ROAM CONSULTING
ENERGY MODELLING EXPERTISE

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AUSTRALIAN SOLAR INSTITUTE

Solar Generation Australian Market Modelling

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VERSION HISTORY

Version History				
Revision	**Date Issued**	**Prepared By**	**Approved By**	**Revision Type**
0.8	2012-05-18	Joel Gilmore Nicholas Cutler Jenny Riesz	Ben Vanderwaal	First draft release
1.0	2012-06-06	Joel Gilmore	Ben Vanderwaal	Complete report release including incorporating feedback from ASI.

DISCLAIMER

The modelling performed for this report is in line with World's Best Practice.

The data used as input to the modelling is the highest quality information available within the public domain. Such public information has been used in order to protect the intellectual property of our individual clients.

*The modelling packages used in the assessment (**2-4-C and LTIRP**) are amongst the most advanced modelling packages specifically focused on the National Electricity Market (NEM). The products conform to the major economic and technical principles of the competitive NEM.*

The assumptions we have made in the formulation of the market development scenarios reflect possible developments in the market. However, we do not claim to have based our analysis on the most probable market development scenario.

This report has been prepared for a general audience and hence the information provided may not be applicable to your specific circumstances. ROAM Consulting recommends that all readers of this report seek personalised, independent advice prior to making any decisions based on the information supplied herein.

As is the nature of market forecasting (despite the use of Accepted Best Practice) the events that unfold in the market may differ from those presented in this report as possible development scenarios. ROAM Consulting accepts no responsibility, save that which cannot be excluded by law, for any losses that might be incurred should the market unfold differently from how it is discussed in this report.

The views expressed in this report are those of ROAM Consulting and do not necessarily reflect those of the Australian Solar Institute or of any other party referenced herein.

EXECUTIVE BRIEFING

Solar power represents a new feature in the Australian energy markets: a daytime peaking, intermittent generator with low running costs (but comparatively high capital costs) and with the options of storage or gas hybridisation to extend or supplement generation.

To understand the interaction of solar power with the market, ROAM Consulting has conducted detailed simulations of the National Electricity Market (NEM) and the South West Interconnected System (SWIS) in Western Australia.

ROAM's modelling suggests that electricity prices will continue to rise over time, driven by a changing generation mix, rising gas prices and carbon pricing. The modelled solar plant received 10-50% higher prices for their energy than the annual average electricity prices. This higher revenue is due to the strong correlation between the daytime solar generation and higher demand (and hence higher prices); daytime generation is more valuable in the market compared with overnight periods when demand is low. Concentrating solar power (CSP) plant and solar photovoltaic (PV) plant with tracking (the ability to follow the sun) are expected to receive higher premiums than fixed flat plate solar PV due to higher generation (facilitated by tracking) in the morning and late afternoon periods when prices are typically higher.

In practice, most solar generators sign power purchase agreements (PPAs) with retailers for their full output, including their Large-scale Generation Certificates (LGCs). LGCs are required by retailers and other liable parties to meet the Large-scale Renewable Energy Target (LRET). Over a 15 year period, ROAM forecasts that solar plant would have average bundled (total) revenues of $130-160/MWh, with revenues being highest in Queensland and the SWIS (driven by higher forecast electricity prices in the short term) and lowest in South Australia (where high penetration of renewables cause lower prices over time). Solar plant should therefore be able to command higher power purchase agreement (PPA) prices from retailers than wind farms, who typically have bundled prices of between $90-110/MWh. Actual PPA prices, however, will typically be lower than the bundled value in the market due to the exchange of price risk.

In the short term, retailers have an oversupply of LGCs and are therefore not under immediate pressure to secure supply; retailers may even be averse to signing new PPAs due to perceived regulatory risks or future LGC price risks. Renewable energy projects may therefore find it difficult to sign PPAs at a level sufficient to secure financing. Based on currently existing and committed projects, the oversupply of LGCs will be absorbed between 2015 to 2017; with a typical construction time for renewables of 24 months, this suggests that retailers will need to start signing PPAs in late 2012 to early 2013.

The previously discussed forecast revenues apply when the total installed capacity of solar generation is small. Higher levels of installed solar generation are likely to depress annual pool prices (the "merit order effect") because solar plant are expected to bid low into the market, thereby ensuring maximum generation and receiving the price set by non-renewable generators. A total of 5GW of solar (around 10% of NEM peak demand) installed around the NEM could depress prices by 10-25% if it is not accompanied by an associated deferral or retirement of coal or CCGT plant, or if others generators are unable to rebid to raise prices. While this outcome may be favourable for retailers and consumers in the short term, it poses long-term difficulties for the profitability of both renewable and non-renewable generation in the NEM, with solar generators themselves being most affected by the solar-induced price reductions.

ROAM modelled a range of CSP plant with various solar multiples (the number of insolation gathering mirrors) and levels of storage (from one to 18 hours). For a given mirror configuration, the availability of storage increases the total plant output (and hence revenue) by allowing excess energy to be stored for later use. This storage enables plant to extend operation into the evening and, with higher levels of storage, into early morning peak demand periods.

Even larger benefits can be obtained from the strategic dispatch of storage, where the station operator withdraws capacity during lower demand periods through the day, storing up the received solar energy to be dispatched later in the day or even the following morning. This can increase revenues by a further 5-10%, and allows the solar plant to better meet peak demand. Such behaviour, however, is contingent on the availability of high quality demand, price and local solar power forecasting systems.

Another option for CSP plants is gas hybridisation, where gas boilers provide additional steam during periods when insufficient solar insolation is available. As with the use of storage, this can extend and supplement the operation of the solar plant, ensuring that capacity is available when called upon (even more so than for storage). However, rising gas prices and the already favourable correlation between CSP generation and peak demand reduce opportunities for gas generation. With gas hybridisation, ROAM's modelling predicts that net revenues will increase by an average 2-11%, depending on the region, but this increase must be sufficient to cover the additional upfront capital costs of the gas hybridisation.

Finally, ROAM's modelling has shown that under a carbon price and rising gas prices, solar generation has the potential to reduce overall system costs, provided that solar capital costs can be reduced to a competitive level. Such reductions are within the range of global forecasts, and initiatives to reduce the capital costs of solar technologies should be considered a high priority.

EXECUTIVE SUMMARY

ROAM has conducted detailed modelling of the interaction between solar generation and the Australian electricity markets in order to identify the value of solar generation (including storage and gas hybridisation) in the market. The modelling was also designed to highlight potential issues with large-scale integration of solar generation.

Solar plant revenues

Key findings

- Fixed flat plate solar PV plant could expect to receive average revenues 10-25% higher than the annual average pool prices, while CSP or solar PV plant with tracking could expect to receive 15-50% uplifts due to higher generation during morning and evening price peaks.
- Wholesale electricity prices are forecast to increase over time due to higher gas prices, carbon pricing and increased demand, providing long-term confidence to solar plant revenues.
- Total revenue forecasts are insulated (although not completely) against higher or lower carbon prices and fuel costs by the LRET scheme (because higher electricity prices translate to lower LGC prices and vice versa).

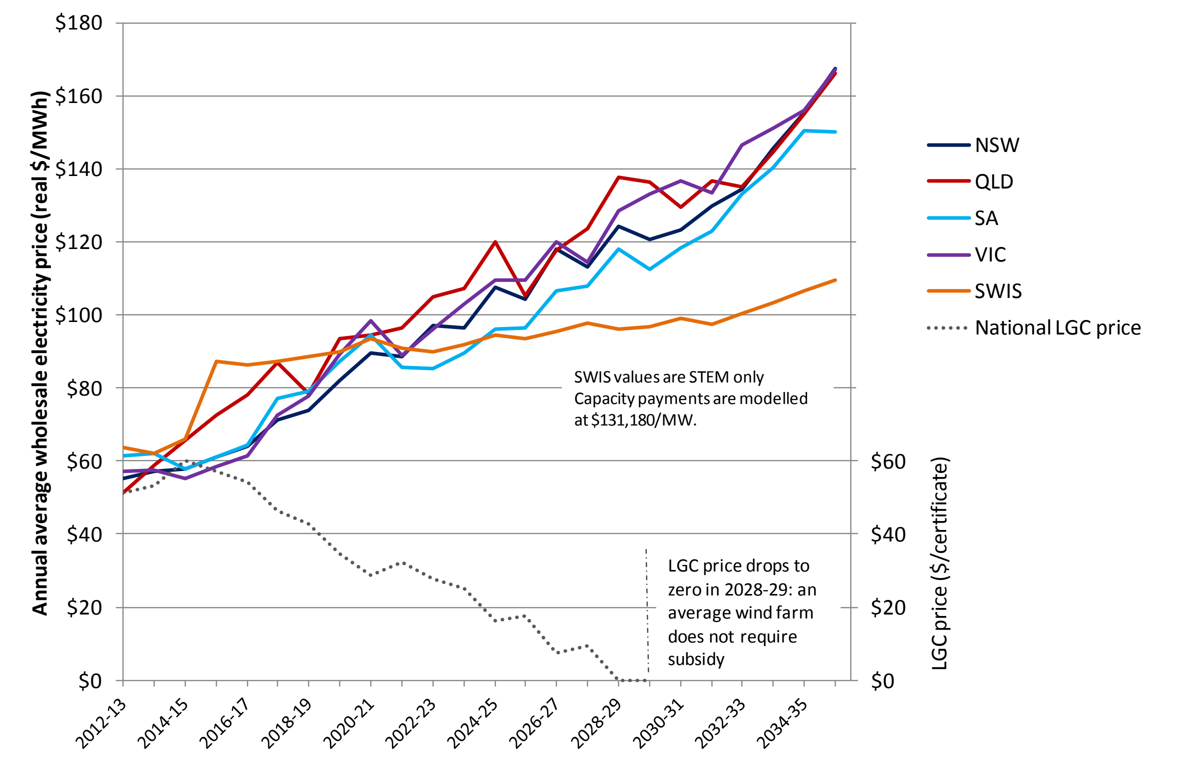
ROAM performed 25 year modelling of the National Electricity Market (NEM) and the South-West Interconnected System (SWIS). Modelling was performed using ***2-4-C***, ROAM's half-hourly dispatch model that calculates least cost dispatch taking into account generator bids and network constraints. ROAM considered a scenario with medium demand and energy growth, the Treasury Core Policy carbon price trajectory, construction of new renewable plant (predominantly wind) sufficient to meet the LRET, and sufficient new thermal plant sufficient to ensure the market reliability standard was met. Fifty Monte Carlo iterations were conducted, capturing a range of plant outages and demand "peakiness" scenarios.

ROAM has also calculated a Large-scale Generation Certificate (LGC) shadow price, defined as the difference between the average long run marginal cost (LRMC) of all wind farms and their average revenue (in $/MWh). This is representative of the average LGC price implied by bundled PPA wind farm contracts. In general, retailers are likely to be indifferent to the source of their renewable energy when it comes to determining the premium they must pay over the wholesale electricity price (i.e., the LGC price). Therefore, solar plant (or other technologies) are unlikely to be able to command LGC prices significantly higher than those of wind farms, and a national LGC price will apply to all technologies. This also provides a natural hedging against increases or decreases in the carbon price, provided the LGC price is greater than zero but less than the scheme cap.

Figure 1 shows the wholesale electricity prices and the shadow LGC price from ROAM's modelling. Prices rise over time due to changing energy mix, rising gas prices and the carbon price. The SWIS has a Short-Term Energy Market (STEM, prices shown with the orange line), where generators are required to bid their short run marginal costs, but also receive capacity payments to recover their fixed costs.

The LGC shadow price starts at \$50-60/MWh, consistent with the prices implied by existing wind farm PPAs (bundled prices of \$90-110/MWh), and decreases over time as the wholesale electricity price rises. By 2028-29, wind farms are on average profitable in their own right due to increased fuel costs and the carbon price (over \$50/tCO_2-e).

Figure 1 – Average solar wholesale electricity price (\$/MWh) and LGC price

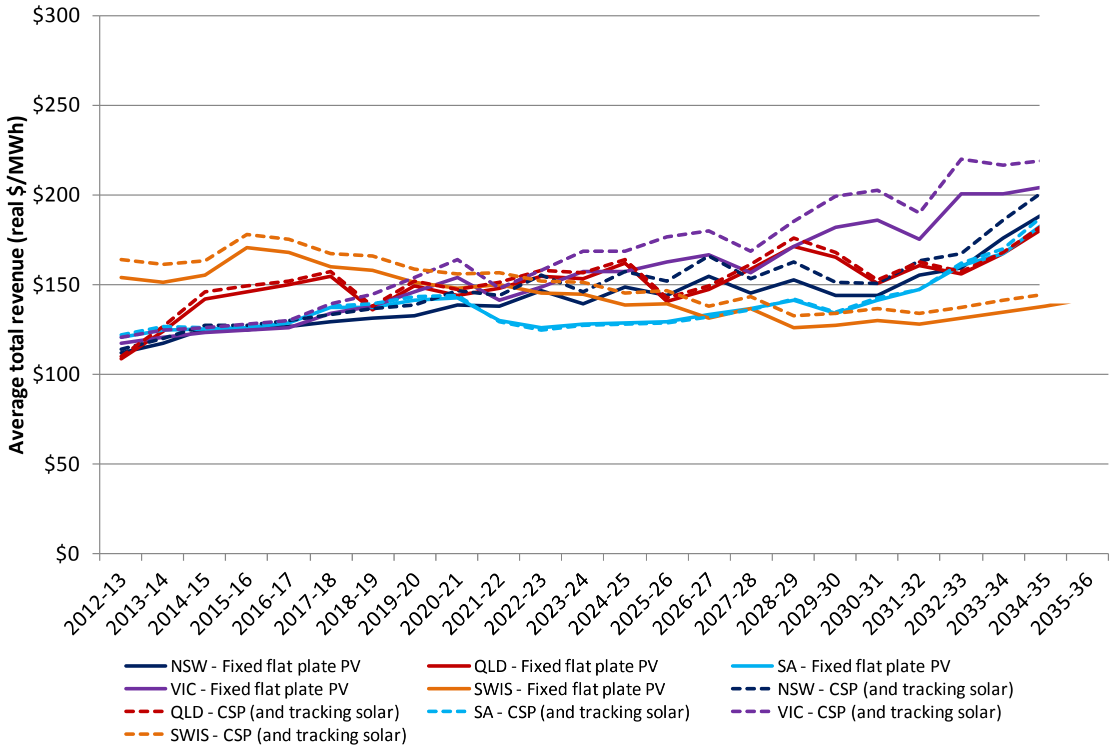


In each year, representative solar plant (less than 30MW capacity, small enough not to significantly impact on electricity prices or other generators) were modelled using ROAM's Solar Energy Simulation Tool that produces hourly solar generation traces based off Bureau of Meteorology gridded data. Financial year 2009-10 was identified as a representative historical year and all forecasts (demand, solar and wind) were built off this year to ensure historical correlations were preserved.

Total annual revenues for solar plant are shown in Figure 2. Solar revenues rise slowly for the duration of the LRET, due to the natural hedging of LGC and wholesale electricity prices. Higher capacity factors, combined with higher average revenues, result in higher total revenues for CSP generators. On electricity revenue alone, solar PV plant receive 10-25% higher revenues than the average pool price, while CSP or tracking PV plant receive 15-50% due to better performance during late afternoon periods.

Revenues are broadly similar across all NEM regions, except for South Australia where increasing penetration of renewables and limited (although still upgraded) interconnector support results in lower prices. A tighter supply-demand balance in Queensland (driven by increased competition for gas due to the expanding LNG export industry) results in higher revenues for Queensland plant in the short term. Increasing price volatility in Victoria drives higher solar revenues towards the end of the study period. In the SWIS, initially higher prices plus forecast capacity credits result in higher bundled prices than in most of the NEM until around 2020. After 2020, however, SWIS capacity credits and average prices rise slower than the LGC price falls, and so total revenues decrease.

Figure 2 – Total solar revenue (wholesale electricity, capacity payments (SWIS) and LGC sales, $/MWh)



CSP or tracking PV plant typically earn higher revenues than solar PV plant, due to more reliable generation at times of peak demand particularly late afternoon periods (when solar PV plants are only generating a smaller percentage of their maximum output). In the SWIS, solar plant with tracking are assumed to contribute more to meeting peak demand (based on the SWIS Market Rules), which results in higher capacity payments.

Power purchase agreements (PPAs)

Key findings

- For plant commissioning in 2014-15, and operating for 15 years, bundled electricity generation and LGCs would have a market value of $130-150/MWh (fixed flat plate PV) or $140-160/MWh (CSP or solar PV with tracking).
- Actual Power Purchase Agreement (PPA) prices (contracts signed with (typically) a retailer for energy and LGCs) will likely be lower due to the transfer of revenue risk. Solar plant should still command PPA prices higher than wind farms, due to the greater time of day value of the solar energy.
- The LGC market is currently oversupplied, due primarily to generation from small-scale generating units (such as rooftop PV). The current oversupply of LGCs is likely to continue until at least 2015.
- Combined with regulatory and LGC price risk, retailers likely have no short term pressures to enter into power purchase agreements (PPAs). However, given typical construction times, retailers are likely to seek new PPAs from late 2012 onwards.

ROAM has calculated flat bundled prices that would produce a net present value revenue stream equivalent to the net present value of the combined average pool and LGC revenues over 15 and 25 year periods. This methodology is different to simply taking an average of revenues over the contract period, because near-term revenues are worth more in the discounted revenue stream.

In practice, PPA prices for solar plant may lower than the bundled value. Retailers signing PPAs are accepting project revenue risk, as well as technological risk and regulatory risks around future prices and demand for LGCs, and will therefore typically require a lower PPA price than the NPV calculation suggests.

For this calculation, ROAM has used a discount rate of 9.79% (as assumed for the 2010 NTNDP[1] Scenario 3) and solar plant are assumed to be installed in 2014-15 with a 15 or 25 year PPA agreement. The resulting contract prices are shown in Table 1 for CSP and solar PV plants in each region. In general, solar plant should be able to command PPA prices 20-40% higher than a typical wind farm PPA of $110/MWh, due to the higher time of day value of solar generation.

[1] The National Transmission Network Development Plan published by AEMO.

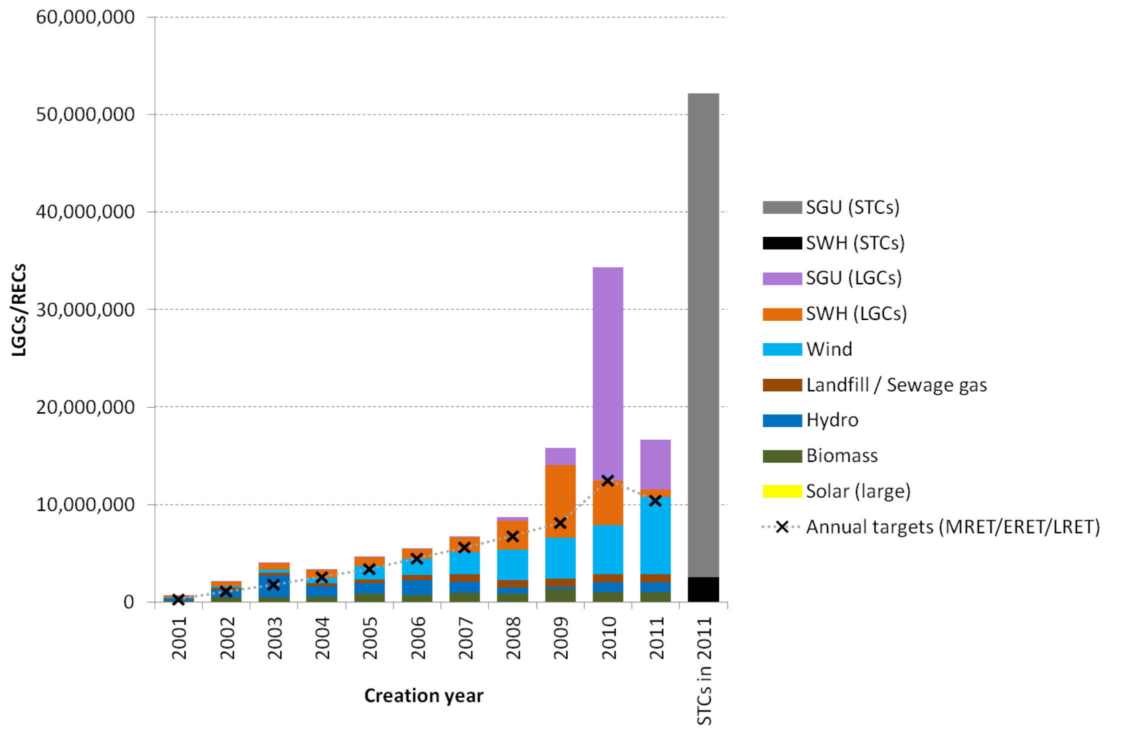
Table 1 – Solar plant PPA prices ($/MWh)				
	15 year PPA		25 year PPA	
	Fixed flat plate PV	CSP (and tracking PV)	Fixed flat plate PV	CSP (and tracking PV)
NSW	$135	$140	$141	$148
QLD	$149	$151	$153	$155
SA	$132	$132	$137	$137
VIC	$141	$149	$151	$160
SWIS	$152	$160	$150	$157

Challenges for securing PPAs

The LGC market is currently oversupplied with LGCs; Figure 3 shows the significant influx of LGCs from small generating units (SGUs, mostly rooftop PV) in 2010 and, to a lesser extent, 2011. As a result, retailers have sufficient banked and committed LGCs to cover their liabilities until at least 2015, or longer depending on their GreenPower liabilities. This has also resulted in low spot market prices, but historically the bulk of LGC/REC transfers have been completed through PPAs at higher implied prices; and once the current excess of certificates are used up, it is expected that this will again be the case.

In the short term, retailers can be highly selective about signing new PPAs; retailers could even be averse to taking longer positions if they perceive regulatory or price risk around future liabilities. The difficulties reported by some renewable proponents and in particular solar sector participants in securing PPAs may therefore, at least in part, be attributable to the current LRET market conditions. Given the development timeline for renewable projects, however, the cumulative LGC analysis suggests that projects will need to begin securing financing from around the period 2012 to 2013, which should lead to more interest from retailers in signing PPAs.

Figure 3 – LGCs created by year and generation type from all sources[2]



Merit order effect

Key findings

- At moderate penetrations (5GW, approximately 10% of NEM peak demand), large-scale solar power reduces annual average wholesale electricity prices by 10-25%, assuming all other market conditions remain unchanged.
- High price periods are especially affected, and revenues for all generators are consequently reduced with solar plant themselves being the most affected (due to prices being reduced most in periods where solar generation is highest).
- In practice, generators may alter their bidding strategies to partially ameliorate the price reductions or, in the longer term, lost revenue may delay new entrant plant or cause unprofitable plant to retire, resulting in increased revenue for remaining generators; solar generator revenue still remains vulnerable.

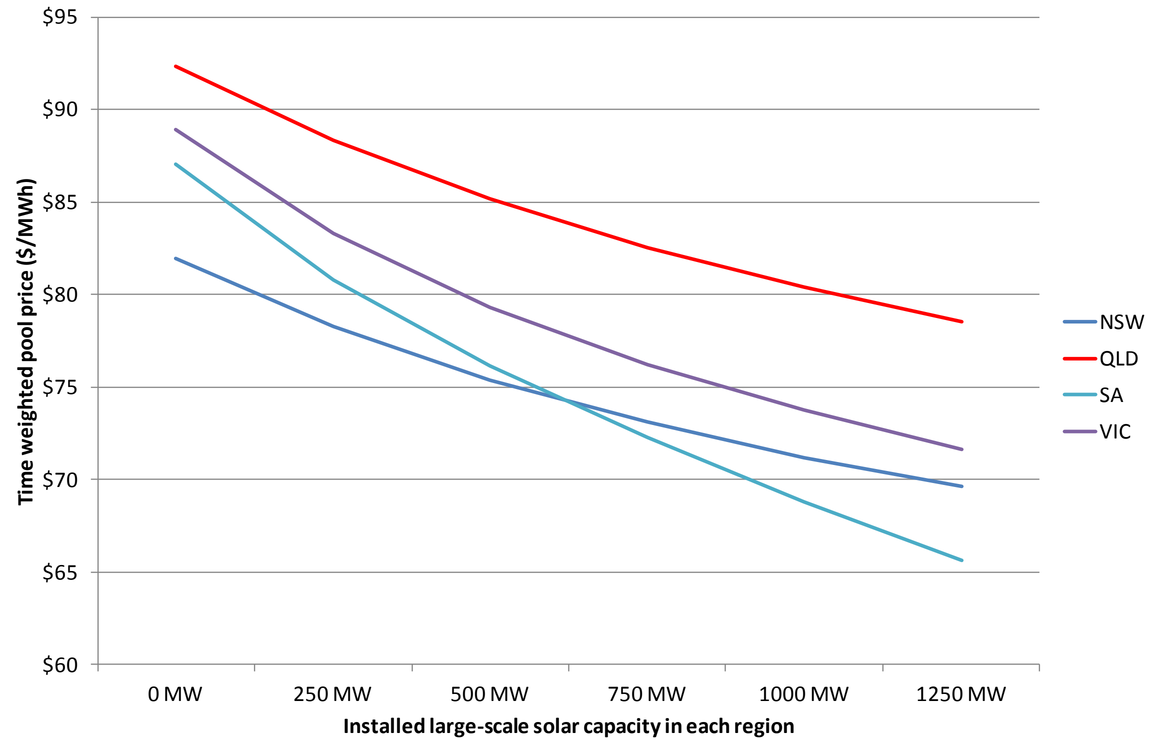
ROAM Consulting considered the impact of large-scale construction (up to 5GW) of solar capacity across the NEM in the year 2019-20. Large-scale 250MW power stations were incrementally installed in each of the NEM mainland regions simultaneously. Solar generation data was derived from two representative locations in each region, sufficient to capture moderate diversity from installed stations. These sensitivity cases were then simulated for the year 2019-20 and compared to the base case simulation. A solar multiple of 1.3 was used for these stations, with no storage.

[2] Extracted from REC Registry on 29th December 2011. Includes all LGCs except those listed in the Registry as invalid due to audit.

Although only a single large-scale technology (solar thermal parabolic trough) was considered here, ROAM expects results to be consistent for all large-scale solar plant (e.g., fixed flat plate solar PV).

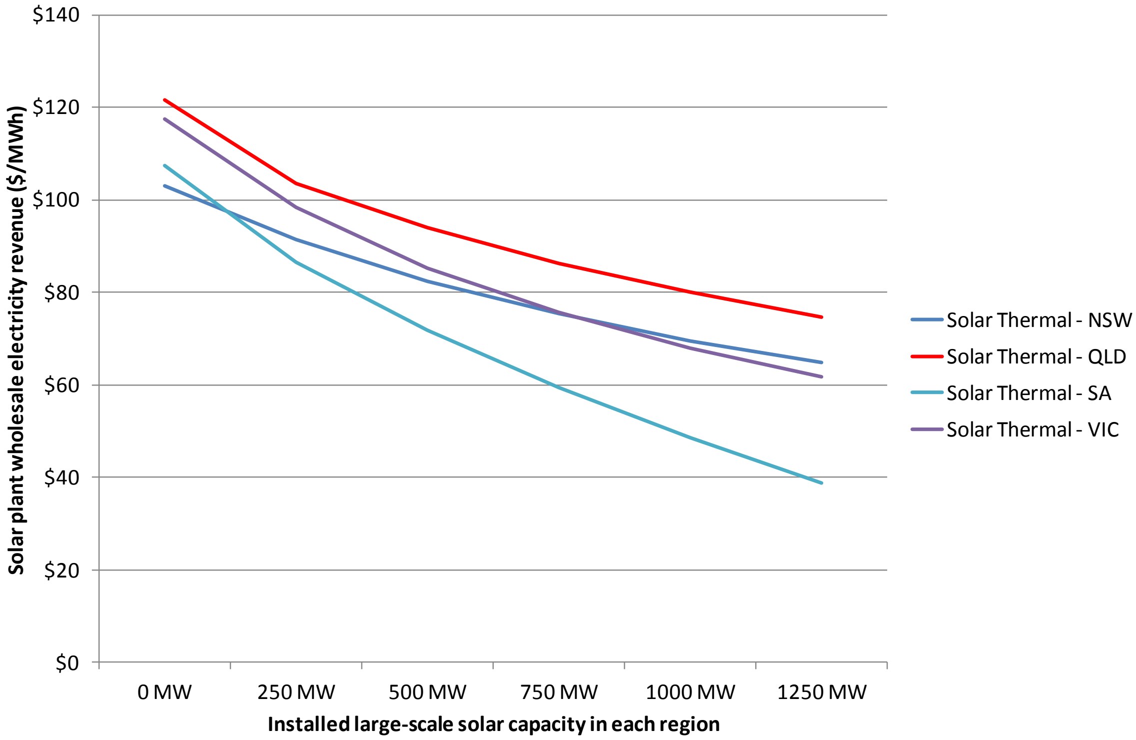
Each region shows a decline in pool prices with increasing solar capacity (Figure 4). This is due to the merit order effect, as ROAM has bid all solar generation into the market at $0/MWh while keeping all thermal generator bidding profiles unchanged; higher priced bids are therefore not needed to meet demand. Without these very high price periods (a significant driver of pool prices and revenues in the NEM, and required by generators to cover not only marginal costs but also their long run “average” costs including capital), pool prices are significantly depressed. South Australia’s pool price decreases more rapidly than the other regions due to its lower demand and limited export capability.

Figure 4 – Large-scale solar impact on time weighted electricity prices (2019-20, $/MWh)



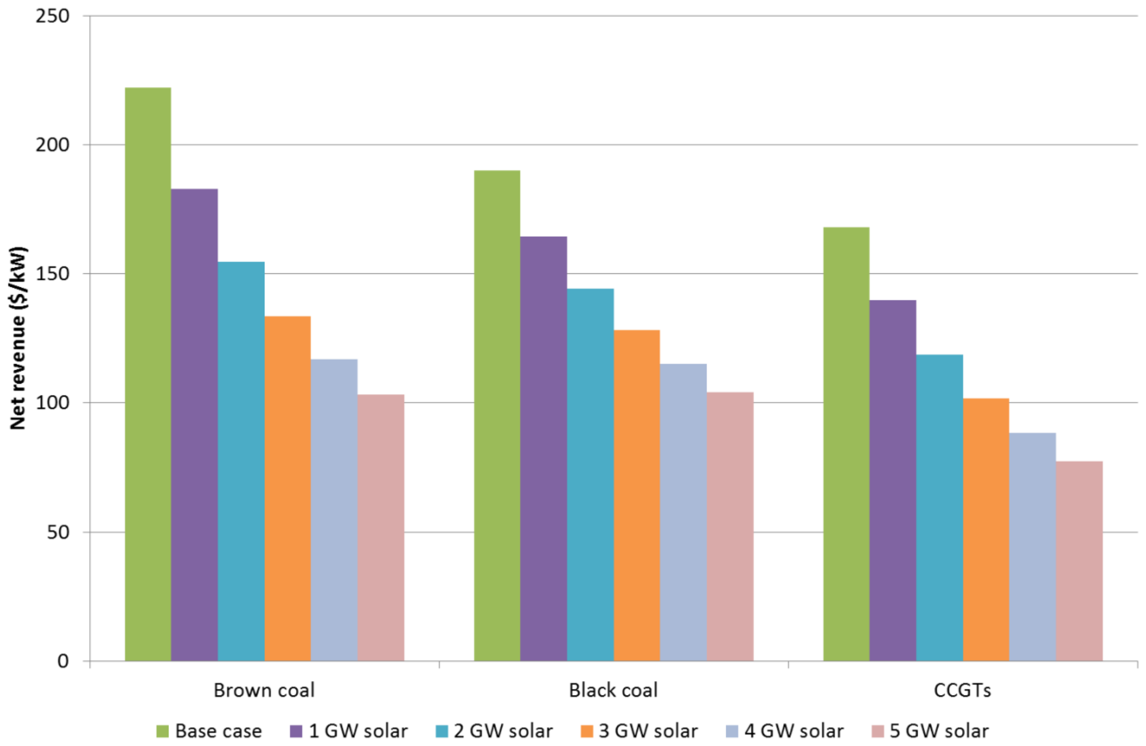
The average revenues of solar generators decrease at an even greater rate than the decline in pool price (Figure 5), because the solar generators are the cause of the reduction in pool prices; by definition, the solar generators are always generating when the prices are depressed due to the solar generation. Some of this lost revenue is recovered through increases in the LGC price, but wind farms are less affected and so the average LGC price rise is insufficient to fully compensate the solar generators. Even in the sensitivities considered below, this effect causes solar revenues to remain depressed and may be an area requiring further investigation by the solar industry.

Figure 5 – Large-scale solar impact on solar generator wholesale electricity revenue (2019-20, $/MWh)



These significant reductions in pool price also significantly impact on the net revenues of thermal generators. Figure 6 shows the revenues net of estimated fixed and variable operating and maintenance costs for brown coal, black coal and CCGT generators in the NEM.

Figure 6 – Large-scale solar impact on thermal generator net revenue



These revenue reductions for thermal generators may not be sustainable in the long term for some generators with higher than average capital cost repayments. In response, some generators may be able to adjust their bidding behaviour to increase revenues or, if their reduced revenues prove unsustainable, they may be retired. Alternatively, with sufficient warning, some new generation may be deferred. ROAM explored these outcomes through sensitivity studies. In all cases, electricity prices increased and the profitability of the remaining non-renewable generators was improved; solar generators, however, still suffered revenue losses due to reducing LGC prices. This suggests that the modelled reductions in pool prices (and consequent savings to consumers) are likely to be only transient effects, but impacts on solar generators themselves may persist over a longer period.

Value of thermal storage

Key findings

- CSP plant with storage and matching higher solar multiples can earn significantly higher revenues, due to both increased generation and better ability to meet evening peak demands.
- Increased revenues would need to be sufficient to cover the increased costs of both additional mirrors (for higher solar multiples) and the storage technology itself.
- Strategic dispatch of storage can increase revenues by 5-12% by allowing for better correlation between generation and price.
- In summer, plant with moderate levels of storage should delay morning start-up and instead use this energy to meet the evening peak prices. With higher levels of storage and higher solar multiples, energy can be stored overnight to better meet the morning peak.
- In winter, prices are typically highest in the morning and afternoon, and plant can increase their revenues by reducing output in the middle of the day to store energy for the evening peak.
- PPAs for solar plant with storage may be more attractive to retailers given the more reliable contribution of the plant to peak demand.

ROAM investigated the value of a range of storage sizes with corresponding solar multiples (Table 2) in two regions, Queensland and South Australia, for the years 2009-10 (a backcast), 2019-20 (with the 20% renewable energy target met) and 2029-30 (exploring a sensitivity with 30% renewables).

Table 2 – Parameters for CSP with storage plant

Storage size	Nameplate capacity (MW)	Storage size (hours)	Storage size (MWh)	Solar Multiple
Small	30	1	30	1.3
Medium	30	3	90	1.6
Large	30	16	480	2.6

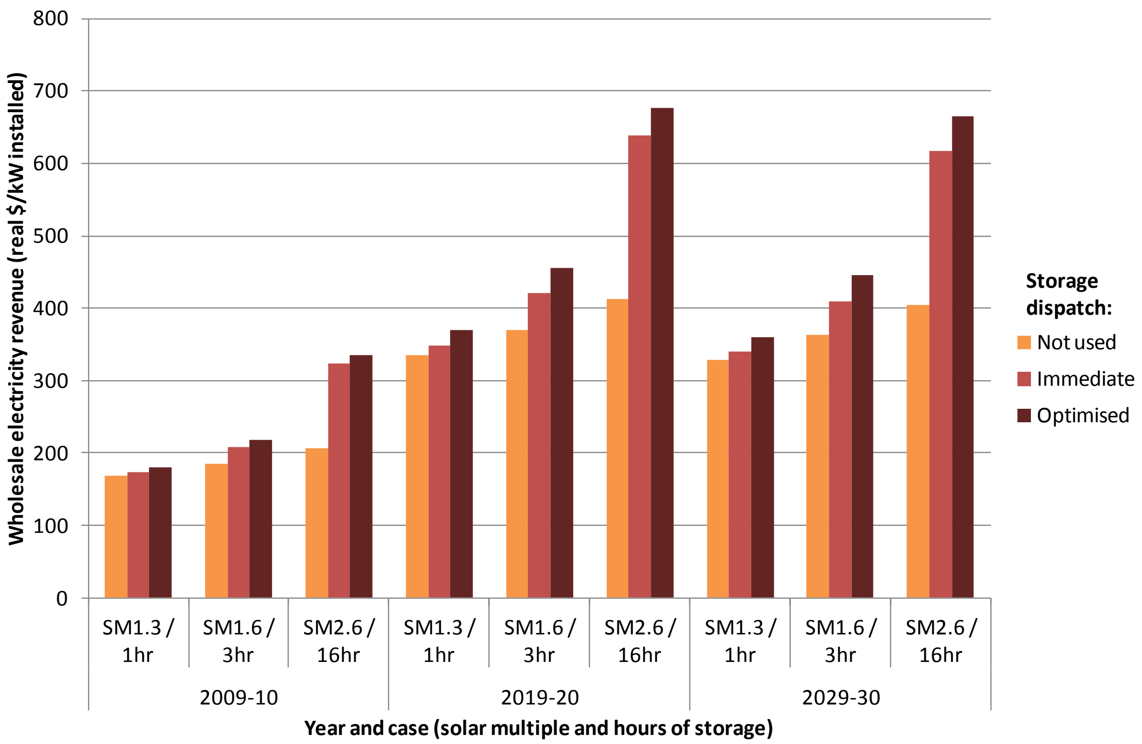
ROAM Consulting considered two methods of dispatching the CSP plant. In the first approach stored energy is used as soon as possible, potentially extending evening operation but not allowing any strategic dispatch. In the second approach, dispatch of the plant was controlled by ROAM's H2Opt storage optimisation tool, and iterative simulations were run to maximise the solar plant revenue. This mode allowed for decisions such as foregoing morning generation in order to store sufficient energy to meet the evening peak. A sensitivity was also considered where no storage was utilised.

Together, these methods represent the range of possible dispatch strategies: CSP with no energy shifting opportunities, a conservative approach with no attempt to predict future price spikes, and an optimised dispatch which effectively maximizes solar plant revenue if perfect knowledge of future conditions were available. In practice, actual outcomes are likely to be between the two options and will depend on the quality of forecast data and preferences of the plant operator (including, potentially, the portfolio and requirements of the PPA counterparty).

Wholesale electricity revenues with and without storage are shown in Figure 7. The higher revenues in the immediate dispatch case are attributable primarily to the increased generation that storage makes possible (due to solar multiples being higher than 1), with average revenues ($/MWh) generally remaining constant (or even decreasing with the simpler immediate dispatch method). An optimised dispatch schedule, however, can double the value of low levels of storage; by 2020 this may be worth an additional $10 to $25/kW annually compared to the immediate dispatch strategy.

With higher levels of storage and corresponding higher solar multiples, the strategic and immediate dispatch strategies become similar, minimizing the need for deferring generation. Higher levels of storage have the added benefit of firming solar capacity during peak demands which may increase the appeal of CSP PPAs to retailers.

Figure 7 – Total electricity revenue for CSP with storage (QLD; SA shows similar trends) (electricity and LGC sales, $/kW installed)

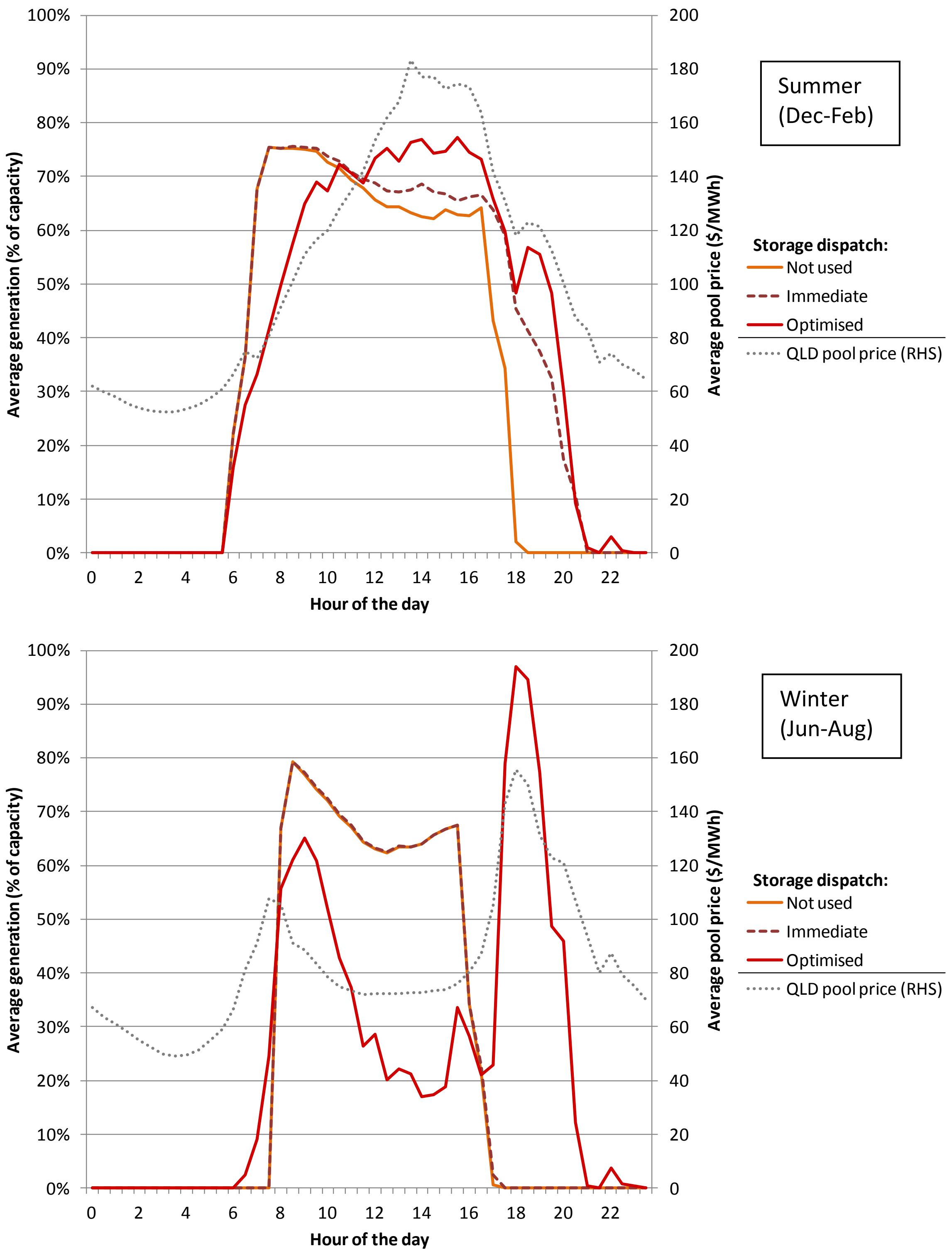


An analysis of the optimised storage dispatch showed that significant benefit could be derived from two low risk strategies, illustrated in Figure 8:

- In summer, revenue can be maximised by delaying the morning start-up of the solar plant by 30 minutes to two hours and storing that energy for meeting the evening peak.
- In winter, when solar insolation is lower, regular high prices in the mornings and evening mean that the optimal operating strategy is to reduce generation during the middle of the day. Stored energy is then used to meet the evening peak as well as speed up morning start-up.

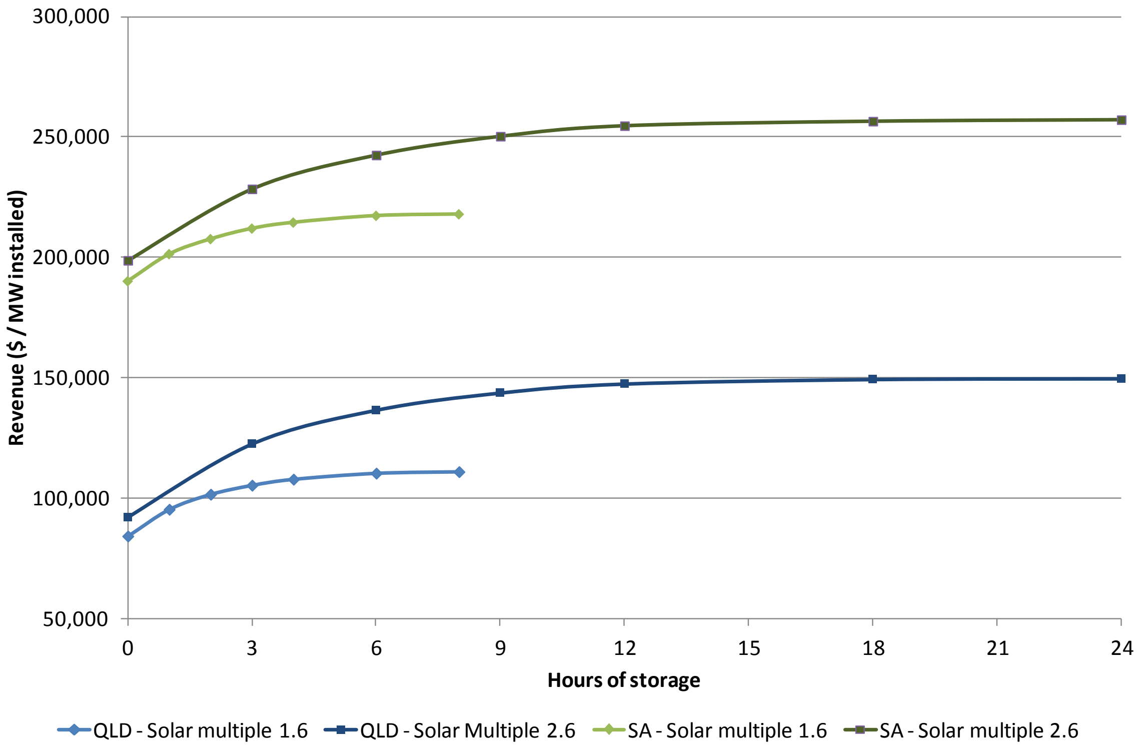
Further strategic dispatch is possible if sufficiently accurate demand and price forecasting systems are available, allowing operators to withdraw capacity in anticipation of high price periods.

Figure 8 – Average summer time of day solar dispatch with storage (QLD, SM 1.6, 3 hours storage, 20019-20)



To investigate optimal storage sizes, ROAM modelled the revenues of solar multiple 1.6 and 2.6 plant with storage from 1 to 24 hours (Figure 9). Higher levels of storage result in higher revenues but with diminishing returns.

Figure 9 – Wholesale electricity revenues for different storage sizes (2009-10, optimised storage dispatch)



Value of gas hybridisation

Key findings

- The value of gas hybridisation is strongly dependent on the volatility of electricity prices.
- Annual net revenues (excluding capital cost repayments) from gas hybridisation are between $10-$50/kW, with net present values of revenues over 15 years of $32-250/kW.
- These revenues would need to be sufficient to cover the capital cost of adding gas hybridisation technology (boilers, piping, gas pipeline, etc.).
- The ability to provide firm capacity may make the PPAs more attractive to retailers, or enable more flexible financing options (including using the futures market).

CSP plants in each region were modelled with gas hybridisation technology, with the backup generation bid into the market at its short run marginal cost. The expected generation in each year is shown in Figure 10. Queensland and New South Wales have higher gas usage due to lower modelled gas prices in these regions; higher price volatility in Queensland results in particularly high usage.

Figure 10 – Generation from gas hybridisation (MWh per MW installed capacity)

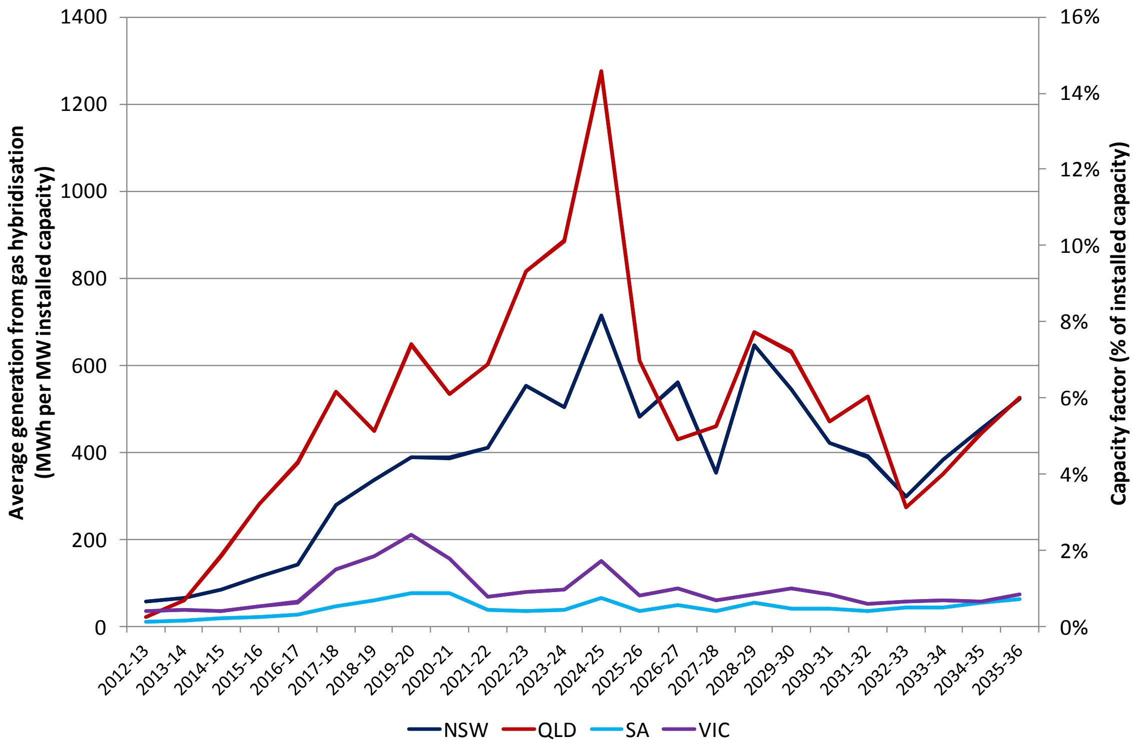
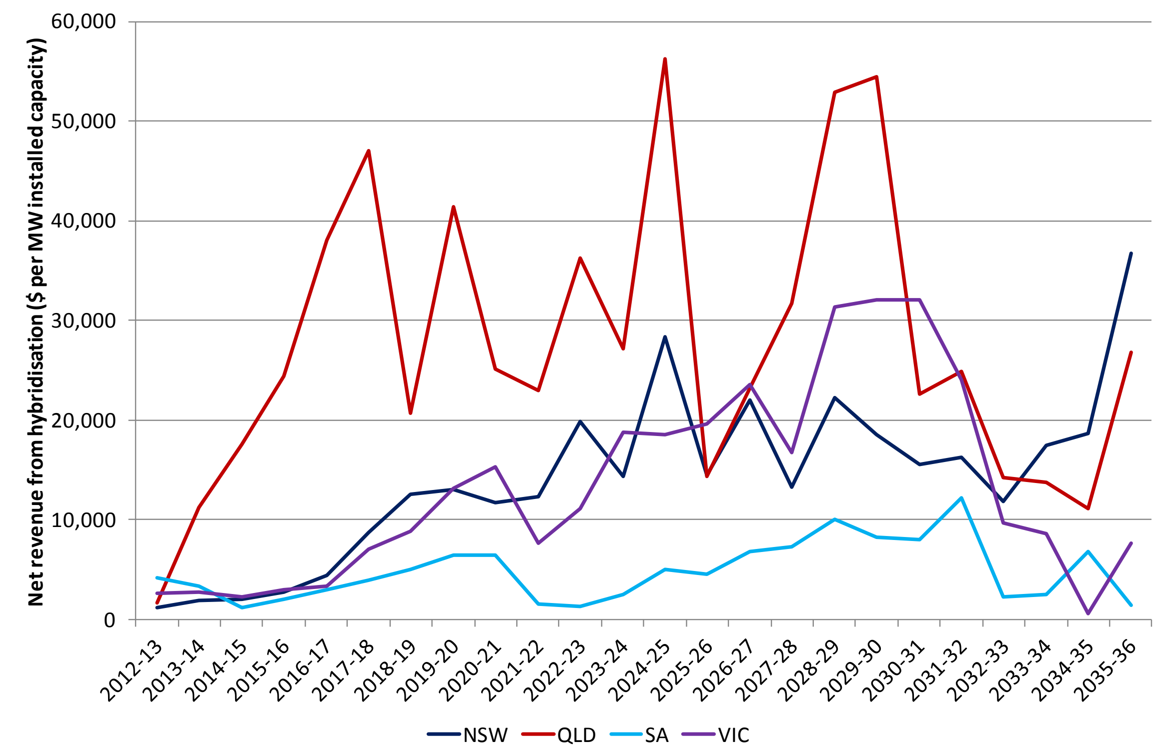


Figure 11 shows the gas generation revenue net of all short run costs (but not of capital repayments or other fixed costs) for each plant. Despite its low generation, a small number of very high price spikes were observed in Victoria, resulting in comparatively high revenues.

Queensland appears as the most profitable region for gas hybridisation to be considered, provided that the additional capital cost (and annual fixed costs) operating gas generation can be recovered through average revenues of around $30,000/MW[3].

[3] ROAM has not attempted to cost the gas hybridisation technology in this report.

Figure 11 – Net revenue from gas hybridisation ($ per MW installed capacity)



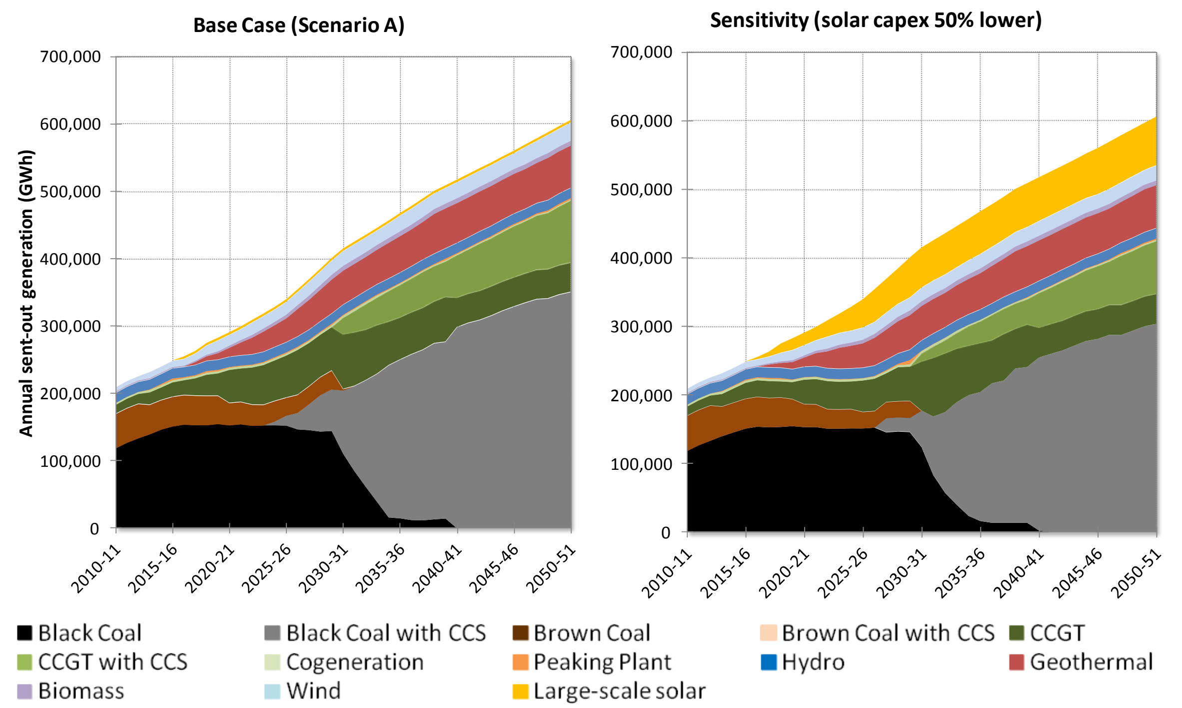
Future solar market share

Key findings

- Under high carbon prices, the least cost outcome for future generation is dominated by low emissions technologies, including renewables and carbon capture and storage (CCS) applied to coal and gas.
- With modest reductions in costs, within the range of global cost estimates, solar technologies can contribute significantly to Australia's energy mix and reduce total costs.
- Initiatives to reduce the capital cost of solar technologies should be considered a high priority.

ROAM has conducted long-term planning studies to explore the long-term cost viability of solar technologies and the sensitivity of these outcomes to capital cost reductions. Figure 12 shows ROAM's forecast generation mix based on technology capital and operating costs presented in Scenario A of the 2011 NTNDP. This scenario featured high carbon prices, high gas prices and high demand and energy growth, conditions that would likely incentivise investment in large-scale renewable energy. Based on the capital cost assumptions of Scenario A, only small quantities of solar PV and CSP plant are built (due to the assumed Solar Flagships program subsidies), with significant energy coming from CCS and geothermal plant.

Figure 12 – Scenario A sensitivity (Solar capital costs 50% lower): Generation comparison



However, with scenario solar capital costs reduced by 50% (within the range of global cost estimates), more than 21,000 MW of large-solar capacity is installed, supplying almost 71,000 GWh pa. The preferred technology is strongly sensitive to the long-run marginal cost of the solar technologies. For the same cost, the model preferred technologies with storage due to the longer operating hours. The additional solar generation replaces gas and coal-fired generation with carbon capture and storage technologies.

This modelling indicates that under favourable conditions solar technologies may compete with other technologies in the absence of subsidies, over the long term. Halving the capital cost of solar technologies produces market outcomes that include substantial quantities of this generation type. This difference in solar capital costs is likely to be within the range of uncertainty. Therefore, initiatives to reduce the capital cost of solar technologies should be considered a high priority.

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1. Background

Large-scale solar is a new technology in Australia. As yet, there are no significant (>10MW) solar installations operating in Australian electricity markets. At present, the majority of market integration studies on intermittent renewables in Australia focus on the more prevalent wind generation technologies.

Solar technologies will operate differently in the market compared to wind generation. It is important that these differences are understood prior to large-scale deployment of solar generation technologies to facilitate smooth entry into the Australian markets.

This work provides an extension to the Concentrating Solar Power (CSP) review by IT Power, now in the final stages of completion. This study builds upon the information and analysis in the CSP review, utilising ROAM's state-of-the-art market modelling capability to provide detailed insight into the operation of solar technologies in the future market. The CSP review recommended further investigation of this nature, particularly in the area of identifying the effect of a large amount of solar generation on energy market pool prices.

2. Scope

This study provides modelling of solar generation operating in two markets in Australia: the National Electricity Market (NEM) and South-West Interconnected System (SWIS). A range of topical issues are addressed, including:

1. **Solar revenue and PPAs** - Solar technologies have the potential to provide significantly higher value than competing renewable technologies, since they operate primarily during peak price periods. Quantifying this additional value assists solar developers in negotiating more competitive Power Purchase Agreements (PPAs), which are essential for project financing. Detailed market modelling has been conducted to forecast the revenue stream of solar plant from wholesale electricity and Large-scale Generation Certificates (LGCs). From these revenues, the PPA price is calculated as an equivalent net present value. The PPA price has been compared to the most prevalent alternative renewable technology (wind) to demonstrate the increased value of solar technologies. Furthermore, plant operating in each NEM and SWIS region are compared to allow detailed comparison of the market dynamics and profitability of solar in different locations around Australia (the value of a solar plant can vary significantly by location).

   The drivers for solar revenues and PPAs are also discussed in detail. Rare periods of very high prices are known to be a significant determining factor in solar revenues, which makes forecasts highly sensitive to anticipated price volatility. Understanding the drivers of price volatility and likely solar operation in those periods is therefore essential for projecting solar revenues. Reasons are identified for why solar plant have not been offered PPAs with this premium value in the past (including lack of retailer awareness, number of bankable off-takers in the Australian market, lack of accepted quantification of increased value of solar, perceived technology risk, and depression of the LGC market in recent years due to the rooftop PV boom).

2. **Impact of solar on pool prices (the Merit Order Effect)** - The introduction of large quantities of solar generation has the potential to reduce pool prices; this has been termed the "Merit Order Effect". To quantify this effect in each region of the Australian market, detailed market modelling has been conducted with incrementally increasing solar capacities installed. The impacts of the Merit Order Effect upon consumers and other market participants are explored (including benefits for consumers in terms of reduced electricity bills, at the expense of incumbent market participants), and the implications for long-term market operation are discussed.
3. **Value of thermal storage** - The addition of thermal storage adds value by allowing solar plant to capture high priced periods even when solar resources are not available. Determining optimal sizing of storage facilities remains challenging, and depends heavily upon interaction with the market. Sophisticated market modelling including advanced optimisation of storage scheduling has been used to calculate the marginal value of storage (in terms of increased solar revenues) at a range of storage sizes in order to determine the optimal storage size. The changing value of storage over time was also assessed as the proportion of intermittent renewable technologies installed increases.
4. **Value of gas hybridisation** - There is the potential to increase the profitability of solar thermal plant by operating steam generation facilities on gas fuel when solar energy is not available. Sophisticated market modelling has been used to quantify plant revenues with and without gas hybridisation to calculate its value. This assists solar developers in making an informed choice when deciding whether to include gas hybridisation on future projects, and may assist in justifying more competitive PPAs for solar plant with gas hybridisation.
5. **Future solar market share** - The future market share of solar technologies in Australia remains uncertain, and dependent upon policies and other measures implemented now. Long-term integrated resource planning has been used to calculate the least cost generation development plan to determine the market share of solar technologies by 2050 under different assumptions, determining the range of possible outcomes for solar in Australia. This demonstrates that solar technology costs are in the range where programs to facilitate large-scale commercial deployment of solar will make the difference between solar being a very substantial part of Australia's least cost energy future, or not.

3. Modelling Methodology

3.1 Modelling Tools

ROAM has utilised the following proprietary modelling tools for the completion of this study:

- **2-4-C**, ROAM's dispatch model. Designed to replicate the operation of the Australian Energy Market Operator’s (AEMO) National Electricity Market Dispatch Engine (NEMDE), it calculates least cost market dispatch taking into account generator bids and network constraints. In short-run marginal cost mode, the 2-4-C dispatch model replicates the dispatch of net pool capacity markets, such as that which operates in the SWIS. More information about 2-4-C is provided in Appendix B).

- **H2Opt**, ROAM's advanced storage scheduling optimiser. H2Opt integrates with 2-4-C to dispatch storage optimally to minimise system costs which in turn maximises storage revenue. Originally designed for optimising the operation of pumped storage hydro and other energy limited technology such as conventional hydro with rainfall inflows, this is the most sophisticated tool of this type available. H2Opt enables detailed insight into optimal use of storage for increasing the value of solar in Australia.
- **LTIRP**, ROAM's long-term integrated resource planning model. This tool calculates a least cost development plan for new generation and transmission, given the short and long-run marginal costs of each technology type available.
- **SEST and WEST**, Solar Energy Simulation Tool and Wind Energy Simulation Tool. These are ROAM’s long-term forecasting tools of half-hour traces for solar and wind plant. The half-hour traces capture the important aspects of the variable renewable resource based on the 2009-10 reference year for the studies in this report. More information is provided in Section 3.5 for SEST and Section C.4.1) for WEST.

3.2 Dispatch Modelling

Backcasts

Some parts of this study involve simulating a backcast. A backcast replicates an historical year, allowing comparison with sensitivities where certain factors are changed (such as the installed capacity of solar technologies). Backcasts have the advantage that a real year is replicated, so the input data is known to accurately capture real behaviour. For example, the actual demand in each region in each half-hour and all of the associated bids of each individual generator in each half-hour are used as an input. Actual solar radiance data can also be included from the corresponding half-hourly periods.

Forecasts

Forecast simulations have also been used for some parts of this study. Forecasts are important, since they allow analysis of the impact of various factors in an anticipated future environment (with demand growth, the changing generation mix and other factors such as the carbon price taken into account). All forecast results in this report quote prices in real July 2011 dollars.

For forecasts, a single historical reference year is used as the basis for creating input data. For this modelling, the year 2009-10 was used (for discussion, refer to Appendix A). The demand from the historical year is manipulated to meet the forecast peak demand and energy targets in each future year. Solar and wind data from the same historical reference year is also used, to ensure that any correlation between demand, solar and wind (and between these at each location) is accurately captured.

Renewable technologies (mostly wind power) were added to meet the Large-scale Renewable Energy Target in 2020, and increased further to 30% by 2030 in one scenario. Wind generation was modelled using ROAM's Wind Energy Simulation Tool (WEST), based upon historically modelled hub-height wind speed data from the Bureau of Meteorology (BoM).

Transmission constraints were applied, using the most recent set of constraint equations released by AEMO, intended to replicate system normal operation similar to NEMDE.

Historical bidding patterns from each NEM generator in the reference year were analysed to determine "typical" generator bids, taking into account half-hourly, daily, weekly and seasonal variations. These were projected forward, with an uplift applied to take account of increases in fuel prices (where relevant), and to take into account increases in the carbon price (for fossil-fuel generators). For this study ROAM used the Australian Government Treasury's Core Policy carbon price trajectory (see Section C.3.3).

3.3 Forecast Modelling Limitations

The price spikes in ROAM's modelling are driven by a combination of high demand (which would be correlated with solar generation) and plant outages. However, it may be that in practice other factors strengthen this correlation. ROAM has identified some possible factors that could lead to a higher correlation between solar generation and pool price than is observed in ROAM's simulations:

- Dynamic bidding strategies are not included in ROAM's modelling (although strategic bids are modelled for each generator based on an analysis of their bidding over the previous 12 months). It is possible that, in anticipation of a high demand period, generators may adjust their bidding strategies to inflate the pool price. This would translate to increased revenue for solar plant whose output is correlated with demand.
    - Another possible future bidding strategy with high penetration of solar power could include generators bidding strategically to take advantage of the loss solar output at (or just before) sunset. This might cause price spikes that solar plant would not have access to and would impact on their *relative* revenue to other generators.
- In ROAM's model, outages are equally likely in all periods (although different plants have different probabilities and durations of outages). However, high temperature periods (typically correlated with high solar generation *and* high demand) may increase the outage rate of generators, further exacerbating high pool prices during solar generation periods.
- ROAM includes a derating of most generators during summer to reflect their lower operating capacity during higher temperature periods. This may, however, underestimate the amount of capacity available on (relatively) cooler summer days (when Solar Dawn has lower generation) and hence lead to more price spikes on those days in the model (than would occur in reality).
- ROAM has not modelled transmission outages and has only modelled "system normal" constraints. Stricter conditions on the network (due to, for example, reduced thermal limits on transmission lines on hot days) have historically resulted in additional price spikes that ROAM has not captured.

3.4 LGC Modelling

To determine the market value of LGCs, ROAM has applied a "shadow price" calculation. This calculation determines the average LGC prices that would be implicitly assumed in Power

Purchase Agreements (PPAs) – the additional amount that renewable energy generators require above their wholesale electricity revenue to meet their levelised cost of supply.

The LGC price required by a generator in order to be cost effective will be closely related to the difference between the average price obtained from the spot electricity market (or contract market depending upon its contract position), and the generator's long-run marginal cost.

Due to the large volume of announced wind projects and expected small contribution (relative to wind) of other renewable energy technologies, the LGC price is likely to be set by the price required by wind generators. To estimate the LGC price, ROAM uses the portfolio of wind generators in the modelling to assess the "shadow price" of LGCs required by wind farms to meet their desired rate of return. The LGC price is determined as follows[4]:

$$\text{LGC (shadow) price} = \frac{\text{Total wind generation cost} - \text{Total wind generation pool revenue}}{\text{Total wind energy production}}$$

Note that any individual wind farm might require a higher or lower price for its LGCs, depending on its pool revenue and its levelised cost of electricity. This shadow price approximation provides a measure of the "typical" LGC price that would be required by the total portfolio of installed wind farms.

Wind farms typically (but not always) sign PPAs for a bundled (wholesale electricity plus LGC) price, and hence are somewhat buffered from fluctuations in both the carbon price and the pool price – increases in the carbon price will result in decreases in the effective LGC price implied by such contracts.

Solar plant LGCs

In general, retailers are likely to be indifferent as to the source of their renewable energy when it comes to determining the premium that they must pay over the wholesale electricity price (i.e., the LGC price). Therefore, in the absence of external drivers (such as solar only GreenPower or for marketing purposes) solar plant are unlikely to be able to command LGC prices significantly higher than those of wind farms. The LGC shadow price (based on wind farms) has therefore been used for solar plant as well.

However, solar plant may still earn a premium over wind farms due to the higher value of their daytime generation.

Further discussion of LGC prices is given in Section 5.5.

3.5 SOLAR MODELLING

Since this study focuses on solar technologies, the method of producing solar generation traces is of particular importance.

[4] This shadow price approximation treats all wind farms as being owned by a single entity, such that revenue and costs can be shared between all wind farms.

Hourly gridded satellite solar data was obtained from the Bureau of Meteorology, and actual (as opposed to “typical”) meteorological years were considered for each site in each region. Two models were used for the analysis:

- The System Advisor Model (SAM)
- ROAM's Solar Energy Simulation Tool (SEST)

These data sources are described in more detail as follows.

Solar data

Solar data was obtained from the Australian Bureau of Meteorology (BOM). This was in the form of hourly global horizontal irradiance (GHI) and direct normal irradiance (DNI) values for the whole of Australia at approximately 5km resolution. For each grid cell, brightness data was obtained by the BoM from visible images taken by geostationary meteorological satellites and a detailed model involving surface albedo and atmospheric conditions was used to convert this to GHI. An atmospheric model was then used by the BOM to separate out the DNI and diffuse components. This data does not replace the need for ground based observations, but comparison with ground based data where available suggests that the satellite data provides a reasonable estimate of solar resource for planning purposes. BOM calibration studies have shown the mean bias difference (average of the satellite - surface difference), calculated on an annual basis across all surface sites available to the BOM, is ±11 to ±40 W/m^2 and typically around ±20 W/m^2. This is ±4% of the mean irradiance of around 480 W/m^2.

System Advisor Model (SAM)

SAM is a widely used tool published by the National Renewable Energy Laboratory (NREL). It allows for detailed modelling of power plants, with a particular focus on solar technologies. A detailed database of plant operating parameters, costs and financial assumptions are provided to allow for both technological and economical modelling of prospective plants and sites.

SAM generally uses Typical Meteorological Year (TMY) weather files, obtainable for Australian locations from the U.S. Department of Energy[5]. For this study, ROAM was also interested in real meteorological year data to understand specific variability. ROAM therefore created appropriate “EPW” (EnergyPlus Weather) format input files based on the Bureau of Meteorology solar, temperature, pressure and wind speed data for the specific locations of interest.

ROAM Consulting used SAM for the preliminary analysis of solar technologies, as well as for comparisons of the TMY and real meteorological year weather and generation patterns.

[5] http://apps1.eere.energy.gov/buildings/energyplus/cfm/weather_data.cfm

Solar Energy Simulation Tool (SEST)

For the solar traces used in the modelling and historical analysis, ROAM Consulting used its in-house Solar Energy Simulation Tool (SEST), a detailed model that uses hourly solar insolation traces, plant technical parameters and a solar position and plant geometry model to produce hourly generation traces. SEST has been used extensively by ROAM in its solar modelling to date, including for the preliminary assessment of Solar Flagship applications and feasibility studies for commercial solar projects.

SEST has the advantage of being specifically designed for rapidly analysing multiple sites across multiple reference years while still providing a high degree of accuracy. Its outputs have been extensively benchmarked against both historical generation (such as from the Alice [Springs] Solar City project) and other solar models. In particular, the simplified loss models in SEST provide good agreement with SAM's generation traces for solar PV and parabolic trough plants, amongst others.

Solar PV

A detailed geometric model was employed to calculate the portion of the direct and global solar insolation on the PV plate or dish, with the tracking angle (if applicable) optimised for maximum generation in each period. The elevation of the panel was optimised to maximise annual generation.

The name plate capacity of the cells is assumed to be under Standard Testing Conditions (STC) which correspond to 1000W/m^2 incident radiation (either beam or global as appropriate) and an operating temperature of 25°C. A derating factor (in the form of a reduction in output energy) was applied to account for the losses, including in the inverter. A simplified cell temperature and efficiency model was used, based on incident radiation, ambient temperature (obtained from BOM) and typical cell operating and temperature derating parameters.

CSP (Parabolic trough)

A geometric model is used to calculate the incident solar radiation on a parabolic trough, with the mirror angle optimised for each half-hour of the year. Various solar multiples (effectively, mirror field size) were considered, referenced to conditions of 1000W/m^2 incident solar radiation. Reflection losses, end losses and shading effects were also included, all of which vary by incident angle.

A thermal model was then used to calculate output generation. This model included a minimum incident radiation for operation, a morning start-up time (dependent on received radiation) and parasitic losses.

4. Preliminary Analysis

4.1 Reference year analysis

In order to model a realistic representation of demand and the generation from intermittent sources, ROAM uses an historical reference year. The demand, wind patterns and solar patterns measured in that historical year are projected forward, capturing diurnal and seasonal patterns and the correlation between the three parameters.

In particular, this approach allows for a quantitative assessment of the generation of solar plant during the highest price periods (which can contribute a significant percentage of the total solar revenue). For market analysis, ROAM considers this preferential to using typical meteorological year (TMY) solar data where any correlation with demand or price will be purely coincidental.

Historical years differ from each other, with some having unusually high or low demand, and similarly variable renewable resources. The distribution of each parameter around the NEM may also differ. These can lead to material differences in modelling outcomes. Ideally, all modelling studies would repeat calculations for a range of reference years, capturing the impacts of inter-annual differences. However, this multiplies the number of simulations required. Therefore, ROAM typically utilises a single reference year that is assessed to be reasonably representative of "average" behaviour across all relevant parameters.

ROAM's analysis (outlined in detail in Appendix A) indicates that 2009-10 is an appropriate reference year, giving "typical" solar and wind generation levels in all parts of Australia, and having a reasonably average demand shape. The demand profile in 2009-10 is weighted towards more energy being delivered at high demand periods, which is likely to be consistent with a growing trend in air-conditioner penetration. This year has therefore been used as the reference year for the modelling included in this study. However, the possible impact of year to year changes should be considered when analysing the results of this study.

4.2 Solar Technologies

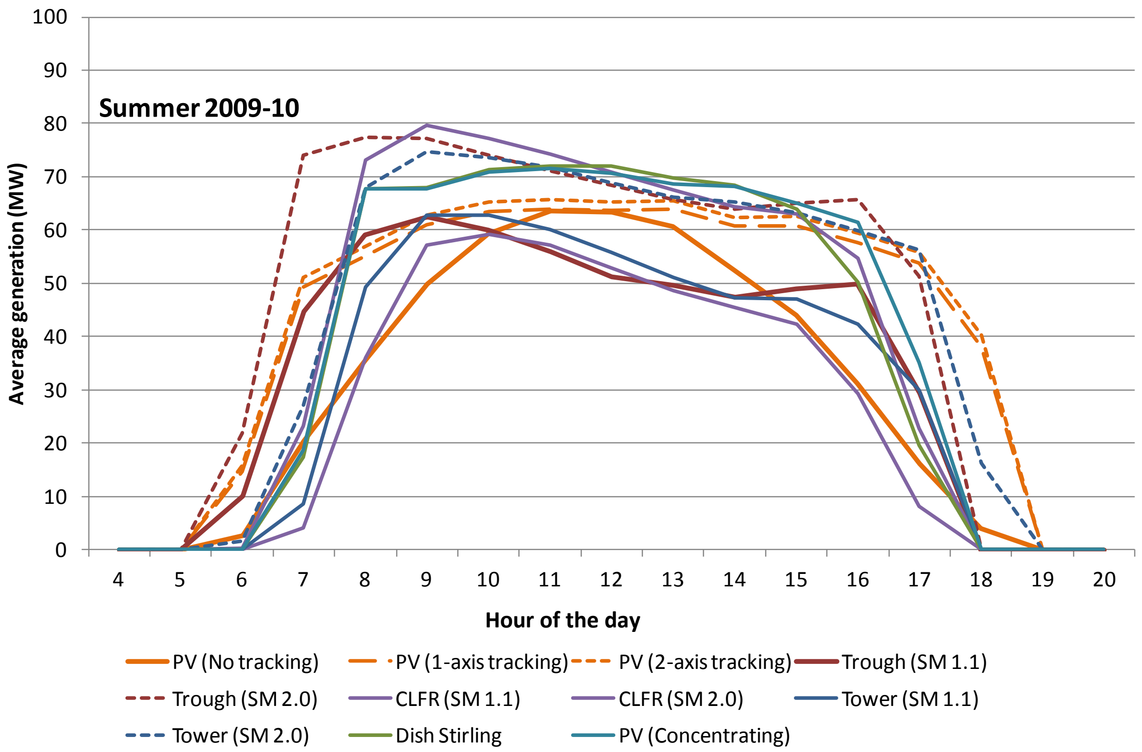
ROAM has considered a range of solar technologies for the purpose of identifying the range of possible diurnal and seasonal variation in output from each and hence identifying a number of representative technologies for further market studies.

The technologies considered by ROAM Consulting were:

- Fixed flat plate solar PV
- Solar PV with 1-axis tracking
- Solar PV with 2-axis tracking
- Concentrating solar PV (2-axis tracking)
- Dish-Stirling
- Parabolic trough with solar multiple 1.1 to 2.0
- CSP Linear Fresnel (CLFR) with solar multiple 1.1 to 2.0
- Molten Salt Power Tower with solar multiple 1.1 to 2.0

For each technology, and for a range of solar multiples (if applicable), SAM was used to produce hourly generation traces for 100MW nameplate capacity plant in Queensland (Kogan Creek) and South Australia (Point Paterson) based on the 2009-10 reference year. Figure 4.1 and Figure 4.2 show the average time-of-day generation for summer (December to February 2009-10) and the remainder of the financial year.

Figure 4.1 – Average time-of-day solar generation (Kogan Creek, QLD)



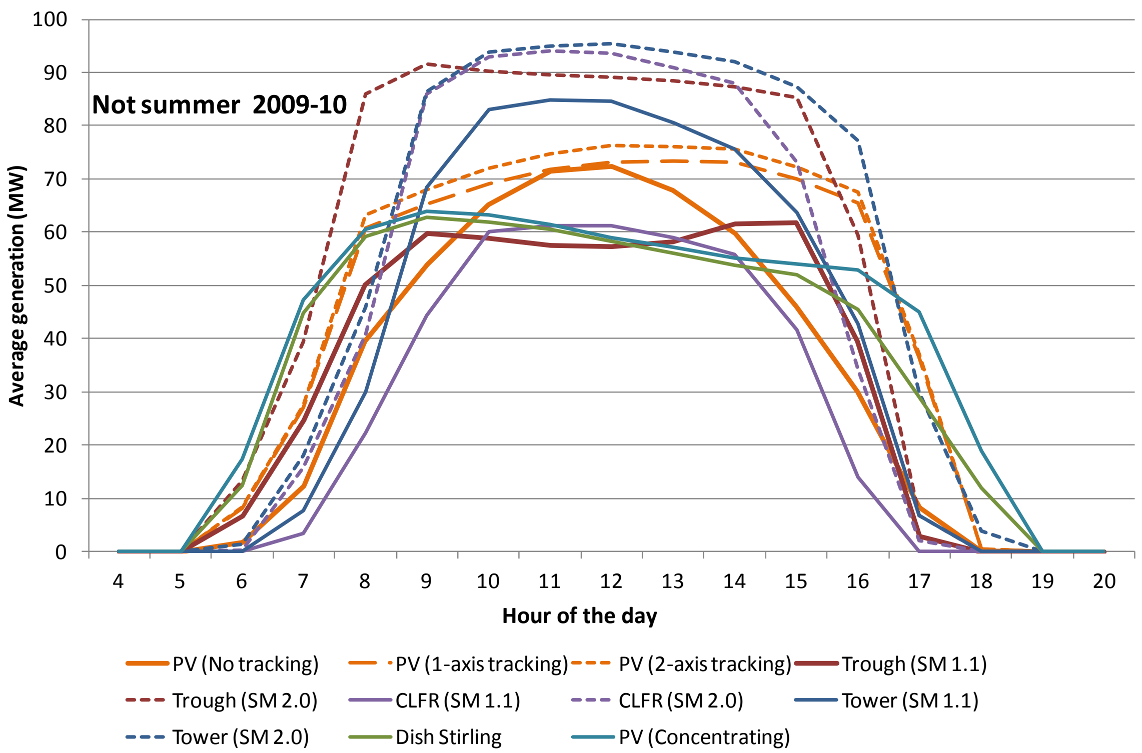
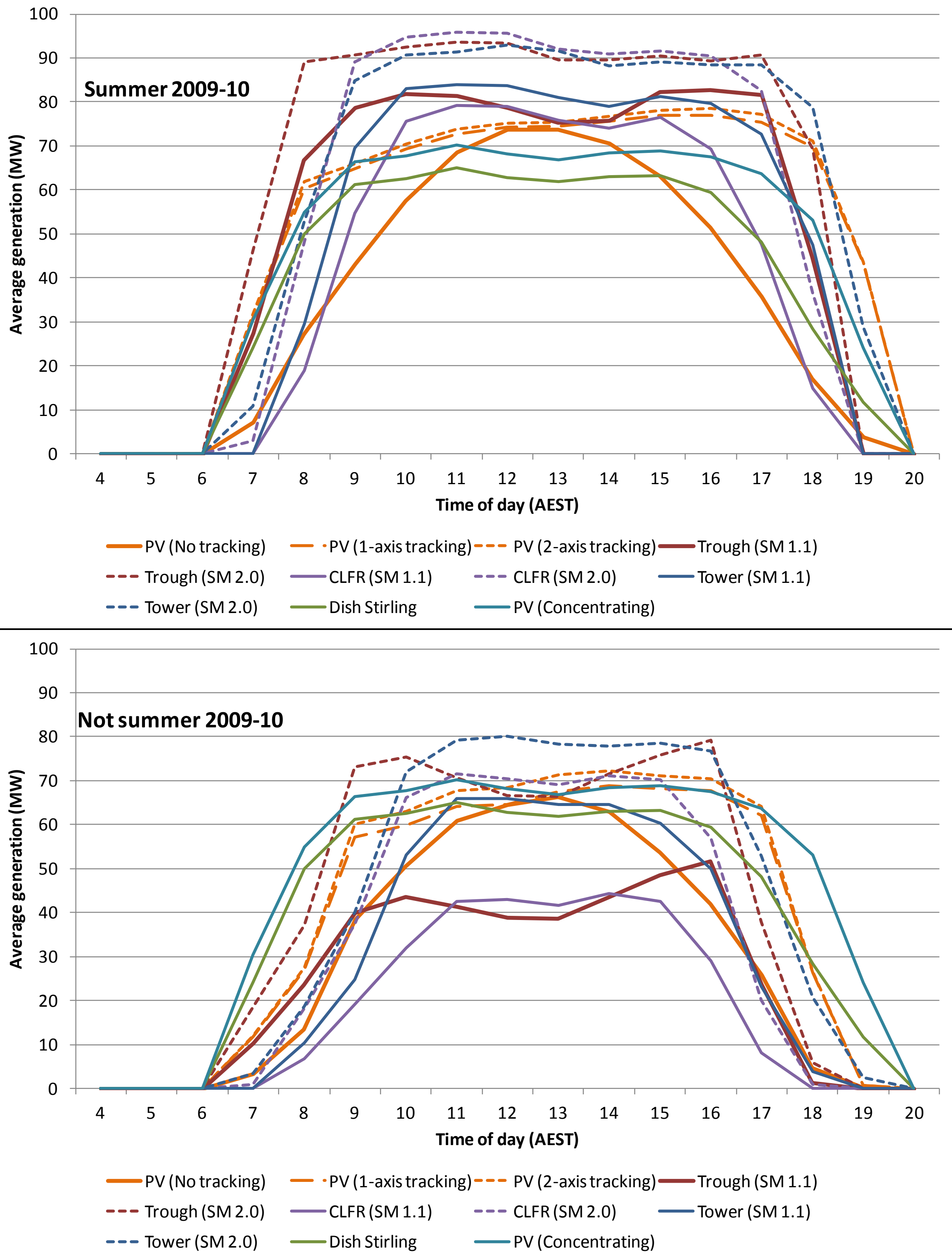


Figure 4.2 – Average time-of-day solar generation (Point Paterson, SA)



For selecting representative technologies, factors that would have the greatest impact on the interaction of the solar plant with the market were considered. These include:

- **Capacity factor.** Higher capacity factors would result in higher total revenues, although average revenues could increase *or* decrease depending on the timing of additional generation.
- **Time-of-day profile.** All technologies exhibited qualitatively similar time-of-day profiles. The most noticeable variation is between fixed flat plate solar PV (with a smooth Gaussian generation profile) and the thermal technologies with tracking (which have a flat profile during the middle of the day).
- **Performance in the morning and afternoon price peaks.** Stronger solar performance during these periods may increase plant revenue by taking advantage of high price events. The inclusion of a tracking component significantly improves solar performance in these periods.

ROAM also notes that, as would be expected by their different weather patterns, Queensland and South Australia have qualitatively different (average) profiles in summer and winter. Queensland experiences significant cloudy periods during the wet season which reduces average summer generation, but receives higher insolation during winter than South Australia. This effect is particularly present for the parabolic trough systems, but is observed in all technologies. Therefore, this factor should not impact on technology choice but is notable for its potential impact on plant revenues and their contributions to reliability. The time shift between the solar generation in Queensland and South Australia (Figure 4.1 and Figure 4.2) implies that solar generation in South Australia may be able to contribute to the demand peaks further east in Victoria in New South Wales, given good transmission connection.

Selected technologies

Based on this analysis, ROAM has chosen two technologies which represent a range of different generation profiles:

- Solar PV without tracking (referred to in the charts and tables in this report as “Fixed flat plate PV”); and
- Parabolic trough with solar multiple 1.3 (referred to in the charts and tables in this report as “CSP / PV with tracking”).

The solar PV technology captures a primary midday peaking technology, and is likely to represent typical solar PV installations in the near-term. This will allow ROAM to assess the market benefits of primarily daytime generation with a smaller contribution to evening peaks.

The parabolic trough system will allow the exploration of the value of a flatter time-of-day profile and, in particular, stronger performance in the later afternoon. Its revenue and PPA outcomes are also expected to be indicative of outcomes for the majority of solar technologies with tracking, including 1- and 2-axis tracking solar PV.

To determine an appropriate solar multiple, a range of simulations were conducted using SAM to determine the levelised cost of electricity (LCOE) for a range of:

- Solar multiples (from 1.0 to 3.0);
- Construction costs (e.g., varying mirror costs from \$270/m^2 to an extreme value of \$910/m^2);

- Locations (QLD, NSW, SA, VIC); and
- Weather data sets (including Typical Meteorological Years and actual historical year data developed as described in Section 3.5.

This analysis suggested that a solar multiple of 1.3 was a conservative field sizing across all scenarios, with most simulations implying a higher solar multiple would be justified on an LCOE basis. Even if higher solar multiples might be justified in theory, difficulties in obtaining funding for near-term plants might produce a trend towards lower solar multiples to reduce upfront costs. It may also be true that higher solar multiples do not necessarily increase revenue on a dollars per megawatt hour basis due to the additional output typically occurring in lower price periods (e.g., winter months) and hence reducing average revenue. Higher solar multiples and the benefits of storage are explored in more detail in Section 7.

5. Solar Revenue and PPAs

ROAM has modelled the output of CSP (solar thermal parabolic trough) and solar PV (fixed flat plate) systems in each of the four mainland NEM regions plus the SWIS in Western Australia. Two separate studies were conducted:

1. Revenues from solar plant in several historical years were compared to highlight inter-annual variability and the important factors contributing to this variability.
2. Solar plant was modelled from the first year of the study (2012-13) to assess the current value of solar technology even though solar penetration is low at present.

Each station was assumed to be sufficiently small that it did not significantly impact on electricity prices (i.e., no merit order effect was considered at this stage of the study). The solar generation and forecast assumptions are described in Section 3.

5.1 Historical Solar Performance

Table 5.1 shows the average revenues for fixed flat plate solar PV and CSP (also representative of solar PV with tracking) plant based on actual historical prices and modelled generation from 2003-04 to 2009-10. In these calculations, matching reference years are used (rather than a "typical meteorological year" generation trace, for example) to ensure that the historical interaction of solar generation with the market is captured.

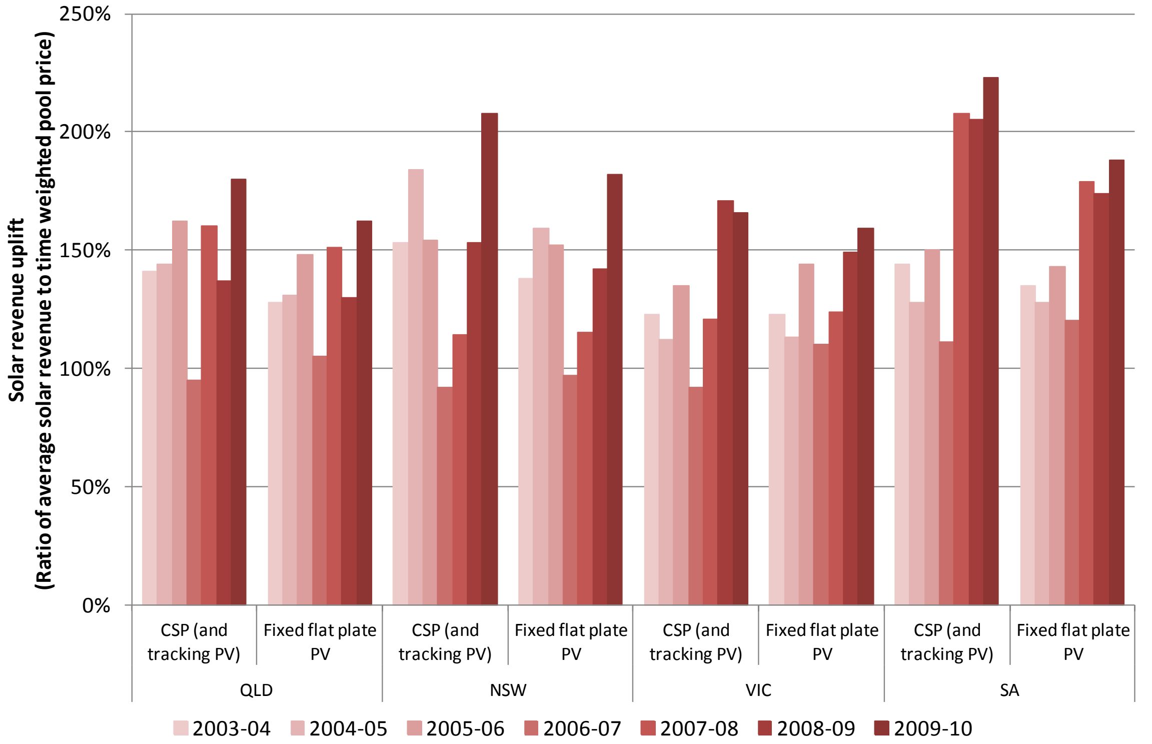
Differences between years and regions are due to changes in pool prices and performance of solar plant, particularly during the highest price periods.

Table 5.1 – Modelled solar revenue in historical years (nominal $/MWh)								
		2003-04	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**
QLD	CSP (and tracking PV)	$40	$42	$46	$50	$84	$47	$60
	Fixed flat plate PV	$36	$38	$42	$55	$79	$44	$54
NSW	CSP (and tracking PV)	$50	$72	$58	$54	$48	$59	$92
	Fixed flat plate PV	$45	$62	$56	$57	$48	$55	$80
VIC	CSP (and tracking PV)	$31	$31	$44	$51	$57	$71	$60
	Fixed flat plate PV	$31	$31	$47	$60	$58	$62	$58
SA	CSP (and tracking PV)	$50	$46	$57	$57	$153	$104	$123
	Fixed flat plate PV	$47	$46	$54	$62	$131	$88	$104

To assess the revenue performance of the solar plant in any year, the solar “uplift” is defined as the ratio between the average solar revenue in that year and the average time-weighted pool price (Table 5.2 and Figure 5.1). This provides a measure of the performance of the solar plant relative to a flat “baseload” generator.

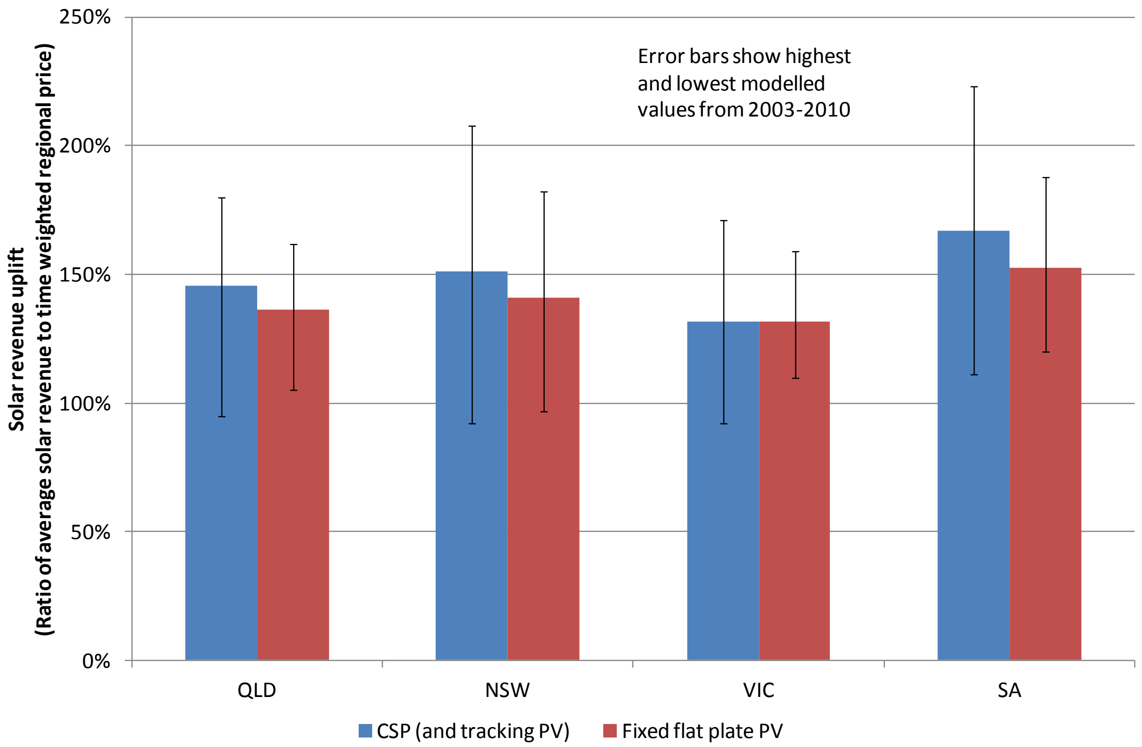
Table 5.2 – Modelled solar revenue uplift (%) in historical years (Defined as average revenue / average time-weighted wholesale electricity price)								
		2003-04	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**	**2009-10**
QLD	CSP (and tracking PV)	141%	144%	162%	95%	160%	137%	180%
	Fixed flat plate PV	128%	131%	148%	105%	151%	130%	162%
NSW	CSP (and tracking PV)	153%	184%	154%	92%	114%	153%	208%
	Fixed flat plate PV	138%	159%	152%	97%	115%	142%	182%
VIC	CSP (and tracking PV)	123%	112%	135%	92%	121%	171%	166%
	Fixed flat plate PV	123%	113%	144%	110%	124%	149%	159%
SA	CSP (and tracking PV)	144%	128%	150%	111%	208%	205%	223%
	Fixed flat plate PV	135%	128%	143%	120%	179%	174%	188%

Figure 5.1 – Modelled solar revenue uplift (%) in historical years (Ratio of average revenue / average time-weighted pool price)



Uplifts vary between 114% to over 200%, depending on the region and reference year. An exception was 2006-07 where a combination of factors caused very high winter prices, increasing the annual average wholesale electricity price whilst not flowing on to the solar generator revenues (due to their reduced output and operating hours in winter). The average uplifts and the minimum and maximum ranges for CSP and solar PV are shown in Figure 5.2.

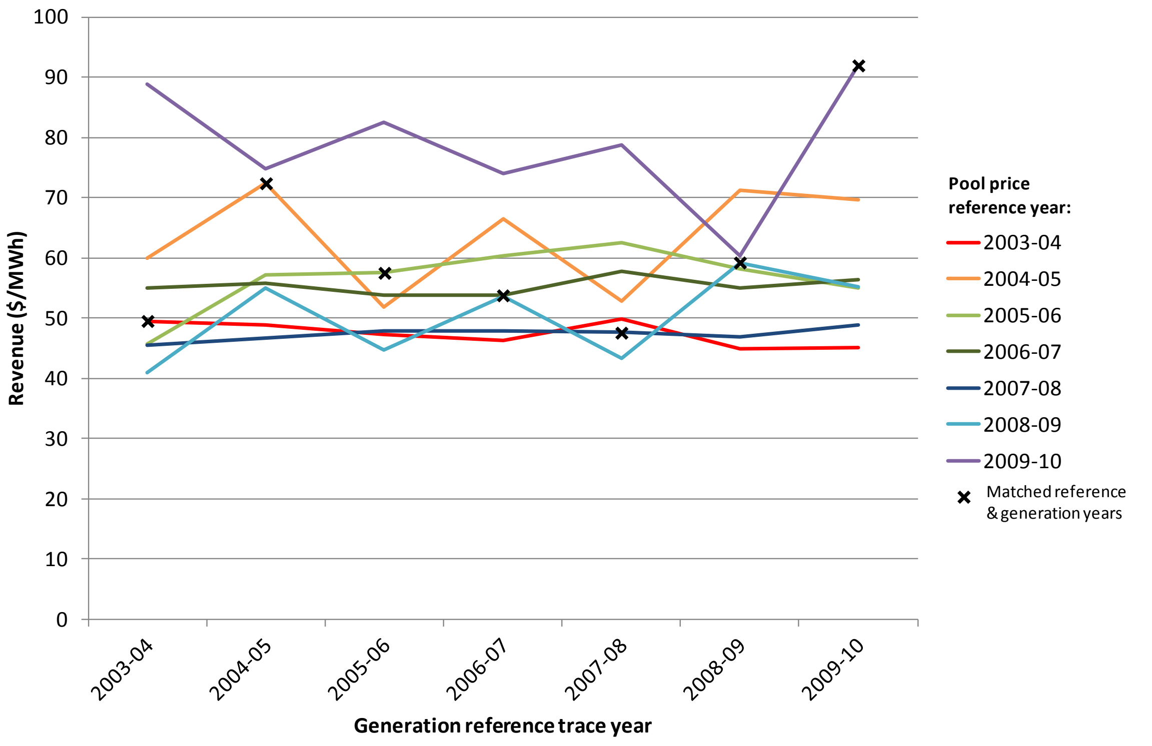
Figure 5.2 – Range of modelled solar revenue uplift (%) in historical years



ROAM also explored the importance of matching price and generation reference years as opposed to using a single reference generation trace for all years (such as a single reference year or a TMY generation trace).

Figure 5.3 shows the sensitivity of a NSW CSP plant to different generation traces. Each line represents a single pool price year (with higher average price years sitting higher on the vertical axis), while the horizontal axis represents the application of different generation reference year traces. The “x” markers show the average revenues when the traces use the same reference year according to ROAM’s methodology. While some price traces show little sensitivity to the generation profile, others decrease by 10-30% if the correlation between solar generation and price is not preserved.

Figure 5.3 – Sensitivity of solar revenue to different generation traces (NSW CSP)



5.1.1 Correlation with peak prices

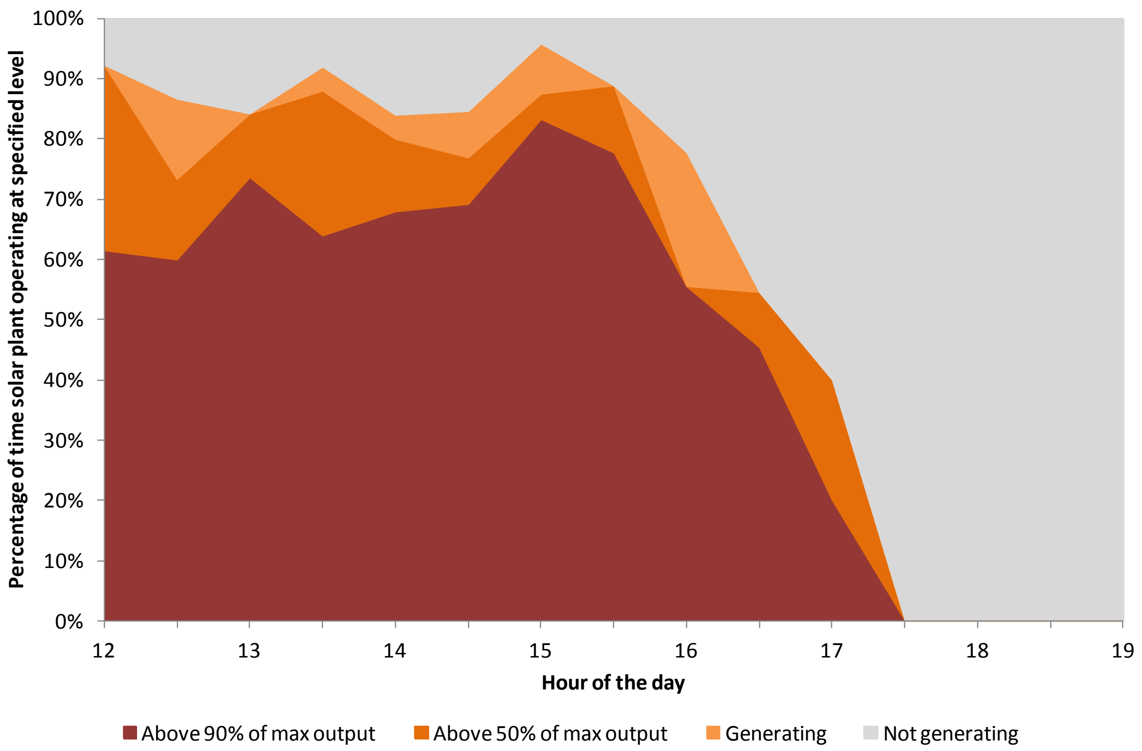
Solar plant, particularly CSP, have high outputs during times of peak demand/price that occur within daytime hours (up to around 5pm). Figure 5.4 shows the performance of the QLD CSP plant during historically high price periods[6] from July 2007 to June 2010. During daytime high price periods (likely to be of particular interest to retailers) there is an 80-90% chance that the CSP plant could have generated above 50% of its capacity, even in the absence of storage or gas hybridization. During evening periods, however, the plant would have been unable to contribute to meeting (and possibly mitigating) those high price periods. Other regions show similar behaviour during high price periods.

Over the whole of summer (including all price periods), Queensland CSP plant would generate at least 50% of its capacity during only 60% of periods from 7am to 5pm, and would not have operated at all for 30% of daytime periods. This is due to the regular summer rain in Queensland. The contrast between the average performance and the high price period performance of Figure 5.4 demonstrates the strong correlation between solar generation and peak prices, at least during daytime periods.

[6] Although $300/MWh is typically considered the cut off for "high" prices in the NEM (e.g., cap contracts usually have a strike price of $300/MWh) there were insufficient periods above $300/MWh during this time frame to present meaningful charts. This assessment applies a $200/MWh threshold.

In contrast, a Victorian CSP plant could have been relied on for 50% of its capacity in 80% of daytime periods as late as 5:30pm; it was at maximum output for 70% of daytime summer periods. CSP plant (or solar PV plant with tracking) is therefore likely to have a strong contribution to meeting peak prices, particularly in the southern states.

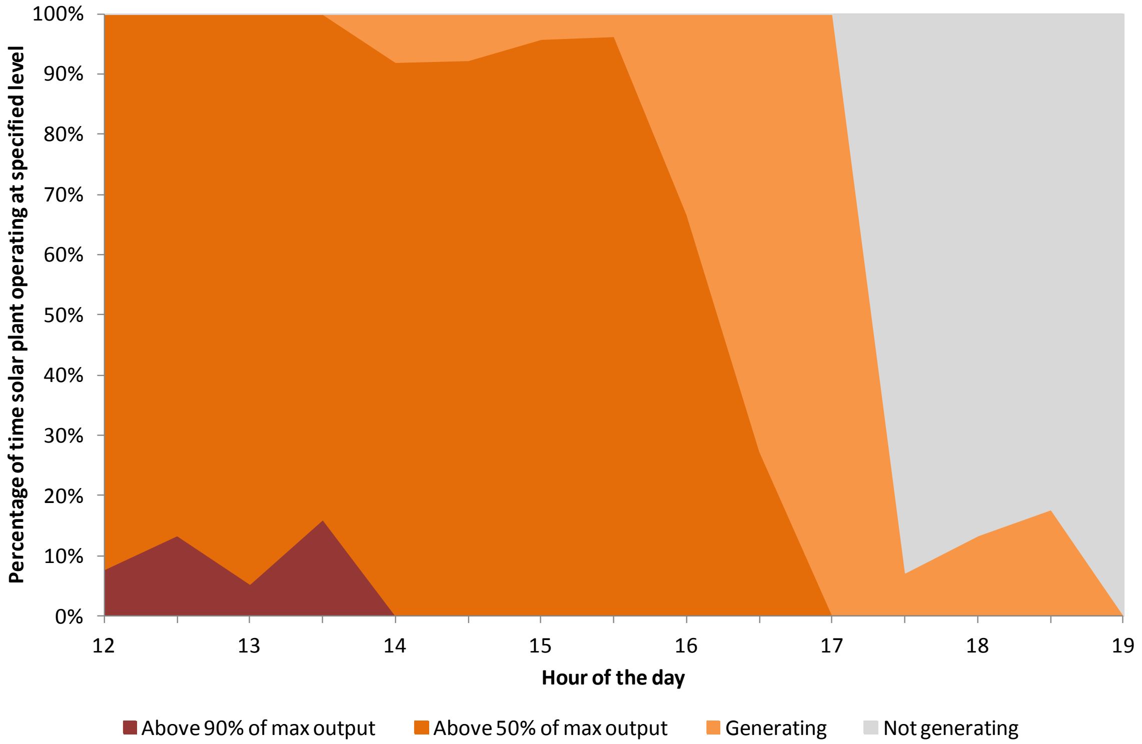
Figure 5.4 – Performance of QLD CSP plant during high price periods (>$200/MWh, 2007-2010)



A fixed flat plate PV plant operating during the same period shows a qualitatively different profile (Figure 5.5). The solar PV plant would have generated above 50% of its typical maximum output[7] in high price daytime periods before 3:30pm. Between 4pm and 5:30pm, solar plant can only be relied on for approximately 20% of its capacity during the highest priced historical periods. Over all summer periods, solar PV plant can be relied on for approximately 50% of its capacity until 3:30pm, but very little for meeting evening high price periods.

[7] Solar PV "maximum output" depends on multiple factors including higher than STC solar insolation, temperature effects and losses. For the figures in this section, ROAM set defined maximum output of solar PV plant at 90% of the plant nameplate capacity.

Figure 5.5 – Performance of QLD fixed flat plate PV plant during high price periods (>$200/MWh, 2007-2010)



Although solar plant contribute strongly during daytime periods, they are unable to contribute to meeting peak demand during evening periods. The "contribution to peak demand" of solar plant will depend on the definition applied; in ROAM's backcast of historical years, CSP/tracking solar generation was close to its maximum output in the top five annual demand periods from 2004 to 2010 in each region (except NSW in earlier winter peaking years). However, across the top 5-15% of all demand periods, solar generation cannot be relied upon at the same level of confidence as a gas turbine, for example. AEMO's recent analysis of rooftop PV[8] suggests that rooftop PV has historically generated at between 3-60% of its capacity at times of peak demand. Quantifying and valuing the reliability of solar capacity will be important as its market penetration increases.

5.1.2 Impact of very high price periods

The strong performance of solar plant during daytime peak price periods is important to their revenue. In the NEM's energy only market design, high price periods are a necessary market outcome, contributing a significant portion of plant revenue as well as providing investment signals for new generation. Very high price periods (such as periods above $1,000/MWh) are especially important for solar plant that are typically (although not always) generating during those periods. Furthermore, since solar plant are a relatively low capacity factor technology, these periods can make up an even larger portion of the solar plant revenue compared to other "baseload" technologies.

8 http://www.aemo.com.au/en/Electricity/~/media/Files/Other/forecasting/Rooftop_PV_Information_Paper.ashx

Figure 5.6, Figure 5.7 and Figure 5.8 show the 50 highest price periods in 2007-08, 2008-09 and 2009-10 along with modelled historical CSP plant in Queensland and Victoria. The blue bars show the wholesale electricity prices in those periods. The position of the red diamonds on the blue bars indicates the generation of the solar plant in those periods (top of the bar means maximum output, middle of the bar means 50%, etc). The black line shows the cumulative revenue from those top periods expressed as a percentage of the total revenue earned by that plant in that year.

Figure 5.6 – 2007-08 highest price periods and CST (and tracking PV) revenues

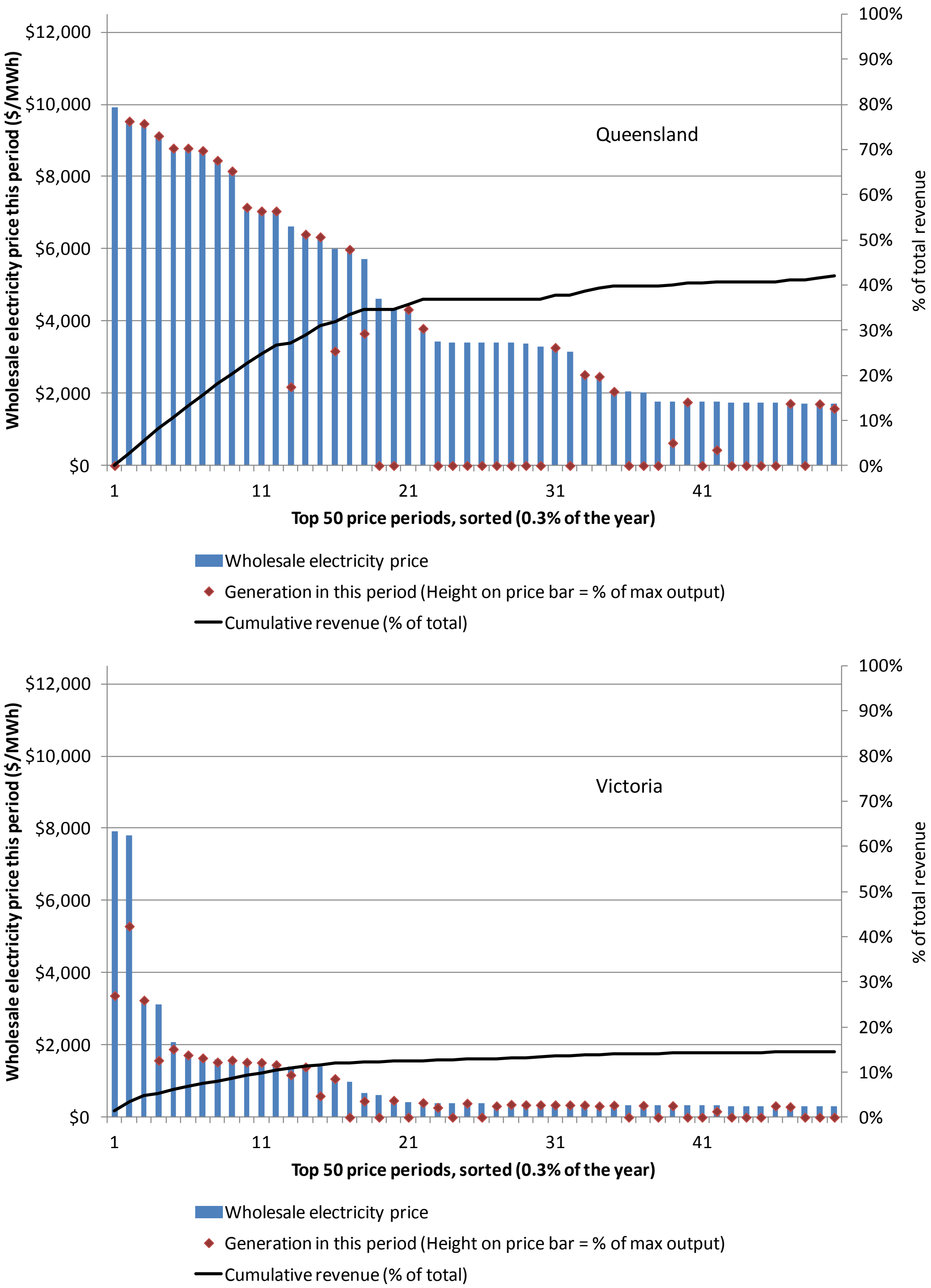
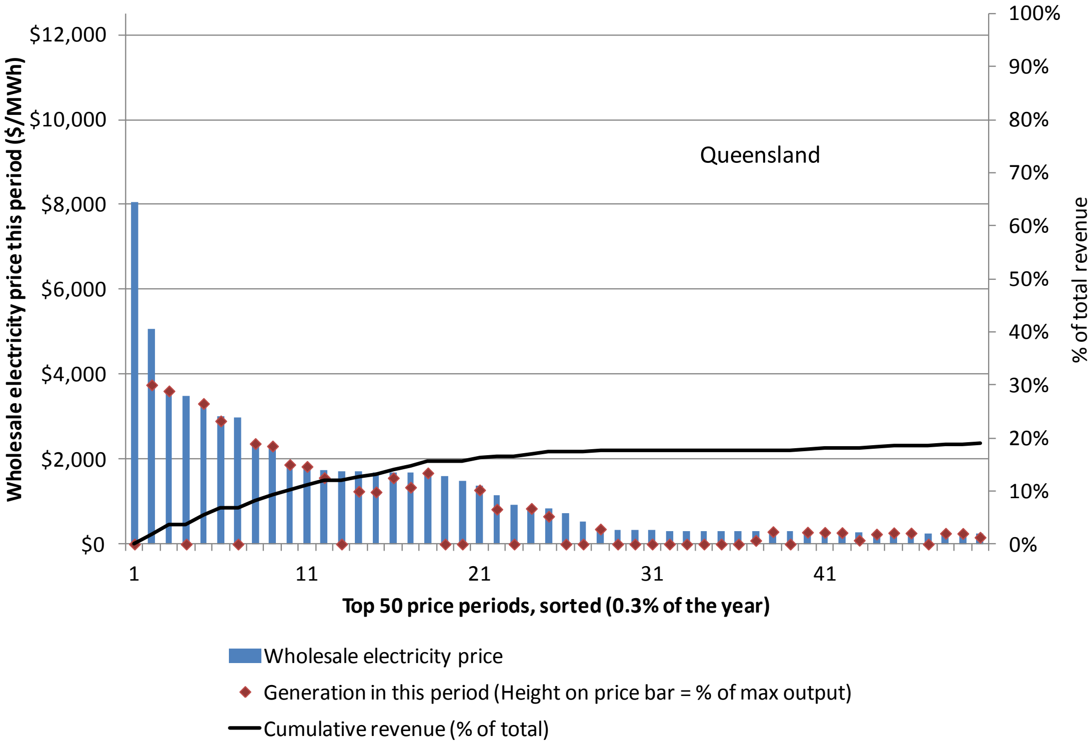


Figure 5.7 – 2008-09 highest price periods and CSP (and tracking PV) revenues



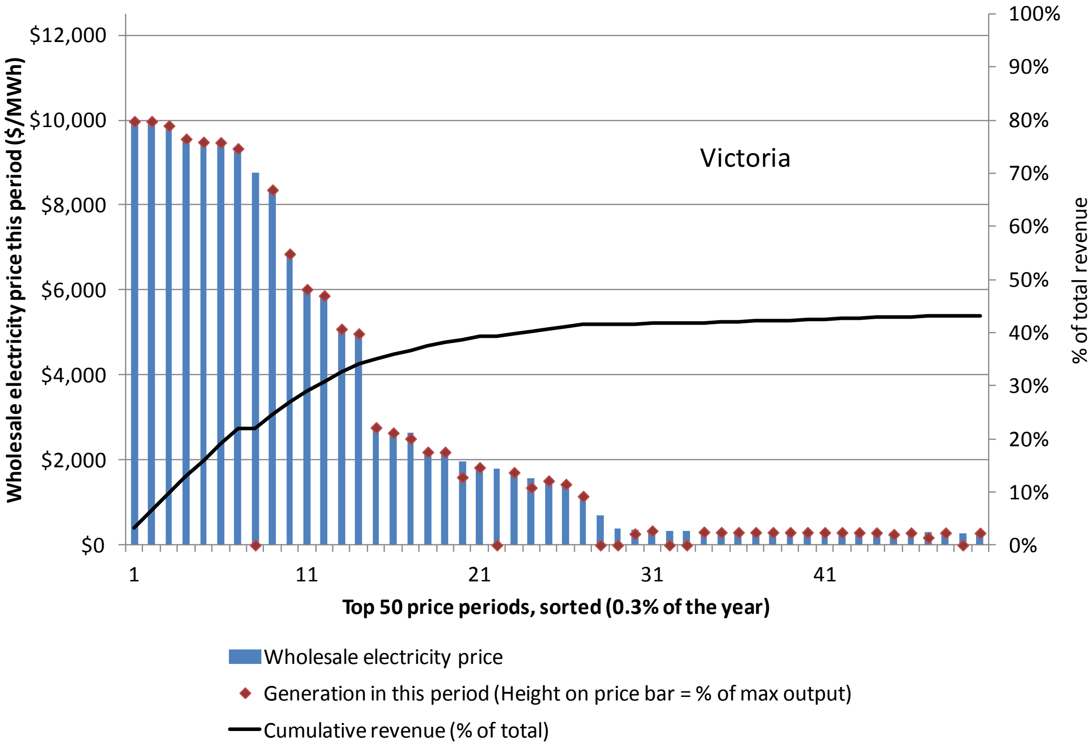
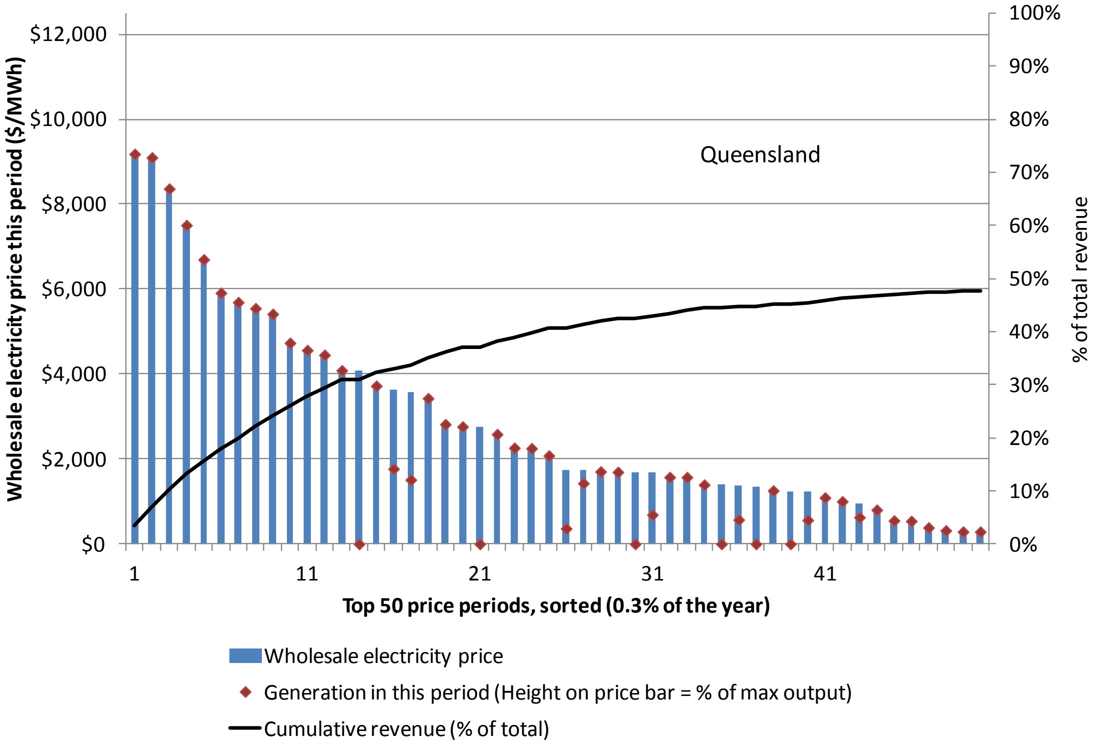
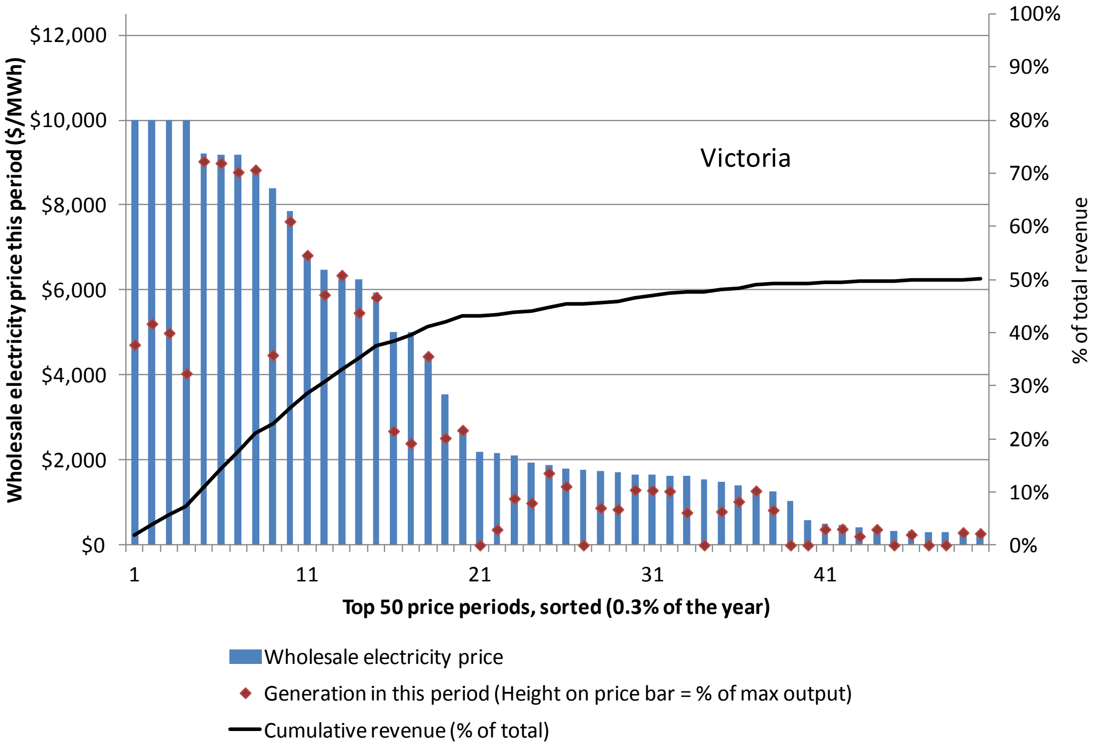


Figure 5.8 – 2009-10 highest price periods and CSP (and tracking PV) revenues





ROAM notes several key features of these plots:

- The top 30 periods (15 hours or 0.17% of the year) are responsible for between 20-50% of CSP plant total annual revenue. Solar PV with tracking is likely to exhibit similar trends (potentially even higher, given the ability of PV plants to utilise diffuse irradiation as well). Fixed flat plate solar PV plant (not shown) exhibit a slightly lower dependency but similar trends.
- ROAM's modelled CSP plants have, according to simulated solar data in these historical years, a high probability of generating at close to full capacity during these high price periods;
- Although all years had different trends in their price-duration curves, the significance of the highest price periods remains the same.

For example, in Queensland in 2007-08, just 20 price periods (10 hours) would have made up 35% of the total CSP plant revenue. However, the solar plant did not generate during a number of periods where prices were $1,700 to $3,500/MWh. These periods occurred between 2pm and 7:30pm; some periods were cloudy at the Kogan Creek site at those times, while others occurred after sunset. If output could have been maintained in those periods (through more favourable weather conditions or through the usage of storage or gas hybridization) then (in this specific year) revenue could have been increased by 10-15%.

In contrast, 2008-09 was a relatively mild pool price year in Queensland with only a few very high price periods, with consequently lower revenues. However, if generator or transmission outages had been coincident with the peak demand periods, and the 50 highest price periods had resembled 2007-08, then total revenue would have increased by 50%.

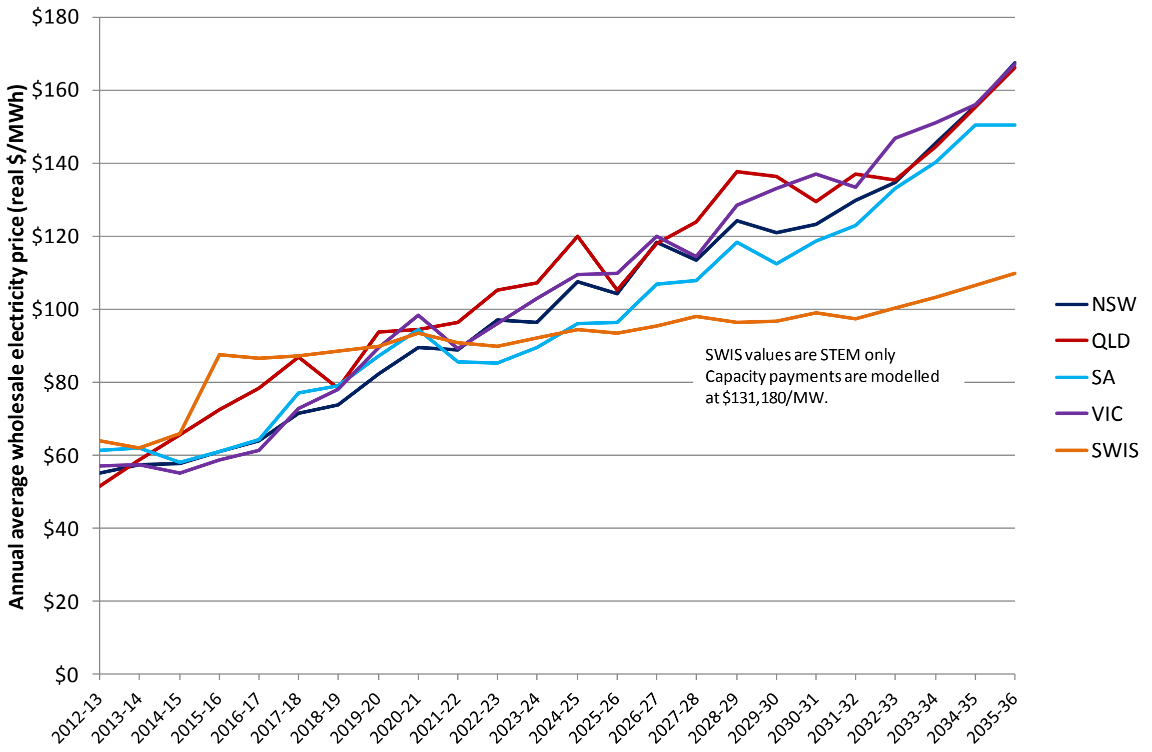
It is acknowledged that the extreme nature of these very high price periods and their sensitivity to multiple factors (including peak demands, generator or transmission outages, network constraints and strategic generator bids) means that there is uncertainty in forecasts. ROAM's modelling includes two demand profiles (a moderate and a "peaky" demand year – see Section 3.2 and conducts Monte Carlo simulation covering a range of generator outages in order to capture both the average and spread of possible price and revenue outcomes.

5.2 Results

Pool prices

Figure 5.9 shows the modelled annual average wholesale electricity prices. Wholesale prices rise due to both the increasing carbon price and the greater reliance on gas generation over coal, with gas prices also increasing over the study period.

Figure 5.9 – Wholesale electricity prices (real $/MWh)



High demand growth and competition for gas in Queensland result in high Queensland prices in the short term, while increasing penetration of renewables in South Australia (offset in the short term by the announced retirement of Playford B and summer only operation of Northern power station) results in lower prices.

SWIS prices refer to the short term energy market (STEM) in the SWIS, where generators are required to bid their short run marginal costs, with long run costs recovered through capacity payments. This results in both lower prices and lower volatility, with initial price rises mainly due to the increased penetration of CCGT with a higher marginal price.

The IMO published Maximum Reserve Capacity Prices (MRCP) each year. The applied Reserve Capacity Price in a given year is then set either by auction or, if sufficient capacity is available through bilateral trade nominations (as has been the case for all historical years), is defined as 85% of the MRCP adjusted for any over or undersupply of capacity. Actual Reserve Capacity Prices historically have been 75-85% of the MRCP (Table 5.3).

These prices are designed to represent the cost of a new entrant, low capacity factor, OCGT generator into the SWIS, and hence provide a measure of the highest possible capacity payment necessary to incentivise new capacity. The IMO has noted that "the 2012/13 and 2013/14 MRCPs are outliers and that the proposed 2014/15 MRCP is more consistent with previous determinations of the MRCP from 2008/09 to 2011/12"[9].

[9] http://www.imowa.com.au/f175,1981344/IMO_Final_Report_Max_Reserve_Capacity_Price_2014_15.pdf

ROAM has assumed that capacity payments for all subsequent years will be 80% of the 2014-15 MCRP, i.e., $131,120. Although construction costs for OCGTs may experience modest decreases (5-10% in NTNDP data), ROAM has assumed other costs (e.g., carbon and fuel cost increases) will offset some of this reduction and that such variations are within the error margins of the historical MCRPs.

Table 5.3 – Maximum and applied Reserve Capacity Prices (nominal dollars)[10]

	Maximum Capacity Reserve Price	Reserve Capacity Price
2008-09	$122,500	$97,837
2009-10	$142,200	$108,459
2010-11	$173,400	$144,235
2011-12	$164,100	$131,805
2012-13	$238,500	$186,001
2013-14	$240,600	$178,477
2014-15	$163,900	Not yet determined
Subsequent years (ROAM)	$163,900	$131,180

Intermittent generators do not necessarily receive capacity credits for their full capacity. Instead, under the current (recently revised) Rules, the assigned capacity credits are defined as the average plant output during the 12 highest demand trading intervals on separate days over five years, less an adjustment based on the variability of plant output.

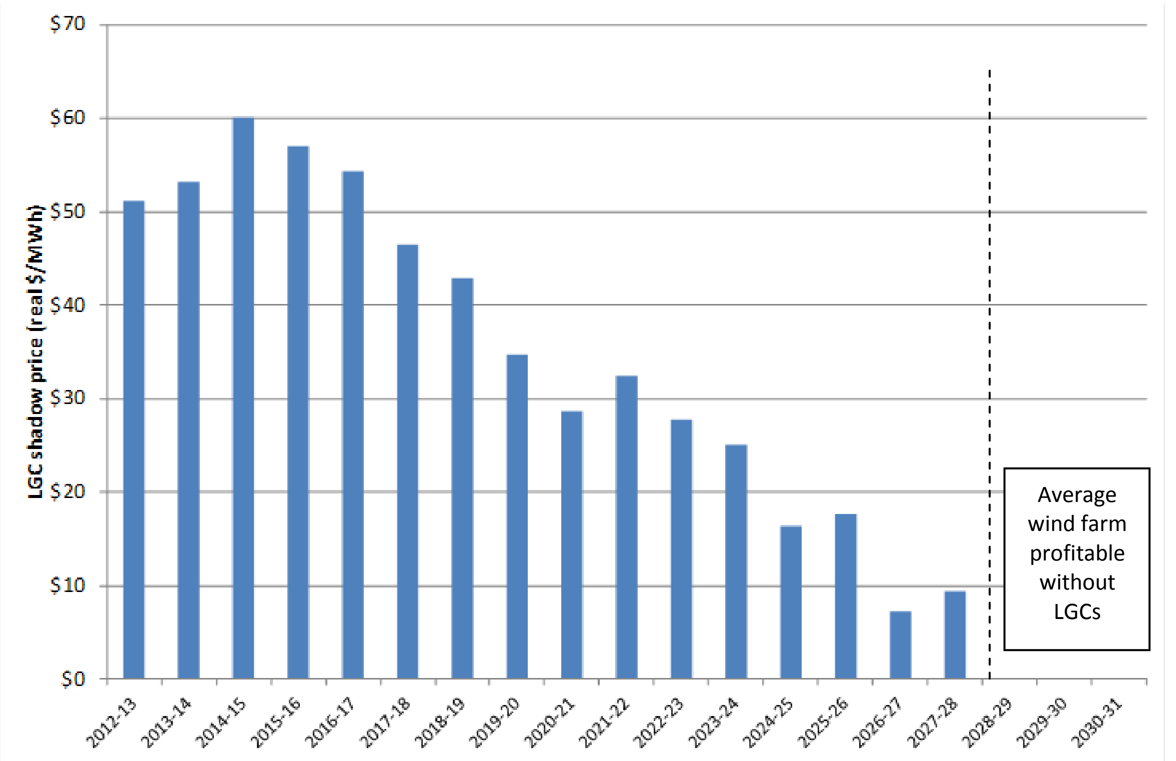
ROAM has not attempted to replicate the specific details of this calculation in this report. Instead, ROAM has investigated financial years 2008-09 and 2009-10 and found that over during the highest demand periods, fixed flat plate solar PV output was between 20%-75% (average 55%) and CSP output (expected to be similar to solar PV with tracking) between 0%-100% (average 80%). Accounting for the variability in plant output, ROAM has therefore applied capacity credits of 35% and 60%; ROAM notes, however, that actual values assigned by the IMO could be higher or lower.

LGC prices

Figure 5.10 shows the LGC shadow price calculated based on the methodology described in Section 3.4.

[10] http://www.imowa.com.au/mrcp

Figure 5.10 – LGC price forecast ($/MWh)

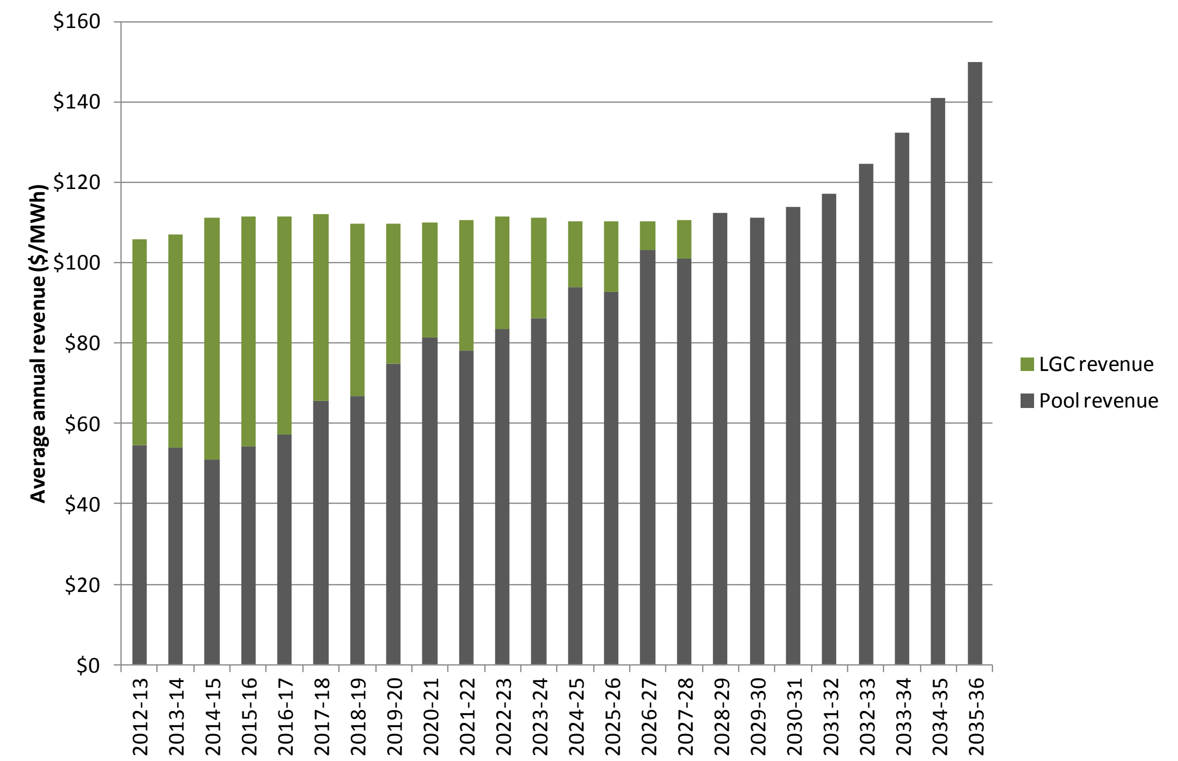


The LGC price rises slightly initially as the average capacity factor of the wind farm portfolio decreases (and so wind farms require higher average revenues to recover costs). Rising electricity prices mean that wind farms require decreasing subsidy over time until 2028-29 when the "average" wind farm is profitable on wholesale electricity sales alone. In that year, however, some wind farms with higher costs or in regions with lower pool prices may still require subsidy under the LRET; many will continue to be supported through the implied LGC prices in their PPAs.

Figure 5.11 shows the average revenue of all NEM wind farms from electricity and LGC sales. The LGC shadow price is sufficient for wind farms, on average, to recover their full costs in each year of operation. As such, it provides natural hedging against increases or decreases in electricity pool prices (provided the shadow price remains greater than zero and less than the effective LRET penalty price of $92/MWh nominal).

Towards the end of the LRET electricity prices rise sufficiently that the LGC price is already zero (before the end of the scheme), and total wind farm revenues continue to rise smoothly beyond that point. This is driven by the higher carbon price (over $50/tCO_2$-e), higher gas prices and the higher proportion of gas generation in the NEM.

Figure 5.11 – Wind farm revenue breakdown (averaged over all NEM wind farms, real $/MWh)



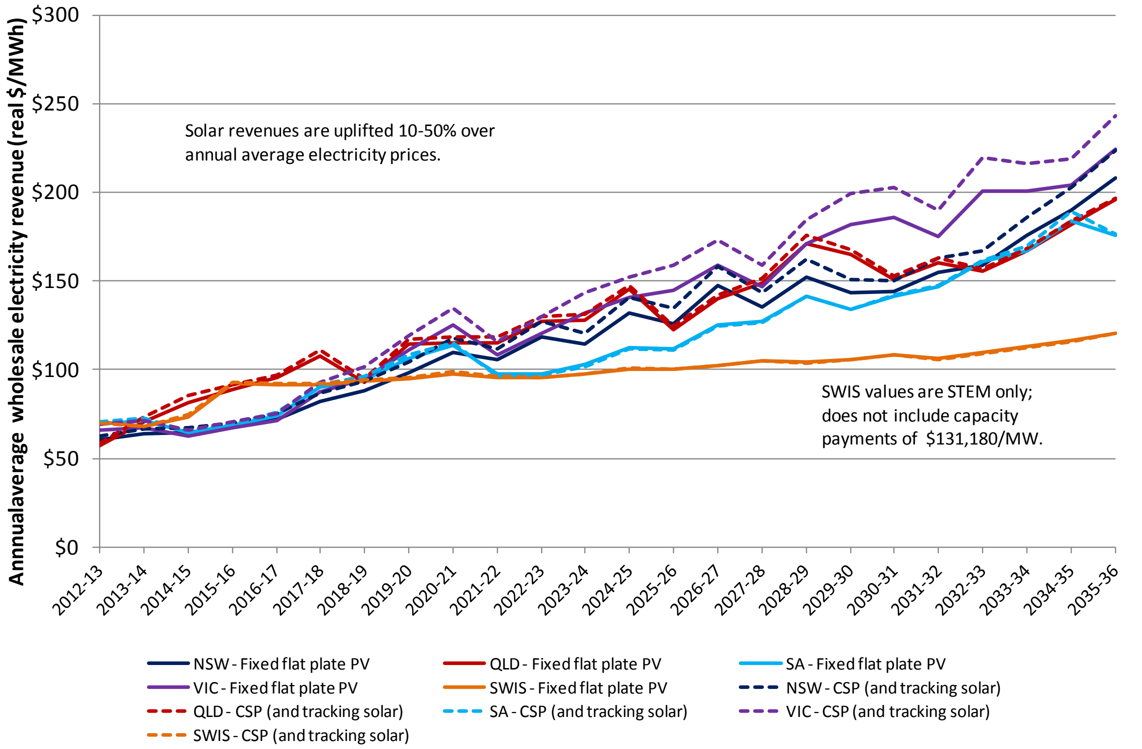
5.3 SOLAR REVENUES

Wholesale electricity revenue

Figure 5.12 and Table 5.4 show ROAM's forecast of average solar revenues from energy sales into the wholesale electricity markets. Revenues from electricity sales into the electricity markets are broadly similar across all NEM regions, except for South Australia where increasing penetration of renewables and limited (although still upgraded) interconnector support result in lower prices. A tighter supply-demand balance in Queensland (driven by increased competition for gas due to the expanding LNG export industry) results in higher revenues for Queensland plant in the short term.

Average revenues from SWIS STEM sales start higher than in the NEM due to higher initial STEM prices, but are lower by 2019-20 and remain lower for the duration of the study. The lack of extreme prices seen in the NEM result in very similar revenue results for all technologies.

Figure 5.12 – Average solar wholesale electricity revenue ($/MWh)



Towards the end of the study period, although the Victorian average pool price is similar to the other regions, increasing frequency of very high price spikes significantly increase the solar revenue. This highlights the impact of very high price periods on solar revenue, as discussed in Section 5.1.2.

Table 5.4 – Average solar wholesale electricity revenue ($/MWh)										
	Fixed flat plate PV					CSP (and tracking PV)				
	NSW	QLD	SA	VIC	SWIS	NSW	QLD	SA	VIC	SWIS
2012-13	$61	$57	$69	$66	$71	$63	$58	$71	$69	$70
2013-14	$64	$71	$71	$67	$68	$66	$73	$73	$71	$68
2014-15	$65	$82	$65	$63	$73	$67	$85	$65	$66	$74
2015-16	$68	$88	$69	$67	$92	$70	$92	$70	$71	$93
2016-17	$72	$96	$74	$71	$92	$75	$97	$76	$75	$92
2017-18	$82	$108	$90	$87	$92	$87	$111	$91	$93	$92
2018-19	$88	$93	$94	$95	$94	$94	$95	$96	$101	$94
2019-20	$98	$115	$107	$111	$95	$104	$117	$109	$119	$95
2020-21	$110	$115	$114	$125	$98	$118	$118	$115	$135	$99
2021-22	$105	$115	$97	$108	$96	$111	$118	$96	$116	$96
2022-23	$119	$127	$98	$120	$96	$127	$130	$97	$130	$96
2023-24	$114	$128	$103	$132	$98	$120	$131	$102	$143	$98
2024-25	$132	$145	$112	$141	$100	$141	$147	$112	$152	$101
2025-26	$126	$122	$112	$145	$100	$134	$125	$111	$159	$100
2026-27	$147	$140	$125	$159	$102	$158	$142	$125	$173	$102
2027-28	$136	$149	$127	$147	$105	$143	$152	$126	$159	$105
2028-29	$152	$171	$141	$171	$104	$162	$176	$141	$185	$104
2029-30	$143	$165	$134	$182	$106	$151	$167	$134	$199	$105
2030-31	$144	$151	$141	$186	$108	$150	$153	$142	$203	$108
2031-32	$155	$160	$147	$175	$106	$163	$163	$147	$190	$106
2032-33	$159	$155	$161	$201	$110	$167	$157	$161	$220	$109
2033-34	$175	$167	$167	$201	$113	$186	$168	$170	$216	$112
2034-35	$190	$182	$184	$204	$116	$202	$184	$189	$219	$116
2035-36	$208	$196	$175	$225	$120	$223	$197	$176	$243	$120

In most years, solar average wholesale electricity revenues are uplifted over flat pool prices by between 10-25% for fixed flat plate solar PV and 15-50% for CST and solar PV with tracking. These uplifts are lower than have been observed historically (Section 5.1), which is mainly due to the introduction of the carbon price.

The impact of carbon pricing on uplift can be understood through a simple model of price uplift, where the impact of the carbon price on the pool price is through a simple average uplift (which may be different during peak and off-peak periods). In this model, the uplift without the impact of the carbon price would have been:

$$\mathrm{Uplift}_{\mathrm{NoCO2}} = \frac{\mathrm{R}_{\mathrm{solar}} - \mathrm{C} * \mathrm{PT}_{\mathrm{peak}}}{\mathrm{PP}_{\mathrm{c}} - \mathrm{C} * \mathrm{PT}_{\mathrm{flat}}}$$

where

$$\begin{aligned}
&\mathrm{R_{solar}} = \text{average solar revenue (\$/MWh)}\\
&\mathrm{PP_c} = \text{average pool price under the carbon price (\$/MWh)}\\
&\mathrm{C} = \text{carbon price (\$/tonne)}\\
&\mathrm{PT_{flat}}, \mathrm{PT_{peak}} = \text{carbon price pass through in peak/offpeak periods } \left(\frac{\$/\mathrm{MWh}}{\$/\mathrm{tonne}}\right)
\end{aligned}$$

For example, in 2019-20, the New South Wales average pool price was $82/MWh and the NSW CSP plant had an average wholesale electricity revenue of $104/MWh – an uplift of 27%. Assuming 90% of the carbon price is passed through to the flat pool price and 80% to the peak pool price, the equivalent uplift without the carbon price would be 45% – consistent with backcast modelling.

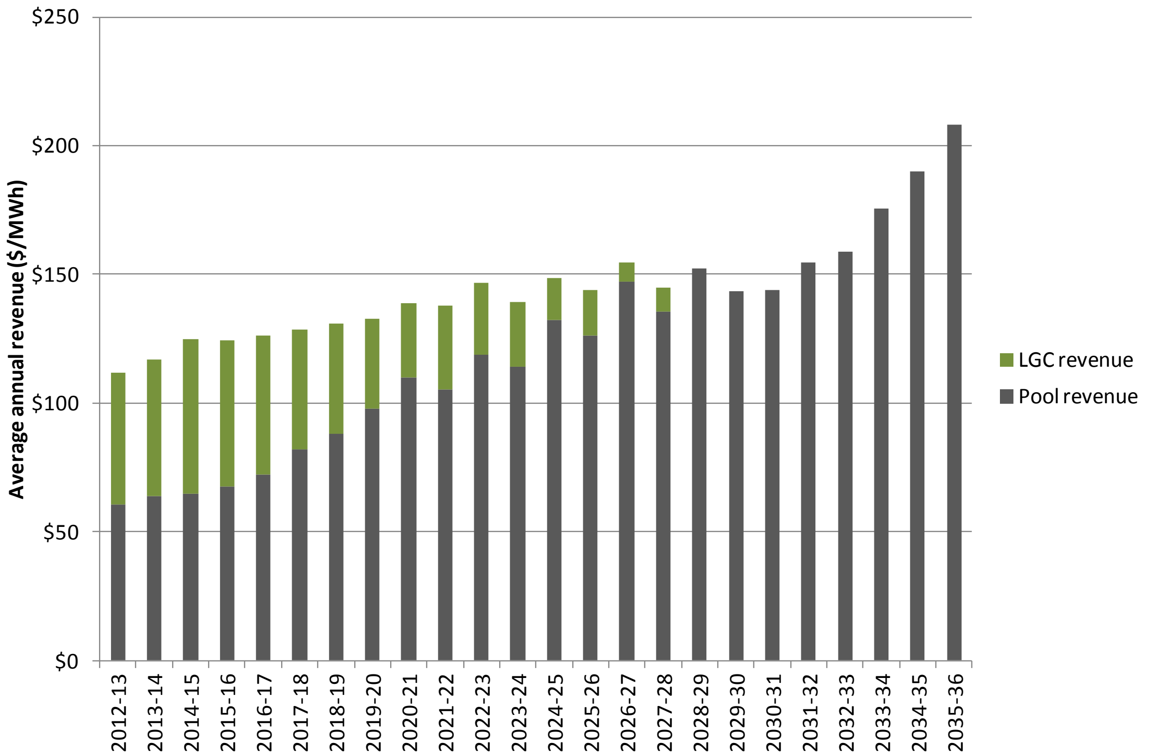
LGC revenue

As with wind farms, solar plant earn revenue from the sale of LGCs. ROAM expects that solar plant will be price takers in the LGC market, and so will receive the same (on average) LGC prices as wind farms.

An example of total solar revenue, for the NSW solar PV plant, is shown in Figure 5.13. Unlike wind farms, whose average total revenue is flat for the duration of the LRET, electricity sales make up a greater proportion of solar revenue. In this case, peak prices (and hence solar revenues) are forecast to increase faster than flat prices resulting in steadily increasing solar revenues.

The natural hedging between the pool price and the LGC price (higher pool prices mean renewables require less subsidy) means that ROAM's total revenue outcomes are relatively robust to changes in carbon prices or other underlying costs (e.g., fuel price, generator bidding strategies, etc). However, LGC prices will likely be driven by wind farm costs and revenues, and solar plant are still disproportionately affected over other generators by effects such as the solar-induced merit order effect.

Figure 5.13 – Solar revenue breakdown (NSW Solar PV plant, real $/MWh)



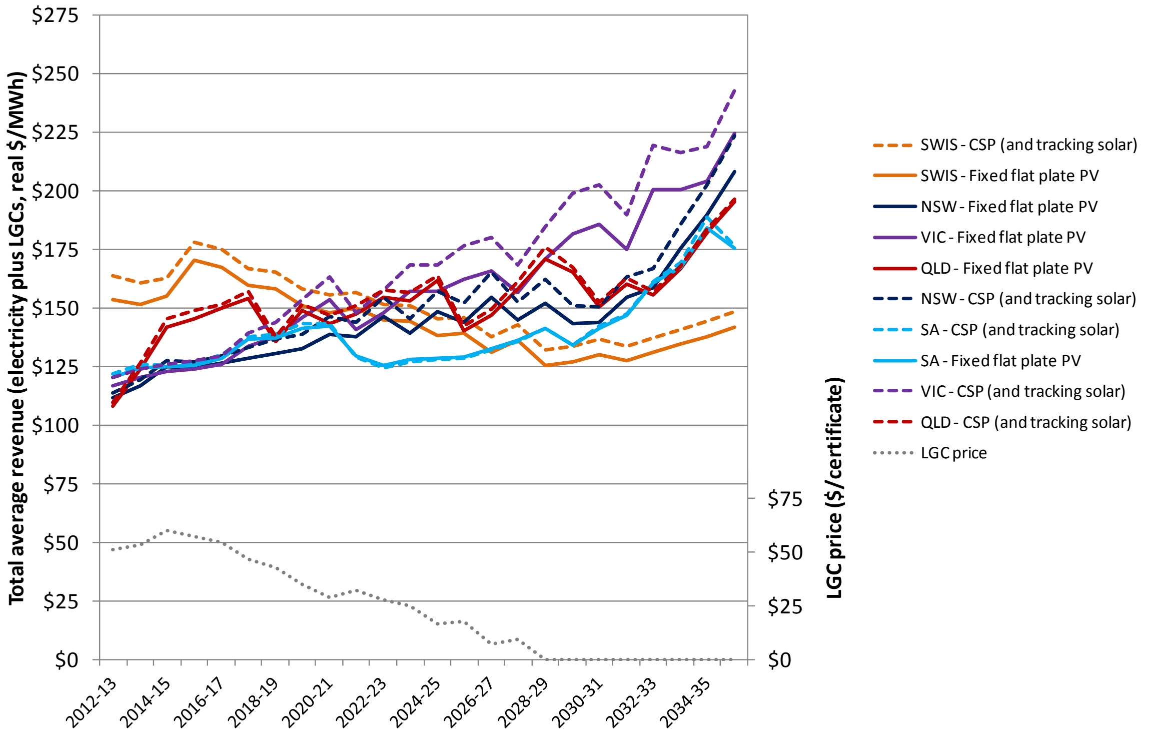
Total revenue

Figure 5.14 shows the total average revenue received by solar plant in the NEM including LGC and wholesale electricity revenue. For the duration of the LRET, increases in the pool price revenue are partially hedged by decreases in the LGC revenue and total revenues rise only slowly. Solar plant can expect to receive $120/MWh to $160/MWh during this period. Beyond 2030 (or once LGC support for wind farms is no longer required) the average revenues will continue to increase with pool price rises.

In real terms, fixed flat plate solar PV would have annual revenues of on average $200 to $300 per kilowatt of installed capacity while CSP (and solar PV with tracking) plants, with higher capacity factors and better correlation with peak prices, would earn between $300/kW and $400/kW.

Actual revenues vary from year to year and are highly sensitive to price spikes (caused by generator outages, extremely high demands or other factors). A particularly mild or particularly "peaky" pool price year could decrease or increase revenues in any year by 10-15%.

Figure 5.14 – Solar total revenues (electricity, capacity payments (SWIS) and LGCs, real $/MWh)



In the SWIS, revenues are initially high due to capacity payments, then decrease as the national LGC price decreases faster than the SWIS STEM price increases, and without a corresponding increase in capacity credits. This effect could be offset, however, if the Reserve Capacity Price were to increase over time.

5.4 Solar Power Purchase Agreements

As with most renewable energy projects, under the current financing climate, solar plant are unlikely to obtain finance without securing an off-take agreement with an energy purchaser. The most common agreement for intermittent generators is a power purchase agreement (PPA) with a retailer, where the retailer agrees to purchase all generated energy and LGCs for a fixed bundled price. This price is typically constant in real terms (rising with inflation), but may include staged increases or decreases.

To provide an estimate of the value of solar plant to retailers and hence an indication of the PPA prices solar plant could command, ROAM has calculated flat 15 and 25 year PPA prices that would produce a net present value revenue stream equivalent to the net present value of the combined pool and LGC revenues over a 15 year period. This methodology is different to simply taking an average of revenues over the contract period, because near-term revenues are worth more in the discounted revenue stream[11].

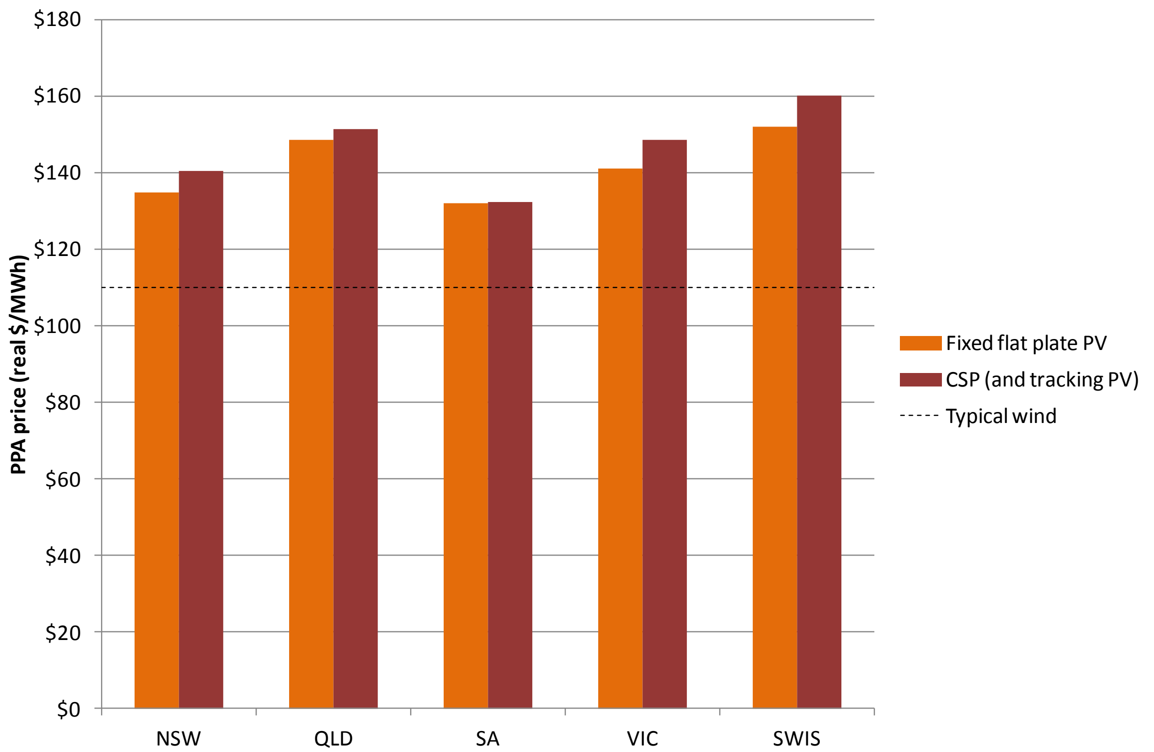
[11] Revenues received in the future are typically "discounted" relative to equal (in real terms) revenues received today because today's revenues could be theoretically invested and thus produce greater revenues in the future.

For this calculation, ROAM has used a discount rate of 9.79% (as assumed in Scenario 3 of the 2010 NTNDP) and solar plant are assumed to be installed in 2014-15 with a 15 or 25 year PPA agreement[12]. The resulting contract prices are shown in Table 5.5 and Figure 5.15 for CSP (and tracking PV) and solar PV plants in each region as well as a typical PPA price ($110/MWh) for wind farms for comparison.

Table 5.5 – Solar plant PPA prices (real $/MWh)

	15 year PPA		25 year PPA	
	Fixed flat plate PV	CSP (and tracking PV)	Fixed flat plate PV	CSP (and tracking PV)
NSW	$135	$140	$141	$148
QLD	$149	$151	$153	$155
SA	$132	$132	$137	$137
VIC	$141	$149	$151	$160
SWIS	$152	$160	$150	$157

Figure 5.15 – Solar plant 15 year PPA prices



This suggests that solar plant should be able to command PPA prices 20-40% higher than wind farms on value alone, due mainly to the higher correlation of solar plant output to demand as well as more reliable performance during very high price periods as compared to wind farms. In

[12] ROAM conducted explicit simulations to 2035-36. For the 25 year PPA, revenues were extrapolated to 2039-40.

addition to the increased revenue, these two effects are likely to make the wholesale electricity component more valuable to retailers and hence increase the attractiveness of solar PPAs over wind.

5.5 Drivers of PPA contracts

To secure finance, a PPA is required at a price point sufficient to satisfy financial backers of the project's ability to repay debt. A number of renewable energy proponents, however, have expressed to ROAM Consulting that they have experienced difficulty in securing PPAs. The difficulties for solar projects in particular has been highlighted by the difficulties experienced by the selected Solar Flagships projects (Moree Solar Farm and Solar Dawn) in securing financial close[13].

These issues have sparked much speculation, across industry, media and politics, about the potential market power of major retailers (Origin, AGL and TRUenergy). For example, Department of Resources, Energy and Tourism (DRET) secretary Drew Clarke noted that DRET was "very conscious" of the issues surrounding "the trend towards vertical integration, the so-called gentailers—companies that have a big balanced portfolio of both generation and retail."[14].

However, projects do continue to secure PPAs under the RET, such as the recently announced PPA for Snowtown II wind farm with Origin[15] and the in-principle PPA for Taralga wind farm with Neighbourhood Energy and Alinta[16]. The Macarthur wind farm in Victoria also secured a PPA, however this was in response to the requirement for the Wonthaggi desalination plant to source renewable energy for its operation[17].

This section aims to explore the actual or perceived current reluctance of retailers to sign PPAs, and possible changes over time.

LGC oversupply

There is presently a significant oversupply of LGCs in the market. Figure 5.16 illustrates the number of LGCs (formerly RECs) created each year and the annual LRET targets (the apparent drop in the target in 2011 is due to the separation of the RET scheme in the LRET and SRES).

[13] http://www.ret.gov.au/energy/clean/sfp/round-one/Pages/round-1.aspx

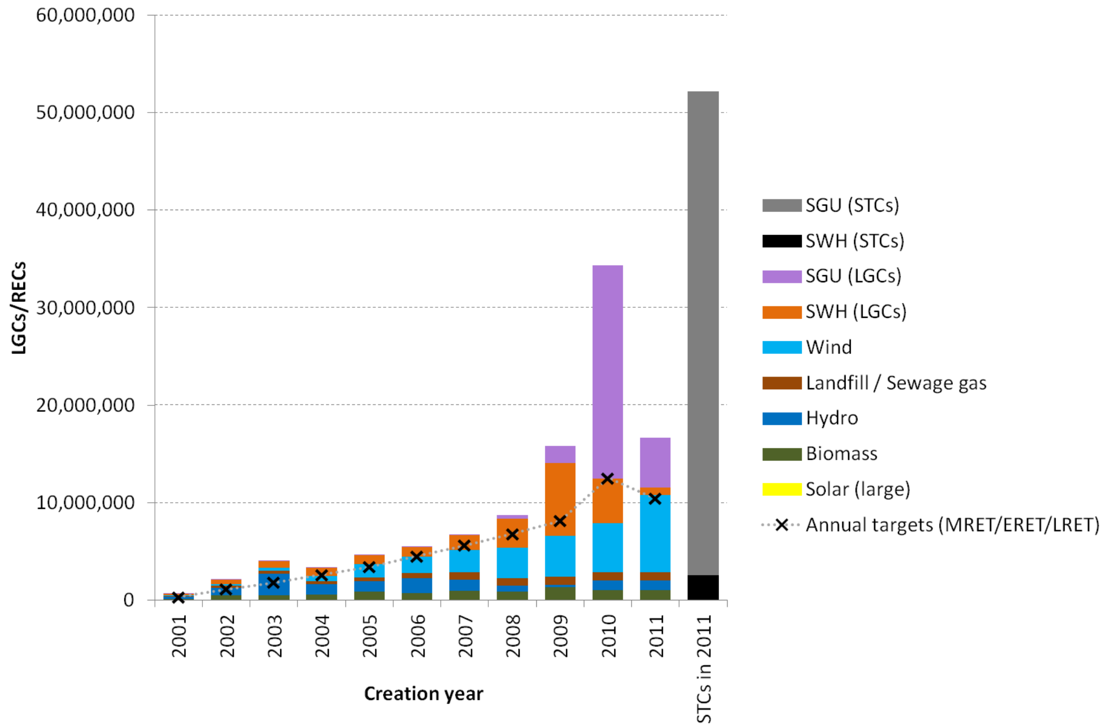
[14] For example, Senator Milne's questions

[15] http://www.originenergy.com.au/news/article/asxmedia-releases/1387

[16] http://www.climatespectator.com.au/commentary/cbd-throws-down-gauntlet

[17] http://www.agl.com.au/about/ASXReleases/Pages/RenewableenergyfromAGLtopower.aspx

Figure 5.16 – LGCs created by year and generation type from all sources[18]



The proportion of certificates created by solar water heating (SWH) and small generating units (SGUs) has increased dramatically in recent years, driven by generous subsidies, feed-in tariffs, the solar multiplier scheme and a significant decrease in the cost of rooftop photovoltaics. Although they do not impact directly on the LGC market, Small-scale Technology Certificates (STCs) are illustrated in grey/black for comparison; the quantity of STCs created in 2011 is extremely large compared with the annual target originally applying in that year, and would have continued to distort the RET scheme had the target not been split.

Figure 5.17 highlights the oversupply of certificates. The black line shows the cumulative creation of LGCs in the past, projected forward based upon the anticipated continued production of existing renewable generators. The following assumptions have been made to create this forward projection:

- ***Wind*** - The expected total number of certificates to be created from wind farms in 2011 was projected forward to all future years (7,879,865 MWh per annum). This was calculated using average historical certificate production of established wind farms, and an estimate of expected certificates from recently installed or commissioning wind farms[19], calculated using estimated capacity factors and their individually assigned 2011-12 Marginal Loss Factor (MLF) values.
- ***Hydro*** - The average hydro generation of LGCs across the period 2001 to 2011 was projected forward to all future years (1,026,718 MWh per annum)

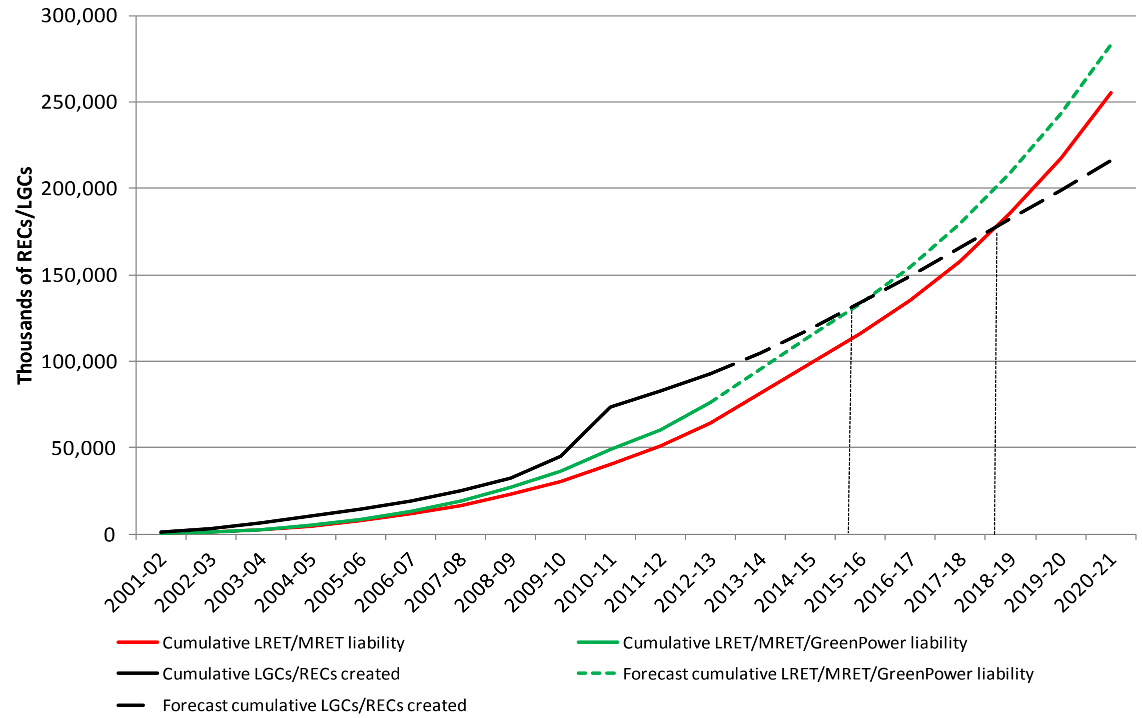
[18] Extracted from REC Registry on 29th December 2011. Includes all LGCs except those listed in the Registry as invalid due to audit.

[19] Includes Gunning, Woodlawn, Lake Bonney Stage 3, Waterloo, The Bluff, North Brown Hill, Oaklands Hill, and Collgar.

- ***Biomass*** - Continues to operate at the level of certificates created in 2010 (962,946 MWh per annum)
- ***Landfill/Sewage gas*** - Continues to operate at the level of certificates created in 2010 (878,855 MWh per annum)
- ***Solar (large)*** - Continues to operate at the level of certificates created in 2010 (4,422 MWh per annum)

The red line in Figure 5.17 illustrates the cumulative MRET/RET liability, while the green line shows this in addition to the certificates required to meet voluntary GreenPower liability.

Figure 5.17 – Cumulative LGC analysis



This analysis suggests that retailers (who hold the bulk of the currently banked certificates) are likely to have their liabilities covered until at least 2015, or longer depending on their GreenPower requirements. This is consistent with public statements from Origin Energy[20]. As such, in the short term retailers can afford to be highly selective about signing new PPAs; retailers could even be averse to taking longer positions if they perceive regulatory risk around future liabilities. Similarly, long positions protect retailers from rises in the cost of renewables (and hence the prices of LGCs) but eliminates the opportunity to benefit from any reduction in costs over time (such as reductions in wind turbine costs, perhaps driven by the growing Chinese market).

The difficulties in securing PPAs experienced by the Solar Flagships projects may therefore, at least in part, be attributable to the timing of the program. Given the development timeline for renewable projects, however, the cumulative LGC analysis suggests that projects will need to

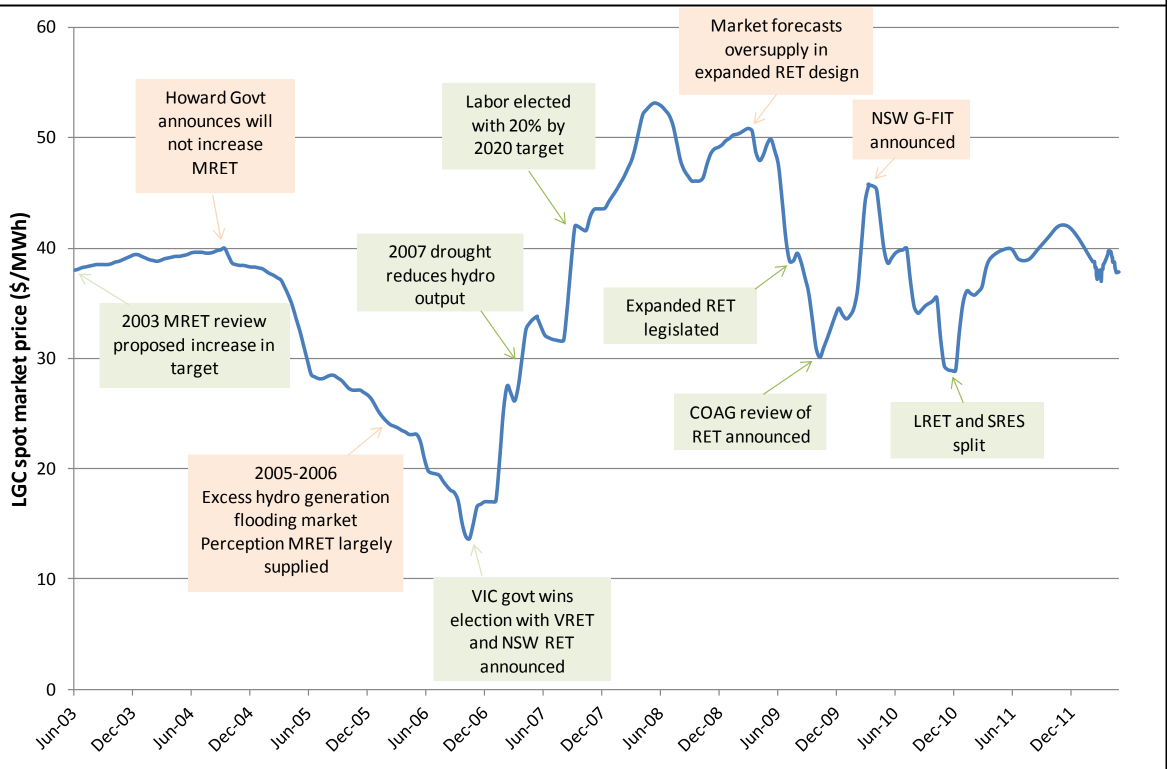
[20] http://reneweconomy.com.au/2012/why-australia-needs-no-new-coal-or-gas-baseload-15623

begin securing financing from around the period 2012 to 2013 which should lead to more interest in signing PPAs.

Low LGC prices

An issue related to the oversupply of LGCs is the presently low value of LGC spot prices relative to the price of certificates that would be required to incentivise new renewable energy projects. Figure 5.18 shows the historical REC/LGC spot market prices, which currently trade at around \$38/certificate which would likely be insufficient to support existing wind farms with costs between \$90-\$110/MWh. Prices are generally thought to remain depressed due to the large number of low cost certificates available from rooftop PV units combined with the solar multiplier.

Figure 5.18 – Historical LGC prices[21]



However, the LGC spot market has typically been used historically only for annual balancing of retailer liabilities and has been responsible only for a relatively small fraction of traded certificates. The historical prices display significant volatility in response to actual or forecast market and regulatory conditions. This volatility suggests that spot market prices are not representative of the underlying costs involved with the creation of the certificates and instead reflect longer term price signals.

[21] Underlying spot price curve sourced from Green Energy Markets and the Clean Energy Council.

Instead, the bulk of retailer LGCs are typically obtained from long-term PPAs with generators. Although most PPAs are treated as commercially confidential, Table 5.6 shows details of wind farm PPAs that ROAM has extracted or inferred from publicly available information.

Table 5.6 – Summary of public PPA prices

Wind farm	Off-taker(s)	Details	Date of PPA announcement	Starting PPA price (2012 dollars)
Snowtown	Sun Retail/ Origin Energy	90% of electricity and LGCs to December 2018	Pre-June 2007	$100[22]
Hallett 2	AGL Energy	All electricity and LGCs	August 2008	$101[23]
Hallett 4	AGL Energy	All electricity and LGCs	October 2009	$121[24]
Oaklands Hill	AGL Energy	All electricity and LGCs	June 2011	$98[25] $115.50 from 2014
Taralga (proposed)	Neighbourhood Energy and Alinta Energy	50/50 split for all electricity and LGCs	September 2011	Approximately $90[26]
Hallett 5	AGL Energy	All electricity and LGCs until 2036	May 2012	$93[27] $110 from 2014

These wind farms, as with the majority of wind projects, achieved PPAs at levels sufficient to obtain finance and are consistent with typical wind farm LRMCs of $90-$110/MWh. LGC spot prices were not significantly higher historically than current prices and were in some cases even lower, while electricity prices continue to rise. Therefore, although retailers could potentially have purchased a small number of certificates at lower prices on the spot market, they were willing to commit to the higher implied LGC prices of these contracts in order to secure a reliable supply.

ROAM therefore expects that the current LGC spot prices are not intrinsically a barrier to entry for new renewable energy projects (although the low prices reflect other issues, as described in this section).

[22] Calculated from
http://annualreport.trustpower.co.nz/en/2011/Financial-Statements-2011/Note-6.aspx
https://www.rec-registry.gov.au/
[23] http://www.agl.com.au/about/ASXReleases/Pages/AGLearns$59milliondevelopmentprofit.aspx
[24]
http://www.agl.com.au/about/media/Pages/AGLtoearn$88millionindevelopmentfeesfromthesaleofHallett4WindFarm.aspx
[25] http://www.agl.com.au/Downloads/ASX%20-%20Oaklands%20Hill%20Sale%20final%20270611.pdf
[26] http://www.climatespectator.com.au/commentary/qa-gerry-mcgowan-1
[27] http://asx.com.au/asxpdf/20120514/pdf/4267mqvs522d9g.pdf

Solar technology costs

A further issue for solar plant is they are presently significantly more expensive than wind farms, even taking into account their higher revenue potential. Despite increasingly strict planning laws, sufficient wind is likely to be available to meet the LRET and retailers will be unlikely to pay a premium for solar LGCs. Therefore it is essential that solar projects are competitive on price if they are to secure PPAs, otherwise retailers in the future may be willing to sign PPAs but not at a price sufficient for solar projects to secure finance.

The two Solar Flagships Round 1 grant offers provide some information about the project costs and the subsidies offered, as summarised in Table 5.7. Based on a 25 year lifetime and a WACC of 9.79%, Solar Dawn and Moree Solar Farm would have levelised costs of approximately $258/MWh and $247/MWh respectively. Without additional funding, these projects would be unable to secure PPAs at a sufficient level. With federal (Solar Flagships) and state funding, however, these costs drop to $142/MWh and $133/MWh which are both comparable to the indicative PPA prices modelled by ROAM.

Table 5.7 – Solar Flagship project costs[28,29]

Levelised cost calculation assumes 9.79% WACC[30], 25 year lifetime

	Solar Dawn	Moree Solar Farm
Project cost	$1200m	$923m
Federal subsidy	$464m	$306.5m
State subsidy	$75m	$120m
Capacity factor(nameplate)	23%[31]	25%[32]
Capital cost (nameplate)	$4800/kW	$5128/kW
Subsidised capital cost	$2644/kW	$2178/kW
LRMC (9.79% WACC)	$258/MWh	$247/MWh
Subsidised LRMC	$142/MWh	$133/MWh
ROAM's indicative regional PPA value	$149/MWh[33]	$140/MWh[34]

ROAM therefore expects that, with appropriate support, the Solar Flagships projects have costs at a level that could successfully secure PPAs from retailers, albeit at a significantly higher level than wind farms (currently signing at between $90-110/MWh) and hence requiring retailers to appreciate the greater value of daytime peaking solar. Without additional funding, however, the LRET and electricity markets on their own are unlikely to be sufficient to fund solar project.

[28] http://www.environment.nsw.gov.au/climatechange/solarflagship.htm

[29] http://www.energymatters.com.au/index.php?main_page=news_article&article_id=1583

[30] Scenario 3, 2010 NTNDP

[31] Estimate only

[32] Based on an annual output of 404GWh and plant size of 180 MW as per http://www.moreesolarfarm.com.au/pdf/Appendix%208%20-%20Economic%20Benefits%20Report%20-%20AECOM.pdf

[33] Queensland parabolic trough with solar multiple 1.3, as per Table 5.5

[34] Moree Solar Farm is proposed to be 1-axis tracking which has a generation profile closer to the parabolic trough output (for example, Figure 4.1). Therefore, the higher PPA price of a NSW parabolic trough plant is more likely to be indicative of the project value.

ROAM notes that these costs (both the total project costs and the subsequent calculations) are only approximate, and actual costs may be higher or lower. In particular, the cost of capital for solar projects may be higher due to banks being unfamiliar with funding large-scale solar projects and hence perceiving them as higher risk. A WACC of 11% would raise project costs by 10%. Similarly, the new Premier of Queensland, Campbell Newman, is reportedly considering withdrawing the Queensland funding for Solar Dawn which would similarly raise the final levelised cost by 10%.

Another risk to solar generators is if wind costs decrease faster than solar costs. This would result in a decrease in the average LGC price without a corresponding reduction in solar costs. In particular, ROAM has modelled an average total wind farm cost of $110/MWh; if a significant number of new entrant projects were viable at a lower cost (e.g., $90/MWh) then average solar revenue (and hence PPAs) could be reduced by up to $20/MWh.

Conclusions

In ROAM's view, the major factor limiting the signing of new PPAs is the current oversupply of LGCs. Retailers are still likely to sign PPAs if they are particularly favourable to the retailer, but depending on other funding sources, solar projects are currently unlikely to be the most competitive sources of LGCs. By 2013, however, retailers will need to begin to offer PPAs in order to ensure a sufficient supply is available post-2015, and renewable energy projects should be able to negotiate more favourable contracts.

6. Impact of Solar on Pool Prices (Merit Order Effect)

Methodology

Increasing capacity of large-scale solar power was installed simultaneously in each of the NEM mainland regions (Table 6.1). Solar data was derived from two representative locations in each region, sufficient to capture moderate diversity from installed stations. ROAM expects that all results for this section are broadly independent of the solar technology, although some differences would be observed for technologies with different time-of-day profiles (for instance, fixed flat plate solar PV would have less impact on early morning and late afternoon prices due to its lower output). ROAM has modelled parabolic trough plant (solar multiple 1.3) without storage for this analysis.

Table 6.1 – Capacity of large-scale solar plant installed in each region

	1 GW solar in NEM	2 GW solar in NEM	3 GW solar in NEM	4 GW solar in NEM	5 GW solar in NEM
SA	250 MW	500 MW	750 MW	1000 MW	1250 MW
VIC	250 MW	500 MW	750 MW	1000 MW	1250 MW
QLD	250 MW	500 MW	750 MW	1000 MW	1250 MW
NSW	250 MW	500 MW	750 MW	1000 MW	1250 MW

This solar generation was simulated for the year 2019-20 (see Section 3 for modelling methodology) and compared to ROAM's 2019-20 base case simulation. These solar stations were in addition to existing rooftop PV installations and solar projects installed in ROAM's base case planting schedule (Section C.2).

In 2019-20, the 20% renewable energy target is modelled as being met predominantly through wind. ROAM has not modified the wind planting schedule in response to the increasing penetration of solar. Although this would result in an oversupply of LGCs, it captures a scenario where the LRET is already mostly supplied by wind farms constructed before the large-scale uptake of solar technology.

Results

Table 6.2 and Figure 6.1 show the time-weighted average pool price outcomes for each region in response to increasing levels of solar capacity. Each region shows a decline in pool prices with increasing solar thermal capacity. This is due to the merit order effect, as ROAM has bid all solar thermal generation into the market at $0/MWh while keeping all non-renewable bidding profiles unchanged. South Australia's pool price decreases more rapidly than the other regions due to the high penetration of wind power in the region, along with limited export capability.

Table 6.2 – Pool price impacts of large-scale solar in 2019-20 ($/MWh)

		Additional large-scale solar capacity installed in the NEM					
		0 GW (Base case)	1 GW solar (250MW/ region)	2 GW solar (500MW/ region)	3 GW solar (750MW/ region)	4 GW solar (1GW/ region)	5 GW solar (1.25GW/ region)
Time-weighted pool price	NSW	$81.93	$78.27	$75.39	$73.08	$71.17	$69.60
	QLD	$92.31	$88.35	$85.14	$82.53	$80.36	$78.50
	SA	$87.04	$80.77	$76.14	$72.26	$68.80	$65.61
	VIC	$88.94	$83.31	$79.28	$76.19	$73.72	$71.65

Figure 6.1 – Large-scale solar impact on time weighted electricity prices (2019-20, $/MWh)

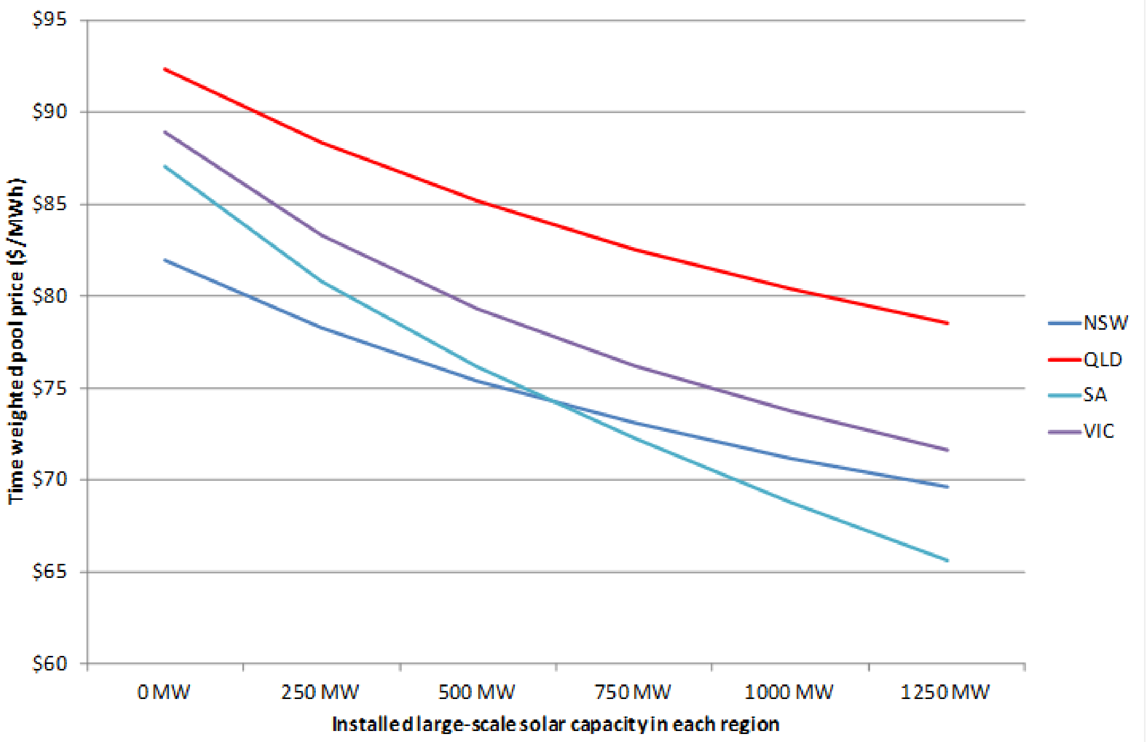


Figure 6.2 shows the average revenue for the solar plant installed in each region of the NEM. Average solar revenues decrease faster than average pool prices. This is because the solar generators are the cause of the reduction in pool prices; by definition, the solar generators are always generating when the prices are depressed due to the solar generation and hence are disproportionately affected by the resulting pool price reductions compared to other generators.

Figure 6.2 – Large-scale solar impact on solar generator wholesale electricity revenue (2019-20, $/MWh)

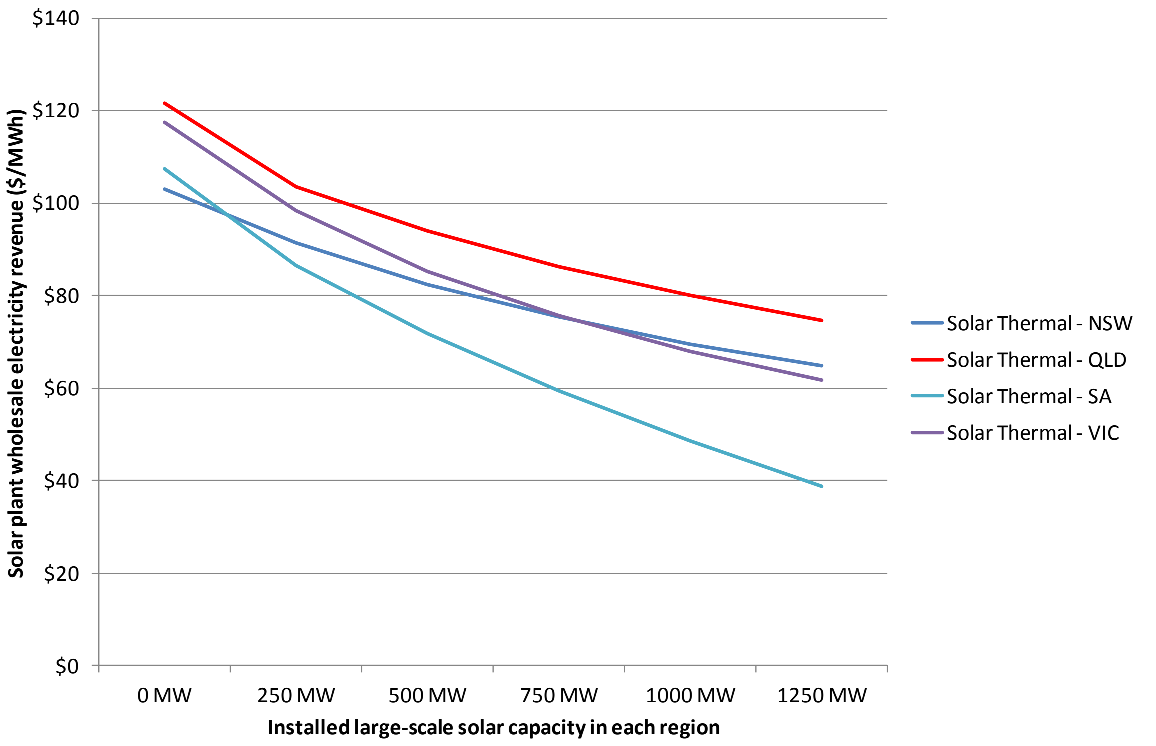


Table 6.3 shows that the number of zero-priced half-hour periods increases with solar capacity. Most notably, South Australia already experiences about 3% of periods with zero prices in the base case due to the wind generation installed. With 5 GW of solar, this increases to over 10% of periods. The 5 GW solar case results in 7% of South Australia's wind generation being curtailed relative to the base case.

Table 6.3 – Number of zero-priced half-hour periods in each region

	Base case	5 GW solar in NEM
NSW	8	22
QLD	0	0
SA	497	1823
VIC	8	31

In regard to other dispatch changes in response to increasing solar capacity, the small amounts of Demand Side Participation (DSP) modelled in 2-4-C are found to reduce with increasing solar capacity. Comparing the 5 GW solar case with the base case, DSP units decrease their use by between 80% and 100% across the NEM regions. This is because of a significant reduction in peak prices due to solar power dispatch.

6.1 SENSITIVITY TO GENERATOR BIDS

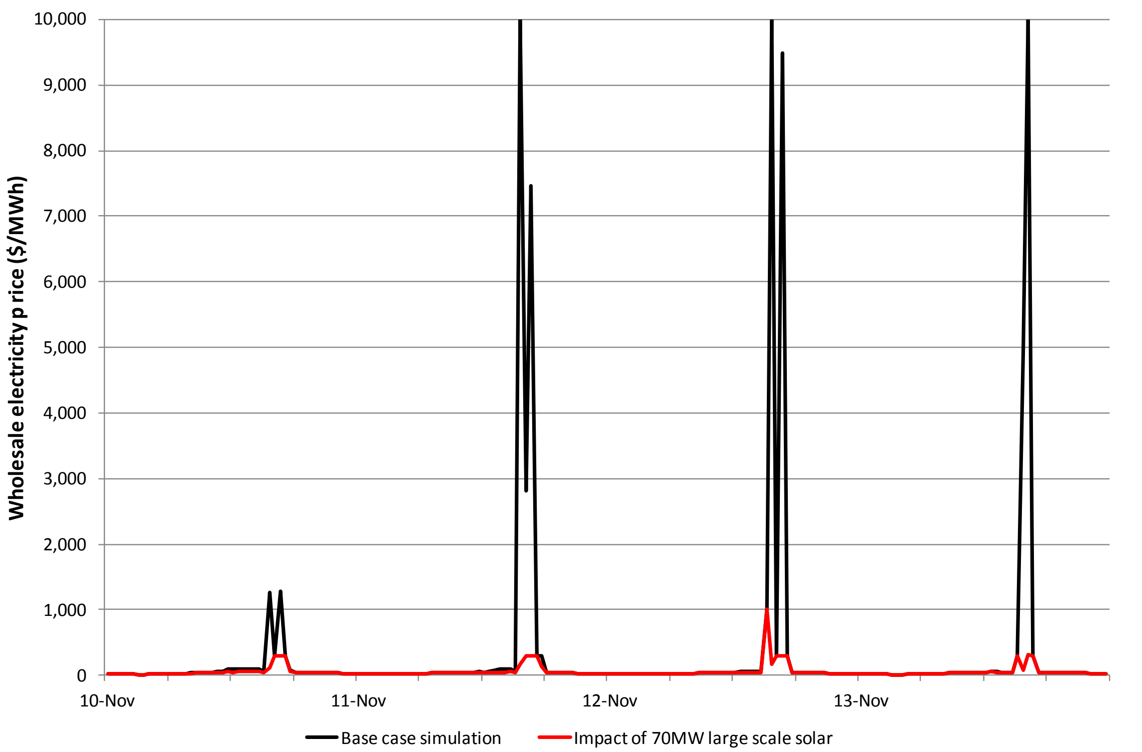
ROAM cautions that static bidding has been applied in this modelling. In reality, in cases where market power exists, generators may be able to rebid into the market and change outcomes.

Market power is most likely to apply at times of extremely high pool prices, which are a significant driver of average prices. This effect may be particularly relevant for South Australia, where market power may allow generators to remain dispatched whilst withdrawing capacity, driving higher prices. In the presence of a limited quantity of PV generation generators are likely to retain this ability.

As an example, ROAM performed sensitivities on the 2009-10 reference year to test the sensitivity of price spikes based on the historical bids active in each period. An example of a particular week in South Australia is illustrated in Figure 6.3. In this case, ROAM observed that the addition of just 70 MW of solar capacity almost entirely eliminated the price spikes observed in the base case. It is possible that the supply-demand balance in South Australia is very narrow, such that this is a real effect. However, it seems more reasonable that the generators in South Australia would be able to withdraw an additional 70 MW from the market, returning prices to the extreme levels observed in the base case. This bidding behaviour has not been captured in this modelling.

However, this effect will only apply in circumstances where generators currently experience market power.

Figure 6.3 – Pricing outcome example for South Australia (2009-10 reference year simulations)



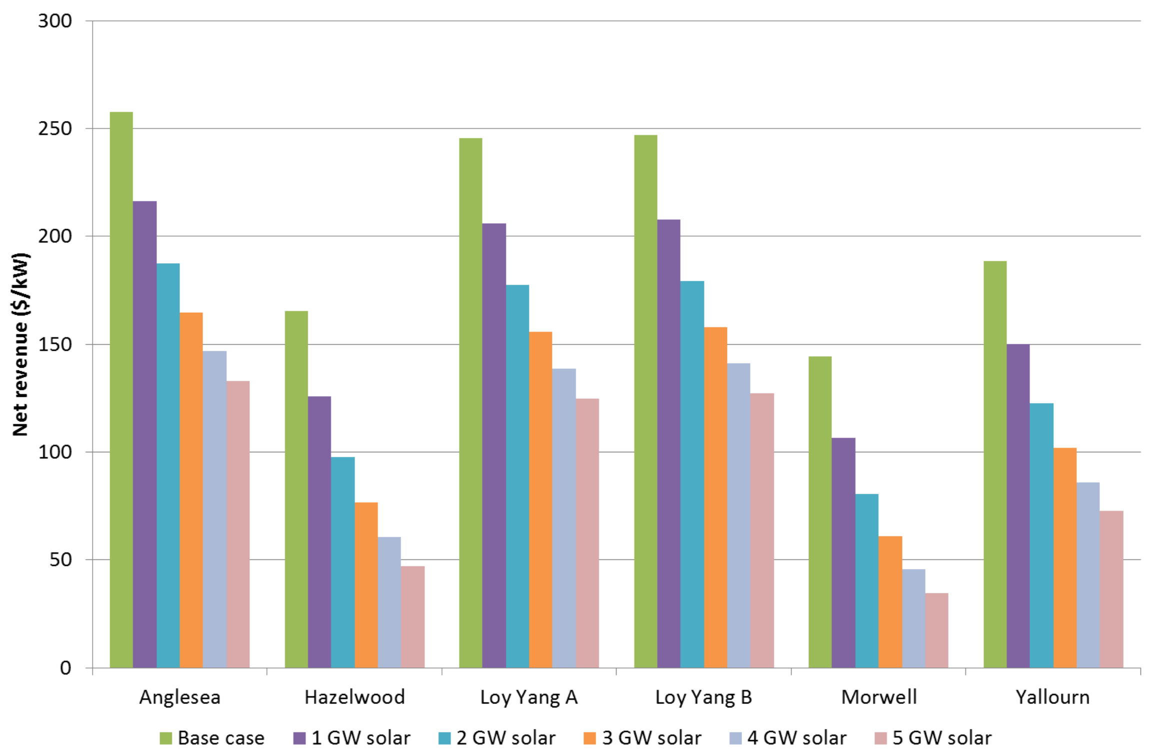
6.1.1 Impact on generator profitability

Thermal generators

Figure 6.4 shows increasing solar capacity consistently reduced the net revenues of the brown coal generators in Victoria. The net revenue is defined as the pool revenue net of the annualised fixed and variable costs (excluding capital cost repayments), divided by the total installed capacity. Capital cost repayments are not included in the charts as data is not publicly available and they differ greatly from generator to generator.

Reduction in pool prices is the biggest contributor to the reduction in the net revenues, but their dispatch is also reduced by an average of 4% in the 5 GW solar cases compared with the base case. ROAM notes again that this result is based on the assumption that all aspects of NEM operation remain static across the different scenarios of installed solar generation. Changes in generator bidding behaviour, or generator retirement could dramatically increase the revenues of the installed generators. (In 2019-20, ROAM has retired six out of the eight units for Hazelwood power station.)

Figure 6.4 – Large-scale solar impact on brown coal generator net revenues

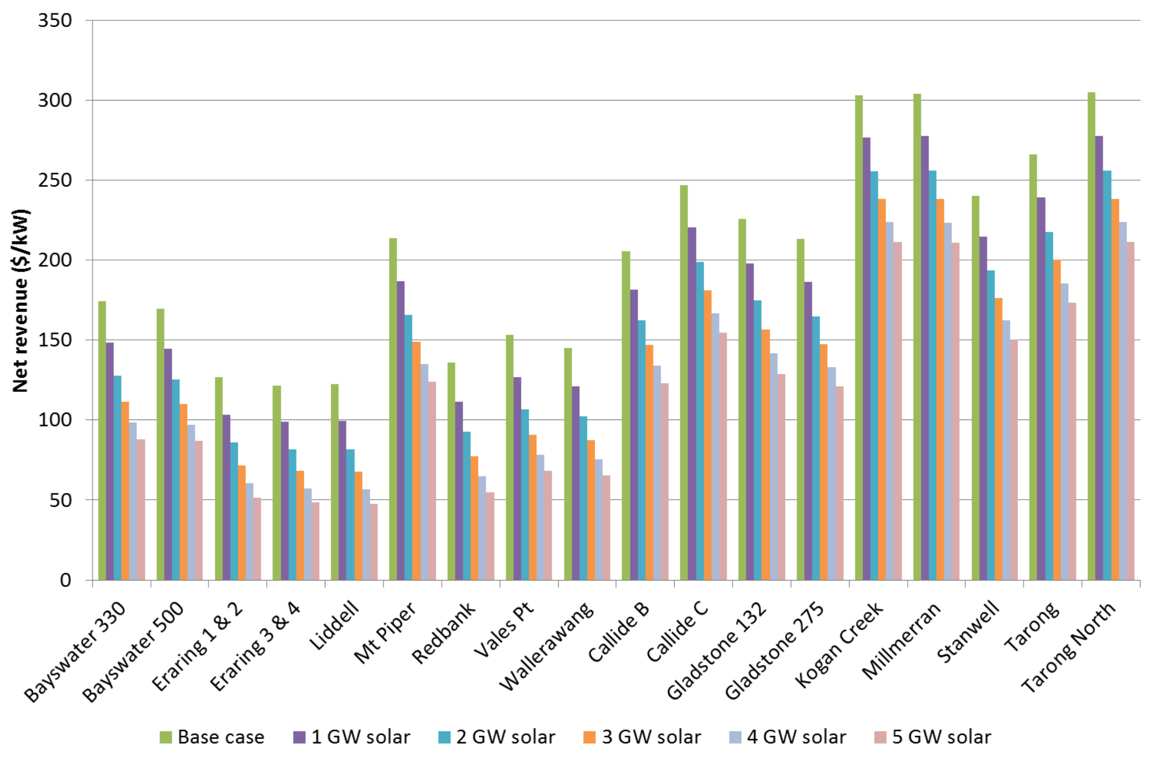


A recent article[35] stated that the existing debt for Loy Yang A power station is $2.5 billion and a presentation[36] from AGL (who recently purchased Loy Yang A) states that the annual borrowing costs are $268 million dollars. This equates to a capital cost repayment of $118/kW, which is only a little less than the net revenue estimated for Loy Yang A in the 5 GW solar scenario. Financial statements from International Power[37] suggests Loy Yang B's debt is $1.107 billion, which is a slightly lower debt per kW installed compared with Loy Yang A.

Although some of these revenue losses are likely to be recovered through rebidding strategies by thermal generators, increasing penetration of solar power in the NEM is likely to have significant impacts on generator profitability.

Figure 6.5 shows the net revenues also reduce for the nineteen modelled existing coal generators with increasing installation of solar capacity. Black coal outcomes are similar to brown coal, with their dispatch also being reduced by a weighted average of 4%.

Figure 6.5 – Large-scale solar impact on black coal generator (Gen) net revenues



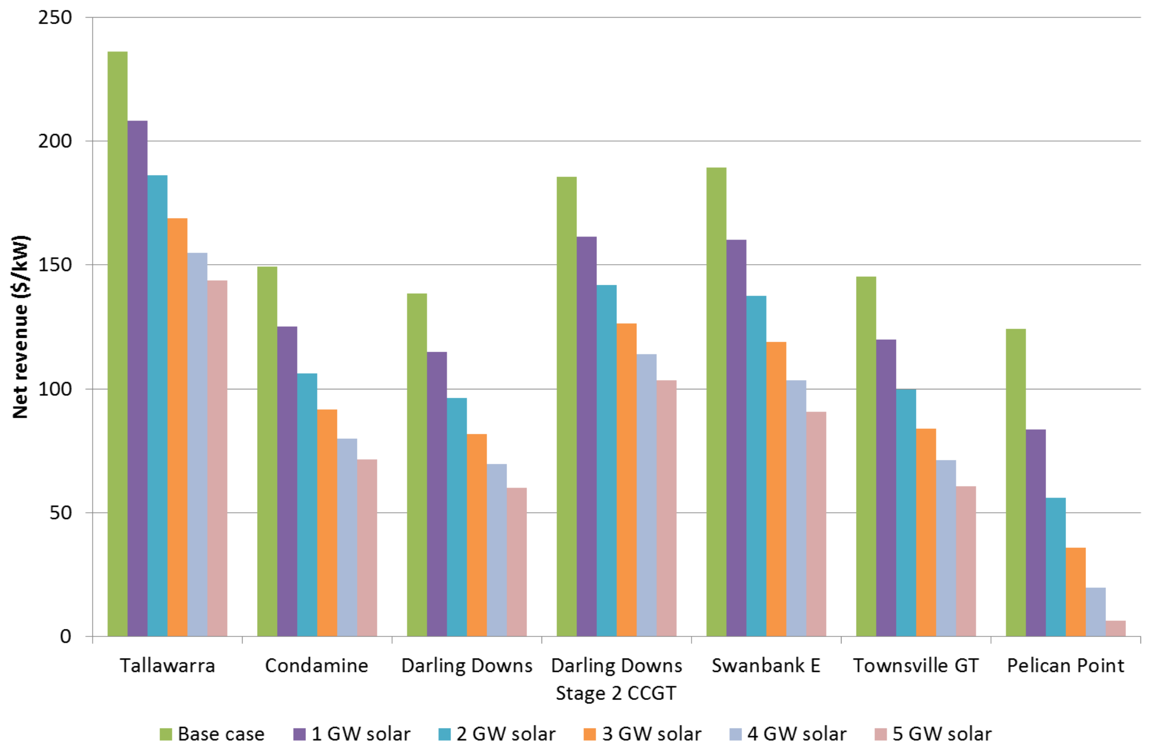
35 http://www.tradingroom.com.au/apps/view_breaking_news_article.ac?page=/data/news_research/published/2012/5/145/catf_120524_170200_0121.html

36 http://agl.com.au/Downloads/20120510%20-%20LOY%20YANG%20POWER%20PRESENTATION%20-%20ASX.pdf

37 http://annualreport2011.iprplc-gdfsuez.com/assets/downloads/pdfs/IP-2011-Financial-statements.pdf

Figure 6.6 shows the net revenues for CCGT generators also decreases with each additional GW of solar. The weighted average reduction in dispatch for CCGT plant is 5%.

Figure 6.6 – Large-scale solar impact on CCGT generator (Gen) net revenues

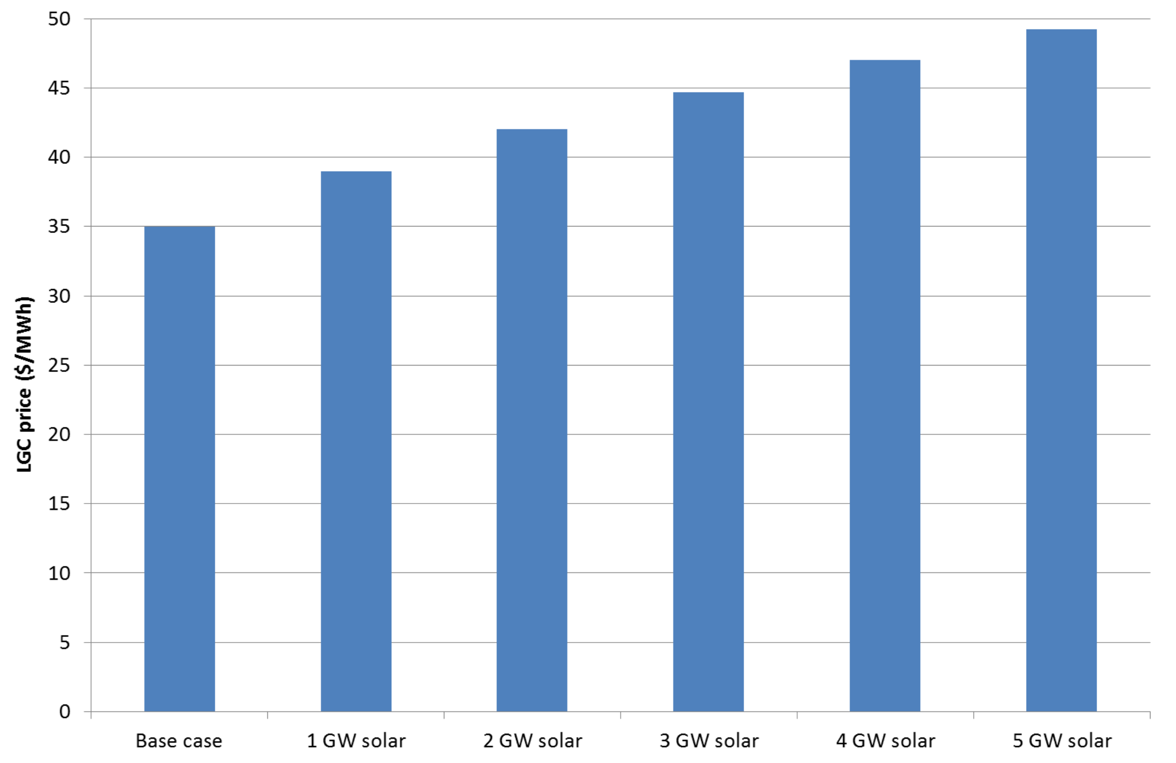


Pelican Point CCGT plant suffers the largest revenue reduction in the 5 GW solar scenario since it is installed in South Australia where the largest drop in the pool price occurs. When capital cost repayments are taken into account, Pelican Point is unlikely to be profitable in the 5 GW scenario.

Wind

Renewable generators are somewhat insulated from reductions in pool prices by the LRET scheme. Figure 6.7 shows that the LGC shadow price increases with increasing solar capacity. ROAM's LGC shadow price estimation methodology is described in Section 3.4.

Figure 6.7 – LGC (shadow) price estimates for each case



As an example, Figure 6.8 shows the average revenue for wind generators in New South Wales, split into pool revenue and LGC revenue. While the average pool revenue decreases with increasing solar capacity, the shadow LGC price increases to ensure that the wind farms continue to receive their LRMC.

The pool prices decrease at different rates for each region (see Figure 6.1), resulting in some wind farms doing better or worse. In particular, South Australian wind farms receive lower prices and are curtailed as a result of the additional solar capacity.

Figure 6.8 – Large-scale solar impact on wind generator revenues in New South Wales

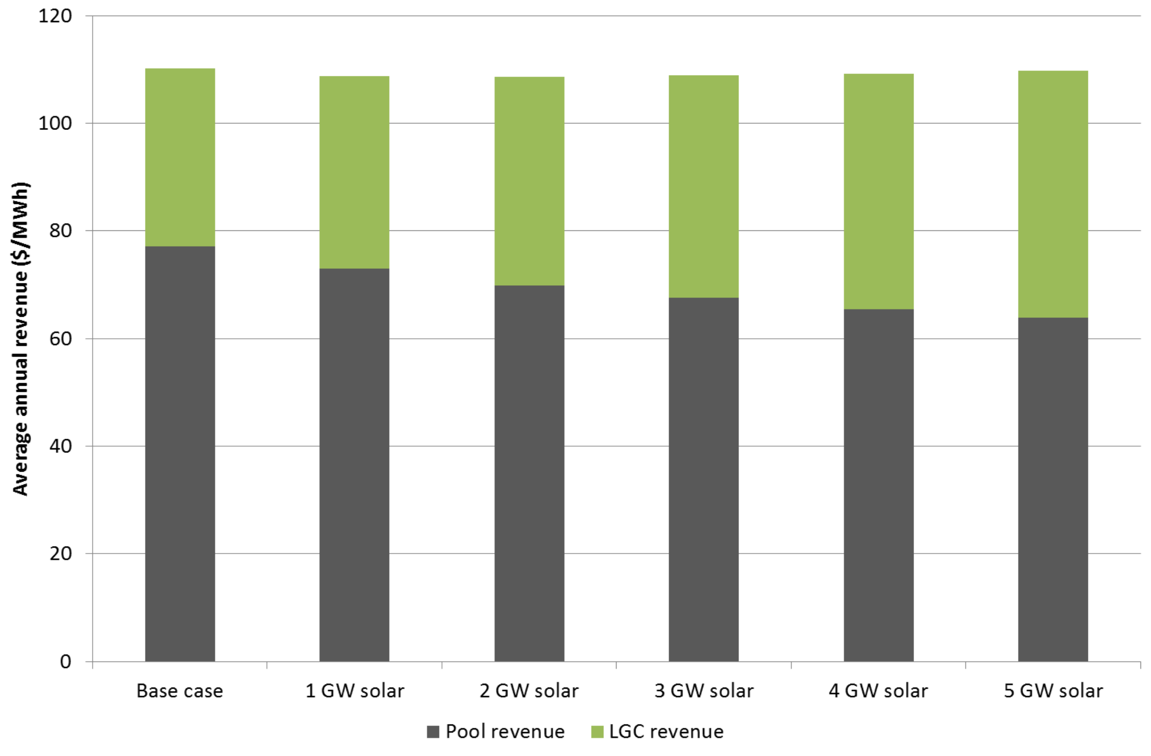
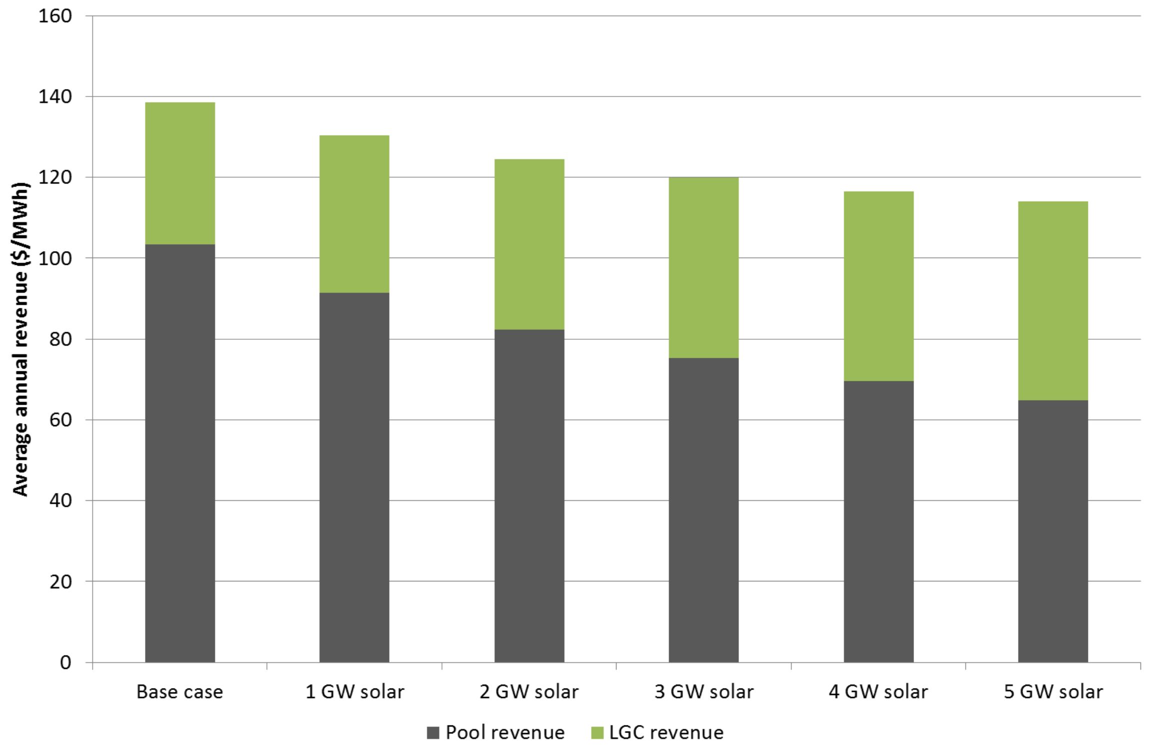


Figure 6.9 shows the total revenue for the NSW solar plant. Despite the increasing LGC prices, the solar generators suffer reduced average revenue with increasing capacity.

This is because wind generators produce energy at any time of the day and will only be affected by the solar-induced merit order effect when they produce energy at the same time as the solar generators. Since the LGC prices are calculated to keep the wind farm average revenues constant, they are not sufficient to maintain the solar revenues.

Figure 6.9 – Large-scale solar impact on total solar generator revenue in New South Wales



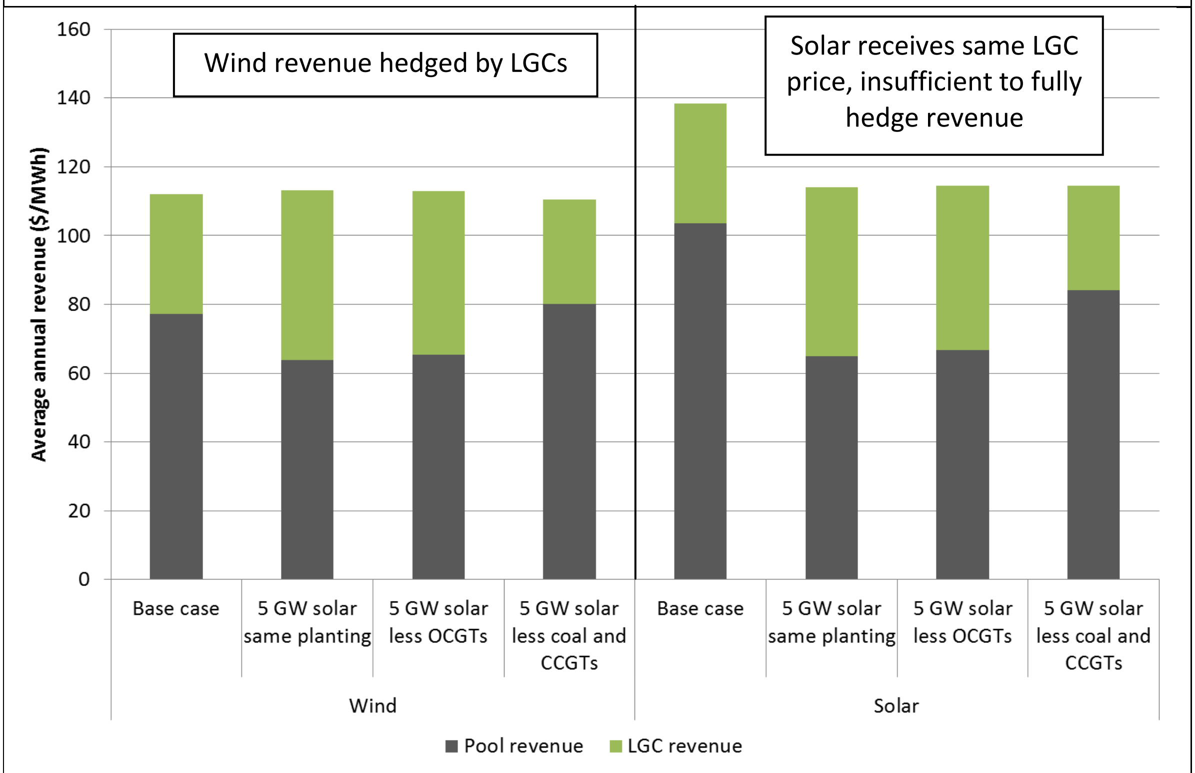
These scenarios assume that all other planting remains constant as the solar capacity increases. In practice, with sufficient lead time, new generation may be delayed and existing capacity (such as brown coal) may be retired (or operate on a reduced basis) if it proves unprofitable. ROAM has considered two sensitivities:

1. Less OCGTs: New OCGT generation was taken out since this generation is typically installed to meet peak demand. The effective peak demand is significantly reduced by the 5 GW of solar.
2. Less coal and CCGTs: Candidate unprofitable brown coal, black coal and CCGTs are retired or deferred, representing a case where the increasing solar capacity causes some plant to retire as no longer profitable. The amount of each generation type removed compared to the base case is:
    a. Brown coal: 760 MW.
    b. Black coal: 694 MW.
    c. CCGTs: 1414 MW.

In each sensitivity, 650 – 750 MW of generation was taken out from the four regions where the large-scale solar capacity was installed. 750 MW represents a 60% contribution to peak demand for the 1250 MW of solar capacity installed in each region.

Figure 6.10 compares the pool and LGC revenues for the average wind generator and the solar capacity in New South Wales for the base case and the 5 GW solar sensitivities.

Figure 6.10 – 5GW large-scale solar impact on wind and solar generator revenues in New South Wales (sensitivities)



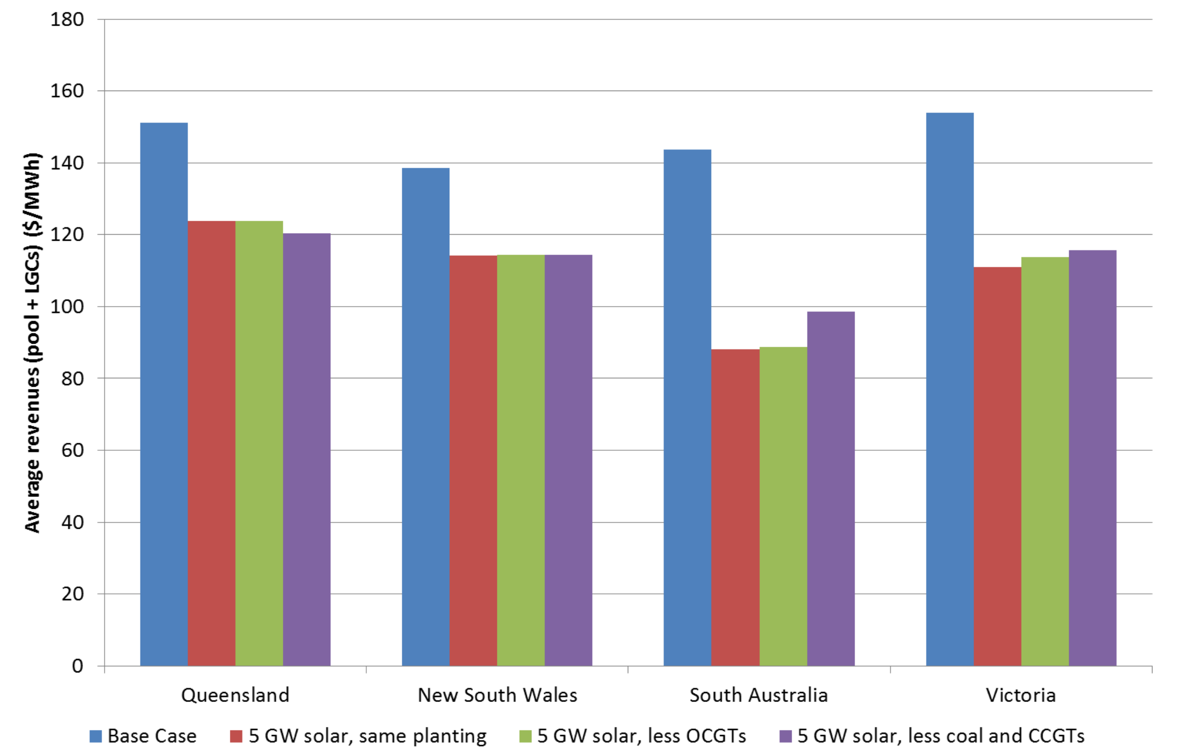
The total revenue of the wind generators remains unchanged in all the sensitivities since the LGC price is set to compensate the wind generation for the changes in pool revenues.

Removing unprofitable generation makes little difference to the solar revenues. In the less OCGTs sensitivity, pool prices are increased by only $1/MWh - $2/MWh. This increases wind farm pool revenues slightly, resulting in a reduction in LGC prices by a similar amount. The net benefit for solar revenues is minimal.

In the less coal and CCGTs sensitivity, pool prices are increased by $15/MWh - $20/MWh. This increases thermal generation revenues significantly, such that all the remaining coal and CCGT generators are slightly more profitable than in the base case. However, since the wind pool revenues are increased, the shadow LGC price is decreased by approximately $17/MWh. This again results in little change to the solar revenues in New South Wales. This unfavourable (for solar plant) hedging will only change if enough solar generation is installed at a price such that the LGC price is set by the solar generators themselves (and their required LGC price is less than the LGC market shortfall charge).

Figure 6.11 compares the total solar revenues (pool + LGCs) for each region in the base case, 5 GW solar case and the two sensitivities (on the 5 GW case). The graph shows that the same trend in unchanging solar revenues in the other regions, apart from a small increase in South Australia where the largest pool price increase occurs.

Figure 6.11 – 5GW large-scale solar impact on solar generator revenue sensitivities (electricity and LGC sales, $/MWh)



Impact of storage

An important question is whether the availability of storage could mitigate these price impacts, either for the CSP plant alone or for the market at large. ROAM has not conducted explicit modelling of these scenarios in this report. However, ROAM has conducted detailed analysis of storage dispatch for small levels of installed solar capacity (Section 7). This analysis showed that CSP plant with storage dispatches to meet the highest price periods, particularly late afternoon/early evening. Only relatively small amounts of storage (3 hours) are required to meet the evening peak demand and prices.

If daytime prices were to be depressed, this would incentivize solar plant to increasingly generate earlier or later in the day (outside of the typical generation hours of solar plant without storage). However, this will only be beneficial if evening prices are higher than the depressed daytime prices, and so will still represent a loss in revenue to the CSP plant. Further investigation into the magnitude of this effect is warranted.

6.2 Summary and Conclusions

The merit order effect from installing large amounts of solar power into the NEM has been modelled by ROAM for the years 2009-10 (backcast) and 2019-20 (forecast). Pool prices decrease in all regions when increasing amounts of rooftop solar PV or large-scale solar are installed, with serious reductions in revenues for large-scale solar plant but potentially significant benefits for rooftop PV installations.

Large-scale solar plant experienced significant reductions in wholesale electricity revenues, caused by depressed electricity prices. Wind farms, however, experienced less reduction in revenue, increasing the gap between wind and solar profitability. Furthermore, increases in LGC prices are not expected to be sufficient to make up solar revenues.

However, pool price reductions are likely to be transitory in the medium to long term and ROAM expects the results presented here to be a conservative view. Firstly, ROAM has assumed that all generator bids remain unchanged. In practice, the installation of significant amounts of large-scale solar causes some existing thermal generation to become unprofitable. These generators may be able to change their bidding structure to increase pool prices again, increasing revenues for both thermal generators and solar plant. ROAM observed several lost price spikes that could have been retained with only modest rebidding by generators.

Alternatively, unprofitable thermal plant may retire, increasing pool prices and hence profitability for the remaining generators. This represents a new market state, operating sustainably with a new mix of generators and with reduced total emissions due to the large-scale solar capacity. However, even under moderate retirements (equivalent to 60% of the solar capacity), solar plant still suffers reducing revenues as more capacity is installed (due, again, to LGC price hedging); this may pose a long-term issue that requires further exploration.

7. VALUE OF THERMAL STORAGE

One of the most compelling reasons for pursuing solar thermal power is the opportunity to harness thermal storage, allowing solar plant to both provide energy during night time periods and to deliver more reliable generation during daytime hours. This is likely to make solar thermal with storage attractive from the perspective of a system operator as well as off-takers looking for firm capacity.

Storage also adds value to the solar plant itself. Storage (with a corresponding increase in the plant’s solar multiple) increases the total energy generation, and hence revenue, of the plant. It also reduces the likelihood of the plant missing very high price periods (due to local cloud cover, for example) which can significantly contribute to the plant’s total revenue. Finally, by being able to offer more reliable supply, solar thermal plant with storage is likely to be more attractive to retailers seeking PPAs.

ROAM has investigated the value of a range of storage sizes with corresponding solar multiples in two regions, Queensland and South Australia, for the years 2009-10 (a backcast), 2019-20 (with the 20% renewable energy target met) and 2029-30 (exploring a sensitivity with 30% renewables).

7.1 Modelling of Storage

CSP plants were modelled with solar thermal storage for the storage size and capacities given in Table 7.1. ROAM specifically modelled solar thermal parabolic trough plant, but expects that these results would be applicable to towers or other concentrating technologies as well.

Table 7.1 – Parameters for CST with storage plant

Storage size	Nameplate capacity (MW)	Storage size (hours)	Storage size (MWh)	Solar Multiple
Small	30	1	30	1.3
Medium	30	3	90	1.6
Large	30	16	480	2.6

The range of storage sizes were chosen to allow exploration of different storage operation regimes:

- Small storage capacity of one hour, sufficient to "fill gaps" in daily output and to extend daily output slightly into the evening
- Medium storage to extend plant output to cover the evening peak
- Large storage sufficient to allow continuous operation

The specific combination of storage sizes and solar multiples chosen for this study were selected on the basis of likely of utilization levels as well as cost estimates derived from parametric simulations in SAM. This allowed realistic combinations to be explored in depth, and sensitivities were carried out to verify these assumptions (Section 7.5).

To model storage, traces of available solar energy were created using ROAM's Solar Energy Simulation Tool (see Section 3.5), representing the thermal energy available for generation or storage in each half-hour period.

Losses were assumed to be independent of whether the energy was going to generation or storage, and also independent of the capacity of stored thermal energy at that time. Loss of thermal energy from storage over the typical storage timescales of the modelling (1-48 hours) was assumed to be zero for the purposes of modelling. To achieve practical modelling times, a plant start-up energy penalty was incorporated into the pre-storage solar availability trace but was not modified in response to the specific start-up and shut-down pattern of the plant. (Any losses not captured by this model could be compensated for by a slight increase in the solar multiple.)

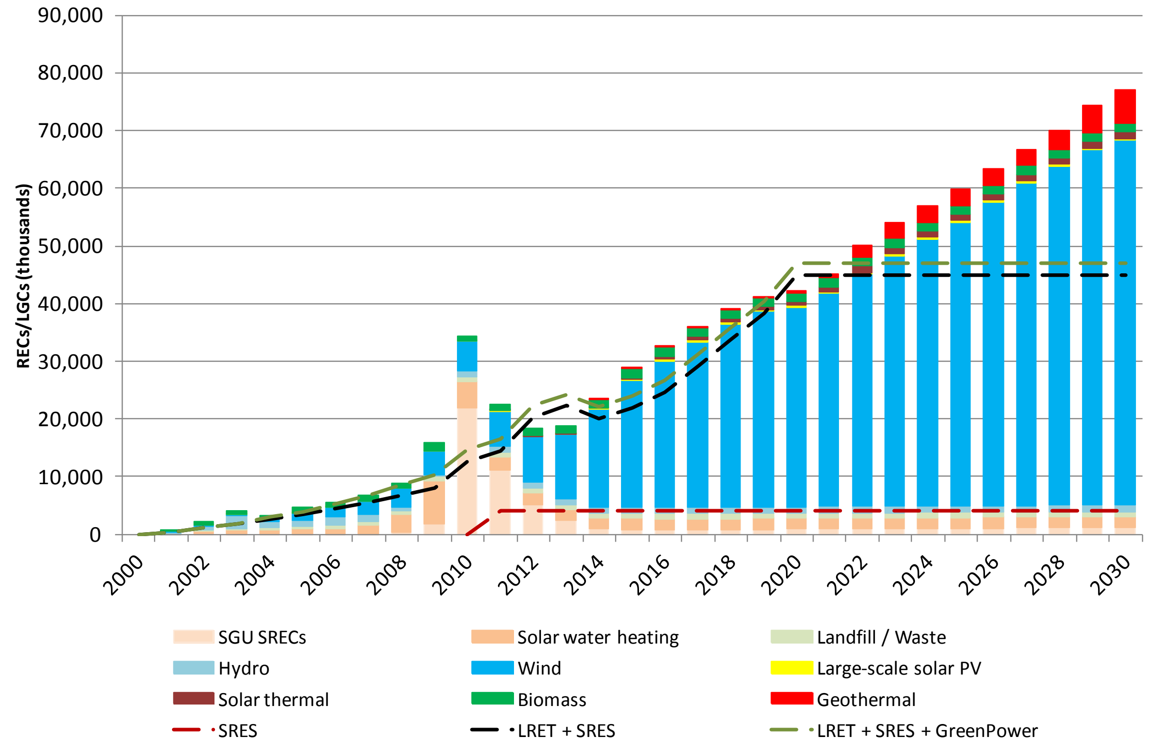
The relatively small size of the solar plant means that impacts on wholesale electricity prices (the merit order effect) are limited; all wholesale prices presented below are for the optimised storage simulation, but are very similar in all cases.

Scenarios

Three simulation years were considered:

- A historical backcast of 2009-10. This backcast used the actual historical bids, demand and generator availability for each half-hour of the year, plus ROAM's modelled solar output for the 2009-10 year. Some extreme price events, however, were lost or only present at a reduced level due to additional events such as transmission outages or additional transmission constraints.
- The year 2019-20, where the 20% LRET has been met. Fifty Monte Carlo simulations across two demand profiles were modelled, representing a broad range of possible price duration curves that could occur in this year.
- The year 2029-30, with additional wind capacity installed to meet a 30% renewable energy target based on 2030 energy forecasts (Figure 7.1). Some geothermal plant was constructed in South Australia from 2020 to 2030 as part of meeting the existing LRET targets. As with 2019-20, fifty simulations with a range of plant outages were simulated.

Figure 7.1 – Renewable generation – 30% renewables sensitivity



7.2 STORAGE DISPATCH METHODOLOGY

ROAM Consulting considered two methods of dispatching the CSP plant. Together, they represent the range of possible dispatch strategies: a conservative approach with no attempt to predict future price spikes, and an optimised dispatch which effectively maximizes solar plant revenue if perfect knowledge of future conditions were available.

In practice, actual outcomes are likely to be between the two options and will depend on the quality of forecast data and preferences of the plant operator (including, potentially, the portfolio and requirements of the PPA counterparty).

Immediate dispatch

In the first approach, stored energy is used as soon as possible. That is, the solar plant is always operated at the maximum possible capacity given the available incident and stored energy. This has the impact of extending solar generation across brief outages and into the immediate evening peak, but does not provide for strategic decisions such as limiting the plant's output earlier in the day in order to generate during an anticipated evening peak.

This dispatch mode reflects a conservative plant operator who seeks to minimize lost energy (by limiting the amount of time spent with full storage) and who is reluctant to sacrifice daytime generation in the hopes of receiving higher prices for energy during an evening peak (or even the following day if it is expected to be cloudy).

H2OPT – optimal dispatch

To understand the maximum possible benefit of strategic dispatch, ROAM Consulting has used its state of the art dispatch modelling tool, H2Opt. Originally designed for optimising the dispatch of hydro-electric plant based on rainfall inflows, it is applicable to any system with a resource availability time series with storage whose use must be optimised.

The operation of the CSP plant including storage was optimised iteratively, with the generation in each trading interval scheduled to minimise system costs. This is used as a proxy for maximising solar plant revenue, as the optimal dispatch (in most cases) corresponds to generating during the highest price periods.

A key input of this model is that the plant operator is assumed to have perfect foresight of:

- Generator bids;
- Demand; and
- Available solar generation.

Forecasting abilities for each of these data sets continue to increase, particularly in response to the increasing penetration of intermittent renewables. For instance, AEMO currently provides forecasts of wind generation on multiple timescales through the Australian Wind Energy Forecasting System[38], and aims to add solar forecasting over time.

AEMO also provides short-term demand forecasts through its Demand Forecasting System and generator bids are publicly available in near real time. ROAM Consulting is presently developing a price forecasting system to incorporate all these data sources into price forecasts suitable for the type of optimisation proposed by H2Opt.

Although in practice perfect forecasts are not available, this dispatch scenario captures the maximum possible benefit of dispatchable solar.

[38] http://www.aemo.com.au/Electricity/Market-and-Power-Systems/Dispatch/AWEFS

7.3 Revenue results

The revenues for the CSP plant with no storage, immediate dispatch and optimised dispatch are shown in Table 7.2.

Table 7.2 – Annual wholesale electricity revenue for CST with storage ($/kW installed)

Key: SM1.3 = Solar multiple of 1.3. 1hr = Storage for 1 hour of full generation

		QLD			SA		
		Storage dispatch mode			Storage dispatch mode		
Year	Storage size	Not used	Immediate	Optimised	Not used	Immediate	Optimised
2009-10	SM1.3 / 1hr	78	80	88	179	182	194
	SM1.6 / 3hr	84	95	105	190	201	212
	SM2.6 / 16hr	92	138	149	199	243	256
2019-20	SM1.3 / 1hr	256	266	286	261	269	290
	SM1.6 / 3hr	281	319	354	285	314	347
	SM2.6 / 16hr	312	473	511	315	448	495
2029-30	SM1.3 / 1hr	329	341	360	258	266	290
	SM1.6 / 3hr	363	409	446	283	317	356
	SM2.6 / 16hr	404	617	666	317	468	527

In all cases, higher solar multiples result in higher revenues (as expected), with revenues increasing by 11-23%. This revenue increase, however, would be offset by the increased cost of a larger mirror field. (ROAM has not attempted to quantify capital costs in this study and so all revenues presented in this section are gross.)

With storage, the increased generation also increases LGC revenue and provides additional benefit for the inclusion of storage; both dispatch strategies produce identical total energy. Figure 7.2 shows the total revenue for QLD and SA solar plant.

Figure 7.2 – Annual total revenue for CSP with storage (electricity and LGC sales, $/kW installed)

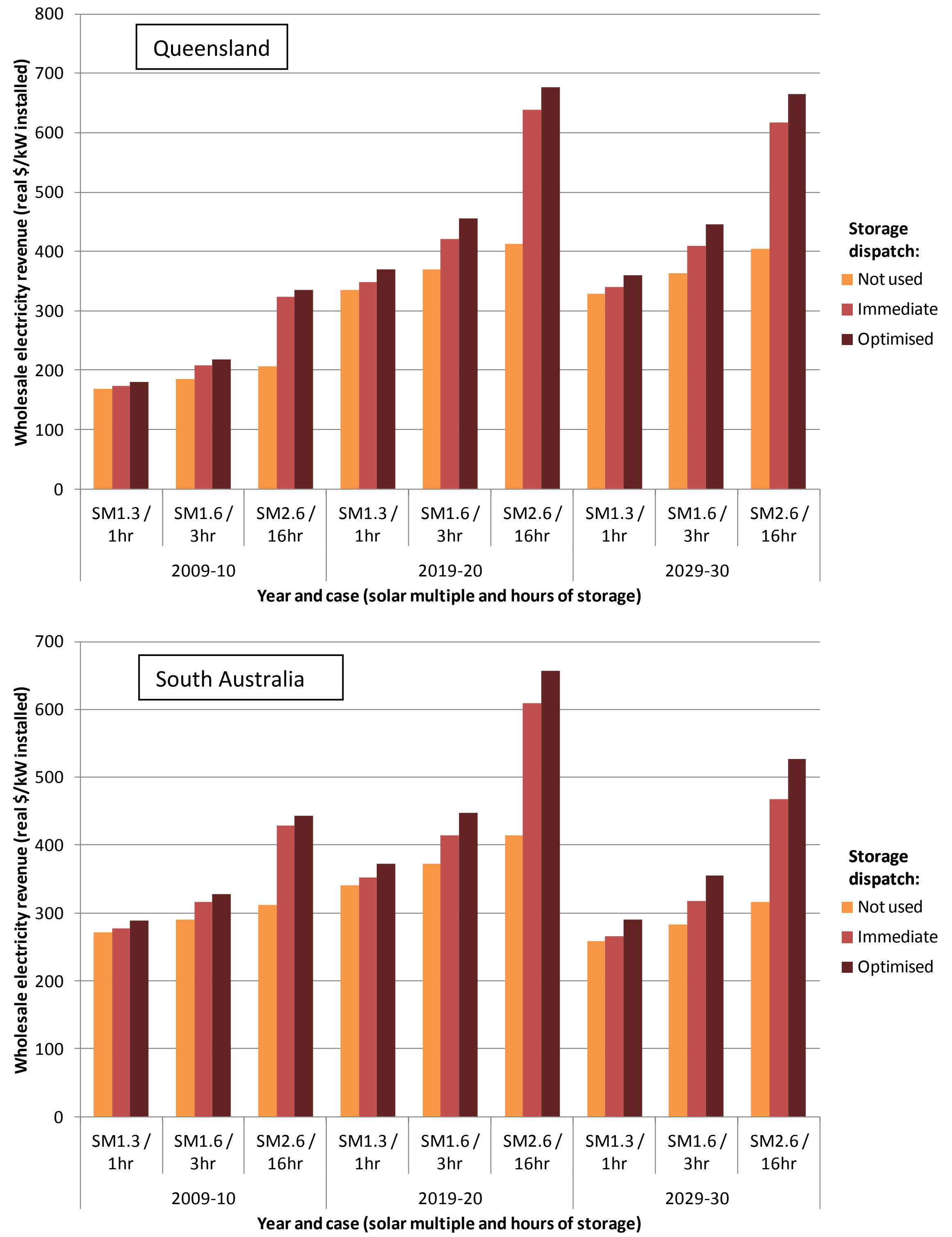


Table 7.3 shows the additional wholesale electricity revenue in each year compared to the reference case of a solar multiple 1.3 plant with no storage. In every case, additional storage results in additional revenue, and this revenue increases over time as the electricity pool prices rise.

By 2019-20, a higher solar multiple plant with 16 hours of storage could earn an additional $250-340/kW on average over ROAM's base case CSP plant. With the same solar multiple, however, even lower amounts of storage are likely to earn comparable levels of revenue (see Section 7.5, potentially improving the cost-benefit trade-off of storage.

With only one hour of storage, significant additional benefit can be obtained through the use of strategic dispatch (3 to 5 times the additional revenue of the immediate dispatch case), although flexible plant operation would be required to achieve maximum benefit (Section 7.4.1). With strategic dispatch, additional revenue increases as higher levels of storage and energy are available, but not in proportion to the increase in total revenue. This means that the benefit of strategic dispatch decreases with storage.

Table 7.3 – Additional total revenue (electricity plus LGC sales, $/kW installed)

Key: SM1.3 = Solar multiple of 1.3. 1hr = Storage for 1 hour of full generation

		QLD			SA		
Year	Storage size	No storage	Immediate	Optimised	No storage	Immediate	Optimised
2009-10 (REC price $40)	SM1.3 / 1hr	Reference	5	12	Reference	6	18
	SM1.6 / 3hr	15	36	47	19	42	53
	SM2.6 / 16hr	34	140	152	38	144	158
2019-20 (20% renewables) (LGC price $34)	SM1.3 / 1hr	Reference	14	34	Reference	11	32
	SM1.6 / 3hr	34	85	120	31	73	105
	SM2.6 / 16hr	76	300	339	72	265	313
2029-30 (30% renewables) (LGC price $0)	SM1.3 / 1hr	Reference	16	36	Reference	12	35
	SM1.6 / 3hr	43	101	138	33	79	117
	SM2.6 / 16hr	95	372	420	77	286	345

ROAM notes that although the total revenue of the solar plant increases with the introduction of storage, the average revenue (in $/MWh, Table 7.4) remains relatively constant or, particularly in the case of the high solar multiple plant, actually decreases when storage is added. Although storage increases the likelihood that the solar plant will meet peak pool price periods, increasing levels of storage result in more generation in the late evenings when prices begin to decrease.

This highlights the importance of considering both average and total revenue when assessing solar plant. It also suggests that PPA prices for solar plant with storage are unlikely to be significantly higher than those already calculated in Section 5.4. Total solar plant revenue, however, will increase and will need to be weighed against the additional costs of mirrors and storage technologies.

Table 7.4 – Average revenue of solar plant with storage ($/MWh)							
		QLD			SA		
Year	Storage size	No storage	Immediate	Optimised	No storage	Immediate	Optimised
2009-10	SM1.3 / 1hr	34	34	37	78	76	81
	SM1.6 / 3hr	33	33	37	75	70	73
	SM2.6 / 16hr	32	30	32	70	52	55
2019-20 (20% renewables)	SM1.3 / 1hr	113	111	119	114	107	116
	SM1.6 / 3hr	111	110	122	113	105	117
	SM2.6 / 16hr	109	100	108	111	95	105
2029-30 (30% renewables)	SM1.3 / 1hr	145	142	150	112	112	122
	SM1.6 / 3hr	143	142	154	113	111	124
	SM2.6 / 16hr	141	131	141	112	104	116

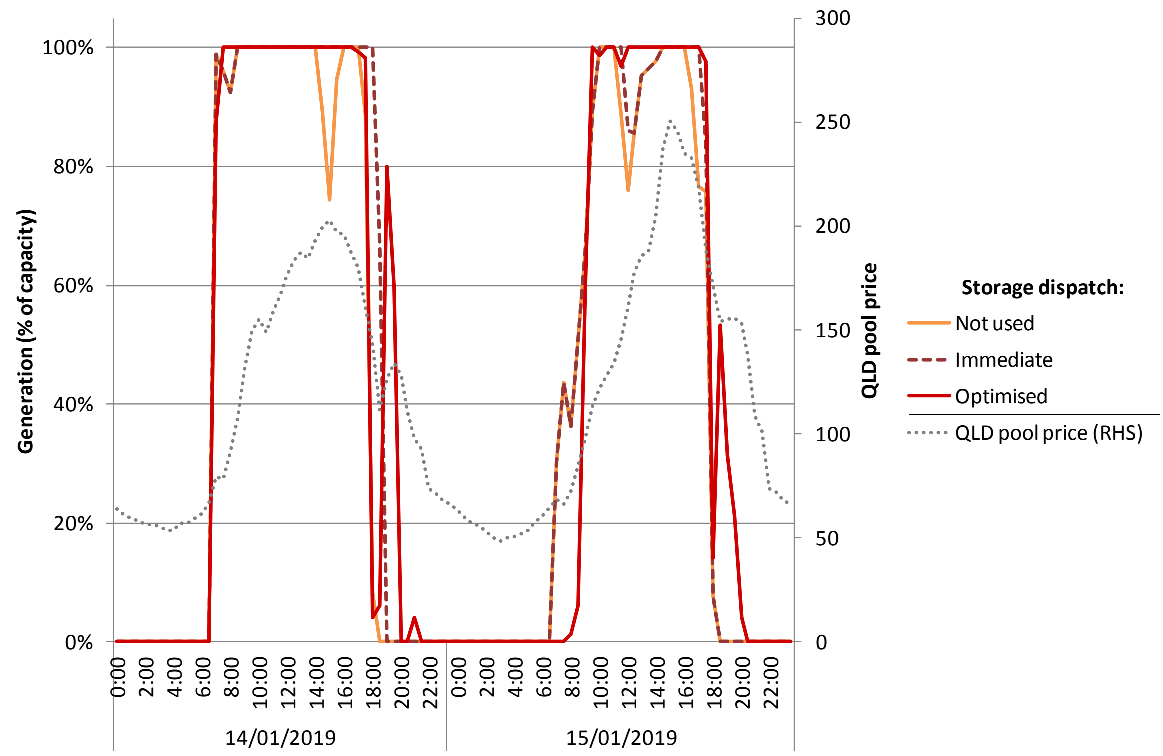
7.4 Dispatch of Storage

7.4.1 One hour storage

With a solar multiple of 1.3, the addition of one hour of storage was able to partially fill “outages” (due to cloudy periods) during the day, as well as extend evening operation by up to one hour. However, total generation increased by only 3% and opportunities to fully utilise the storage were limited unless a more strategic approach to plant dispatch was taken (through ROAM’s “Optimised” scenario). Generally, the strategies observed in the optimised dispatch were constrained versions of the higher storage level strategies discussed in more detail in Sections 7.4.2 and 7.4.3.

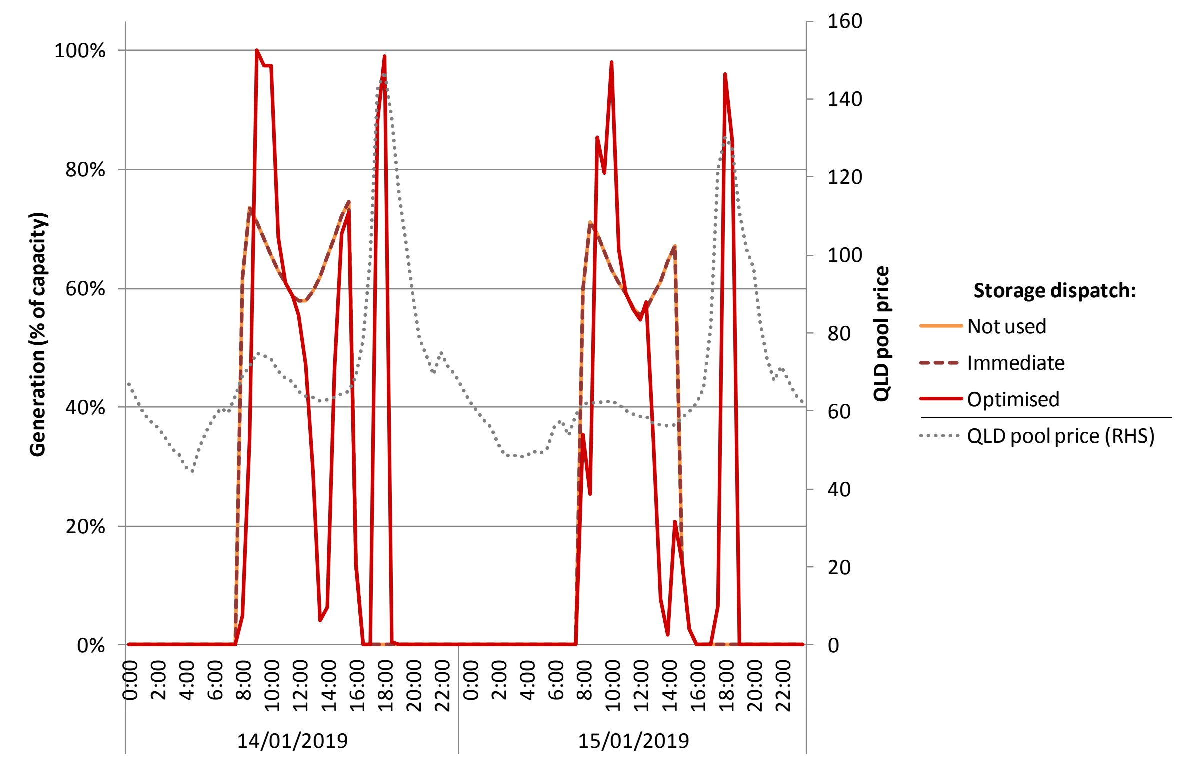
Figure 7.3 shows the generation and pool price in Queensland over two days in the 2019-20 summer. In the “Immediate” dispatch methodology, the stored energy is utilised as soon as solar-only output begins to drop, which smoothes over the daytime generation and extends output for an hour in the evening on the first day. On the second day, insufficient stored energy is available for evening generation unless, as in the optimised dispatch case, generation is sacrificed earlier in the day in order to meet the evening peak and maximise revenue.

Figure 7.3 – Example summer dispatch of CSP with storage (QLD, SM 1.3, 1 hour storage, 2019-20)



On most winter days there is insufficient energy available to fill the storage reservoir unless strategic dispatch is utilised. With perfect foresight, additional revenue can be gained through holding back energy and releasing it even over the course of a few hours, thus maximising morning and evening peaks (Figure 7.4). This would require high quality demand and price forecasting and flexible plant operation. There may also be difficulties in engaging in behaviour that may be perceived as “risky”, depending on off-take agreements, although (given the high prices available in the early evening) strategic dispatch is unlikely to produce lower revenue outcomes on average.

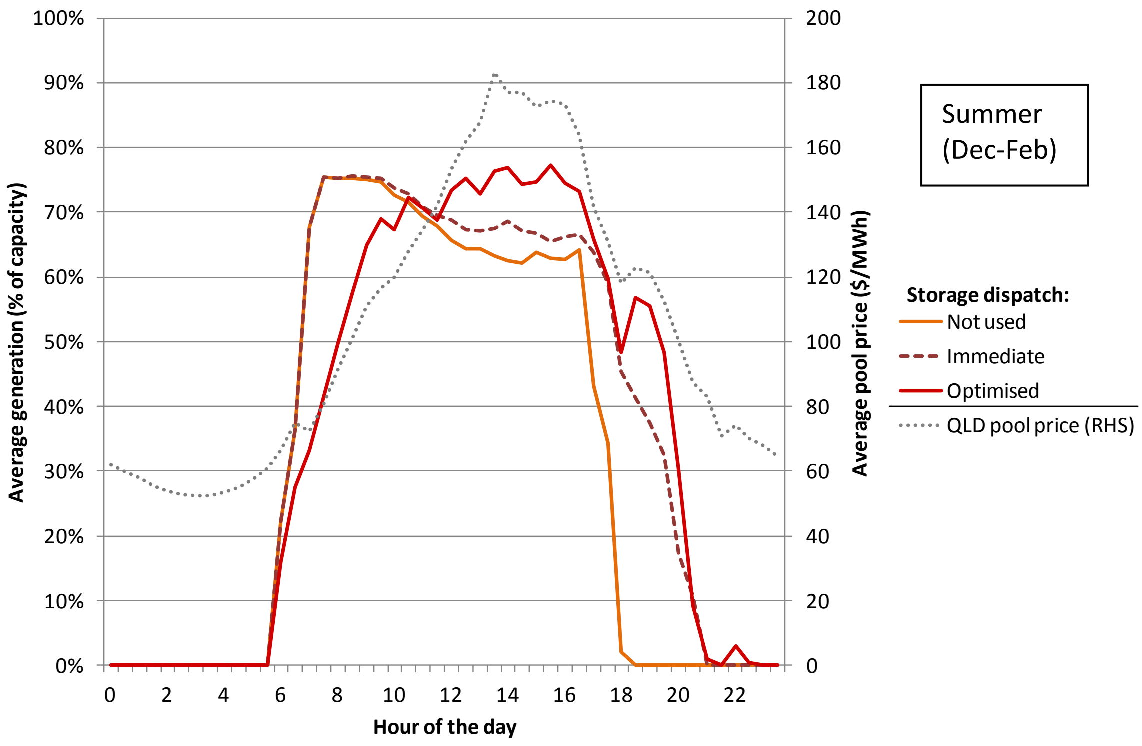
Figure 7.4 – Example winter dispatch of CSP with storage (QLD, SM 1.3, 1 hour storage, 2019-20)



7.4.2 Three hours storage

The average time-of-day usage in summer and winter for a solar plant with moderate storage levels (3 hours, solar multiple 1.6) is shown in Figure 7.5 and Figure 7.7. With this level of storage, significantly different behavior is observed during winter and summer months. These sample charts are shown for Queensland plant in 2019-20, but results were consistent across regions and years/penetration of renewables.

Figure 7.5 – Average summer time-of-day solar dispatch with storage (QLD, SM 1.6, 3 hours storage, 2019-20)

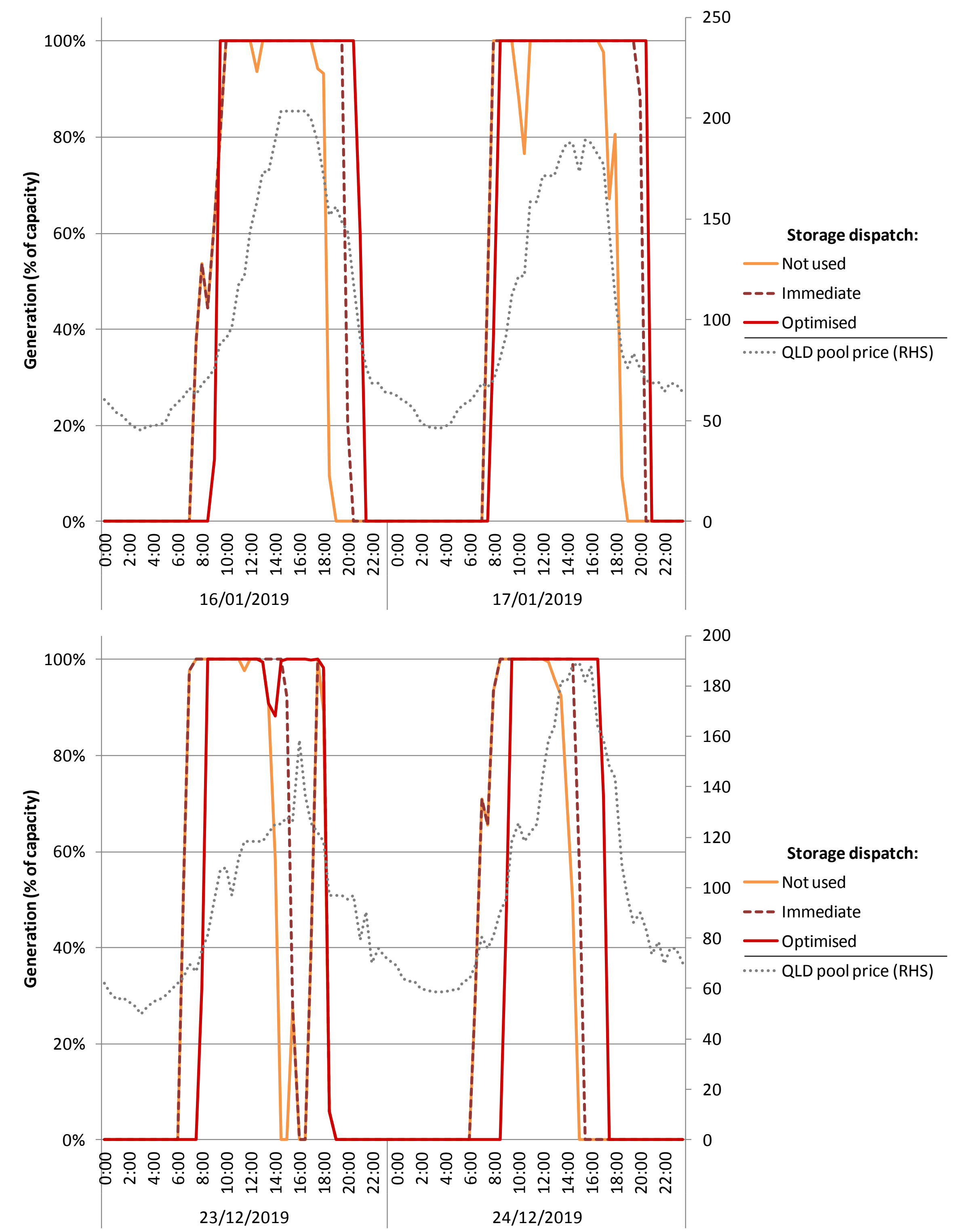


On sunny summer days, sufficient energy is available to allow for storage to be utilized to meet the evening peak while still generating during the high priced periods during the middle of the day. This is true even with no strategic energy storage procedures. However, ROAM's storage optimisation algorithm regularly delays the morning start time by 1-2 hours. This energy is put into storage in order to maximise generation opportunities in the higher priced afternoon and evening periods.

Four sample summer days are shown in Figure 7.6. The first two days show the strategy of sacrificing a small amount of morning generation in order to extend evening generation until past 8:30-9:00pm. Even without optimisation, storage significantly increases the plant operating hours. The next two days show how strategic use of storage can be used to firm up afternoon capacity to ensure that generation is available during the peak prices periods. This increased reliability is likely to appeal to retailers seeking to hedge against high price events.

Given the consistent nature of the summer afternoon peak, the strategy of storing energy in the mornings for 30-120 minutes is likely to be a straightforward revenue optimisation that could be employed with relatively little risk (provided that appropriate planning is done to ensure that no energy is wasted on the sunniest days).

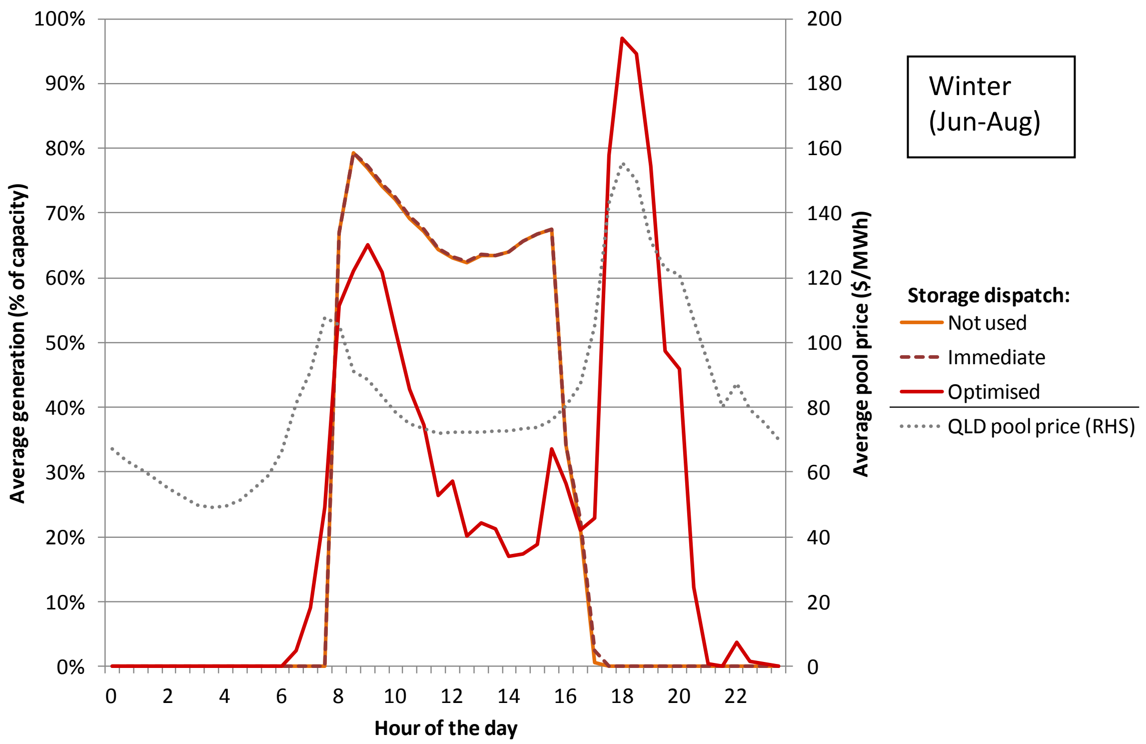
Figure 7.6 – Example summer dispatch of CSP with storage (QLD, SM 1.6, 3 hours storage, 2019-20)



The Queensland pool price in winter typically peaks in the evening between 6pm and 7pm, with a smaller morning peak around 8am (Figure 7.7). Both of these peaks are outside the typical operating range of the CSP plant. In winter, the solar multiple of 1.6 is sufficient to produce peak plant output but not to store significant amounts of energy in the storage system. As such, there is limited benefit from attaching storage if no strategic plant operation is used. However, additional revenue opportunities are available by foregoing generation during lower priced periods and storing energy to meet both morning and evening peaks.

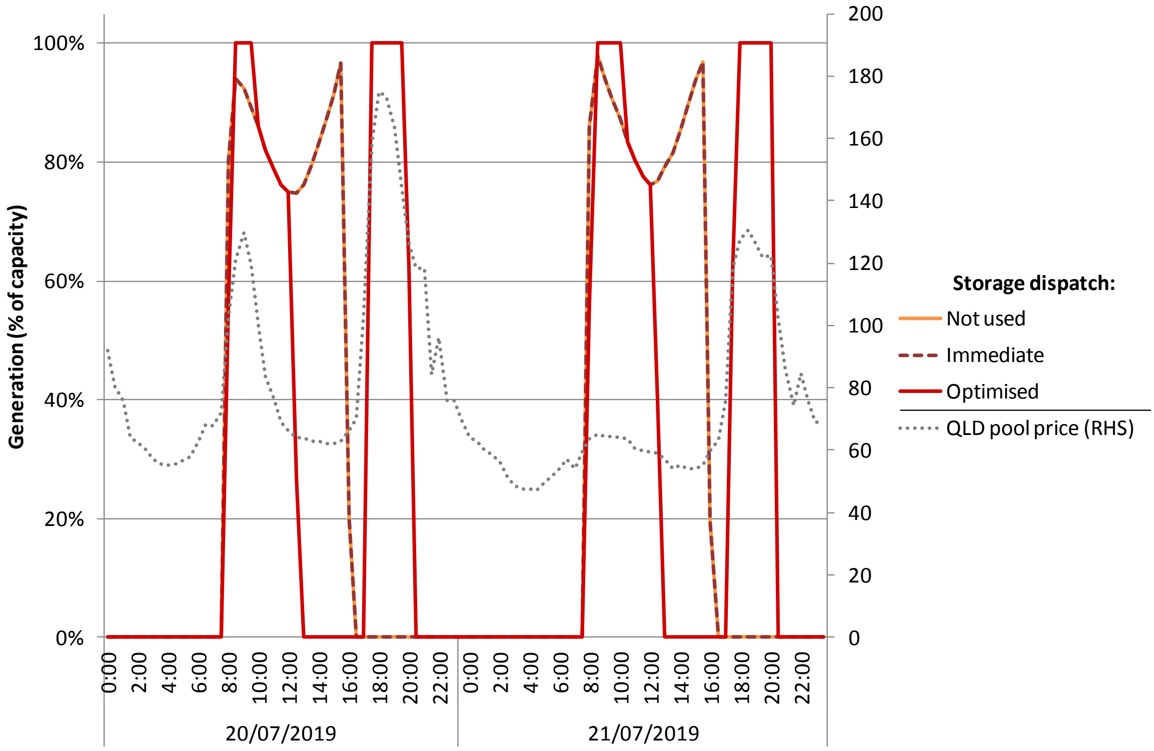
Figure 7.7 shows that the optimal storage during winter months involves curtailing the afternoon solar generation by approximately 50% and instead dispatching this energy during the 7pm evening peak. Again, the consistently bimodal winter price peaks should allow plant operators to adopt a strategy of reducing plant output during the early afternoon with low risk of wasting energy or losing revenue.

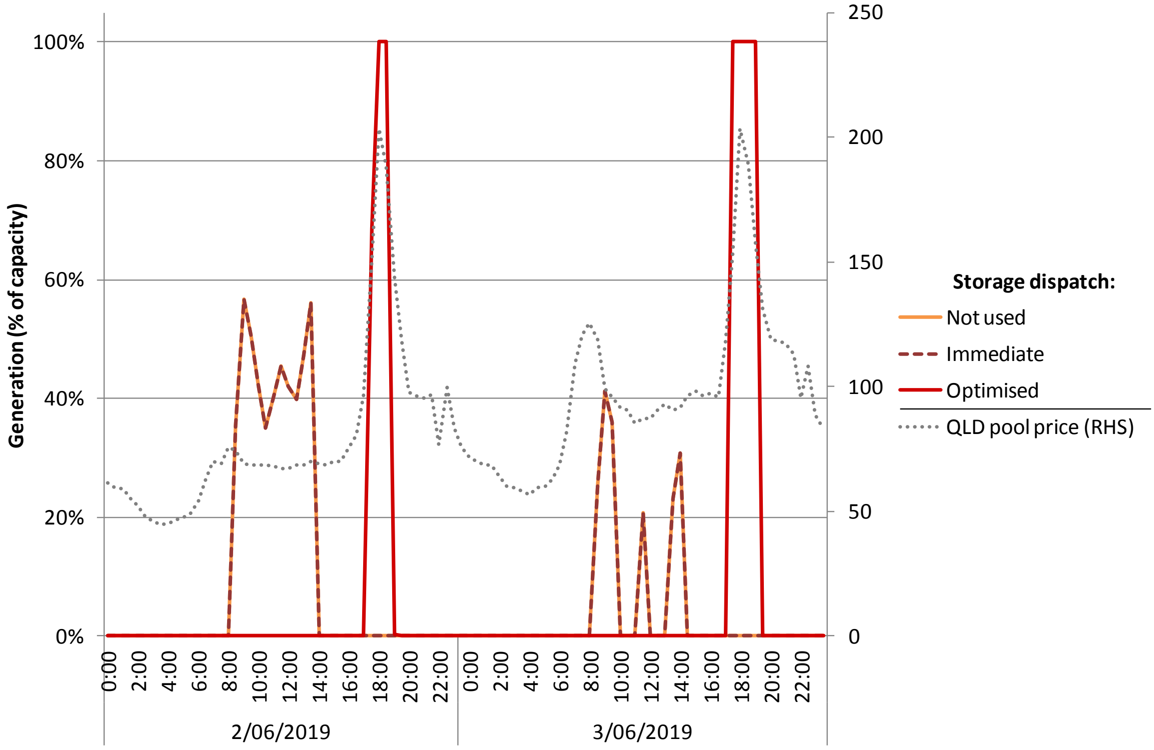
Figure 7.7 – Average winter time-of-day solar dispatch with storage (QLD, SM 1.6, 3 hours storage, 2019-20)



Four typical winter days are shown in Figure 7.8. On the first two days, the solar plant did not generate during the lower priced early afternoon periods, instead saving that energy for the evening peak. Morning generation was also slightly delayed (30 minutes) in order to store energy to meet the morning peak at full load. The next period shows two partially cloudy days where the solar plant operated only in the evening, saving all available thermal energy during the day. These are reasonable strategies that could be employed by a CSP plant to maximise its winter revenue and contribution to meeting peak demand.

Figure 7.8 – Example winter dispatch of CSP with storage (QLD, SM 1.6, 3 hours storage, 2019-20)





A final winter dispatch strategy observed on some days (and visible as generation between 6am and 8am during the winter period of Figure 7.7) was to store energy overnight to meet higher than average morning peak prices (before the solar plant would typically be able to operate based on available resource). In practice, this may be a difficult strategy to implement due to the need to sacrifice generation on the previous day in anticipation of an uncertain price spike on the following morning. However, with a strong demand and price forecasting system there may be situations where such a strategy can be justified.

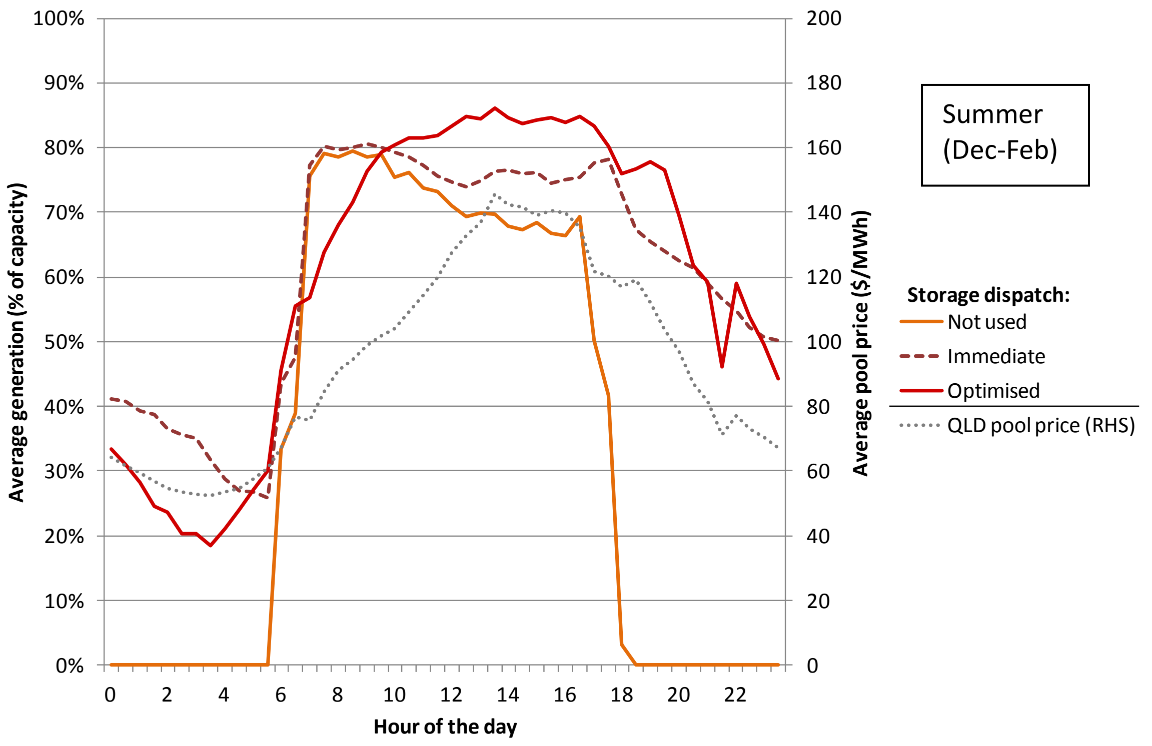
With this combination of solar multiple and storage, the solar plant was available (and generating at close to maximum output) during approximately 80-85% of the 5% highest price periods modelled in 2019-20 in Queensland. This reliability is comparable to that of some thermal generators and suggests that, with storage, solar plant could be treated as close to firm capacity.

7.4.3 16 hours storage

With higher levels of storage, and a correspondingly higher solar multiple, solar generation can closely match the daily price curve and maximise revenue, even with no strategic storage dispatch (Figure 7.9). Slightly higher revenues can again be obtained by foregoing some of the mid-morning generation and maximising output during the afternoon and evening peaks. Some energy can also be stored overnight and used to extend plant operation earlier in the morning.

24 hour generation is possible, provided that sufficient insolation is received on the preceding day. However, 24 hour generation occurs less frequently with the optimised storage dispatch. This is because there is little value to the solar plant (or market) in dispatching during the midnight to 5am period (when prices are low). Instead, unless the next day *also* has high insolation, the energy is stored to further supplement daytime output.

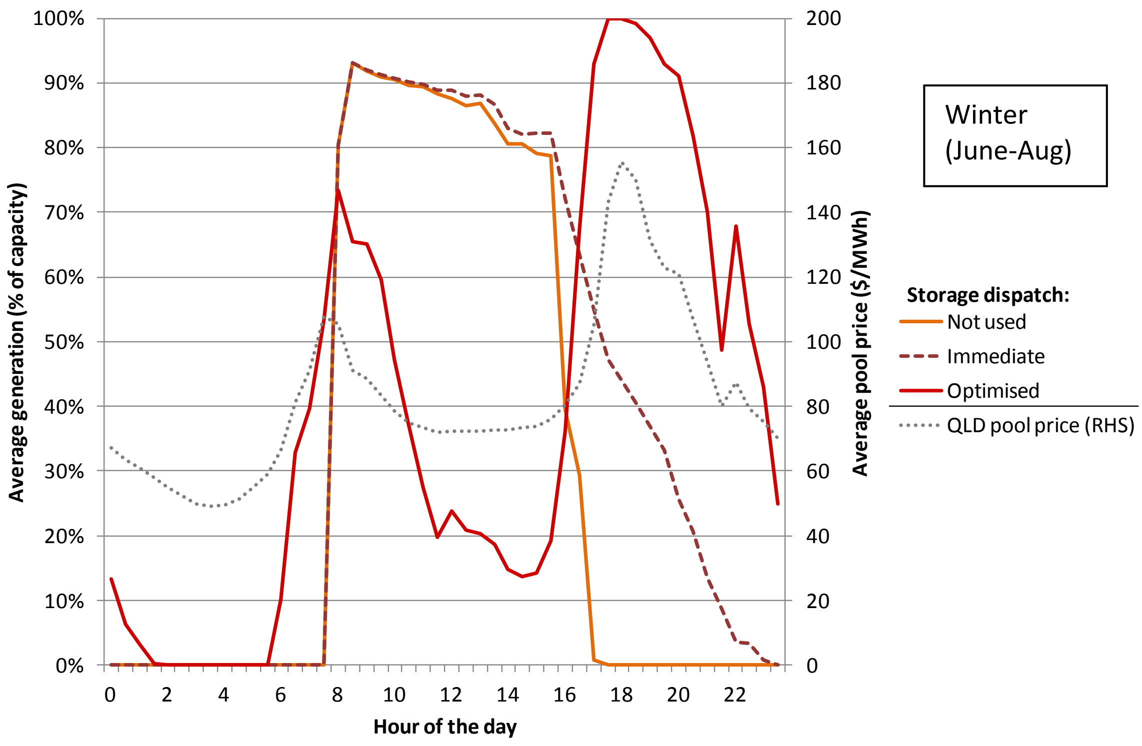
Figure 7.9 – Average summer time-of-day solar dispatch with storage (QLD, SM 2.6, 16 hours storage, 2019-20)



The winter average time-of-day generation is shown in Figure 7.10. With the higher solar multiple, moderate levels of storage are now available and the generally fine winter weather in Queensland results in the solar plant performing at high levels during winter. This is likely to be valuable as the penetration of solar power increases by ensuring that winter demand can be met as well as summer.

Despite the strong daytime performance, the storage can be used to shift daytime generation to meet the evening peak. The greater storage capacity means that *more* of the daytime generation is shifted (as compared to the 3 hour storage scenario) to ensure maximum possible generation during evening peaks. In ROAM's simulations, the solar resource was sufficient to ensure 100% reliability during the 5:30-6:30pm peak periods when the storage was dispatched optimally; in practice, imperfect knowledge would result in lower contributions to peak.

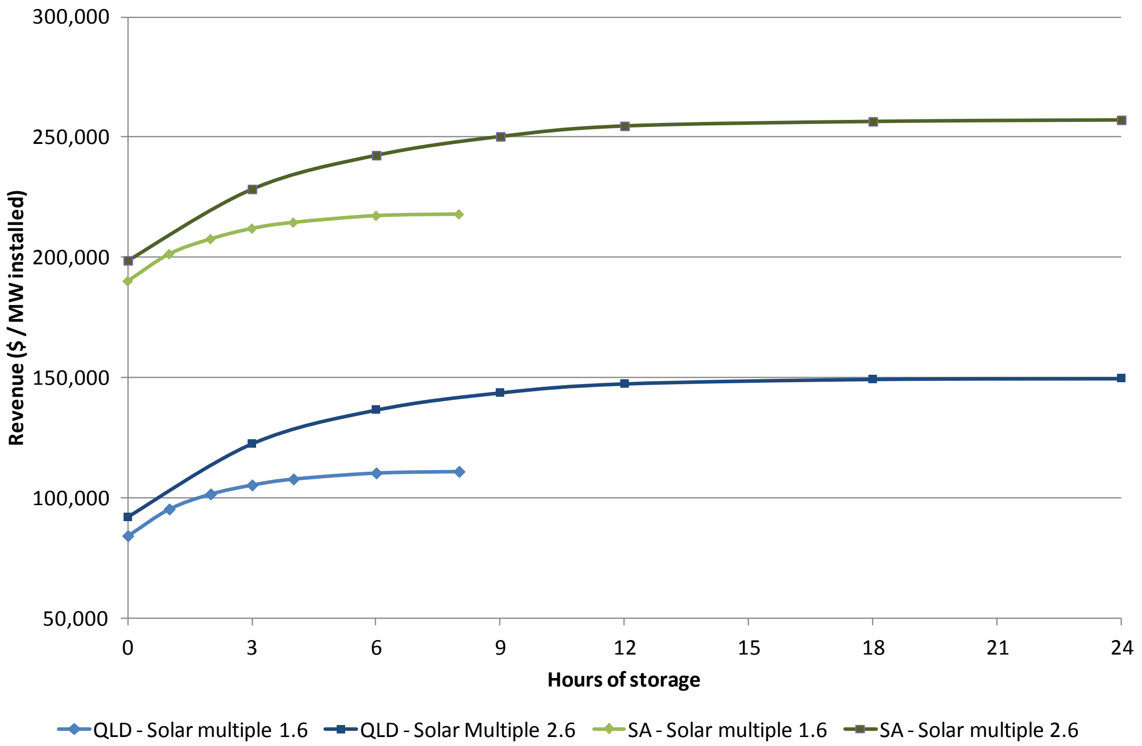
Figure 7.10 – Average winter time-of-day solar dispatch with storage (QLD, SM 2.6, 16 hours storage, 2019-20)



7.5 Optimisation of Storage Size

ROAM also conducted additional simulations for the 2009-10 reference year to determine the value of different storage sizes for solar plant with solar multiples of 1.6 and 2.6 (Figure 7.11). With a solar multiple of 1.6, the maximum possible revenue is obtained with approximately six hours storage; with the three hours of storage used in ROAM's base case simulations, approximately 95% of the maximum possible revenue would have been obtained. With a higher solar multiple, 12-18 hours maximises the available revenue.

Figure 7.11 – Revenues for different storage sizes (2009-10, optimised storage dispatch)



8. Value of Gas Hybridisation

Hybridisation of CSP plant has been proposed as a mechanism for increasing the viability of solar projects, through firming up solar capacity (potentially appealing to PPA counterparties) and dual usage of installed infrastructure (such as turbines and transmission).

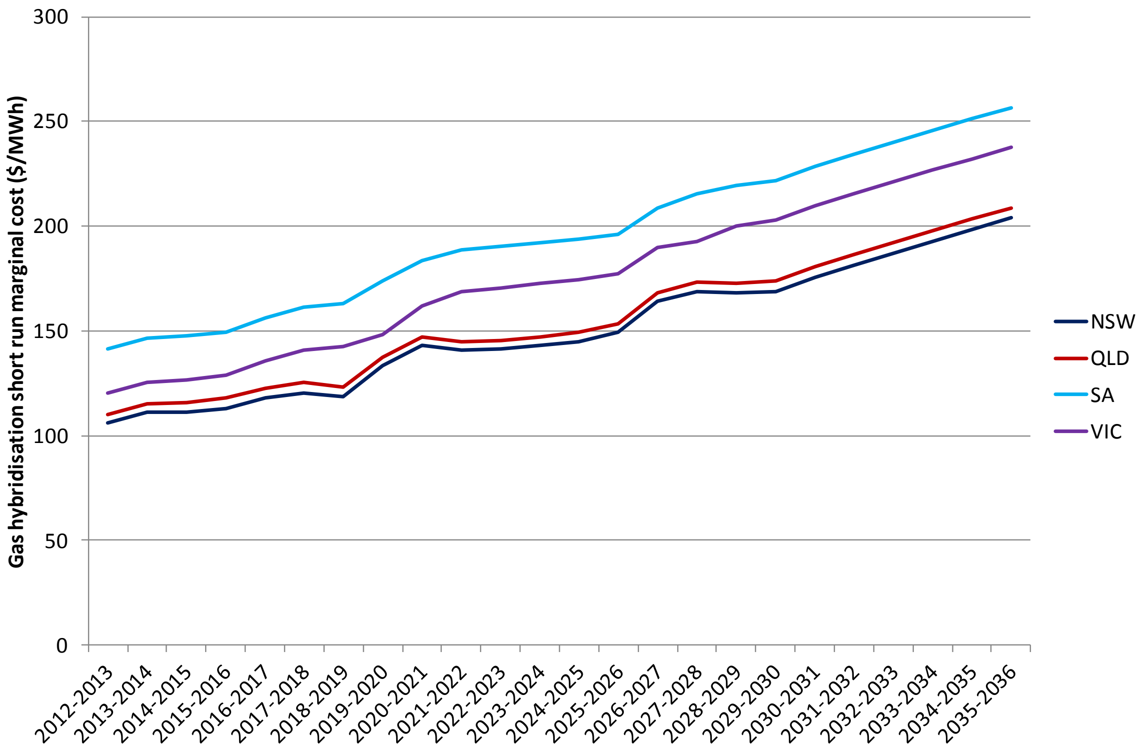
8.1 Methodology

Each CSP power station was modelled with a complementary gas backup system. The gas backup system was bid into the market at its short-run marginal cost (SRMC), assuming:

- Gas prices as shown in Figure C.6 (NTNDP Scenario 3) increased by 25% to reflect the premium typically assumed for low usage gas plant.
- A heat rate of 12GJ/MWh, capturing that power generation through steam turbines is likely to be slightly less efficient than from a new entrant OCGT.
- A variable O&M cost of $2.68/MWh, equivalent to a new entrant OCGT.
- Start-up times are less than 30 minutes (such that gas backup is available to meet sudden price spikes), including periods where plant has not been recently operating (on either gas or solar). Alternatively, price forecasting systems are usually sufficient to ensure appropriate preparations are made in anticipation of high price periods (e.g., burning gas to keep the boilers warm leading up to expected high price periods).
- Plant output was assumed to be lower when operating the gas boilers, at 95% of its maximum output under solar.

The resulting SRMCs for each region are shown in Figure 8.1. This bidding model ensures that the gas hybridisation plant will operate in any period where it is profitable, supplementing any available solar generation at that time up to the rating of the CSP power station. In practice, there may be operational limitations that would prevent the optimal operation of the gas plant, such as longer cold start times or gas pipeline limitations. Additional costs associated with either maintaining the gas boilers in a warm state or starting up the boilers are not considered in this analysis.

Figure 8.1 –Short-run marginal costs for gas hybridisation ($/MWh)

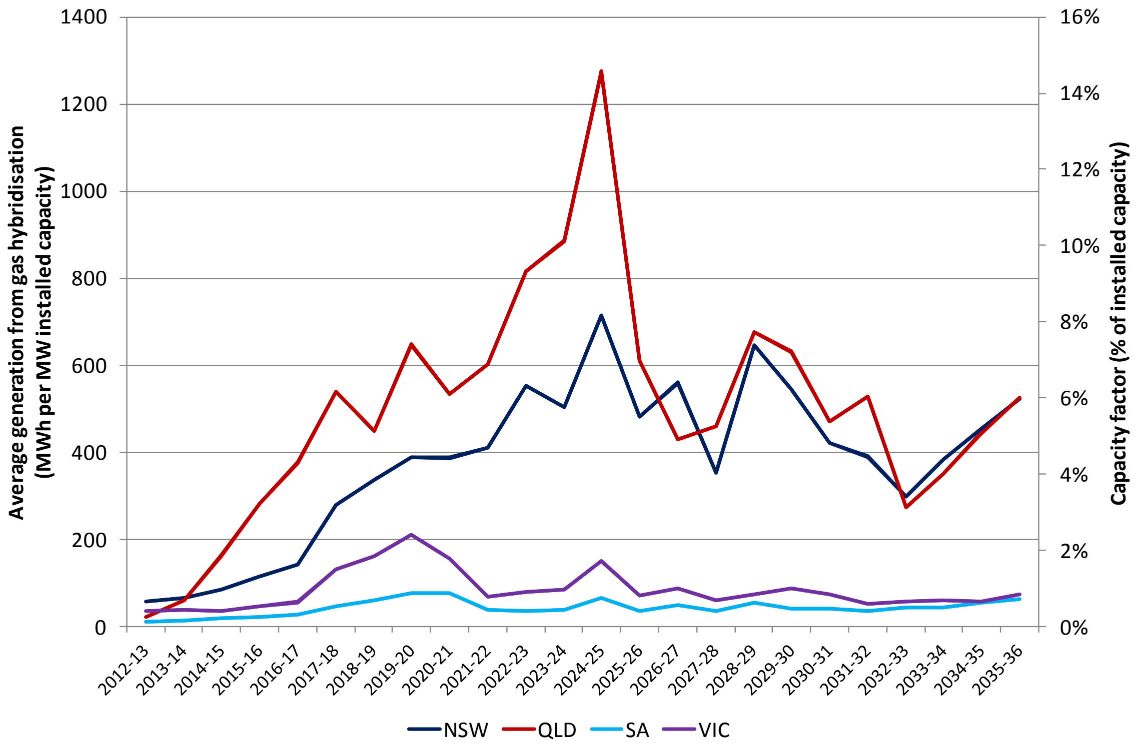


Only small capacity solar stations were installed for these simulations so that impacts on price (the merit order effect) were kept to a minimum; larger installations of solar plant (with or without gas hybridisation) would depress daytime prices and likely reduce the value of gas hybridisation (the merit order effect is discussed in Section 6). Fixed capital costs of the gas components were not estimated for this study, but conclusions on the viability of gas hybridisation can be made from the increase in net revenues.

8.2 Results

Figure 8.2 shows the generation from the gas hybridisation plant attached to each CSP unit. In all regions, modelled gas usage is low in the near-term but increases over time. Significant variation in usage between years was observed, driven by changes in the supply demand balance and specific outage patterns, as is typical for peaking plant that operate only during high price periods.

Figure 8.2 – Generation from gas hybridisation (MWh per MW installed capacity)



The Queensland solar plant showed the highest gas usage driven by several factors, including:

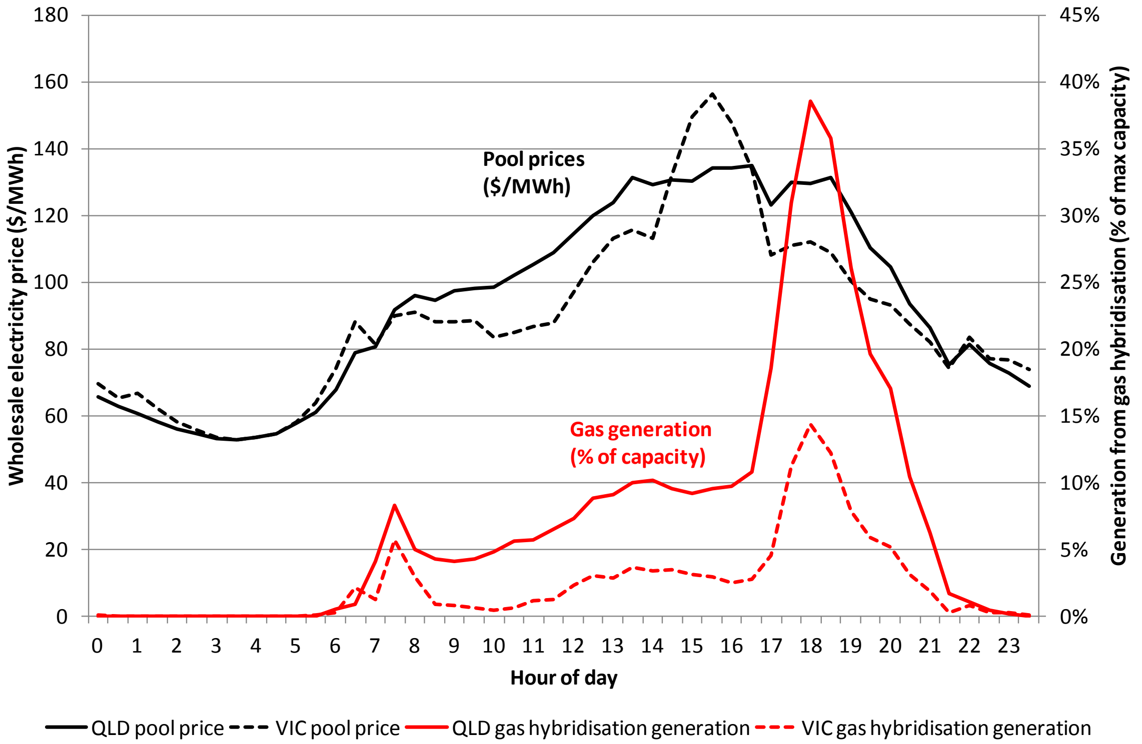
- Lower gas prices than South Australia or Victoria;
- High Queensland pool prices, and more very high price periods than New South Wales; and
- Slightly poorer CSP performance during the very high price periods, leaving more opportunity for firm capacity from gas hybridisation to increase revenue.

The peak in gas usage in 2024-25 in Queensland is a result of particularly volatile prices in Queensland that year. The reduced usage in the years that follow is due to new plant entering to relax the supply demand balance (hence reducing pool prices and volatility) and an increase in the Queensland gas prices (reducing the available operating periods).

In South Australia, high gas prices contributed to a low utilisation of the hybridisation plants, but the lower South Australian pool prices (and, in particular, the reduced frequency of high price periods) also resulted in fewer periods where the pool price exceeded the gas plant SRMC.

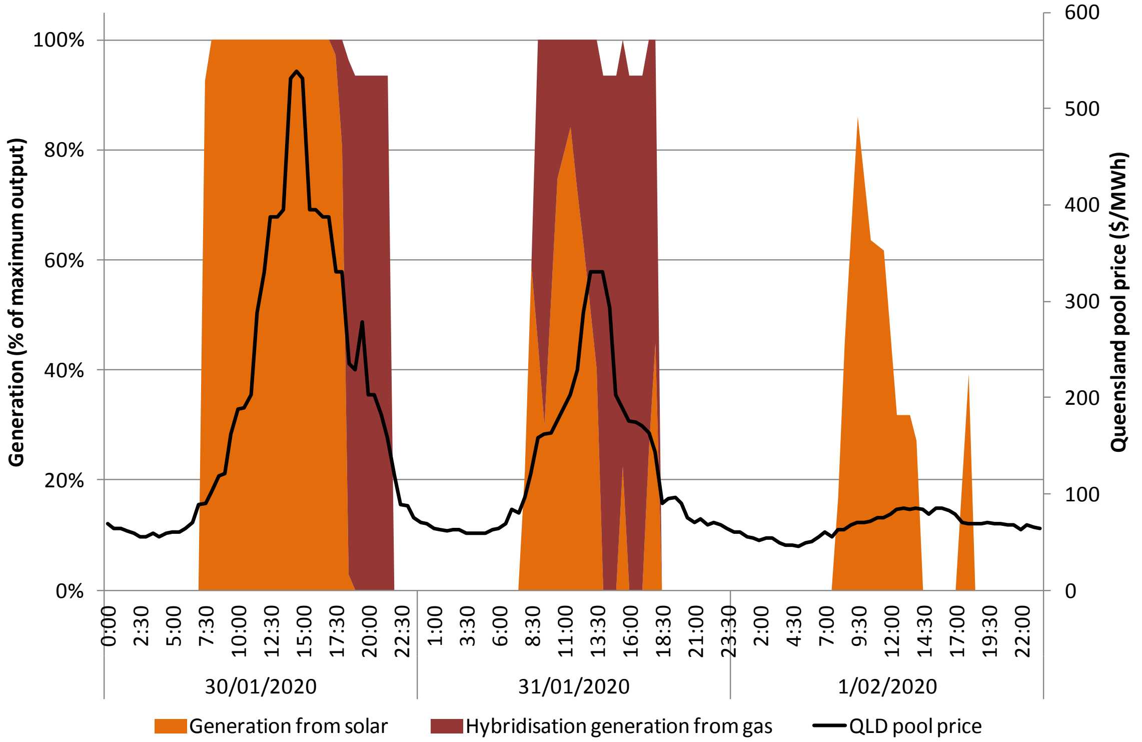
Gas hybridisation is most predominantly used to increase generation during the evening and, to a less extent, morning peaks when solar output may be low but prices are high. Figure 8.3 shows an example of the average time-of-day pool price and gas usage for the Victoria and Queensland in 2019-20. Similar qualitative trends are observed across all regions.

Figure 8.3 – Average time-of-day generation from gas hybridisation (QLD and VIC, 2019-20)



Three days of operation for one Monte Carlo iteration in Queensland in 2019-20 is shown in Figure 8.4. Each day highlights a different mode of operation – extending solar generation to cover the evening peak (30/01/2020), supplementing solar output on a partially cloudy day (31/01/2020) and a day when the pool price was not sufficient to justify using the gas boilers to supplement the solar generation.

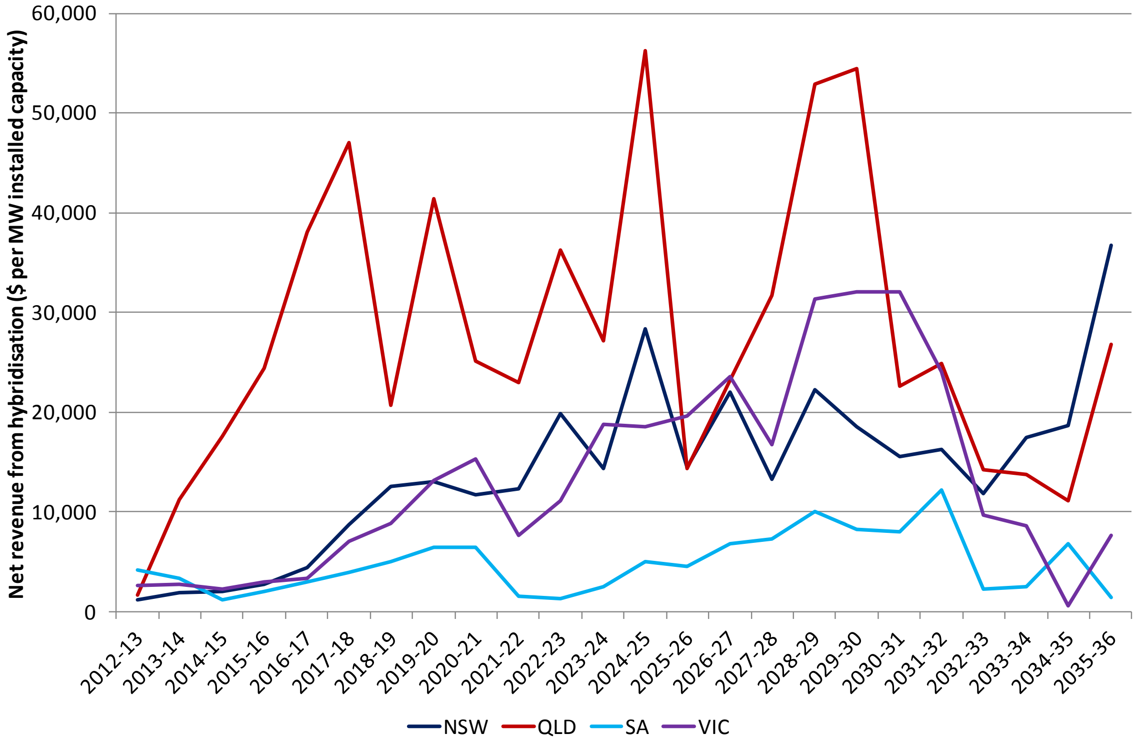
Figure 8.4 – Time series operation of gas hybridisation in Queensland



8.3 VALUE OF GAS HYBRIDISATION

Figure 8.5 shows the revenue from the gas hybridisation generation in each region net of the short-run marginal costs of operating the gas (i.e., after subtracting off the fuel costs, carbon costs and variable operation and maintenance costs).

Figure 8.5 – Net revenue from gas hybridisation (GWh per MW installed capacity)



The Victorian solar plant receives comparable revenue to New South Wales despite having significantly lower utilisation. This is due to the different price duration curves observed in Victoria; compared to New South Wales, Victoria experiences fewer but more extreme high price periods. Queensland's higher gas utilisation combined with higher prices and lower gas costs leads to (generally) higher value for its gas hybridisation. South Australia's low generation is responsible for its relatively low revenue.

The increase in revenue for the solar plant due to gas hybridisation, relative to solar plant operation with no storage, is shown in Figure 8.6. After the costs of carbon permits, fuel and variable operating and maintenance costs are subtracted, hybridisation only contributes an additional 1-8% of revenue in each year to the CSP plant, except in Queensland where its contribution was up to 15%. The average performance of the solar plant (in both average and net present value (NPV) terms) is given in Table 8.1.

Figure 8.6 – Increase in total revenue of solar plant due to gas hybridisation (including sales of electricity and LGCs)

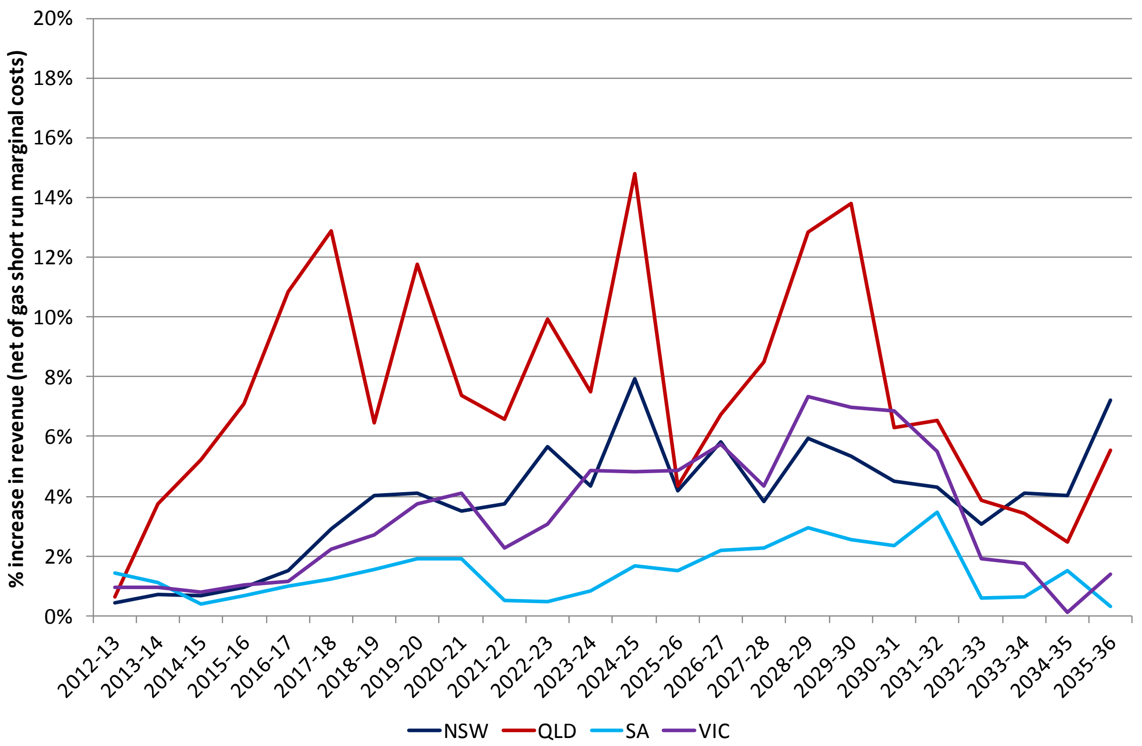


Table 8.1 – Value of gas hybridisation (2014-15 to 2028-29)

Excludes fixed costs and capital repayments; values are net of short run costs (fuel, VOM, carbon)

	Average annual net revenue ($/kW/year)	NPV of gas revenue ($/kW)	Increase in total plant NPV due to gas
NSW	13	89	4%
QLD	32	250	11%
SA	4	32	2%
VIC	13	88	4%

These revenues do not take into consideration the capital repayments for the actual gas boilers, gas pipelines and other fixed costs. Table 8.1 notes that over a 15-year lifetime, the gas hybridisation revenue has a NPV of only $30-250/kW installed.

There are significant upside and downside risks around these revenues, depending on the specific conditions observed in any given year. Various scenarios have been captured through ROAM's modelling of multiple Monte Carlo iterations. Increases or decreases in revenue would be driven by:

- The frequency of moderately high price periods (above the hybridisation SRMC);
- The magnitude and frequency of very high price periods (above $1000/MWh); and
- The performance of the solar component during high price periods (higher solar performances translates to less need for gas hybridisation).

Based on the variability seen in ROAM's simulations, revenues could be 50% higher or lower in any given year.

More generally, higher (lower) gas prices would result in higher (lower) costs for the CSP plant, but also higher (lower) electricity prices and hence revenues. The results of this section are therefore expected to be moderately insensitive to uniform changes in the gas prices. However, favourable or unfavourable contract conditions for the solar plant could be significant.

8.4 Impact on PPAs

For plant with hybridisation, the additional generation and value could theoretically be bundled with the solar generation as part of a PPA. This inclusion, however, may be problematic given that the gas generation does not earn LGCs (typically the main reason for a retailer to sign a PPA) and hence the average value of the energy in the PPA would be contingent on the (highly variable) gas generation each year. Even so, average wholesale electricity revenues only increase slightly (typically $1-10/MWh) with the inclusion of gas hybridisation, and so PPA prices are unlikely to rise significantly due to the inclusion of hybridisation on the basis of revenue alone.

However, the opportunity for firm capacity, particularly at times of peak demand, is likely to make the energy component of such a solar generator more valuable to retailers. The benefits of this are hard to quantify, but it increases the flexibility of solar generators when negotiating PPAs. One option could include involve a PPA only for their LGCs and then trading their electricity separately – either through a swap contract or the futures market.

Another option for solar plant operators is to sell the retailers the dispatch right to the gas hybridisation and all associated revenue. However, this would also involve a transfer of risk from the solar plant to the retailer and any estimated value would presumably be discounted accordingly.

8.5 Summary

ROAM modelled CSP (parabolic trough) power stations in each mainland NEM region, and considered the benefit of attaching gas hybridisation technology to each. Gas plants were bid into the market at their short-run marginal cost such that they supplemented or extended solar generation during high price periods.

Over the study period, gas plants were observed to operate at average capacity factors of between 1% (South Australia and Victoria) to 7% (Queensland and New South Wales), although in particularly volatile years gas usage could be twice as high. This type of capacity factor is consistent with typical peaking plant, such as OCGTs. However, the operation of the gas hybridisation in this model was qualitatively different because the solar component was already generating in many of the highest price periods, and the absence of any strategic bidding resulted in hybridisation generation in many lower value periods that may have been ignored by higher bidding OCGTs.

The inclusion of gas hybridisation was shown to increase solar plant revenue by an average of 2-10%, depending on the region, with additional revenues net of short-run costs of between $4,500 to $32,000 per megawatt per year. In net present value terms, over a fifteen year period, this corresponds to between $32/kW (South Australia) and $250/kW (Queensland) installed, which would be required to cover all fixed costs (including construction and annual maintenance). Although ROAM has not attempted to estimate the capital costs of including gas hybridisation, the lower end of these revenues are unlikely to be sufficient to justify the inclusion of gas hybridisation in CSP plant.

9. Future Solar Market Share

It is important to understand the possible role that solar technologies might take in the Australian energy market over the long term, given projected costs and operational modes of solar technologies, and available competing technologies. If solar technologies are at the margin of viability, solar support mechanisms may be able to produce a dramatic increase in the market share occupied by solar technologies in the future. However, if all reasonable estimates of future solar technology costs put them far beyond market competitiveness, government intervention is unlikely to significantly increase the market penetration of solar technologies. The modelling in this section aims to explore where solar technologies lie on this spectrum.

9.1 Modelling Data Set

A significant amount of data is required to conduct long-term modelling studies. For each possible technology, in each possible location, all applicable costs (capital, fuel, operations and maintenance, fixed etc) must be defined, in addition to emissions factors, operational behaviour and other relevant parameters. Projections of peak demand and energy consumption are also required, as well as external parameters such as the carbon price trajectory over time.

A variety of long-term modelling studies have been completed for the electricity sector in recent times. A significant body of work was completed to underpin the development of the Clean Energy Future legislation, and the preceding Carbon Pollution Reduction Scheme. The Australian Energy Market Operator (AEMO) also conducts annual long-term planning studies to develop and update the National Transmission Network Development Plan (NTNDP). Comprehensive peer-reviewed data sets have been developed for each of these studies, and many are publicly available. For example, five scenarios were developed and modelled as part of the Energy White Paper process and 2010 National Transmission Network Development Plan (NTNDP). Input assumptions to these studies were developed by KPMG, AEMO and ACIL Tasman, informed by earlier EPRI studies and feedback from an industry stakeholder reference group.

In early 2011, AEMO released updated scenario descriptions and technology assumptions for the five scenarios, to be used in the 2011 NTNDP. The updated technology assumptions were prepared by WorleyParsons and Intelligent Energy Systems (IES). AEMO commissioned WorleyParsons to conduct a review of the generation technology costs, while IES was engaged to review and update the fuel cost assumptions. A distinct set of cost estimates was prepared for each scenario, with differences between scenarios and the 2010 NTNDP assumptions determined by changes in assumed exchange and economic growth rates and increased learning on emerging technologies over the past year[39]. AEMO prepared demand and energy forecasts for each region in each scenario.

For this study, ROAM has used the 2011 NTNDP Scenario A as a "base" scenario, and conducted a sensitivity with different solar capital costs for comparison. The 2011 AEMO NTNDP consultation paper[40] provides a detailed description of this scenario. In summary, the key drivers are:

- High demand and energy growth;
- A very high carbon price, aiming for a 25% reduction in carbon emissions below 2000 levels by 2020 and a 90% reduction by 2050 (based on the Garnaut-25% trajectory); and
- Relatively high gas prices. Moomba hub gas prices start at \$5.68-\$5.77/GJ[41] (exact price dependent on domestic demand) and reach \$10.70/GJ by 2031 and \$12.00/GJ by 2051. Beyond 2016, prices are insensitive to domestic gas demand; instead, they are set by the international export price.

9.2 *Modelling of Intermittency*

Long-term economic models of this nature necessarily involve extensive simplifications to allow simulations to complete within a reasonable timeframe. The model employed for this study is not time sequential, but rather models the system in a discrete number of "load blocks", each having a demand level and a frequency of occurrence calculated to capture the demand duration curve. Each load block represents the average operation of the system at a particular demand level, with results from the simulations being weighted by the frequency of occurrence. Demand diversity between regions is also taken into account in the determination of load blocks.

The use of load blocks provides an excellent approximation of electricity systems with conventional technologies, and dramatically reduces simulation times, allowing longer studies that consider a wider range of technology alternatives. However, modelling of intermittent renewable technologies is challenging in non time sequential models. In many studies intermittency is ignored entirely, assuming as a first approximation that renewable technologies contribute at their average capacity factor in all load blocks. This does not provide a realistic representation of the operation of these technologies. Instead, ROAM has employed the following methodology for application in the long-term planning model (LTIRP) used for the analysis in this section of the report:

- **Wind** - The generation duration curve for each wind farm zone was calculated, divided into pieces and distributed randomly over the load blocks. This assumes that wind generation in Australia has no correlation with demand, which is consistent with analysis

[39] The WorleyParsons and IES data and reports, along with the AEMO Consultation Paper and attachments are publicly available at http://www.aemo.com.au/planning/ntndp2011consult.html

[40] AEMO, *National Transmission Network Development Plan – Consultation Paper 2011*, 31 January 2011, available from http://www.aemo.com.au/planning/ntndp2011consult.html

[41] Prices are in real January 2011 Australian dollars.

by ROAM and others[42]. This approach mimics the behaviour of wind operating at maximum capacity in a small number of periods, at zero in a range of periods, and at each level in between for a proportion of periods as observed in real wind data. The contribution of wind in the rare highest peak periods was forced to zero to ensure that the model had appropriate drivers to install sufficient alternative capacity to meet annual peak demands.

- **Concentrating solar power** - Solar thermal plant were considered to contribute consistently during high demand periods, and zero during low demand periods. The generation duration curve of solar thermal stations (modelled as central receiver technologies with 6hrs of storage) was divided into pieces and aligned with the load blocks such that the highest capacity factors were associated with the highest regional demands. Some minor adjustments to the ordering were made to ensure that the overall capacity factor of the original solar trace was maintained through this process.
- **Solar photovoltaics** - Similarly to wind, solar PV was modelled via its generation duration curve, distributed randomly across the load blocks. This approximates the intermittency of solar PV, but does not capture the correlation of generation with demand. ROAM is working at present to develop more sophisticated methodologies for accurately representing intermittent technologies that exhibit a correlation with demand, for use in future studies.

Figure 9.1 illustrates the load blocks used in this study for the year 2011. Figure 9.2 illustrates an example of the solar blocks used in this study, for Queensland in 2011 (with load blocks ordered by total NEM demand, as illustrated in Figure 9.1). The randomisation process is applied to each year and each site separately.

[42] N. Cutler, N. Boerema, I. MacGill and H. Outhred, "High penetration wind generation impacts on spot prices in the Australian national electricity market", Energy Policy 39 (2011) 5939-5949.

Figure 9.1 – Load blocks for the NEM in 2011

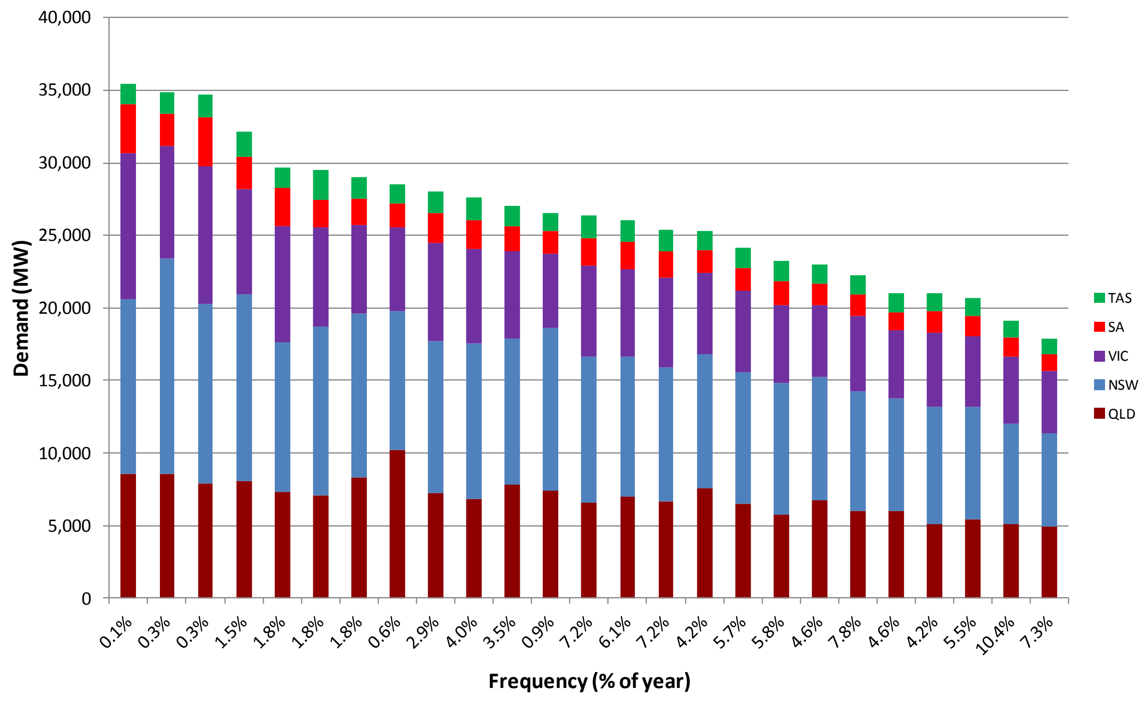
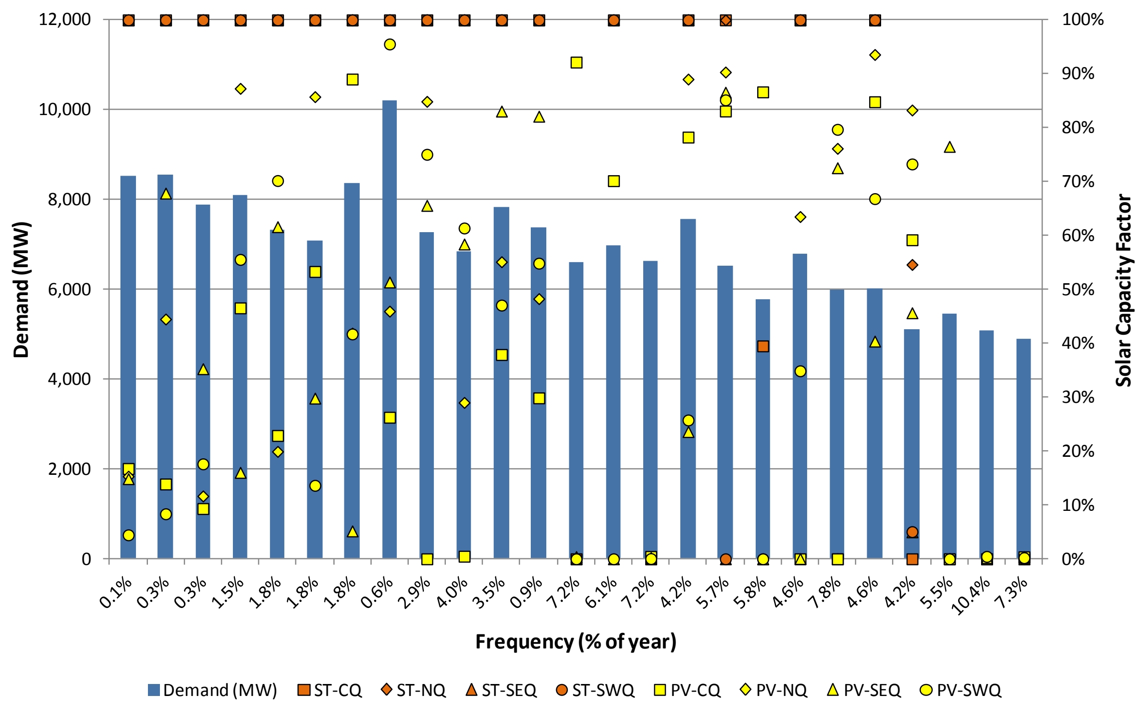


Figure 9.2 – Solar blocks for Queensland in 2011



To determine the reliability of any outcome from this model, more detailed time-sequential studies would be required, looking at the geographic placement of solar plant, correlations in their outputs and the flexibility of the rest of the generation fleet to accommodate fluctuations in output and meet overnight demand. If additional schedulable generation (thermal or renewable) is required to ensure adequate reliability, then this will come at a cost, and possibly with additional emissions, not covered in this modelling. Conversely, the full value of solar technologies may not have been captured by this modelling, especially for solar photovoltaics, given that no correlation between solar operation and demand was assumed. ROAM is constantly working to improve these aspects of our models, ensuring that we continue to lead the state of the art.

9.3 Results

Figure 9.3 shows the projected generation in the NEM over the study period by technology type, for the base case (Scenario A), and a sensitivity where solar costs are halved, which is within the range of global cost estimates.

In the base case, the existing black coal fleet largely maintains its current generation levels and capacity until 2030, when a sharp decline in generation is accompanied by a large number of retirements. By 2040, all conventional black coal plant is retired. Some existing brown coal capacity is retired in 2013-14 with the introduction of the carbon price; however, much of the existing fleet persists until 2030.

Prior to 2020, load growth in Queensland is predominantly met by new CCGT plant (without CCS). One gigawatt of CSP plant is installed in Queensland with funding under the Solar Flagship Program (equivalent to reducing the capital cost by $1,500/kW installed)[43]. New South Wales load growth is supported by imports from Queensland across an augmented Queensland-New South Wales interconnector. Nearly 1,000 MW of geothermal plant is installed in South Australia between 2017-18 and 2019-20[44], in addition to 500 MW of new wind generation. In Victoria, around 1,000 MW of wind and 350 MW of geothermal plant is installed by 2020. The Large-Scale Renewable Energy Target is met largely by geothermal generation. By 2020, only 3,000 MW of new wind farms are installed across the NEM, 1,500 MW of which are in Tasmania.

Between 2020 and 2030, nearly 10,000 MW of black coal plant with CCS is installed in Queensland, along with over 4,000 MW of CCGTs. Additional interconnection with New South Wales is built in this period to export power from Queensland (to a total export limit of 1500 MW on top of the existing capacity). Additional geothermal plant is built in South Australia and the excess power exported to Victoria along new interconnector capacity. The total available capacity of South Australian geothermal plant (4,250 MW) is installed by 2029-30.

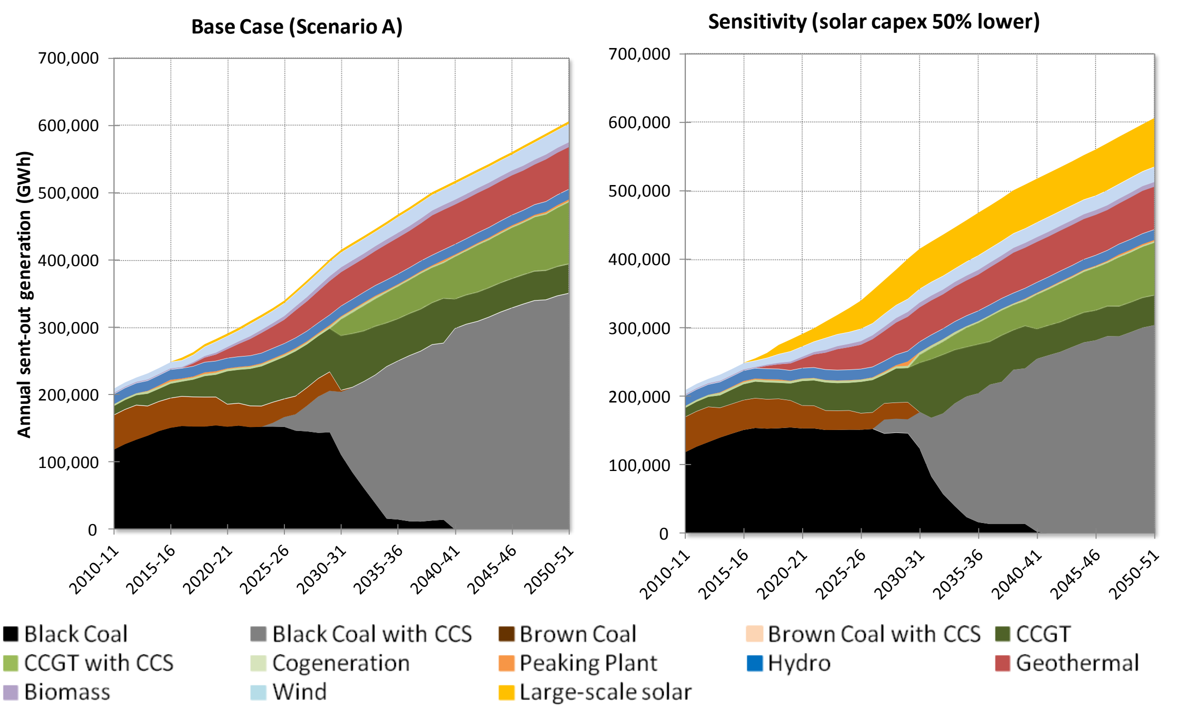
Beyond 2030, black coal plant with CCS is built in both Queensland and New South Wales to meet new load growth and replace the existing conventional coal fleet. New South Wales imports heavily from Queensland through this entire period. In Victoria, brown coal with CCS does not prove to be least cost. Instead, CCGTs and CCGT with CCS plant is built to replace the existing brown coal fleet and meet new load growth.

[43] Fulfilment of the 1,000 MW Solar Flagship Program quota was not a constraint on the model. Instead, solar technologies were subsidised and plant entered if it was least cost with the subsidy.

[44] Note that geothermal plant is assumed to be available from 2015 onwards in the Worley Parsons data.

The sensitivity with lower solar costs also shows a diversified generation mix with some CCS-enabled black coal, CCS-enabled CCGTs, geothermal, wind, existing hydro and photovoltaic and CSP plants. By 2050, more than 21,000 MW of solar capacity is installed, supplying almost 71,000 GWh pa. The installed capacity of solar grows rapidly from 2015 to 2030. The preferred solar technology by the model is highly sensitive to the underlying long-run marginal costs; with identical costs, a CSP technology with storage is preferred due to the longer operating hours. The additional solar generation replaces gas and coal-fired generation with carbon capture and storage technologies.

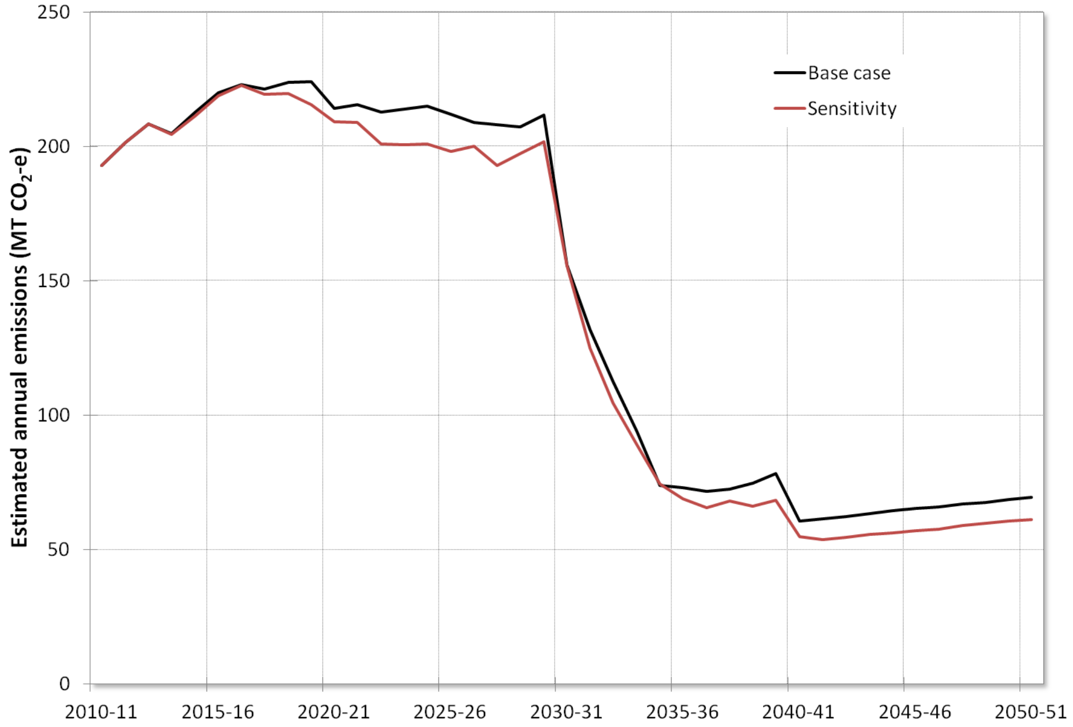
Figure 9.3 – Scenario A sensitivity (Solar capital costs 50% lower): Generation comparison



Greenhouse emissions

In the base case, significant emissions reductions from the stationary energy sector only occur once conventional coal is retired and CCS technologies are widely deployed. Figure 9.4 shows the annual emissions in the NEM for the base case, and sensitivity. From 2015-16 emissions are lower in the sensitivity than in the base case, when the rapid expansion of solar capacity begins.

Figure 9.4 – Scenario A sensitivity (Solar capital costs 50% lower): Emissions comparison



Scenario costs

Figure 9.5 shows the annual total cost of energy supply for the NEM in each scenario, broken down into components of:

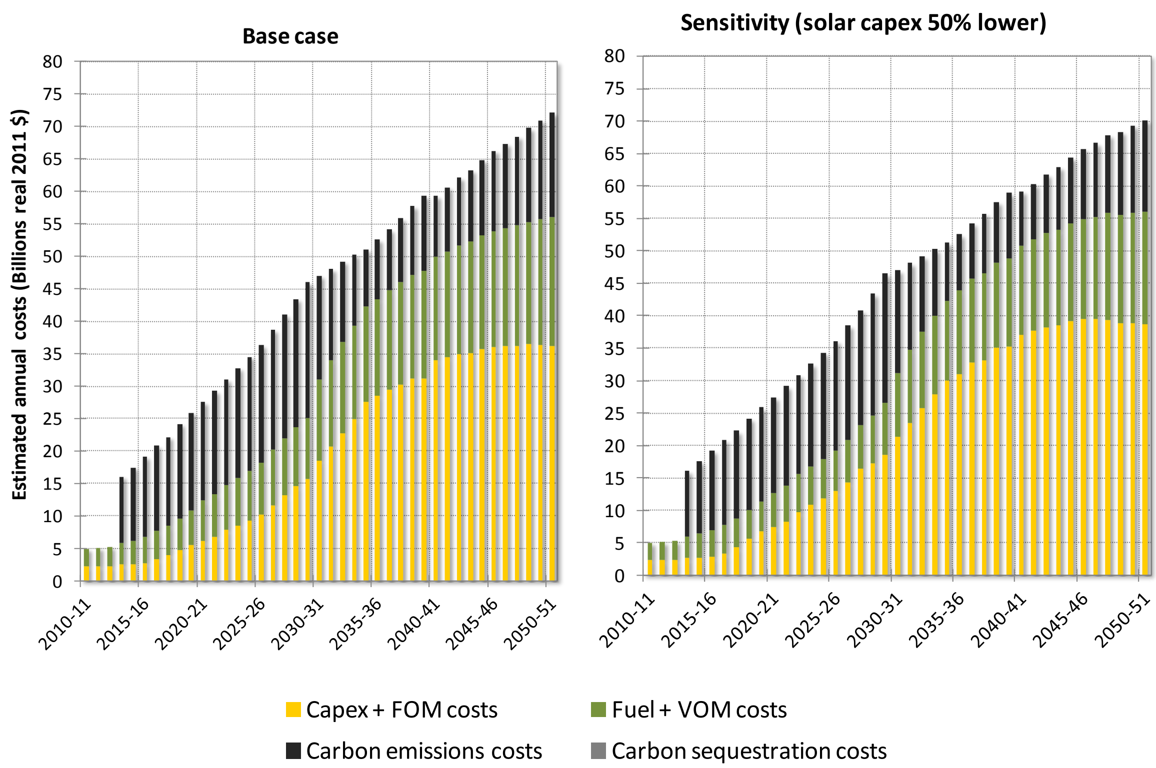
- annualised capital costs of new entrant generation and fixed operations and maintenance costs of existing and new plant (existing plant capital costs are assumed to be sunk);
- fuel and variable operations and maintenance costs;
- carbon emissions costs; and
- carbon sequestration costs.

In the base case, the carbon emissions cost component declines with increasing capacity of low emissions technology. However, this comes with significant growth in capital costs. Moreover, it is likely that the carbon sequestration costs are optimistic, since the sequestration cost in dollars per tonne does not vary over time, with injection rate or with injection volume[45].

In the sensitivity, the capital cost component makes up a larger proportion of total costs by 2050. Fuel, VOM and carbon costs are reduced compared with the base case.

[45] The assumed costs in dollars per tonne of injecting and storing carbon emissions are taken from the report, *The Costs of CO2 Transport and Injection in Australia*, CO2Tech, September 2009, prepared for the Department of Resources, Energy and Tourism Carbon Storage Taskforce.

Figure 9.5 – Scenario A sensitivity (Solar capital costs 50% lower): Total cost comparison



9.4 SUMMARY

This modelling indicates that under favourable conditions solar technologies may compete with other technologies in the absence of subsidies, over the long term. Halving the capital cost of solar technologies, and particularly storage, produces market outcomes that include substantial quantities of this generation type. This difference in solar capex is likely to be within the range of uncertainty. Therefore, initiatives to reduce the capital cost of solar technologies should be considered a high priority.

Appendix A) Reference Year Analysis

In order to model a realistic representation of demand and the generation from intermittent sources, ROAM uses an historical reference year. The demand, wind and solar patterns measured in that historical year are projected forward, capturing diurnal and seasonal patterns and the correlation between the three parameters.

Historical years differ from each other, with some having unusually high or low demand and the renewable resources are similarly variable. The distribution of each parameter around the NEM may also differ. These can lead to material differences in modelling outcomes. Ideally, all modelling studies would repeat calculations for a range of reference years, capturing the impacts of inter-annual differences. However, this multiplies the number of simulations required. Therefore, ROAM typically utilises a single reference year that is assessed to be reasonably representative of "average" behaviour across all relevant parameters. This appendix provides a summary of the analysis used for selection of an appropriate reference year.

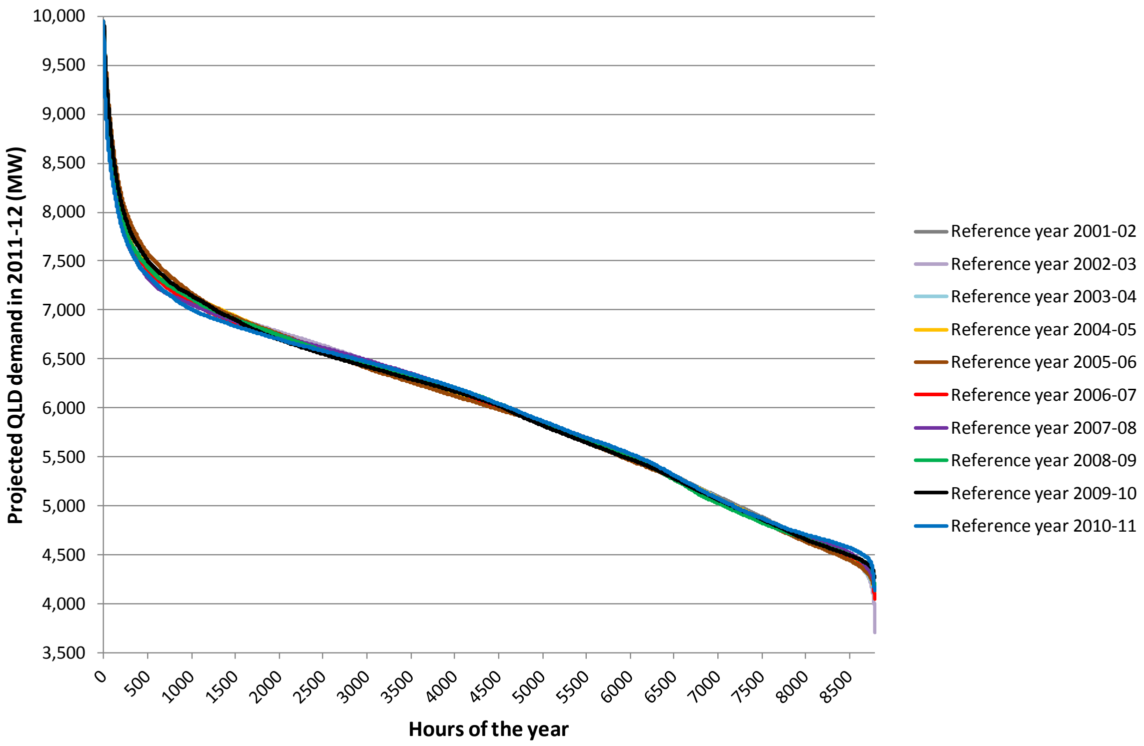
Demand

Demand is one of the most important parameters in any electricity modelling exercise, being one of the most fundamental drivers of market outcomes. In most regions of Australia, peak demands and energy consumption have been growing over time. This can make it challenging to compare historical reference years on an equal footing. Therefore, to allow comparison of historical reference years, ROAM has utilised a Load Trace Synthesizer (LTS) tool. This tool uses a selected historical reference year to produce a forecast demand trace, based upon peak demand and energy targets for the forecast year. The historical load trace is "stretched" to meet the new peak demand, and the load duration curve adjusted throughout so that the energy target (given by the area under the load duration curve) is also met. The half-hourly shape of the historical reference trace (and therefore the shape of the load duration curve) is preserved as closely as possible. The tool also adjusts the trace so that weekends and public holidays (which typically feature lower demands) are appropriately matched from the historical reference year to the forecast year.

As an example, Figure A.1 illustrates the load duration curve[46] for the forecast demand trace for Queensland in the year 2011-12, calculated based upon different historical reference years. The peak demand is consistent across all traces, since this has been normalised to the 2011-12 target values in the forecast process. Similarly, the area under each curve (equivalent to the total energy consumption in the year) is maintained. However, small differences in the shape of each curve are evident, and although they appear minor on this scale they can produce substantially different modelling outcomes.

[46] The load duration curve illustrates the demand (in MW) in each half hour of the year, sorted from highest to lowest.

Figure A.1 – Forecast load duration curve[47] for 2011-12, based upon different historical reference years (QLD)



In order to compare the shape of the load duration curve across reference years, ROAM calculated the root mean square error of each curve, for each region. This is calculated at each point in the duration curve as the square of the difference between that curve and the average across all reference years at that point. The square of the difference at each half-hourly point is then summed over the whole year. The square root of the sum then provides the root mean square error, giving a measure of how similar the shape of the curve is to the average. These were then calculated as a percentage of the average root mean square error across all reference years, to produce the numbers in Table A.1. A number of 100% indicates that the forecast duration curve in that region differs from the average curve by an average amount. A number of less than 100% means that the curve differs from the average curve by less than the average amount, and vice versa. The ideal reference year for modelling studies would have the lowest values in all regions.

Based upon this metric, 2004-05 appears to have the most "average" load duration curve. 2010-11 and 2005-06 would be poor reference years, since their duration curves deviate significantly from average in several regions. With respect to the most recent years, 2008-09 and 2009-10 appear to have appropriately small deviations from average curves, and therefore would be suitable reference years.

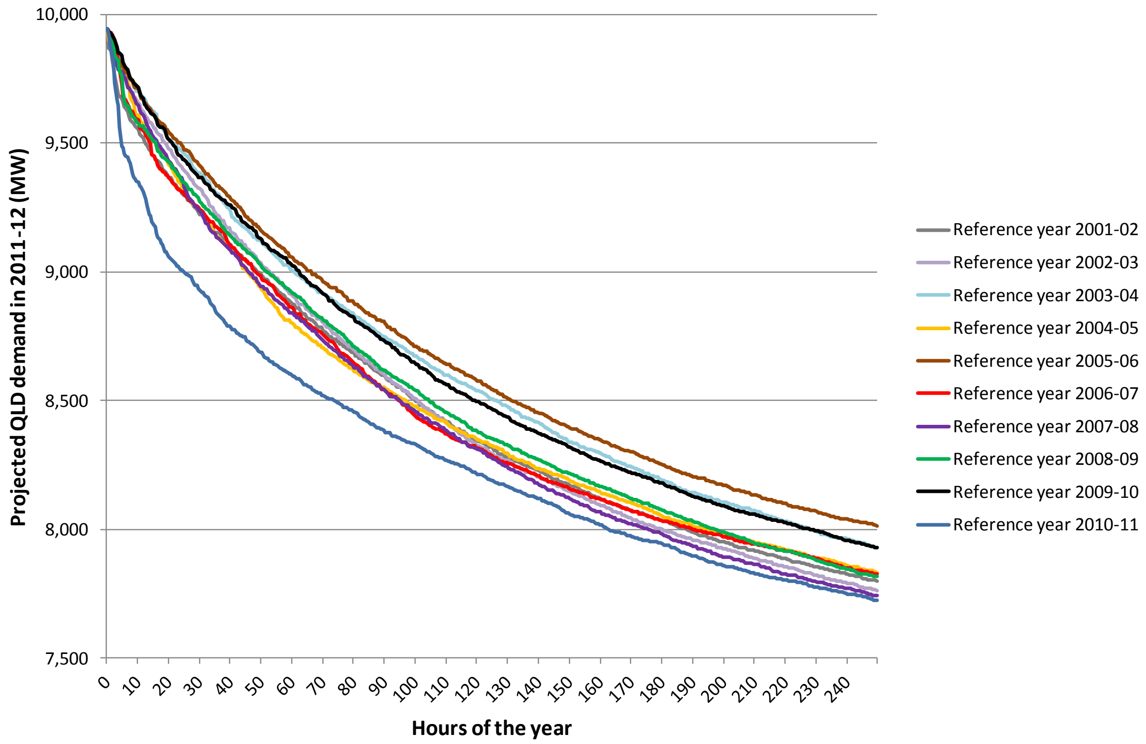
[47] The load duration curve illustrates the demand (in MW) in each half hour of the year, sorted from highest to lowest.

Table A.1 – Root mean square difference from average across annual load duration curve, by reference year

Region	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
QLD	53%	97%	85%	75%	183%	53%	106%	59%	110%	180%
NSW	80%	81%	92%	44%	91%	145%	154%	112%	68%	133%
VIC	110%	111%	96%	49%	31%	125%	59%	98%	124%	197%
SA	160%	92%	65%	36%	110%	166%	97%	56%	96%	121%
TAS					164%	96%	121%	56%	114%	49%

It is also important to analyse carefully the shape of the duration curve at the highest demand periods, since this is a significant driver of high prices and market outcomes. As an example, the duration curves for Queensland in the top 500 trading periods (250 hours) based upon each reference year are illustrated in Figure A.2. Confirming what was identified via the previous metric, it is clearly evident that 2010-11 and 2005-06 are not average representative years (for Queensland).

Figure A.2 – Forecast load duration curve for 2011-12, based upon different historical reference years (QLD)



For ease of comparison across all regions and all reference years, the area under the duration curve in the top 500 trading intervals (250 hours) was calculated. This equates to the energy (MWh) supplied in the top 250 hours. Calculating the difference in this metric from the average across all reference years (for each region) gives the values listed in Table A.2. Values close to zero indicate that the year is close to "average". From this metric, 2008-09 is identified as a suitable recent reference year (close to average in all regions). 2009-10 is high in South Australia and Victoria, but close to average in NSW and Tasmania.

Table A.2 – Percentage difference in average energy delivered in each region in highest 250 hours in 2011-12 forecast year, with different reference years

Region	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11
QLD	-0.4%	-0.3%	1.4%	-0.4%	2.0%	-0.5%	-0.8%	0.0%	1.3%	-2.3%
NSW	-0.6%	-0.8%	1.4%	0.0%	0.7%	1.5%	-1.7%	0.0%	0.1%	-0.6%
VIC	-0.9%	0.3%	-1.5%	0.4%	0.5%	3.4%	-0.5%	-0.7%	2.4%	-3.5%
SA	-5.7%	-1.3%	1.4%	-1.0%	-1.6%	4.1%	3.4%	1.8%	3.8%	-4.9%
TAS					1.6%	1.2%	-1.2%	-0.7%	-0.9%	0.1%

Based upon this analysis, considering only the demand shape, 2008-09 appears to be the best choice of reference year. However, the solar and wind also need to be considered (outlined below). Also, a further consideration is the likely change in load shape over time. In most regions of Australia, peak demands are increasingly driven by rising air-conditioner loads. As the penetration of this type of consumption increases over time, we might expect a larger percentage of energy to be delivered at high demand times. On this basis, the selection of a reference year that is higher than average on this metric could be considered reasonable. Therefore, 2009-10 could also be considered a suitable reference year for forecasts.

Solar

Since this study focuses on the role of solar technologies in the market, the selection of a representative year of solar behaviour is critical.

Solar data was obtained from the Australian Bureau of Meteorology (BOM). Hourly global horizontal irradiance (GHI) and direct normal irradiance (DNI) values for the whole of Australia at approximately the 5km resolution were provided. For each grid cell, brightness data was obtained from visible images taken by geostationary meteorological satellites and a detailed model involving surface albedo and atmospheric conditions was used to convert this to GHI. An atmospheric model was then used by the BOM to separate out the DNI and diffuse components. This data does not replace the need for ground based observations, but comparison with ground based data where available suggests that the satellite data provides a good estimate of solar resource for planning purposes. BOM calibration studies have shown the mean bias difference (average of the satellite - surface difference), calculated on an annual basis across all surface sites available to the BOM, is ±11 to ±40 W/m^2 and typically around ±20 W/m^2. This is ±4% of the mean irradiance of around 480 W/m^2.

ROAM Consulting's Solar Energy Simulation Tool (SEST) was used to calculate the generation from a 1 MW flat panel solar photovoltaic plant at a range of locations in each region. A detailed geometric model was employed to calculate the portion of the direct and global solar insolation on a 1 MW tilted photovoltaic (PV) plate. Both the direct and diffuse components were assumed to be utilised by the flat panel solar PV unit. The nameplate capacity of the cells was assumed to correspond to AC power output at Standard Testing Conditions (STC) which correspond to 1000 W/m^2 incident radiation (either beam or global as appropriate) and an operating temperature of 25°C. Solar PV cells display a generally linear response to incident radiation. However, efficiency decreases at high temperatures. A simplified model was used to estimate the cell temperature based on incident radiation and ambient temperature (obtained from BOM), and an energy derating factor of 0.44%/°C was applied.

Fixed flat plate solar PV plants were modelled at several sites in each region, as described in Section 3.5. The capacity factor of PV panels in each region in each historical year was calculated, and the average capacity factor for each location across all historical years determined. Table A.3 illustrates the difference in capacity factor in each year from the average across all years at that location. Solar capacity factors are observed to vary by up to ±1.2% (in percentage points[48]) from year to year. For ease of comparison with other technologies, Table A.4 illustrates the percentage change in energy from solar in each year from the locational average across all years. This shows that solar energy produced can vary by up to ±6%, or more in Tasmania (where the quantity of solar energy produced is relatively low).

The variation in energy produced from year to year is dampened somewhat due to the temperature derating of solar photovoltaics, reducing efficiencies at high temperatures (which have a high correlation with high solar insolation).

[48] Percentage points refers to the direct change in capacity factor. For example, a shift in capacity factor from 20% to 21.2% would be a +1.2% change in percentage points, but would correspond to a 6% increase in annual energy produced.

Table A.3 – Difference in solar capacity factor from locational average in each solar zone for each reference year (percentage points change in capacity factor)

Solar zone	Region	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
NQ	QLD	-0.2%	0.5%	-0.2%	0.1%	0.0%	-0.5%	0.0%
CQ	QLD	0.0%	0.6%	0.0%	0.2%	0.0%	-0.7%	-0.2%
SEQ	QLD	-0.1%	-0.1%	0.5%	0.4%	-0.1%	-0.4%	0.1%
SWQ	QLD	0.0%	0.3%	0.5%	0.2%	-0.5%	-0.5%	0.0%
NNSW	NSW	-0.1%	0.5%	0.4%	0.4%	-0.2%	-0.6%	-0.7%
NCEN	NSW	-0.3%	0.1%	0.4%	0.3%	0.3%	-0.2%	-0.5%
SWNSW	NSW	0.0%	0.1%	0.1%	0.1%	0.2%	0.0%	-0.4%
CAN	NSW	-1.1%	-0.7%	0.3%	0.9%	0.5%	0.0%	-0.1%
NVIC	VIC	-0.9%	-0.5%	0.1%	0.9%	0.2%	0.1%	-0.2%
LV	VIC	-1.3%	-1.1%	0.1%	1.1%	0.7%	0.4%	0.4%
MEL	VIC	-1.2%	-0.4%	0.1%	1.2%	0.4%	0.2%	0.0%
CVIC	VIC	-0.2%	-0.1%	-0.1%	0.4%	0.4%	-0.2%	-0.3%
NSA	SA	-0.2%	0.0%	0.2%	-0.1%	0.4%	0.0%	0.0%
ADE	SA	-0.7%	-0.7%	0.1%	0.6%	0.7%	0.0%	0.1%
SESA	SA	-1.1%	-0.8%	-0.1%	1.0%	0.7%	0.3%	-0.1%
TAS	TAS	-2.1%	-1.9%	0.1%	1.1%	0.9%	0.8%	0.8%
SWIS	SWIS	-0.9%	-0.8%	0.6%	0.6%	0.1%	0.2%	0.1%

Table A.4 – Percentage change in solar energy from locational average in each solar zone for each reference year

Solar zone	Region	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
NQ	QLD	-0.7%	2.2%	-0.7%	0.6%	0.2%	-1.9%	0.2%
CQ	QLD	0.1%	2.5%	0.1%	0.9%	0.1%	-2.8%	-0.8%
SEQ	QLD	-0.6%	-0.6%	2.0%	1.5%	-0.6%	-1.9%	0.2%
SWQ	QLD	0.0%	1.3%	2.1%	0.8%	-2.1%	-2.1%	0.0%
NNSW	NSW	-0.2%	2.3%	1.9%	1.9%	-0.7%	-2.3%	-2.8%
NCEN	NSW	-1.3%	0.4%	1.6%	1.2%	1.2%	-0.9%	-2.2%
SWNSW	NSW	-0.1%	0.4%	0.4%	0.4%	0.8%	-0.1%	-1.7%
CAN	NSW	-4.7%	-2.9%	1.4%	4.1%	2.3%	0.1%	-0.3%
NVIC	VIC	-3.8%	-2.0%	0.6%	4.2%	1.1%	0.6%	-0.7%
LV	VIC	-6.7%	-5.7%	0.3%	5.3%	3.3%	1.8%	1.8%
MEL	VIC	-5.7%	-2.0%	0.3%	5.3%	1.6%	0.7%	-0.2%
CVIC	VIC	-0.8%	-0.4%	-0.4%	1.8%	1.8%	-0.8%	-1.2%
NSA	SA	-1.0%	-0.2%	0.6%	-0.6%	1.5%	-0.2%	-0.2%
ADE	SA	-3.1%	-3.1%	0.4%	2.5%	2.9%	-0.1%	0.4%
SESA	SA	-5.0%	-3.6%	-0.4%	4.7%	3.3%	1.4%	-0.4%
TAS	TAS	-11.5%	-10.4%	0.8%	6.4%	5.3%	4.7%	4.7%
SWIS	SWIS	-3.7%	-3.3%	2.6%	2.6%	0.5%	0.9%	0.5%

Table A.3 and Table A.4 indicate that 2006-07 was a particularly high solar insolation year, and therefore would be a poor choice of reference year (since it would overestimate the contribution of solar technologies). Similarly, 2003-04 and 2004-05 had lower than average solar insolation across Victoria, South Australia and Tasmania. 2009-10 appears to be a good reference year, since the solar capacity factors are close to average in most regions (with the exception of Tasmania, which is not being considered for solar development in this study). Similarly, 2008-09 would be a suitable choice.

Wind

Table A.5 lists the difference in wind farm capacity factors from the long-term average in each "wind bubble", as calculated by the Australian Energy Market Operator (AEMO)[49]. Wind farm capacity factors can vary by ±4.5 percentage points (equivalent to approximately ±10% in absolute energy terms) from year to year. 2003-04 appears to have been a particularly windy year, while 2004-05 and 2005-06 were unusually low wind years across all wind bubbles. 2009-10 appears to be a relatively "typical" year, being close to long-term averages in all bubbles. In 2008-09 Queensland and New South Wales experienced higher than average wind.

[49] AEMO, "Wind Integration in Electricity Grids Work Package 5: Market Simulation Studies", January 2012. Available at: http://www.aemo.com.au/planning/0400-0057.pdf

Table A.5 – Variation in wind capacity factor in each wind bubble for each reference year[50]

Wind bubble	Region	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
SWQ	QLD	0.1%	-0.5%	0.9%	-2.3%	-1.7%	1.6%	2.3%	-0.4%
SEN	NSW	0.3%	3.3%	-2.6%	0.0%	-1.4%	-0.9%	1.4%	-0.1%
MRN	NSW	0.0%	2.7%	-2.7%	-1.7%	-0.7%	-0.9%	3.0%	0.4%
NWV	VIC	1.7%	2.6%	-2.8%	-2.0%	0.4%	0.7%	0.0%	-0.6%
SWV	VIC	1.8%	3.4%	-1.9%	-2.2%	-0.5%	0.6%	-0.8%	-0.4%
CS	VIC/SA	2.0%	3.5%	-2.2%	-2.6%	0.6%	0.8%	-1.2%	-0.9%
MNS	SA	1.4%	1.6%	-2.0%	-2.3%	1.1%	0.4%	0.4%	-0.5%
WCS	SA	2.0%	1.2%	-2.2%	-3.9%	0.5%	1.4%	0.2%	0.6%
EPS	SA	1.7%	1.5%	-0.8%	-3.3%	1.4%	0.4%	-0.4%	-0.5%
FLS	SA	3.2%	2.5%	-2.8%	-3.3%	0.6%	1.3%	-0.6%	-0.8%
YPS	SA	3.0%	2.0%	-2.2%	-4.5%	1.4%	1.4%	-0.1%	-1.0%
NWT	TAS	1.6%	3.2%	-2.7%	0.1%	0.3%	-1.1%	-0.5%	-0.9%
NET	TAS	1.3%	4.0%	-3.1%	0.2%	1.3%	-4.1%	-0.4%	0.8%
ST	TAS	1.6%	4.1%	-1.2%	0.9%	-0.4%	-3.1%	-1.3%	-0.5%

Summary

ROAM's analysis indicates that 2009-10 is an appropriate reference year, giving "typical" solar and wind generation levels in all parts of Australia, and having a reasonably average demand shape. The demand profile in 2009-10 is weighted towards more energy being delivered at high demand periods, which is likely to be consistent with a growing trend in air-conditioner penetration. This year has therefore been used as the reference year for the modelling included in this study. However, the possible impact of changes year to year should be considered when analysing the results of this study.

Following the selection of the 2009-10 reference year, a range of Typical Meteorological Year files from the U.S. Department of Energy were also considered and found to have broadly consistent average solar generation profiles, reinforcing the choice of 2009-10 as a representative year.

50 Reproduced from AEMO "Wind Integration in Electricity Grids Work Package 5: Market Simulation Studies", January 2012. Available at: http://www.aemo.com.au/planning/0400-0057.pdf

Appendix B) MODELLING WITH 2-4-C

B.1) *FORECASTING WITH 2-4-C*

2-4-C is ROAM's flagship product, a complete proprietary electricity market forecasting package. It was built to match as closely as possible the operation of the AEMO Market Dispatch Engine (NEMDE) used for real day-to-day dispatch in the NEM. However, it is capable of modelling any electricity network, and is in use to model small systems such as the North-West Interconnected System (NWIS) of Western Australia, and the large 4000 bus CalISO system of California.

2-4-C implements the highest level of detail, and bases dispatch decisions on generator bidding patterns and availabilities in the same way that the real NEM operates. The model includes modelling of forced full and partial and planned outages for each generator, including renewable energy generators and inter-regional transmission capabilities and constraints.

ROAM continually monitors real generator bid profiles and operational behaviours, and with this information constructs realistic 'market' bids for all generators of the NEM. Then any known factors that may influence existing or new generation are taken into account. These might include for example water availability, changes in regulatory measures, or fuel availability. The process of doing this is central to delivering high quality, realistic operational profiles that translate into sound wholesale price forecasts.

2-4-C has been used on behalf of AEMO (previously NEMMCO) since 2004 to estimate the level of reliability in the NEM and consequently set the official Minimum Reserve Levels for all regions of the NEM.

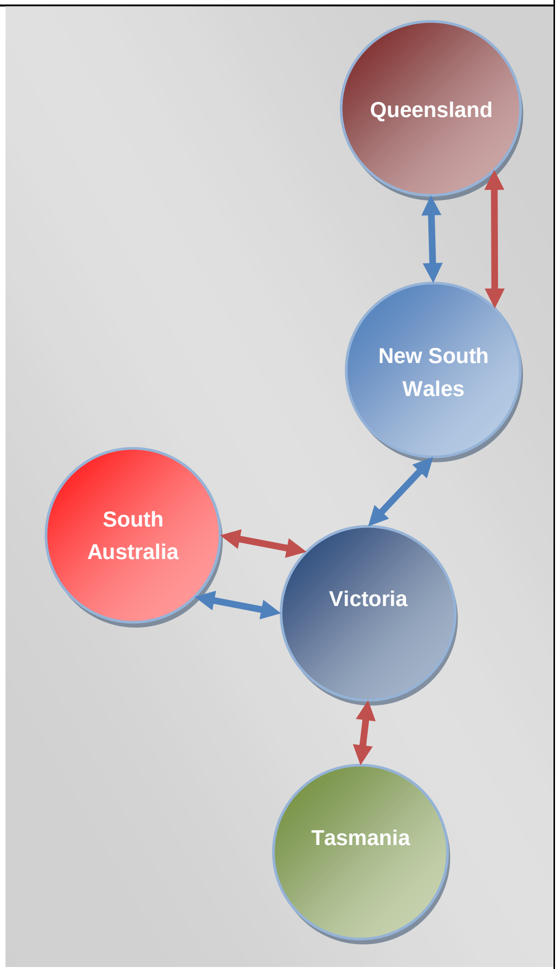
B.2) *THE 2-4-C MODEL*

The multi-node model used by ***2-4-C*** is shown in Figure B.1. This nodal arrangement features a single node per region of the NEM, the same as the regional configuration used by NEMDE.

This network representation means that there is no direct visibility of intra-regional network capabilities. In order to model these important aspects of the physical system, AEMO employs the use of constraint equations that transpose intra-regional network issues to the visible parts of the network; that is, the inter-connectors joining the regions of the NEM. These constraint equations consist of several hundred mathematical expressions which define the interconnector limits in terms of generation, demand and flow relationships. ***2-4-C*** implements these constraint equations within its LP engine in fully co-optimised form.

Modelling major transmission lines and constraint equations delivers an outcome consistent with the real operation of the NEM under normal system conditions. Additionally, the occurrence of congestion in the network is the primary factor that drives out-of-merit dispatch outcomes and hence price volatility. These important aspects of the NEM would not be seen in a more simplistic model.

Figure B.1- 2-4-C NEM Representation



Blue bi-directional arrows signify the AC interconnectors between the regions of the NEM, while the red arrows signify High-Voltage DC Links.

B.3) *MODELLING THE TRANSMISSION SYSTEM*

ROAM's ***2-4-C*** dispatch model implements the full set of AEMO NTNDP constraints as supplied by AEMO with the annual Statement of Opportunities. These constraint equations define interconnector flow limits in terms of generation, demands and flows. A constraint equation for an interconnector is defined in a particular direction and is of the following form:

$$X * Flow_{InterconnectorA_{DirectionB}} + Y * Output_{GenA} \leq$$
$$Constant + Z * Demand_{RegionA} + P * Output_{GenA} + Q * Output_{GenB} + R * Flow_{InterconnectorB_{DirectionA}}$$

where : X, Y, Z, P, Q are constants

B.4) *KEY PARAMETERS USED BY THE MODEL*

Data contained within the ***2-4-C*** model is a combination of the best information sources within information available in the public domain including:

- All released AEMO Statements of Opportunity through to the present, together with half-hourly historical load profiles by region;
- Annual Planning Statements by Network Service Providers:
    - All published Powerlink statements, together with half-hourly historical load profiles by zone;
    - All published TransGrid statements;
    - All published AEMO VAPR statements;
    - All published AEMO SASDO statements, and;
    - All published Transend statements.
- Corporate Annual Reports for many market participants (generators, retailers and network service providers), and;
- General reports from market participants.

Appendix C) MODELLING ASSUMPTIONS

C.1) *DEMAND SIDE ASSUMPTIONS*

C.1.1) Demand and energy forecasts

To account for sensitivities to the load, ROAM considers a variety of load forecasts, as supplied annually by AEMO. These include:

- M10 case - Medium load growth, 10% P.O.E.
- M50 case - Medium load growth, 50% P.O.E.

where P.O.E. is the probability of exceedence.

The 10% P.O.E. case represents an extreme weather year resulting in demand levels exceeded only 1 year in 10. The 50% P.O.E. case represents a reasonably mild weather year (exceeded 1 year in 2).

These 10% and 50% P.O.E. cases represent upper and lower bounds. To show the 'likely' case, ROAM calculates a 'weighted' value for all properties. This weighted value is calculated as 30% of the 10% P.O.E. value and 70% of the 50% P.O.E. value.

The regional load trace forecasts (that is, the half-hourly load data) have been developed using the actual recorded 2009-10 financial year load traces for each region as the reference year. For the years beyond those forecast by AEMO, the following extrapolation methodology has been applied.

Forecast Demand and Energy Extrapolation Methodology

For demand and energy forecast extrapolation past the end of the period specified by AEMO or the TNSP's (in this case past 2020-21), ROAM has designed a methodology based on forecast population growth. This methodology is essentially an extrapolation of energy consumption on a per capita basis. ROAM believes this is a good approximation method for computing future energy consumption, as it relates consumption to expectations of population, rather than merely extrapolating energy use from the relatively short ten-year forecasts provided by AEMO and the TNSP's.

ROAM uses ABS (Australian Bureau of Statistics) population forecasts[51] to compute electricity consumption per capita beyond the AEMO/TNSP forecast period. The relationship between population and per capita consumption is then assumed to continue past this period, subject to the long-term population forecasts provided by ABS.

Demand and energy projections used

Table C.1 outlines the demand and energy projections applied in the modelling. They are based on the AEMO 2011 SOO and the SOO Update released by AEMO in April 2011.

[51] http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/3222.02006%20to%202101

Table C.1 – Annual Total Energy As-Generated (GWh)					
Year	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
2011-12	77605	50555	13753	10171	49529
2012-13	79475	53722	13934	10421	50949
2013-14	80399	57019	14267	10484	51757
2014-15	81373	60560	14301	10534	51858
2015-16	83313	63107	14396	10577	51979
2016-17	84632	64598	14727	10767	52731
2017-18	85876	66141	14959	10838	53301
2018-19	87134	67639	15313	10913	54136
2019-20	88703	69265	15544	11016	55311
2020-21	90509	70756	15792	11125	56363
2021-22	91971	72314	16076	11231	57248
2022-23	93439	73882	16361	11335	58135
2023-24	94912	75458	16647	11437	59023
2024-25	96389	77042	16934	11537	59912
2025-26	97868	78632	17221	11635	60801
2026-27	99346	80228	17508	11730	61688
2027-28	100822	81827	17795	11823	62571
2028-29	102294	83429	18081	11914	63451
2029-30	103760	85033	18366	12001	64327
2030-31	105220	86638	18650	12086	65197
2031-32	106673	88243	18933	12168	66062
2032-33	108119	89848	19214	12247	66921
2033-34	109556	91453	19494	12323	67775
2034-35	110986	93059	19773	12397	68624
2035-36	112409	94666	20050	12468	69468

Figure C.1 shows the energy demand targets, starting with the actual energy demand value for 2010-11.

Figure C.1 – Annual total energy targets as-generated (GWh)

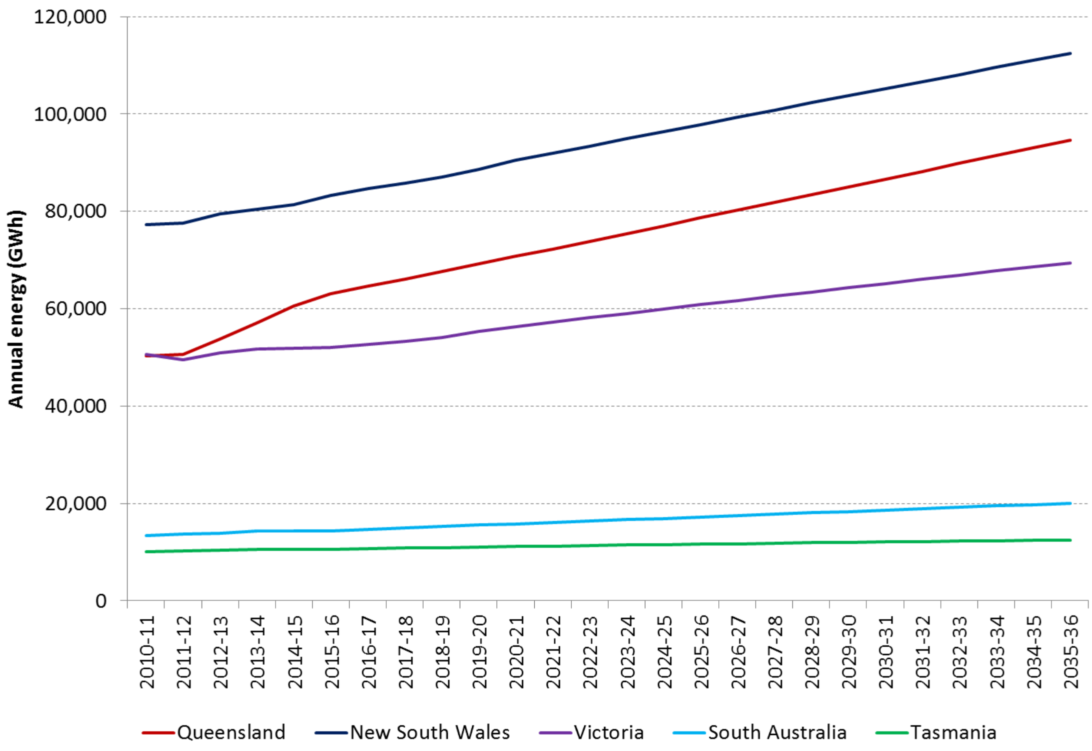


Table C.2 displays the summer peak M50 demand targets for each region, while Table C.3 displays the winter peak M50 targets.

Table C.2 – Summer peak M50 demand as-generated (MW)

Year	NSW	QLD	SA	TAS	VIC
2011-12	14363	9399	3164	1465	10107
2012-13	14602	10014	3220	1506	10452
2013-14	14891	10593	3300	1528	10697
2014-15	15186	11258	3350	1544	10895
2015-16	15425	11687	3384	1557	11056
2016-17	15744	12010	3444	1587	11262
2017-18	16071	12362	3504	1605	11479
2018-19	16410	12699	3584	1622	11731
2019-20	16750	13042	3644	1645	11997
2020-21	17074	13287	3684	1668	12264
2021-22	17350	13580	3750	1684	12457
2022-23	17627	13874	3817	1699	12650
2023-24	17856	14131	3873	1710	12808

Table C.2 – Summer peak M50 demand as-generated (MW)					
Year	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
2024-25	18183	14467	3950	1730	13036
2025-26	18462	14766	4017	1744	13230
2026-27	18741	15066	4084	1759	13423
2027-28	18968	15324	4140	1768	13578
2028-29	19297	15667	4218	1786	13806
2029-30	19574	15968	4284	1799	13997
2030-31	19849	16269	4351	1812	14186
2031-32	20068	16526	4405	1819	14335
2032-33	20396	16872	4482	1836	14562
2033-34	20667	17174	4548	1848	14747
2034-35	20937	17475	4613	1859	14932
2035-36	21147	17729	4665	1864	15074

Table C.3 – Winter peak M50 demand as-generated (MW)					
Year	**NSW**	**QLD**	**SA**	**TAS**	**VIC**
2011-12	13690	8180	2500	1794	8184
2012-13	13925	8484	2536	1837	8395
2013-14	14133	8923	2566	1865	8542
2014-15	14381	9428	2626	1884	8628
2015-16	14696	9926	2630	1898	8700
2016-17	15084	10385	2680	1929	8786
2017-18	15403	10751	2730	1951	8891
2018-19	15708	10987	2780	1975	9035
2019-20	15977	11343	2850	2005	9219
2020-21	16347	11541	2890	2037	9391
2021-22	16611	11795	2942	2056	9538
2022-23	16876	12051	2994	2075	9686
2023-24	17096	12274	3038	2088	9807
2024-25	17409	12566	3099	2112	9982
2025-26	17676	12826	3151	2130	10130
2026-27	17943	13086	3204	2148	10278
2027-28	18160	13310	3248	2159	10397
2028-29	18476	13608	3309	2181	10572
2029-30	18740	13870	3361	2197	10718
2030-31	19004	14131	3413	2213	10863
2031-32	19214	14354	3455	2222	10977
2032-33	19528	14655	3516	2242	11150
2033-34	19787	14917	3568	2256	11293
2034-35	20046	15179	3619	2270	11434
2035-36	20247	15399	3659	2277	11543

Figure C.2 shows the summer and winter M50 target peaks demands graphically, and Figure C.3 shows the same for the M10 targets. Tabulated M10 target values can be supplied on request.

Figure C.2 – Summer and winter peak M50 demand as-generated (MW)

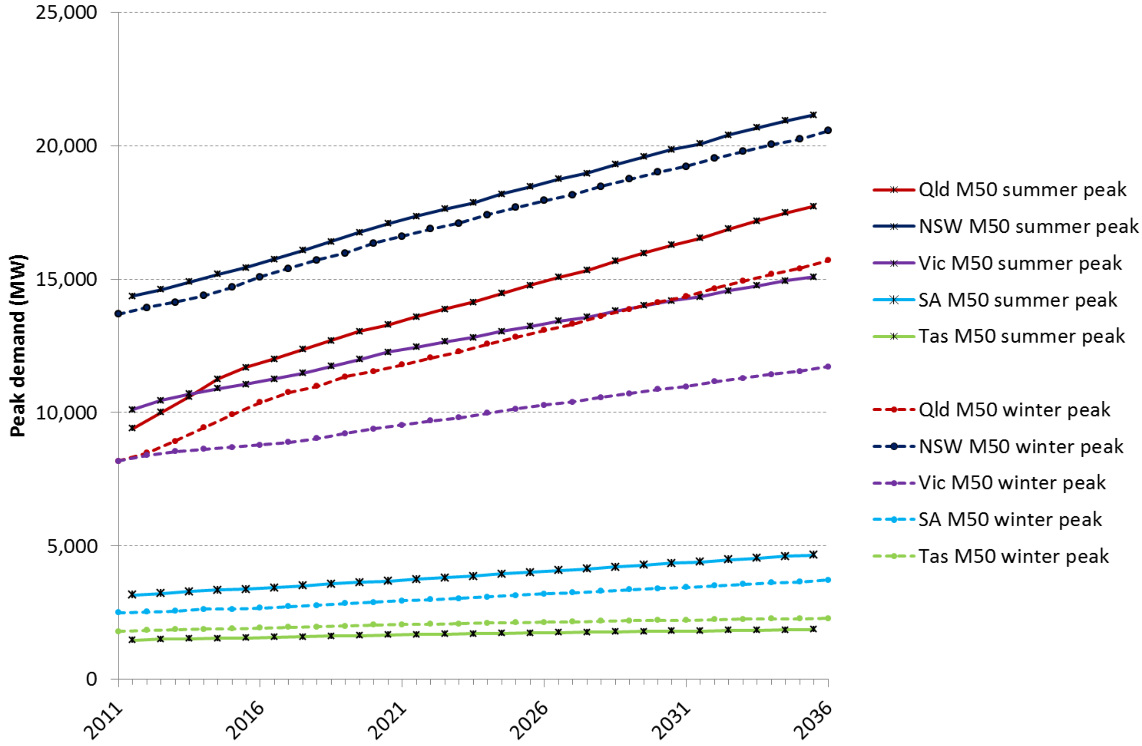
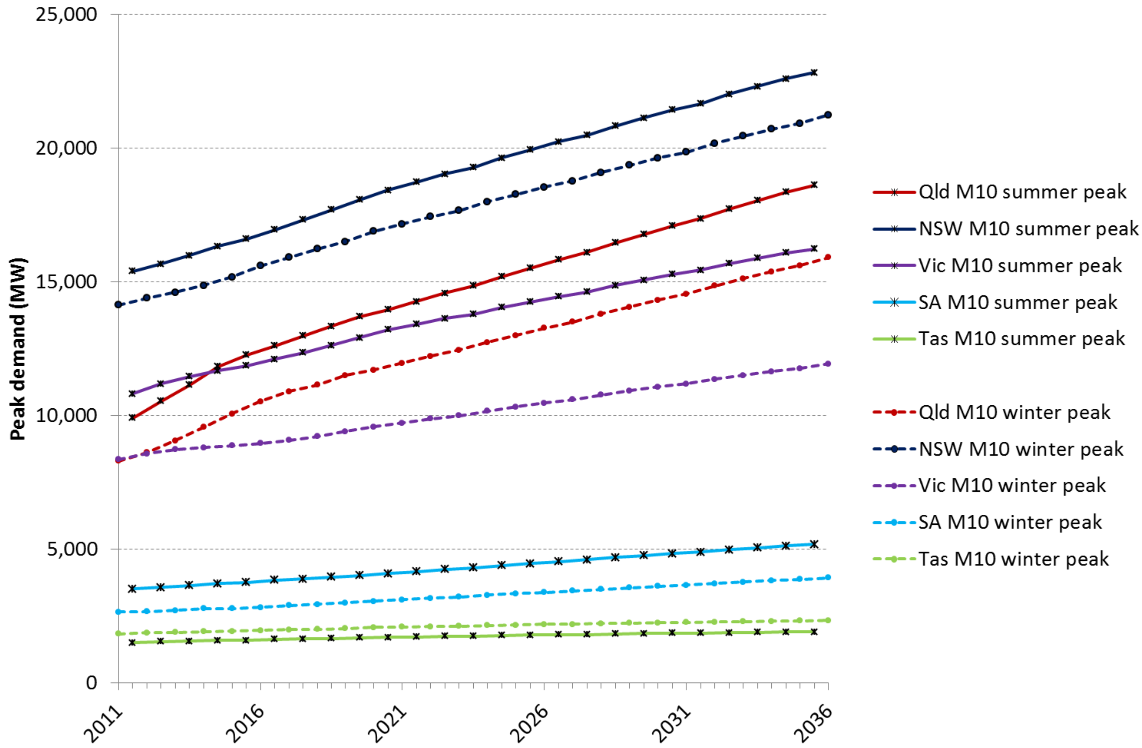


Figure C.3 – Summer and winter peak M10 demand as-generated (MW)



Forecast Load Trace Development

When ROAM constructs a half-hourly demand trace for a specific region the forecast annual energy, summer and winter peak demands are all used in producing the trace. ROAM's algorithm for creating these traces meets all three of these forecast values while maintaining the inherent daily shape of a region's demand trace.

C.1.2) Inclusion of customers

At each region, a bulk load consumption facility has been included to represent the cumulative, time-sequential, load consumption profile anticipated at each of the five regions used in the study.

C.1.3) Regional load profiles

Load data for each bulk consumption facility has been derived directly from historical load profiles for each region, and grown to meet the energy and demand forecasts published in the most recent energy and demand projections from AEMO.

C.1.4) Demand-side participation

The vast majority of demand in the wholesale market currently operates as a series of aggregated loads for the purposes of schedule and dispatch. Though some individual customers may be responsive to price, the majority of end-consumers are shielded from short-term price fluctuations through retail contracts. Thus, incentives to reduce demand during high-price periods are dissipated.

In this study, as detailed in AEMO's 2011 Statement of Opportunities, DSP is captured as part of the actual measured demand and therefore inherently part of the demand forecast.

C.1.5) Changes to base loads

No new base loads are included in this study, aside from those included in the AEMO demand projections. However, some base load reductions have been factored into the demand forecasts as described in Section C.1.1).

C.1.6) Hydroelectric pump storage loads

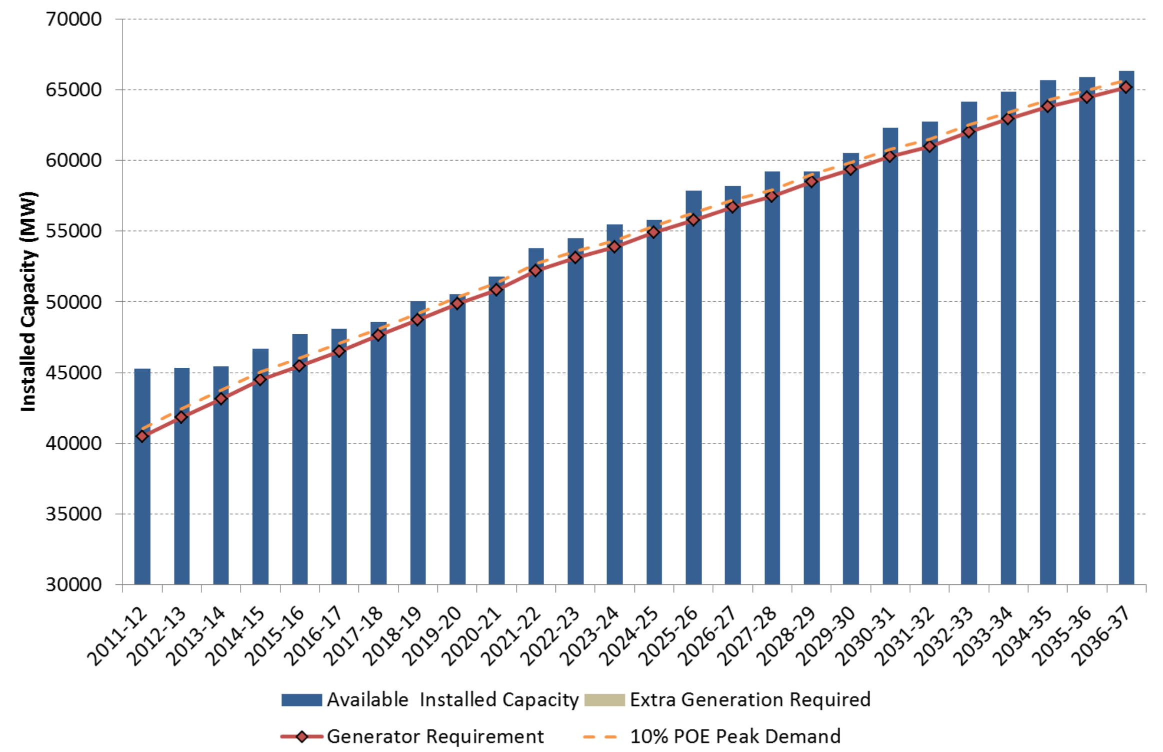
The ***2-4-C*** version used for this study includes a hydroelectric model, including pump storage loads. The pumping loads for the following hydroelectric facilities have been included in the load profile:

- Wivenhoe power station;
- Shoalhaven power station
- Snowy Mountains Scheme: Tumut 3 power station.

C.2) *SUPPLY SIDE ASSUMPTIONS (GENERATION ASSETS)*

ROAM uses its latest view of the market's response to demand triggers for new entry plant. The generation development schedule is required to at least provide sufficient reserve capacity to meet AEMO's minimum reserve criteria. The plant mix is informed by ROAM's least cost expansion modelling of the next several decades. The generation installed in each year is adjusted to meet the Minimum Reserve Level (MRL) and then, in a second pass, further planting date adjustments are made iteratively for individual generators based on profitability considerations. Figure C.4 shows the supply demand balance over the NEM, after all planting adjustments were made for this study.

Figure C.4 – NEM supply demand balance



C.2.1) Thermal generation development

The thermal generators to be included in the assessment are shown in the following table. As the forecast period is over a long time horizon, increased uncertainty exists regarding the development of generation projects.

Table C.4 – New fossil-fuelled generation included in MLF assessment

Timing	Station	Region	Zone	Capacity	Type
2011-12	Racecourse Upgrade	QLD	NQ	27	Bagasse
1/4/2012	Swanbank B Unit 3	QLD	SEQ	-120	Retirement
2014-15	Blackstone OCGT Unit 1	QLD	SEQ	250	OCGT
	Cherokee OCGT	SA	ADE	250	OCGT
	Darling Downs 2 OCGT	QLD	SWQ	500	OCGT

Table C.4 – New fossil-fuelled generation included in MLF assessment					
Timing	**Station**	**Region**	**Zone**	**Capacity**	**Type**
	Playford	SA	NSA	-200	Retirement
	Quarantine 6	SA	ADE	125	OCGT
1/12/2014	Munmorah	NSW	NCEN	-600	Retirement
2015-16	Blackstone OCGT Unit 2	QLD	SEQ	250	OCGT
	Burdekin Falls Hydro	QLD	NQ	37	Hydro
	Dalton OCGT	NSW	SWNSW	500	OCGT
2016-17	Aldoga OCGT Unit 1	QLD	CQ	250	OCGT
2017-18	Aldoga OCGT Unit 2	QLD	CQ	250	OCGT
	Hazelwood Units 1 and 2	Vic	LV	-400	Retirement
	Mackay GT	QLD	NQ	-32	Retirement
	Mortlake Stage 2 OCGT Unit 1	Vic	MEL	275	OCGT
	Pelican Point Stage 2	SA	ADE	320	OCGT
2018-19	Darling Downs 2 CCGT	QLD	SWQ	630	CCGT
	Hazelwood Units 3 and 4	Vic	LV	-400	Retirement
	Mortlake Stage 2 OCGT Unit 2	Vic	MEL	275	OCGT
	Spring Gully OCGT Stage 1	QLD	SWQ	500	OCGT
	Tarrone OCGT Stage 1	Vic	MEL	350	OCGT
2019-20	Collinsville	QLD	NQ	-187	Retirement
	Hazelwood Units 5 and 6	Vic	LV	-400	Retirement
	Tarrone OCGT Stage 2	Vic	MEL	270	OCGT
	VIC OCGT 1	Vic	MEL	300	OCGT
	Wellington Stage 1	NSW	NCEN	510	OCGT
2020-21	Hazelwood Units 7 and 8	Vic	LV	-400	Retirement
	Shaw River CCGT Stage 1	Vic	MEL	500	CCGT
	Spring Gully CCGT Stage 2	QLD	SWQ	500	CCGT
	Tarrone OCGT Stage 3	Vic	MEL	300	OCGT
	Westlink Stage 3	QLD	SEQ	330	OCGT
	Leafs Gully	NSW	NCEN	360	OCGT

Table C.4 – New fossil-fuelled generation included in MLF assessment					
Timing	**Station**	**Region**	**Zone**	**Capacity**	**Type**
	Shaw River CCGT Stage 2	Vic	MEL	500	CCGT
	VIC CCGT 1	Vic	MEL	450	CCGT
	Braemar Stage 3	QLD	SWQ	563	OCGT
2022-23	Kerrawary Stage 1	NSW	CAN	500	OCGT
2023-24	Braemar Stage 4	QLD	SWQ	471	OCGT
	NSW CCGT 1	NSW	NCEN	500	CCGT
2024-25	VIC OCGT 2	Vic	MEL	300	OCGT
2025-26	Blackstone CCGT	QLD	SEQ	500	CCGT
	NSW OCGT 1	NSW	NCEN	400	OCGT
	QLD CCGT 1	QLD	SWQ	600	CCGT
	Shaw River CCGT Stage 3	Vic	MEL	500	CCGT
2026-27	VIC OCGT 3	Vic	MEL	300	OCGT
2027-28	NSW CCGT 2	NSW	NCEN	600	CCGT
	VIC CCGT 2	Vic	MEL	450	CCGT
2029-30	NSW CCGT 3	NSW	NCEN	600	CCGT
	QLD OCGT 4	QLD	SWQ	400	OCGT
	SA CCGT 1	SA	ADE	300	CCGT
2030-31	NSW OCGT 2	NSW	NCEN	400	OCGT
	QLD CCGT 2	QLD	SWQ	600	CCGT
	QLD OCGT 1	QLD	SWQ	400	OCGT
	VIC OCGT 4	Vic	MEL	300	OCGT
2031-32	VIC CCGT 3	Vic	MEL	450	CCGT
2032-33	NSW OCGT 3	NSW	NCEN	400	OCGT
	QLD CCGT 3	QLD	SWQ	600	CCGT
	QLD OCGT 2	QLD	SWQ	400	OCGT
2033-34	SA OCGT 1	SA	ADE	200	OCGT
	VIC OCGT 5	Vic	MEL	450	OCGT
2034-35	Kerrawary Stage 2	NSW	CAN	500	OCGT
	VIC OCGT 6	Vic	MEL	450	OCGT
2035-36	Torrens Island C U1	SA	ADE	132	OCGT
	Torrens Island C U2	SA	ADE	132	OCGT

C.2.2) Wind Farm Development

The list of wind farm projects to be included in the model is provided in Table C.5. The wind bubbles referred to as connection locations are shown in Figure C.5.

Table C.5 – Wind farm planting schedule for the study

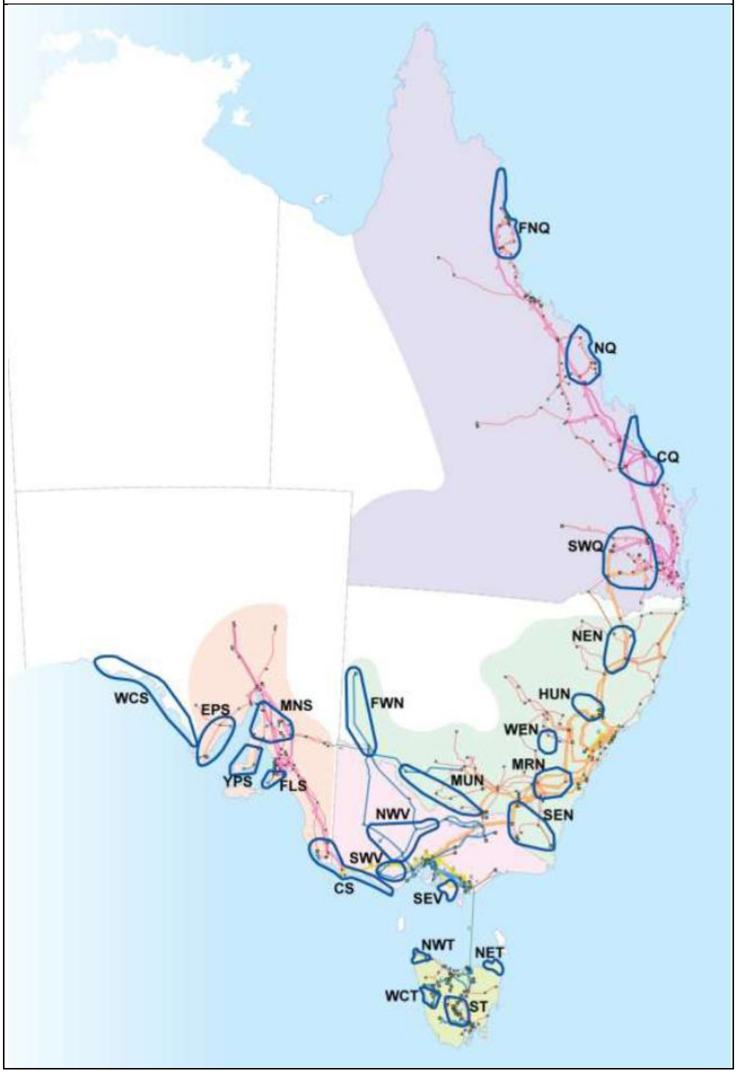
Commissioning Date	Wind Farm Project	Connection Location	Capacity (MW)
Existing	Challicum Hills	CHALLHWF	52.5
	Starfish Hill	STARHLWF	34.5
	Woolnorth	WOOLNTH1	139.75
	Lake Bonney	LKBONNY1	80.5
	Canunda	CNUNDAWF	46
	Wattle Point	WPWF	90.75
	Cathedral Rocks	CATHROCK	66
	Mount Millar	MTMILLAR	70
	Lake Bonney 2	LKBONNY2	159
	Portland	PORTWF	102
	Snowtown	SNOWTWN1	100.8
	Waubra	WAUBRAWF	192
	Hallett 1	HALLWF1	94.5
	Cullerin Range	CULLRGWF	30
	Clements Gap	CLEMGPWF	56.7
	Lake Bonney 3	LKBONNY3	39
	Hallett 2	HALLWF2	71.4
	Capital	CAPTL_WF	140.7
2011-12	Waterloo	WATERLWF	111
	Woodlawn	CAPTL_WF	48.3
	Oaklands Hill	SWV - TER220	63
	Hallett 4	NBHWF1	132.3
	Gunning	MRN330	47
	Hallett 5	HallettWind-Mokota-EAST	52.5
2012-13	Mortons Lane	CVIC - SWV-TER220	19.5
	Yaloak South	CVIC - SWV-TER-MBL220	29.4
	Macarthur	MEL - CS-HY500	420
2013-14	Woolsthorpe	CVIC - SWV-TER220	40
	Mt Mercer	CVIC - NWV-BLR220	131
	Woorndoo	CVIC - SWV-TER220	29.9
	Cape Sir William Grant	MEL - CS-HY500	32

Table C.5 – Wind farm planting schedule for the study			
Commissioning Date	**Wind Farm Project**	**Connection Location**	**Capacity (MW)**
	Willogoleche Hill	NSA - Mokota-EAST	74
	Cape Nelson (North)	MEL - CS-HY500	22
	Capital 2	Capital Connection	100
	Hawkesdale	CVIC - SWV-TER220	62
	High Road	NQ	35
	Mount Gellibrand	CVIC - SWV-TER-MBL220	189
	Ryan Corner	CVIC - SWV-TER220	134
	Snowtown Stage 2	NSA - MNS-BGT275	206
	Taralga	CAN - MRN330	122
	Waterloo Stage 2	NSA - MNS-ROB275	18
	Bald Hills	CVIC - NWV-BLR220	104
	Musselroe	NET220	168
2014-15	Mount Emerald	NQ	225
	Collector	CAN - MRN330	149
	Ceres	ADE - Ceres	600
	Cattle Hill	ST-WAD220	240
	Boco Rock	CAN - SEN132	270
	Newfield	MEL - CS-HY500	22.5
	Crookwell 2	CAN - MRN330	92
	Crookwell 3	CAN - MRN330	75
	Forsayth	NQ	70
	Mortlake South	CVIC - SWV-TER220	100
	Stockyard Hill	CVIC - SWV-MBL-HY500	471
	Black Springs	NCEN - WEN330	19
2015-16	Lexton	CVIC - NWV-BLR220	38
	Gullen Range	CAN - MRN330	182.5
	Flyers Creek	NCEN - WEN330	108
	Berrybank	CVIC - SWV-TER-BLR220	178
	Sapphire	NNS - NEN330	356
2016-17	Crowlands	CVIC - NWV-BLR-HOR220	172
	Yass Coppabella	CAN - MRN330	164
	Rugby	CAN - MRN330	290
	Keyneton	NSA - MNS-ROB275	131
	Yass Marilba	CAN - MRN330	132
	Coopers Gap_S1	SWQ275	200
	Conroys Gap	CAN - MRN132	30
	Ararat	CVIC - NWV-BLR-HOR220	150

Table C.5 – Wind farm planting schedule for the study

Commissioning Date	Wind Farm Project	Connection Location	Capacity (MW)
	Paling Yards	CAN - MRN330	150
2017-18	Crediton	NQ	60
	Ben Lomond	NNS - NEN330	200
	Bowen	NQ	101
	Crudine Ridge	NCEN - WEN330	165
	Rye Park	CAN - MRN330	200
	Adjungbilly	CAN - MRN330	39
2018-19	Bango	CAN - MRN330	375
	Birrema	CAN - MRN330	140
	Bodangora	NCEN - WEN330	100
	Hornesdale	NSA - MNS-BRT275	315
	Coopers Gap_S2	SWQ275	150
	White Rock	NNS - NEN330	238
2019-20	Winchelsea	CVIC - SWV-TER-MBL220	28
	Crystal Brook	NSA - MNS-BGT275	80
2030-31	Penshurst	MEL - CS-HY500	300
	Golspie	CAN - MRN330	250
	Crows Nest AGL	SWQ275	150

Figure C.5 – Wind Bubbles in the NEM (NTNDP[52])



[52] National Transmission Network Development Plan

C.2.3) Non-wind Renewable Developments

The list of other renewable (non-wind) projects to be included in the model is provided in Table C.6. Note that this is the list of all non-wind renewable energy projects included in the base case, and for specific sections additional solar generation is added where stated explicitly.

The methodology used to model non-storable renewable energy generators (wind and solar) is described in Section C.4.1).

Table C.6 – Planting schedule for non-wind renewable generation in the base case of the study

Commissioning Date	Generation Project	Connection Location	Capacity (MW)	Technology
2012-13	SFP BP Solar_S1	NSW - NNS	30	Single axis tracking PV
2013-14	SFP BP Solar_S2	NSW - NNS	30	Single axis tracking PV
2014-15	SFP BP Solar_S3	NSW - NNS	60	Single axis tracking PV
	Mildura Heliostat	Vic - CVIC	100	Concentrating PV
	Penola Geothermal Stage 1	SESA	6.7	Geothermal
	Tully Upgrade	QLD	NQ	30
2015-16	Solar Dawn (Solar)	QLD - SWQ	250	Linear Fresnel
	SFP BP Solar_S4	NSW - NNS	60	Single axis tracking PV
	Burdekin Falls Hydro	NQ	37	Hydro
2019-20	Penola Geothermal Stage 2	SESA	23.4	Geothermal
2020-21	Whyalla	SA - NSA	22.2	Dish-Stirling
2021-22	Geodynamics CDP	NSA	25	Geothermal
	Geodynamics Stage 3a	NSA	100	Geothermal
2022-23	Geodynamics Stage 3b	NSA	100	Geothermal
	Penola Geothermal Stage 3	SESA	100	Geothermal

C.2.4) Existing projects

These market forecasts take into account all existing market scheduled generation facilities. In addition, the likely commissioning schedule (beginning typically three months prior to commercial operation) for new generators has been taken into account.

C.2.5) Individual unit capacities and heat rates

Details of unit capacities and heat rates (for thermal plants) have been collated and included on the basis of information available in the public domain.

C.2.6) Unit emissions intensity factors

Emissions Intensity Factors have been collated from public sources and along with heat rates are the basis for determining the uplift in Short-Run Marginal Cost (and hence market bids) for each generator under the Australian Government's Clean Energy Future carbon pricing scheme.

C.2.7) Unit operational constraints

Information on unit minimum load and ramp rate constraints is included in the ***2-4-C*** database. This database has been developed based on pre-market information, moderated with information being currently supplied to the market. Such information is taken into consideration in the simulation of market operation (to ensure that an infeasible solution is not simulated).

C.2.8) Forecast station outage parameters

2-4-C utilises independent schedules for each unit of:

- Planned maintenance, and
- Randomised forced outage (both full and partial outage) distribution.

These schedules have been constructed based on information in the public domain and historical generator availabilities - in particular, the following six key parameters are used in the development of outage schedules and are detailed in the table below.

Table C.7 – Generator outage modelling assumptions

Full Forced Outage Rate:	Proportion of time per year the unit will experience full forced outages.
Partial Forced Outage Rate:	Proportion of time per year the unit will experience partial forced outages.
Number of Full Outages:	The frequency of full outages per year.
Number of Partial Outages:	The frequency of partial outages per year.
Derated Value:	Proportion of the unit's maximum capacity that the unit will be derated by in the event of a partial outage.
Full Maintenance Schedule:	Maintenance schedule of planned outages (each planned outage has a start and end date between which the unit will be unavailable).

C.3) *GENERATOR BIDDING STRATEGIES*

Generator bids are based on analysing past bid profiles for all generators across the NEM and taking into account any known factors that may influence existing or new generation, for instance in response to water availability. For this analysis, ROAM has developed a Quadratic Programming methodology that creates an equivalent 10 band bid for each generator that reproduces the bidding behaviour in terms of pricing and dispatch outcomes over any chosen period (eg month/ year, weekday/weekend, peak/off-peak). In the case of base load generators, these are generally bid at negative price levels up to their minimum operating levels and then at marginal costs for the remainder of the capacity. These base load generators are referred to as 'price-takers' in the market. In the case of intermediate plants, these are bid as price-takers for the peak periods of the day and may be started at other periods in response to a high price signal. Peaking generators are generally bid at or above their marginal costs and start when prices reach these values due to low generator reserve margins caused by high demand intervals or periods of generator failures.

Since prices may be set at different times by base, intermediate and peaking plant, depending on load levels and simulated failures of generating units, the simulation faithfully replicates the price variability in the real market.

C.3.1) Generation commercial data

In the development of the chosen trading strategy for each generator across the NEM, key commercial data is used, including:

- The intra-regional Marginal Loss Factor (MLF);
- Operations and maintenance cost;
- Fuel cost, which has been computed with reference to:
    - Unit heat rate;
    - Fuel heating value, and;
    - Fuel unit price;
- Emission factors for greenhouse gas production.

C.3.2) Energy constraints

Time-varying bid profiles for all hydro power stations including Hydro Tasmania, Snowy Hydro, Southern Hydro, Kareeya and Barron Gorge have been engineered to deliver production patterns corresponding to historical patterns whilst maintaining appropriate price signals. Competitive bidding strategies for pumped storage hydro plant have been developed to maintain high revenues whilst ensuring energy limitations are not violated.

C.3.3) Applying a carbon price

The Australian Government's Clean Energy Future legislation passed through the senate on 15 November 2011. It specifies a fixed price period of three years starting 1 July 2011 and from 1 July 2014 an emissions trading scheme will commence. ROAM used the Government's Core price trajectory, which is associated with a 5% reduction in emissions by 2020 (relative to 2000 levels)[53]. shows the carbon prices applied after discounting them to June 2011 dollars. The early years (2012-13 to 2014-15) are set to the fixed prices dictated in the Clean Energy Future legislation.

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[53] Australian Government, Treasury, 2011. "Strong Growth, Low Pollution, Modelling a Carbon Price". http://cache.treasury.gov.au/treasury/carbonpricemodelling/content/report/downloads/Modelling_Report_Consolidated.pdf

Table C.8 – Australian Government's Core Policy carbon price trajectory (in real June 2011 dollars)		
Fixed price period	**2012-13**	22.37
	2013-14	22.65
	2014-15	23.25
Flexible price period	**2015-16**	25.49
	2016-17	26.52
	2017-18	27.77
	2018-19	29.01
	2019-20	30.46
	2020-21	32.22
	2021-22	34.19
	2022-23	36.26
	2023-24	38.44
	2024-25	40.82
	2025-26	43.31
	2026-27	45.90
	2027-28	48.59
	2028-29	51.70
	2029-30	54.49
	2030-31	57.40
	2031-32	61.02
	2032-33	64.65
	2033-34	68.48
	2034-35	72.42
	2035-36	76.46

The carbon cost for each generator (in $/MWh) is given by each generator's emissions factor (tCO_2/MWh), multiplied by the cost of emissions permits. Since the electricity market in Australia is not internationally trade exposed, it is anticipated that generators will largely increase their bids by the amount of their respective carbon costs. Hence, the effects of a carbon price on the NEM is modelled by adding the carbon cost ($/MWh) to the bids of each generator. Once these uplifts are applied to all bid bands of all generators, the competitive dispatch is recalculated for each half-hourly interval.

C.3.4) Gas prices

The gas prices used for the modelling are taken from Scenario 3 of the 2010 NTNDP forecasts. Scenario 3 is based on some of the currently proposed LNG export projects coming to fruition, but not all, and this represents ROAM's view of the most likely outcome. Scenario 3 specifies a gas price at the Moomba hub, along with delivery costs to the various regions over the eastern states of Australia.

Figure C.6 shows the proposed $6-8/GJ gas price scenario for the 16 NTNDP zones in the NEM which is broadly taken from the NTNDP Scenario 3 Run 3 data set. The 'Run' label refers to the annual volume of gas usage expected in the NEM. Broadly, a higher run number indicates a greater annual gas demand and a correspondingly higher gas price. There are other factors built into the price including LNG export development and corresponding linkage to expectations of international parity pricing.

In bidding gas generators, ROAM uses these gas prices to uplift all generator bid offer bands for all new gas generators as well as for existing gas generators after the date their existing gas contracts are due to expire.

Figure C.6 – NTNDP Zones Gas Prices $6-8/GJ Case

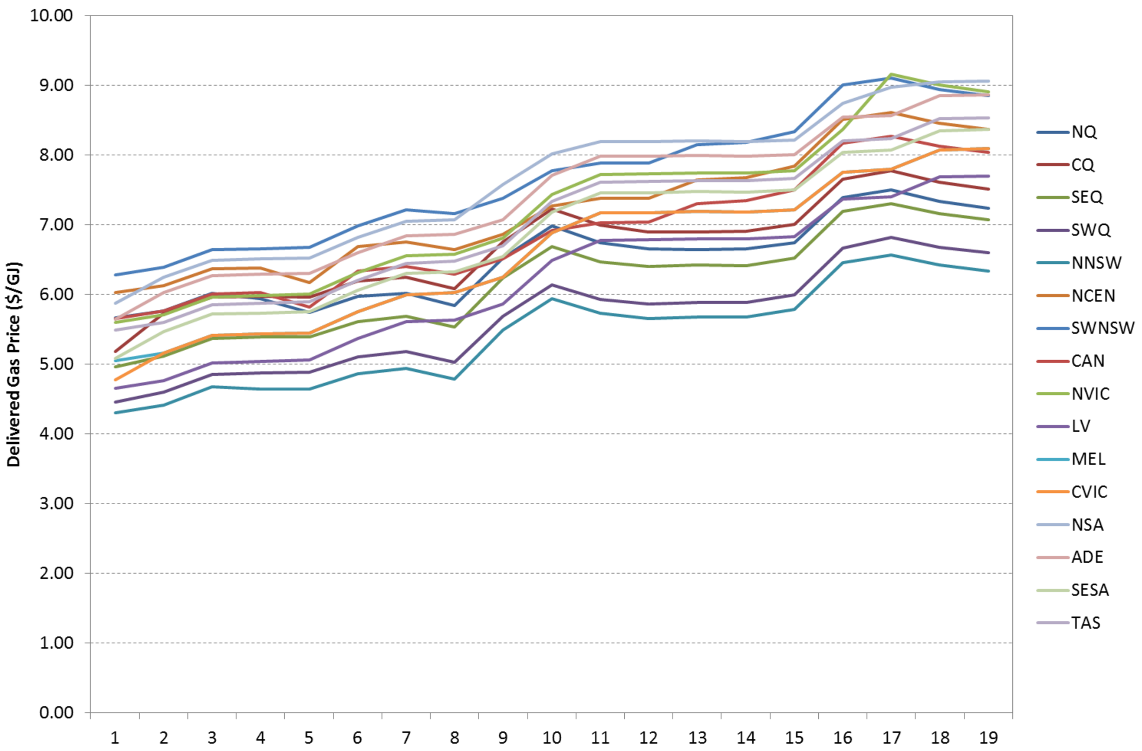
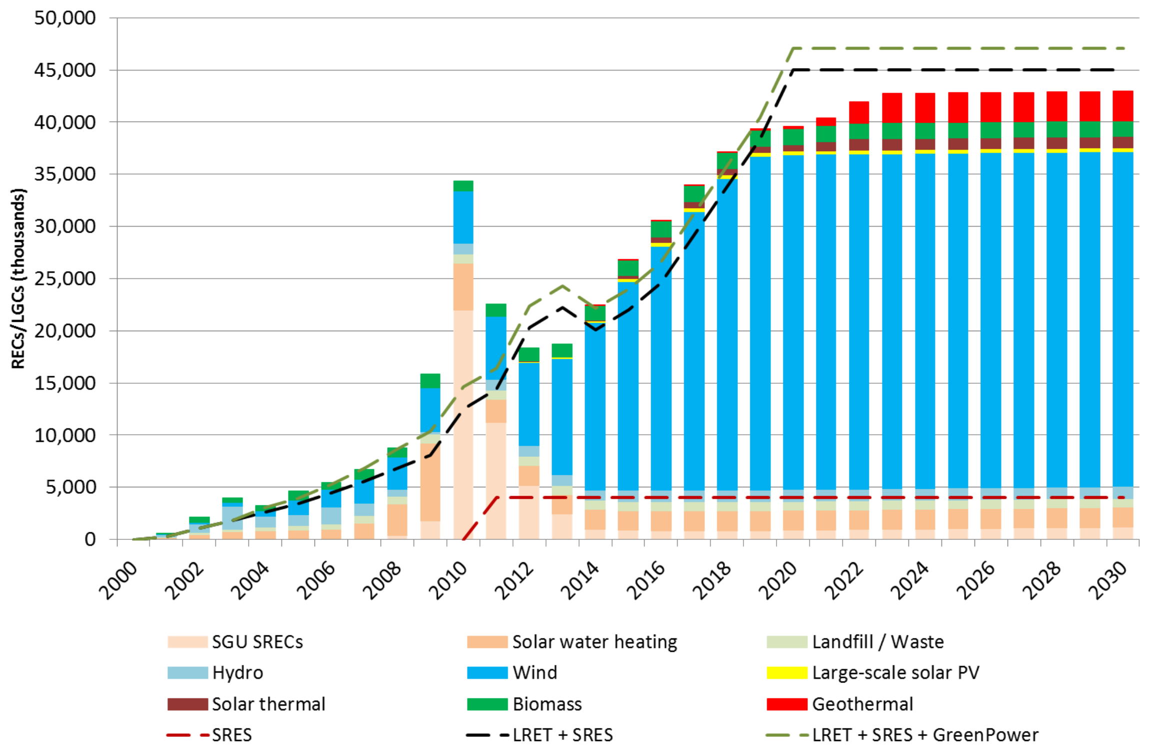


Table C.9 – NTNDP Zones Gas Prices $6-8/GJ Case																
	NQ	CQ	SEQ	SWQ	NNSW	NCEN	SWNSW	CAN	NVIC	LV	MEL	CVIC	NSA	ADE	SESA	TAS
2011-12	5.67	5.19	4.97	4.45	4.31	6.03	6.29	5.66	5.60	4.66	5.05	4.77	5.87	5.65	5.09	5.50
2012-13	5.77	5.74	5.12	4.61	4.42	6.13	6.39	5.76	5.71	4.77	5.16	5.16	6.25	6.03	5.47	5.60
2013-14	6.02	5.97	5.37	4.86	4.68	6.37	6.64	6.01	5.97	5.02	5.41	5.41	6.49	6.27	5.72	5.86
2014-15	5.94	5.98	5.39	4.88	4.65	6.39	6.66	6.03	5.99	5.04	5.43	5.43	6.51	6.29	5.74	5.88
2015-16	5.74	5.96	5.40	4.89	4.65	6.18	6.68	5.82	6.01	5.06	5.45	5.45	6.52	6.30	5.76	5.90
2016-17	5.97	6.20	5.62	5.11	4.87	6.69	6.98	6.34	6.31	5.37	5.76	5.76	6.82	6.60	6.06	6.21
2017-18	6.02	6.25	5.69	5.18	4.94	6.76	7.22	6.40	6.56	5.61	6.00	6.00	7.06	6.84	6.30	6.45
2018-19	5.85	6.08	5.54	5.04	4.79	6.65	7.17	6.30	6.58	5.64	6.03	6.03	7.08	6.86	6.33	6.48
2019-20	6.52	6.76	6.23	5.69	5.49	6.87	7.38	6.52	6.81	5.86	6.25	6.25	7.58	7.08	6.55	6.70
2020-21	6.98	7.22	6.69	6.14	5.94	7.27	7.78	6.93	7.44	6.50	6.89	6.89	8.02	7.71	7.18	7.33
2021-22	6.75	6.99	6.48	5.93	5.73	7.38	7.89	7.03	7.72	6.78	7.17	7.17	8.19	7.98	7.46	7.61
2022-23	6.65	6.90	6.40	5.86	5.66	7.38	7.89	7.04	7.73	6.79	7.18	7.18	8.20	7.98	7.46	7.62
2023-24	6.65	6.90	6.42	5.89	5.68	7.65	8.15	7.30	7.75	6.80	7.19	7.19	8.20	8.00	7.48	7.64
2024-25	6.65	6.91	6.42	5.89	5.68	7.68	8.18	7.34	7.74	6.80	7.19	7.19	8.19	7.98	7.47	7.63
2025-26	6.74	7.01	6.53	6.00	5.79	7.84	8.34	7.51	7.77	6.83	7.22	7.22	8.22	8.01	7.50	7.67
2026-27	7.39	7.66	7.20	6.67	6.46	8.51	9.00	8.17	8.37	7.37	7.76	7.76	8.75	8.54	8.04	8.20
2027-28	7.51	7.78	7.31	6.82	6.57	8.61	9.10	8.28	9.16	7.41	7.80	7.80	8.97	8.57	8.07	8.24
2028-29	7.34	7.61	7.16	6.68	6.42	8.46	8.95	8.12	9.00	7.69	8.08	8.08	9.06	8.85	8.35	8.52
2029-30	7.24	7.51	7.08	6.60	6.34	8.37	8.86	8.04	8.91	7.70	8.09	8.09	9.06	8.86	8.37	8.54

C.4) *Modelling of Renewable Generation*

Sufficient renewable generation is planted to meet the expanded 20% by 2020 renewable energy target, as shown in the figure below. The structure of the scheme, which allows for 'banking' of renewable energy certificates (RECs), means that the shortfall in annual generation in later years is covered by banked RECs created in earlier years.

Figure C.7 – Renewable energy planting to meet the RET



C.4.1) Wind modelling

Individual announced wind farm projects are planted in their announced locations around the grid to make up the LRET target, and are included in transmission congestion calculations on a half-hourly basis.

For modelling the half-hourly dispatch of the NEM into the future, it is important to accurately model half-hourly traces of available wind power production for each wind farm. These available wind power production traces may then be curtailed at certain times when congestion occurs in the dispatch model.

Table C.10 summarises desirable characteristics for available wind farm power output time-series' to be used for half-hourly dispatch modelling. The table also summarises the methodology used by ROAM's Wind Energy Simulation Tool (WEST[54]) to produce wind farm time-series.

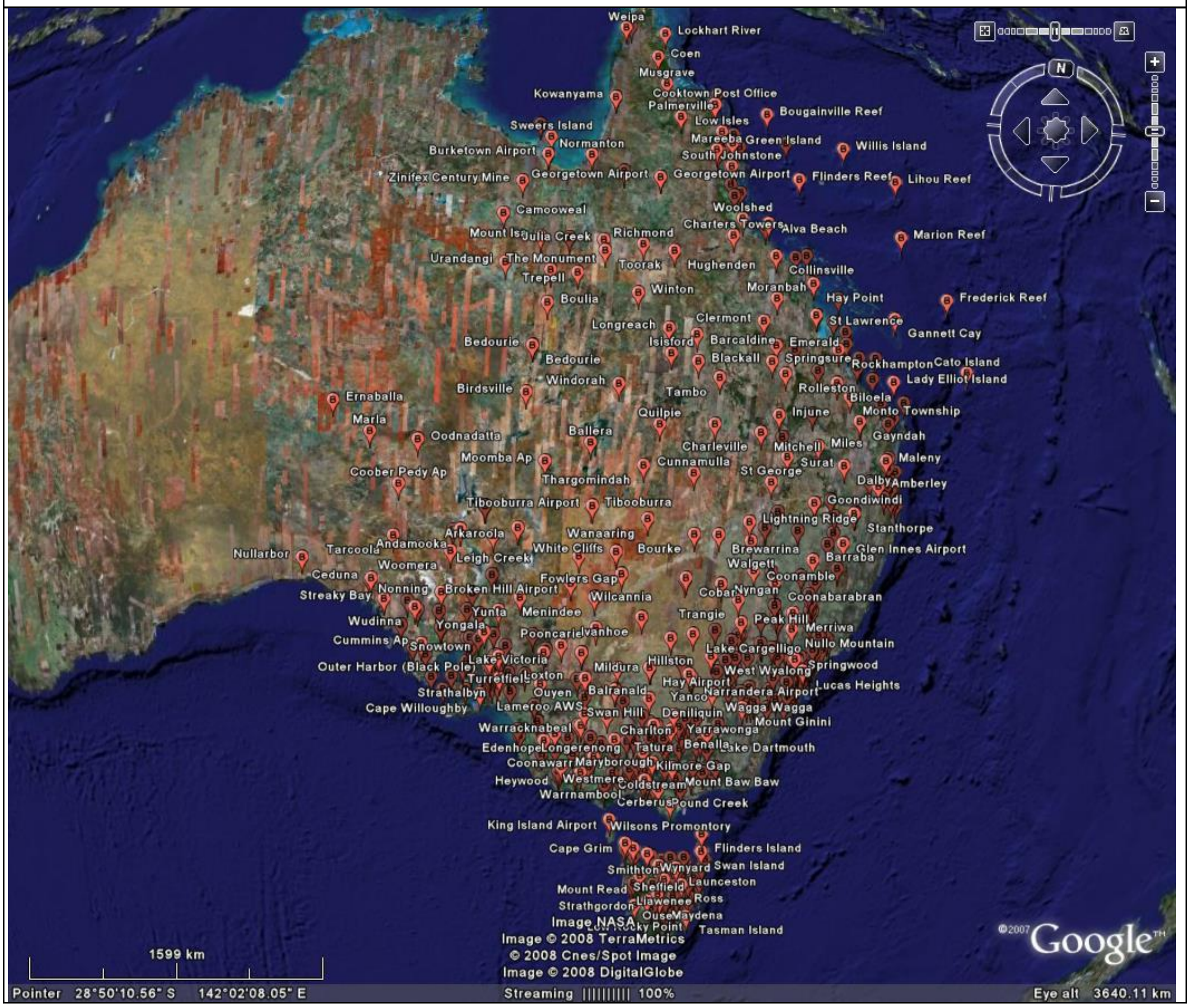
[54] WEST is ROAM's Wind Energy Simulation Tool. WEST converts wind profiles (either actual or simulated wind data) to energy production from manufacturers design data for input to 2-4-C and then AC power flow for congestion, stability and MLF forecasting.

Table C.10 – Desirable characteristics for half-hourly available wind farm output time-series		
Characteristic	**Reasons**	**WEST approach**
Capture variability of wind	Wind output can vary significantly from half-hour to half-hour, which requires other generation to respond accordingly and can have an impact on transmission constraints and marginal loss factors.	WEST uses a combination of ground based weather station data and Numerical Weather Prediction model outcomes to produce variable generation traces.
Exhibits realistic correspondence with half-hourly demand levels on average over the year	Each wind farm exhibits a typical time-of-day generation profile (although day to day output can vary significantly). It is important to capture this trend and, in particular, its correlation with demand and impact on pool prices. For example, if wind power from a certain region is typically high overnight when demand is low, this may result in congestion and $0/MWh prices or less if a wind farm becomes the marginal generator.	Uses a Numerical Weather Prediction model to predict the average wind power production for each hour of the day over the year for existing and prospective wind farms.
Exhibits realistic behaviour during extreme demand events	Since the market price cap is high ($12,500/MWh), capturing such potential price events is essential for the accuracy in predicting annual average spot prices. The contribution from wind power during such events can affect prices, and the levels of unserved energy. Since extreme demand is driven by large weather patterns, it is important to capture the effect the same weather patterns have on wind power.	WEST uses historical half-hourly wind speed observations from the same year as the reference demand trace to estimate wind power production for existing and prospective wind farms. This ensures a good match with the broad weather patterns during extreme demand periods.
Model wind farm capacity factors accurately	Total wind power production contributes to meeting energy demand, and thus displaces other sources of power to feed into the greenhouse gas emissions results and average interconnector flows. It is therefore important for wind farm capacity factors to be modelled as accurately as possible.	For existing wind farms, a capacity factor target based on historical performance is used. For prospective wind farms a Numerical Weather Prediction system is used to predict their capacity factor, with a de-rating for assumed turbine availability.

The WEST methodology, used to produce an available wind farm power output trace for this issue of ROAM Insight, was:

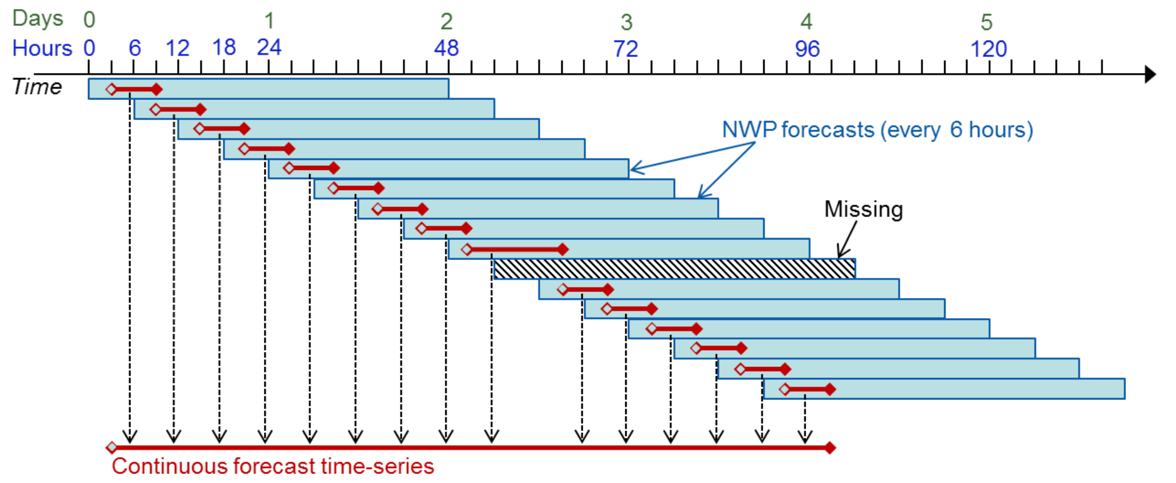
1. **Select a nearby automatic weather station to obtain a half-hourly time-series of wind speed observations for the 2009-10 year to represent the wind farm site.** Automatic weather stations are managed by the Bureau of Meteorology (BoM) and the locations of the stations in eastern Australia are shown in Figure C.8 . The wind data from the weather stations is taken at a variety of elevations (from 1m off the ground to 70m above the ground), and elevation strongly affects wind speeds. The wind at the height of a turbine hub (from 50m to 80m) will be much faster than the wind at ground level, and the amount of the increase in speed is strongly dependent upon many factors, including the type of ground cover (rock, grass, shrubs, trees) and the nature of the weather pattern causing the wind. In addition, the local topography affects wind speeds very strongly (winds tend to be focused by flowing up hillsides, for example). The wind speed at a weather station perhaps 30km distant from a wind farm is likely to be correlated strongly in time with the wind at the site of the turbines, but the absolute scaling of the speeds is highly uncertain.

Figure C.8 – Locations of BoM weather stations



2. **Use data from the Australian Bureau of Meteorology's regional Numerical Weather Prediction model, ACCESS-A[55] to predict time-of-day profiles and capacity factors to target for each wind farm.** The ACCESS-A model provides wind speed forecasts at around the hub height of wind turbines on a 12 km grid representing the atmosphere over the Australian topography. A continuous hourly wind speed trace for the financial year 2010-11 is extracted for a representative grid point for each wind farm site by combining the forecasts with the method illustrated in Figure C.9. These wind speed traces are adjusted by some tuning parameters based on the wind turbine installation height above sea level, and the model's representation of the elevation and surface roughness at the selected grid point. The resulting hourly wind speed trace is used to provide an average wind speed (converted to capacity factor) target and hourly time-of-day profile target to scale the BoM weather station data.

Figure C.9 – Constructing a continuous hourly time-series from ACCESS-A Numerical Weather Prediction (NWP) forecasts



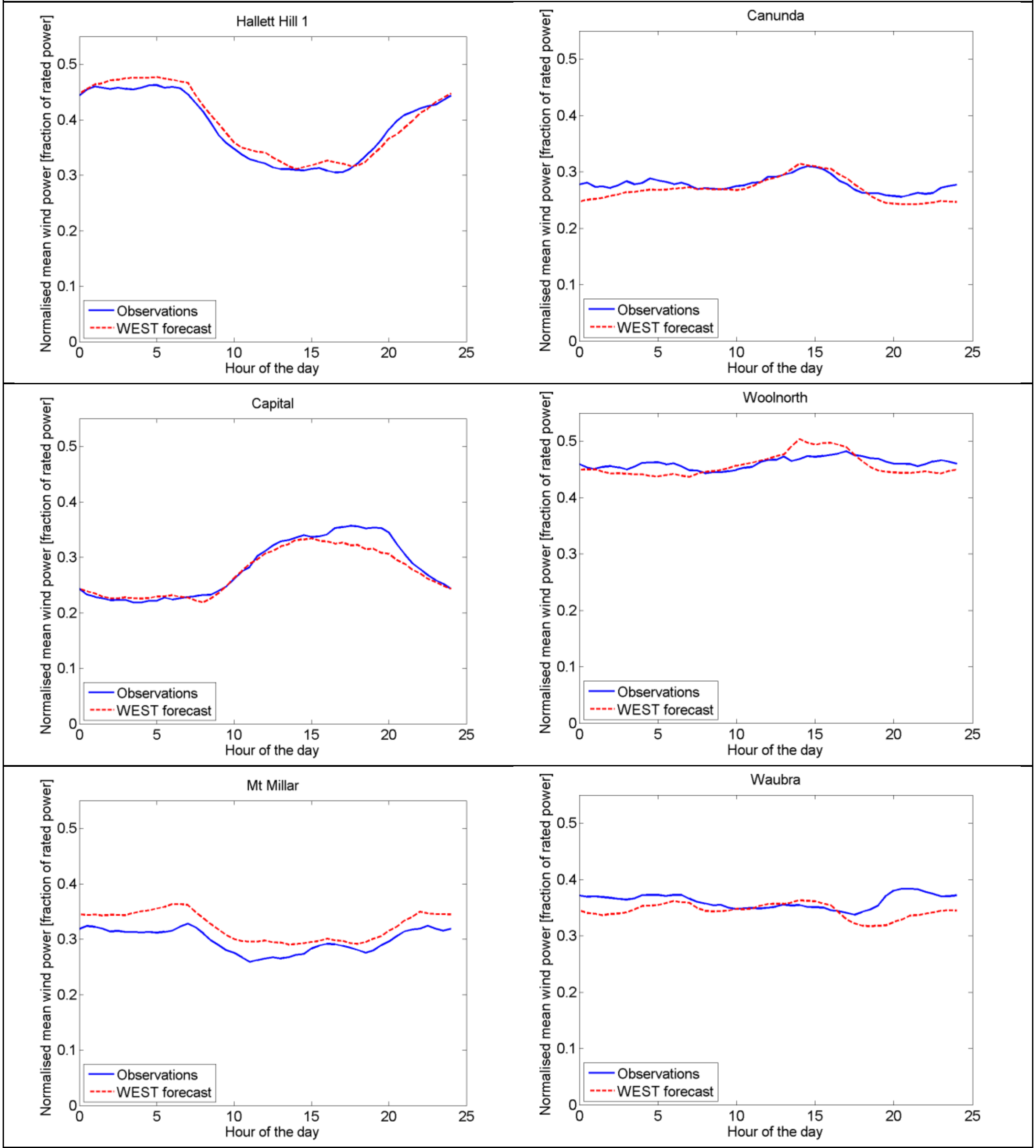
3. **The BoM weather station wind speeds are scaled to target the relevant time-of-day profiles and capacity factors, and then converted to wind power traces using wind turbine power curves.**

4. **Finally, the wind power traces are adjusted (reduced) to account for turbulence and shading across the wind farm (the "park effect"), calibrated by historic data from existing wind farms.**

Comparisons with historical wind farm generation from existing wind farms has shown a very good match to the equivalent ACCESS-A derived targets for long-term modelling purposes. As mentioned in Table C.10 above, the time-of-day profile for wind farm modelling is especially important for modelling wind generation and electricity prices, and consequently, wind farm spot market revenues. Figure C.10 compares the WEST time-of-day targets with observations over 2010-11 for six existing wind farms,

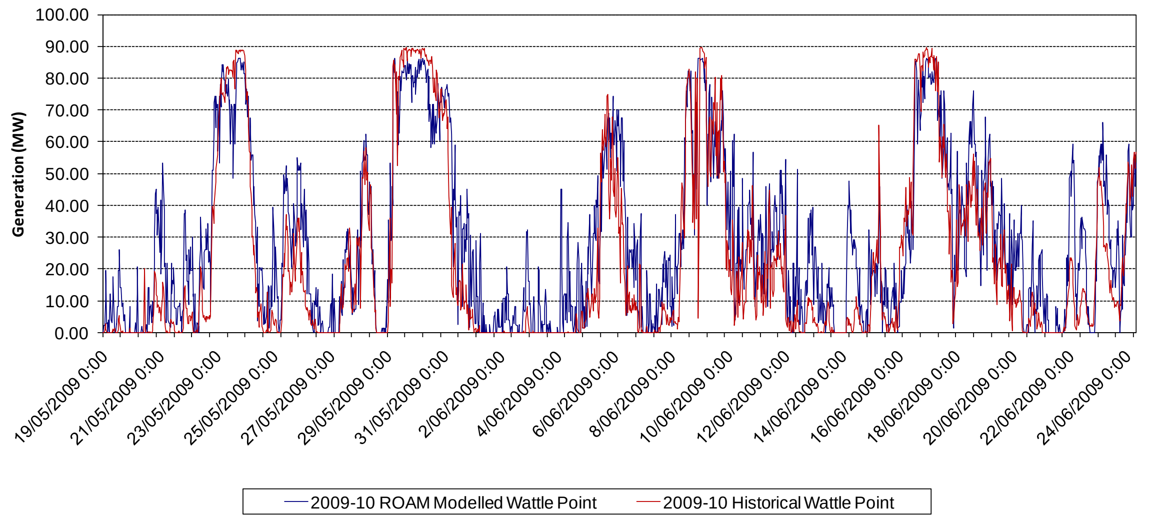
[55] See http://www.bom.gov.au/nwp/doc/access/NWPData.shtml for more information.

Figure C.10 – Comparison of WEST time-of-day targets and observations for six existing wind farms



There is a very good agreement between the results of this method and the known output of existing wind farms. As a benchmarking exercise, ROAM compared the historic generation profile of Wattle Point with a generation profile developed with the method as described above. The results are shown in a graphical form presented in Figure C.11.

Figure C.11 – Wattle Point Generation Benchmark



Wind farms are bid into the market at $0, with volumes based upon their unit trace outputs in each half-hour period.

C.4.2) Bidding of renewable generators

Schedulable renewable generation (geothermal and biomass/bagasse) were bid into the market at prices which reflect their fuel and variable operation and maintenance costs, while intermittent generators were bid at $0/MWh.

Table C.11 – Renewable generator bidding

Plant type	Bid price
Biomass / Bagasse	$29.77/MWh
Geothermal	$2.05/MWh
Solar PV and solar thermal	$0/MWh
Wind	$0/MWh

C.5) *TRANSMISSION AND DISTRIBUTION SYSTEM ASSUMPTIONS*

C.5.1) Transmission losses

Losses are modelled commercially in either of two ways, in accordance with existing market rules. Treatment is as follows:

Inter-regional losses

Inter-regional losses over AC interconnectors are modelled using dynamic loss equations supplied by AEMO.

Intra-regional losses

Intra-regional losses are modelled by static, but periodically adjusted, Marginal Loss Factors in relation to a Regional Reference Node (RRN). These MLF's are published annually by AEMO (and assumed for new stations).

Market forecasting has been completed on a gross basis. Therefore, the energy profiles assumed for each node have incorporated allowance for (transmission and distribution) losses and generator auxiliary energy.

C.5.2) Transmission limits

For each of the links between the nodes defined in the ***2-4-C*** model, bi-directional limits are dynamically calculated based on the most recent publicly available set of transmission limit equations incorporated in the NTNDP data set. This data has been added on the basis of information provided within the relevant planning documentation listed as references in the previous section.

C.5.3) Transmission asset development

The ANTS constraint equations supplied by AEMO assume some limited transmission asset development over time, accounting for minor upgrades. However, they do not include significant transmission development that will be necessary over longer modelling timeframes. To account for this, in longer studies ROAM may 'switch off' a given constraint equation at the point in the study where a significant transmission upgrade is clearly required. From that point onwards, notional transmission limits are applied to the various inter-regional transmission network flow paths, as listed in the table below.

Table C.12 – Notional Transmission Line Limits[56]

From region	To region	Interconnector limit (MW)			
		Summer peak	Summer off-peak	Winter peak	Winter off-peak
QLD	NSW	1078	1078	1078	1078
NSW	QLD	400	550	400	550
NSW	VIC	1900 minus Murray Generation	1900 minus Murray Generation	1900 minus Murray Generation	1900 minus Murray Generation
VIC	NSW	3200 minus Upper & Lower Tumut Generation	3200 minus Upper & Lower Tumut Generation	3200 minus Upper & Lower Tumut Generation	3200 minus Upper & Lower Tumut Generation
VIC	SA	460	460	460	460

[56] AEMO, List of Regional Boundaries and Marginal Loss Factors for the 2011-12 Financial Year.

Table C.12 – Notional Transmission Line Limits[56]					
SA	VIC	460	460	460	460
Murraylink VIC	SA	220	220	220	220
Murraylink SA	VIC	188 minus North West Bend & Berri loads	198 minus North West Bend & Berri loads	215 minus North West Bend & Berri loads	215 minus North West Bend & Berri loads
Terranora Interconnector QLD	NSW	220	220	220	220
Terranora Interconnector NSW	QLD	122	122	122	122
Basslink VIC	TAS	478	478	478	478
Basslink TAS	VIC	594	594	594	594

C.5.4) Terranora (Gold Coast to Armidale interconnector)

Terranora is modelled as a regulated market scheduled interconnector. As the HVdc link is controllable it will be dispatched to maximise inter-regional competition if this is the optimal dispatch outcome.

C.5.5) Murraylink (Melbourne to South Australia interconnector)

Murraylink is modelled as a regulated market scheduled interconnector. Murraylink is dispatched in a similar way to Terranora as described above.

C.5.6) Basslink (Latrobe Valley to Tasmania interconnector)

Basslink is modelled as a bi-directional interconnector. The bidding profile allows for transfers of energy from Tasmania to Victoria during peak times and from Victoria to Tasmania during off-peak times.

C.6) *MARKET DEVELOPMENT ASSUMPTIONS*

Several assumptions are made about the development of the market.

C.6.1) Market Price Cap

The Market Price Cap (MPC) was set at the value of $10,000/MWh up until 30 June 2010, after which the MPC increased to $12,500/MWh based on the recommendations of the Australian Energy Market Commission Reliability Panel's *Review of VoLL 2008*[57]. It was further increased to $12,900/MWh from 1st July 2012 in line with inflation.

[57] http://www.aemc.gov.au/pdfs/reviews/VoLL%202008%20Review/reliability/000Reliability%20Panel%20Review%20of%20VoLL%202008%20Draft%20Determination.pdf

C.6.2) Developments in regional configurations

The potential reconfiguration of pricing regions was not considered in this study.

C.7) *ASSUMPTIONS WITH REGARD TO MARKET EXTERNALITIES*

There are numerous externalities that will impact on the operation of the competitive energy market. Several of these are outlined below.

C.7.1) Inflation

All monetary figures provided in this report are listed in equivalent December 2011 dollars (net of the impact of inflation) unless otherwise specified.

C.7.2) The impact of the Goods and Services Tax

Wholesale market prices are quoted exclusive of the Goods and Services Tax (GST). Hence, projections of the wholesale spot price are provided net of GST.