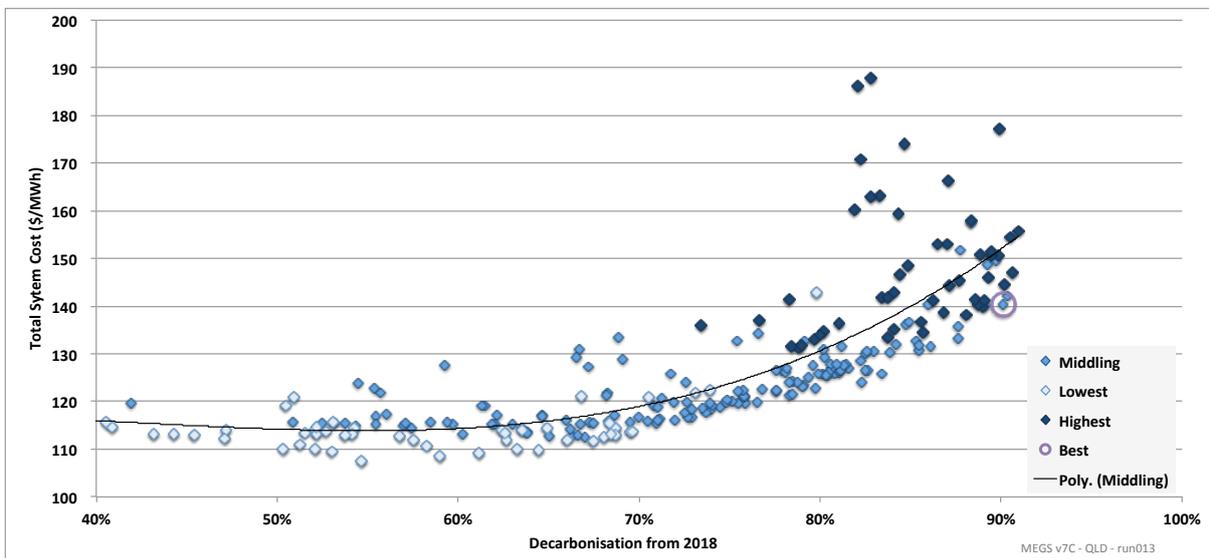


Figure 16 Scenarios for 2050 with varying levels of renewables, gas and CCS

Figure 16 shows all 250 scenarios plotted on the TSC vs decarbonisation chart. The line of best fit (3rd order polynomial) is also displayed. The best scenario (furthest below the average cost line) within ½ percentage point of 90% is marked.

Step 3: An examination of the optimum 2050 scenario

The optimum plant mix from 2050, found from the previous steps was run in MEGS with a better resolution (one point every 2.5 hours) to examine the scenario in more detail.

Step 4: Composing the Pathway to 2050

The capacity mix from the optimum scenario of Step 3 was taken as the “end point of the pathway”, or the lowest total system cost configuration in 2050. With the optimum plant mix for 2050 being determined in Step 3, the intermediate points (between 2018 to 2050) were determined using interpolation and engineering judgement. The pathway conformed to the following constraints:

- Thermal plant closed (at the latest) according to AEMO’s ISP.
- Renewables were assumed to have a 30 year life (i.e. all renewable plant operating now would be decommissioned by 2050).
- CCS was assumed to be commissioned at a demonstration scale between 2025 and 2030 (a maximum of one unit of around 500MW in each state where it is to be used).
- CCS would be available commercially from 2030 onwards.
- Plant build rate for all technologies between its first being available and 2050 was initially assumed to be constant.
- Plant build rate was accelerated prior to years where the capacity margin over demand would fall below 10%, and slowed down if the plant margin exceeded 20% on a state by state basis.

Once the capacity mix was determined MEGS was run at the enhanced resolution for cardinal points every 5 years.

Step 5: Sensitivities

To test the robustness of the results some sensitivities were undertaken around some of the least certain input parameters. Gas price can vary significantly, CCS cost is not well understood as it is a relatively new technology when combined with power generation, and likewise new CSP technologies are often seen as bringing the best of both worlds (emission free renewables combined with inherent storage and a conventional steam generator).

Therefore step 2 was repeated for the following three sensitivities:

- A low gas price of \$9/GJ and a high price of \$16/GJ
- A low CCS cost that saw Capex and Opex of the capture plant halved
- A lower CSP cost taken from CSIRO’s estimate (less than 40% of base case)²⁷

²⁷ Hayward, and Graham, P. (2017). *Electricity generation technology cost projections: 2017-2050*. Newcastle, N.S.W.

Disclaimer

This analysis for this report was completed on 1st of March 2019 and therefore the Report does not take into account events or circumstances arising after that time. The authors of the Report take no responsibility to update the Report.

The Report's modelling considers only a limited set of input assumptions which should not be considered entirely exhaustive. Modelling inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from actual events. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. The authors of the Report take no responsibility for the modelling presented to be considered as a definitive account.

The authors of the Report highlight that the Report does not constitute investment advice or a recommendation to you on your future course of action. The authors provide no assurance that the scenarios modelled will be accepted by any relevant authority or third party.

Conclusions in the Report are based, in part, on the assumptions stated and on information which is publicly available. No listed author, company or supporter of this Report, nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from information that may be later be proven to be incorrect.

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