Responding to Peak Electricity Loads Using Renewable Fuel

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ABSTRACT

South Australia's existing electricity market is operated as part of the National Electricity Market. This operation works very well for the majority of the year when demand is moderate. Under these conditions normal fluctuations in demand result in predictable supply responses. However when demand is unusually high, in particular during the afternoons of extended heat-waves, the electricity market becomes much more difficult to operate and manage. Under these conditions, market prices peak excessively relative to power consumption variation. This paper evaluates the potential of using large scale storage of hydrogen to enable suppliers and market operators to manage peak loads more effectively. The hydrogen can be produced via electrolysis during periods when the potential supply of renewable power is greater than actual consumption – we designate this as "excess renewable energy". Stored energy could be used to supplement supply in response to actual demand during short periods of peak demand during heat-waves. A comparison is made between a preliminary estimate of excess renewable energy, and actual peak demand quantum energy per year. Various alternative peak-demand generation options, and market operation implications are also discussed.

1. Introduction

Australia's National Electricity Market (NEM) covers all eastern states, and South Australia. The rules for the operation of the NEM are written by the Australian Energy Market Commission (AEMC 2010), and are enforced by the Australian Energy Regulator (AER 2009). The Australian Energy Market Operator implements the rules and operates the market (AEMO 2010):

> "The NEM facilitates exchange between electricity producers and consumers through a pooled system where output from all generators is aggregated and scheduled to meet consumer demand. … Metering and financial transactions are facilitated by highly sophisticated technology systems that balance supply with demand, maintain reserve requirements, select which components of the power system operate at any one time, determine the spot price and facilitate financial settlement of the physical market."

The entire South Australian market forms a single region within the NEM, and has its own unique Regional Reference Price (RRP) variability. Figure 1 shows the present range of electricity prices. "Normal" prices vary from around $20-$80 / MWh. Note that on the left end of the RRP range in Figure 1, there exists a potential RRP for curtailed and/or withdrawn wind power – but this price is presently undefined in practice. At the right end of the range, the price is capped to a statutory maximum, presently $12,000 / MWh. Until recently this cap was $10,000 / MWh. In the summer of 2009-10, there were 11 extreme price peaks, most of which were capped.

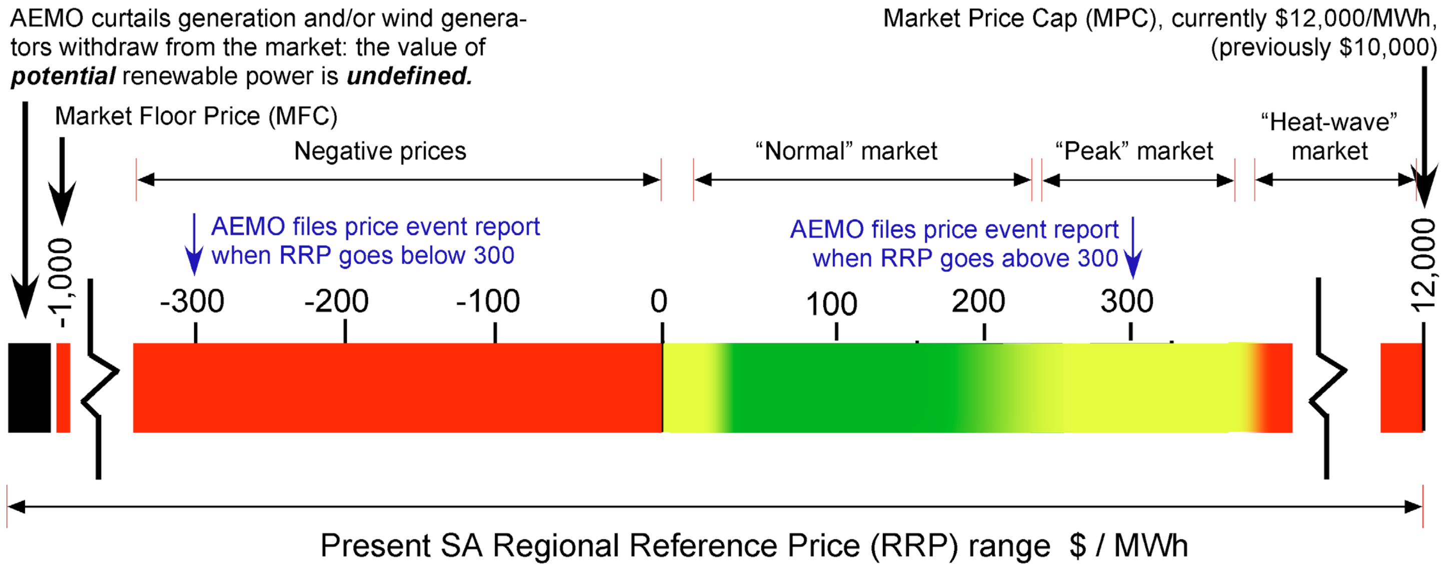

Fig. 1: The present range of SA's Regional Reference Price, including the undefined region below the MFP

Extreme price peaks occur when demand approaches or exceeds the available supply during the afternoons of heat-waves. As illustrated in Figure 2, demand correlates very well with ambient temperature during heat-waves. Hence these extreme price peaks are not driven by an inability to predict the peak demand.

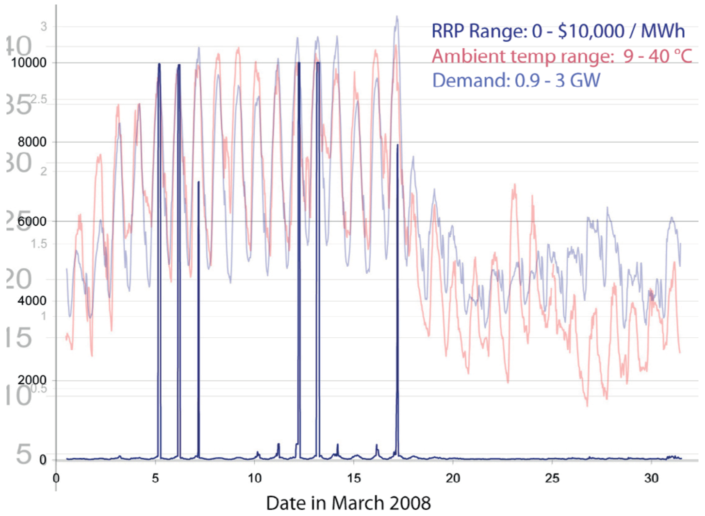

Fig. 2: March 2008 heat-wave: demand, ambient temperature, and RRP

Notwithstanding these extremes, for the most part, South Australia's price responses to demand and supply fluctuations reflect a stable and classical market economy. This is illustrated in Figure 3. Quoting from Cutler et al.'s conclusions: "For the 2008-9 data set, demand remains as the dominating factor affecting price in South Australia and wind power has a significant secondary influence" (Cutler et al. 2009: 30).

There are two notable features of the demand curve versus price variation in Figure 3:

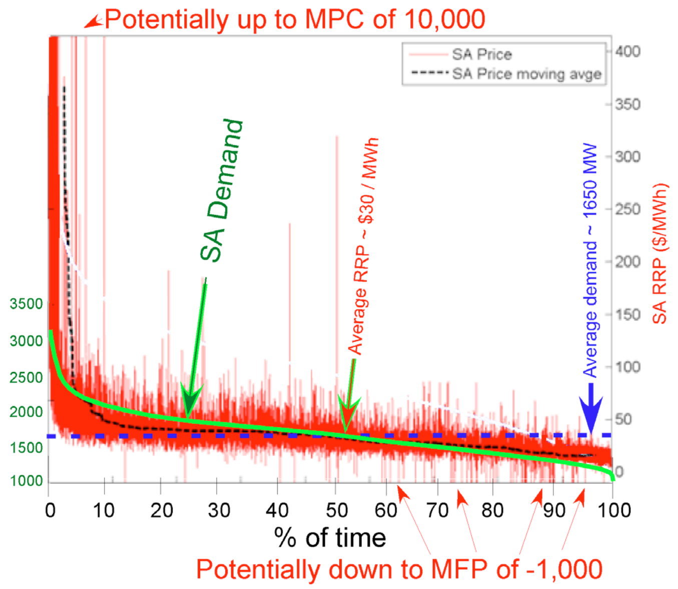

Fig. 3: SA demand and RRP graphs for the 12 month period July 2008 through June 2009. Adapted from Figure 5a of Cutler et al (2009)

1. During infrequent and short periods, (the left end of the graph in Figure 3) as noted above, prices peak to extreme values.

2. During frequent periods of below average demand (the right-most part of Figure 3) average prices become high relative to the demand curve. One potential explanation for this is that otherwise low prices during periods of low demand are smoothed out as a result of the layer of financial arrangements that operate outside AEMO's direct operation of the market. These arrangements include futures contracts and over-the-counter hedging contracts.

The excessively high prices on the left suggest that the present market is not creating sufficient incentives for generators to install additional supply capacity during heat-waves.[1] Similarly, the drop in demand relative to price on the right suggests that the present market is not creating sufficient incentives for suppliers to collectively and efficiently follow the low demand during overnight off peak times.

An introduction to hydricity

The term "hydricity" has been coined to describe the dual and complementary use of hydrogen and electricity as mutually exchangeable energy commodities (Sanborn Scott, 2008). By generating hydrogen during periods of excess supply and using it to mitigate peak demand, hydricity has the potential to address both of the above market operation instabilities. However, no detailed assessment of the viability of this concept in the Australian context appears to have been reported. Hence the overall aim of the present paper is to address the need for such an assessment.

In South Australia, during frequent periods when demand is so low that wind farms bid negative prices, renewable electricity could instead be harvested at operating capacity, transported to demand-side renewable hydrogen production sites, and either stored for later use or consumed immediately to displace natural gas consumption. The latter is beyond the scope of the present paper, but the notion of storing renewable energy for later use forms the crux of the present investigation.

The first aim of this investigation is to assess the emergence of periodic excess renewable energy production. The second aim is to quantify both the monetary value and energy quantum associated with the extreme price peaks. The third aim is to seek realistic electricity regeneration options for peak market supply. Finally, the fourth aim is to identify implications to market operational procedures.

2. SA heads for periodic excess renewable energy production

To demonstrate whether periodic excess renewable energy production may already be occurring, we present in Figure 4 the variation through a day of minimum, average, and maximum demand curves together with the supply of wind power generators and that of the Pelican Point CCGT plant, and the market price. These data are averaged over the 365 day period from June 2009 to May 2010. There is a well-defined minimum in all three curves, centred at about 4:30 am. The lowest maximum is about 1600 MW, and the peak demand is about 3100 MW. The lowest minimum is about 750 MW, so the ratio of highest to lowest demand overall, is about 4.

Note that the peak in daily market value is an order of magnitude higher in the middle to late afternoon, due to the electricity prices in the afternoons of summer heat waves being so extreme that their influence is still significant when averaged across the year.

The top part of Figure 4 shows the normalised average wind supply of several key wind farms across a diversity of geography (Cathedral Rocks, Hallet Wind Farm Stages 1 and 2, Lake Bonney Stages and 2, Snowtown, and Wattle Point). These data were sampled for the 3-month period of March to May 2010, but the general trend is clear. On average, wind supply potential is relatively flat over the course of the day, even though it fluctuates widely over the course of any specific day. Also, in contrast to wind power supply being relatively independent of demand, on average the Pelican Point plant follows demand. It dips to a low point at about 4:30 am.

The bottom part of Figure 4 presents the times when negative prices occur, and their impact market value. Over this 12 month period, South Australia half-hour RRP dipped below zero 91 times. For the duration of these periods, suppliers paid consumers to consume the "over supply". The drop in supply from Pelican Point correlates strongly with the morning peak in negative pricing, consistent with base load supplier expectations. Most suppliers seek to shed supply whenever possible under these circumstances, to minimise monetary losses. The exception is the wind industry, which can still generate net revenue under negative pricing, as long as their REC revenue exceeds the "negative revenue" from supplying energy to consumers during these periods.

The time-of-day period in Figure 4 of particular interest is from 2am to 6:30 am. South Australia's total wind energy capacity is already approaching of the lowest point of the minimum demand curve, and wind supply is not correlated with demand, but rather, for some wind farms at least, is inversely correlated with peaks in supply at night and lows during the day. As shown in the Pelican Point curve, conventional generators are already reducing their supply in response to low demand at night. However, further responses will be needed due to the increasing renewable energy supply that is emerging. As of early 2010, the capacity of operating wind farms was about 870 MW, and farms with a capacity of an additional capacity of 288 MW were under construction. Proposals with a capacity of a further 2570 MW were undergoing the approval process required in advance of future construction. Of this 2570 MW, about 1000 MW can be installed using existing network infrastructure, (Baker & McKenzie et al., 2010). Further, of this 2570 MW, only 240 MW is included in the additional 2000 MW envisioned for the growth in Eyre Peninsula wind farms proposed in a recent overview of the "Green Grid" (Baker & McKenzie et al., 2010). Clearly, this capacity will lead to significant periods when available wind supply exceeds minimum demand.

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[1] It might even be argued that as long as suppliers are able reap such extreme financial benefits from the artefact of limited supply relative to demand, there is a disincentive to install additional supply out of fear that doing so would reduce their profits.

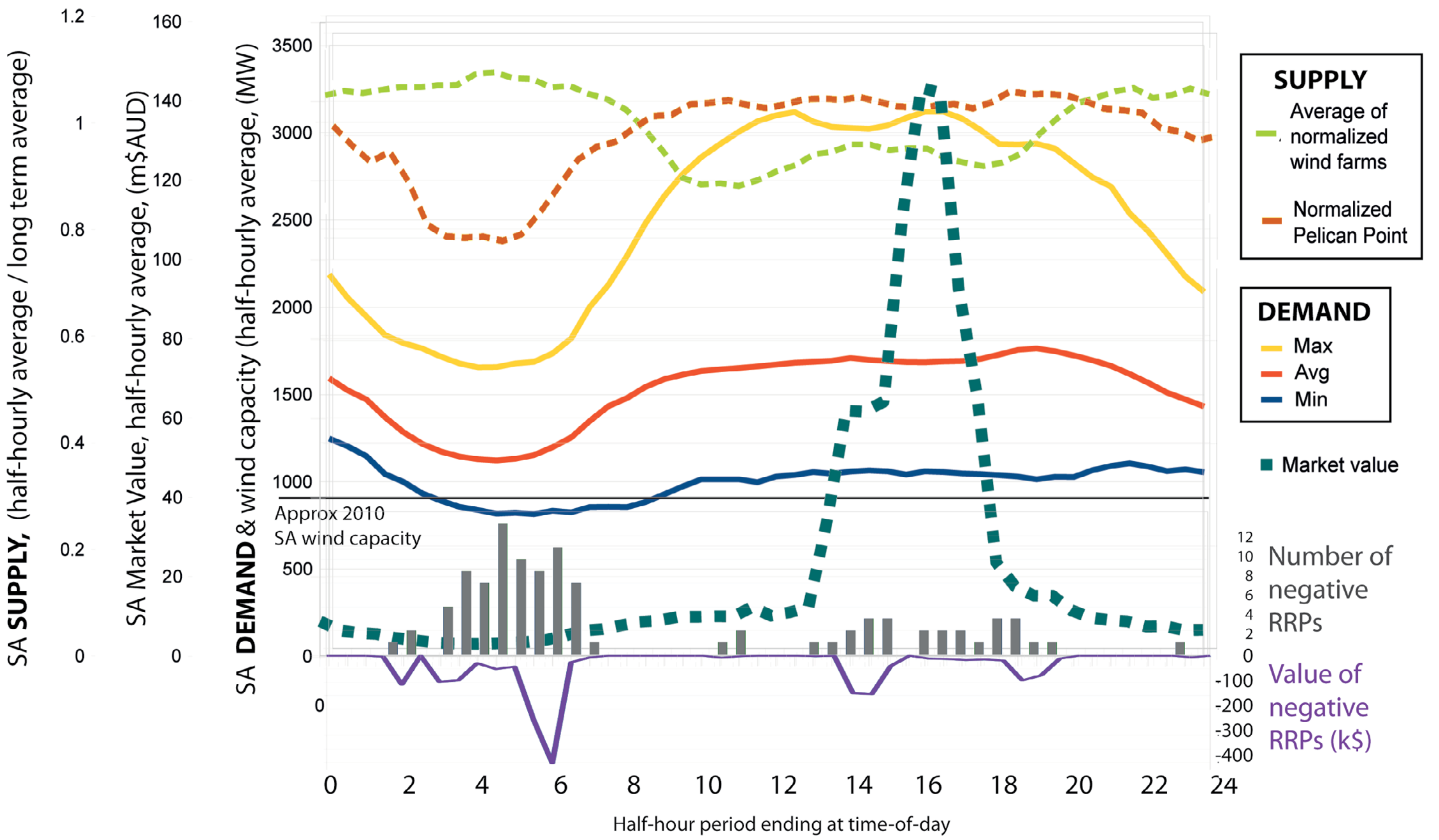
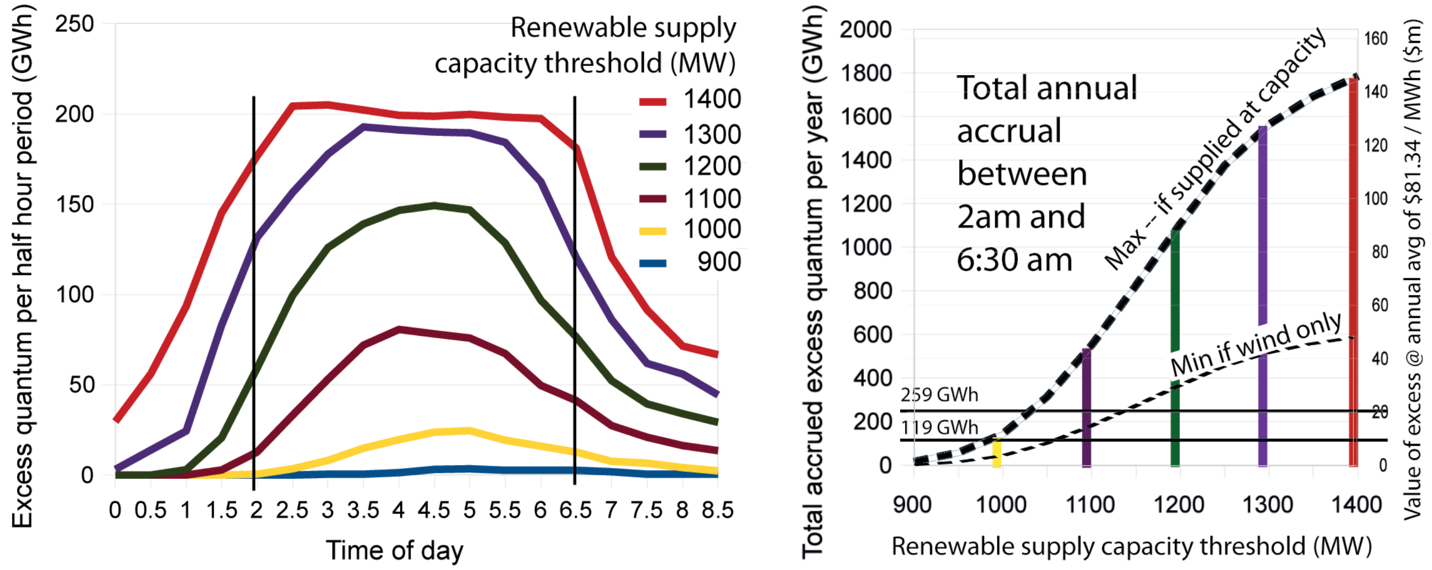


Fig. 4 Variation with respect to time-of-day, of demand and market value, averaged over 12 months (June 2009 to May 2010), and supply for March to May 2010. Data extracted from archived daily 5 min and/or 30 min data published on aemo.com.au



(a) (b)

Fig. 5 Excess night-time energy for a series of constant inputs; (a) variation of half-hourly average with respect to time-of-day, and (b) quantum of annual excess energy accrued between 2 am and 6:30 am each day, and its value based on the annual average for this period of $81/MWh.

Figure 5 evaluates the impact of increasing wind generation on the production of excess renewable energy, assuming no other changes in supply or demand. Note that, in principle, other forms of renewable energy such as geothermal, could contribute to these renewable energy quanta. However wind is expected to remain dominant in the immediate term.

Figure 5 a) plots the extent to which, in the period June 2009 to May 2010, an average half hour period would have resulted in an excess energy quantum had the deliverable renewable supply been at the capacity threshold in the legend. The curve in Figure 5b) shows the corresponding S-shaped quantum energy curve and its average market value (quantum times annual average price of $81 / MWh) starting from near zero at recent wind energy capacity levels, and increasing rapidly through realistic wind energy growth to about 1050 MW by 2011, and beyond through the remainder of the coming decade. The value of quantum energy values of 259 and 119 in Figure 5b) are of particular interest, because the top 259 GWh of quantum energy per year is worth about $700 million, and the energy quantum associated with periods in which the RRP exceeds $300 / MWh is about 119 GWh. Note that if the renewable supply remains exclusively wind power, then the curves in Fig 5a), and the upper curve in Fig 5b) represent the maximum possible excess for a given overall statewide installed wind capacity. In practice, on average, about one third of the excess based on the installed capacity would be realisable if the only renewable source is wind, because the typical capacity factor of wind farms is about 30% of its rated capacity. This is represented by the lower curve in Figure 5b). However for other potential sources of renewable energy in the longer term, notably geothermal and to a lesser extent wave power, the annual contribution to accrual would be as shown in the upper curve of Figure 5b), measured in terms of their production capacity.

3. Alternative responses to excess energy production

There are at least four alternative responses to substantial excess renewable energy production:

1. Dump the excess; i.e. selectively curtail (shut down) wind-turbines, geothermal heat transfer cycles, and so on, for the duration of the excess renewable energy production period. Clearly, this option should only be invoked if a profitable use of the excess energy cannot be found.

2. Export the excess to remote regions; e.g. this option forms a large part of the rationale behind the “Green Grid” (Baker & McKenzie et al., 2010). The cost of the proposed new infrastructure is of the order of 1.5 billion AUD. Sections 10, 11 and 12 of the report detail the high capital and operating costs of “accessing load centres in eastern states”. Section 13 of the report summarises the economic and employment impacts of the proposed Green Grid: increased GSP from construction, direct and indirect employment during construction, permanent jobs associated with operation and maintenance, and GSP increase associated with these maintenance jobs. However the public report does not address a key financial parameter: the revenue potential of excess renewable energy exported to the eastern states. In particular, this revenue will tend to be lower than average, because it is being sold at times when both local and eastern state demand is lower than average. This is an important consideration because this time-of-day dependent revenue will determine the intermediate and long term viability of such a proposal. The authors consider that without a thorough and publicly accountable evaluation of time-of-day dependent excess energy export revenue potential, this option has yet to be adequately evaluated.

3. Introduce new demand management procedures; a detailed consideration of this option is also beyond the scope of the present paper. (It is not presently clear how such procedures might be capable of eliminating the substantial drop in demand between 2 and 6:30 am, relative to the rest of the day).

4. Convert the excess to a renewable fuel; i.e. a more economically rational use for excess renewable energy, particularly in the near and intermediate term, might be to locally store it as a renewable fuel, and then either use it to displace natural gas (e.g. in large scale industrial fuel burners), or to regenerate electricity during periods when the local price of electricity is high. The former use is beyond the scope of the present paper, but the latter is the approach explored in the next section. That is, we propose introducing a new periodic electrical load in the form of intermittent renewable hydrogen production.

4. Quantifying the extreme peak price market

Figure 6 shows the cumulative value of the electricity market from June 2009 to May 2010. In the absence of an absolute definition, we choose to define an extreme price for electricity to be anything greater than $300/MWh. This is 10 times the average price. This is also the threshold above which AEMO is obliged to file a “Price Event Report” (PER). While the size of the peak demand is small relative to the annual quantum demand of 13.4 TWh, this market value graph shows that extreme price periods comprise about 70% of the value of the overall market. The dates of all the PERs for this 12 month period are indicated in the insets in Figure 6.

Figure 7 presents a series of cumulative demand thresholds for South Australia. Each graph represents the time to reach a given quantum of total energy supplied (in GWh) at power levels (in MW) at or above a given threshold.

On this basis we estimate the size of the heatwave demand peaks in particular at around 200 to 400 GWh / year. This is clearly at the bottom end of the curve in Figure 5b). The 2800 MW threshold graph in Figure 7 illustrates that Price Event Reports are associated with demand in excess of 2800 MW, while average summer demand increasingly influences the smoother shapes of remaining graphs.

Figure 8 presents both the hours of supply and the decremental fraction of the total SA market as a function of increasing demand. That is, with in-

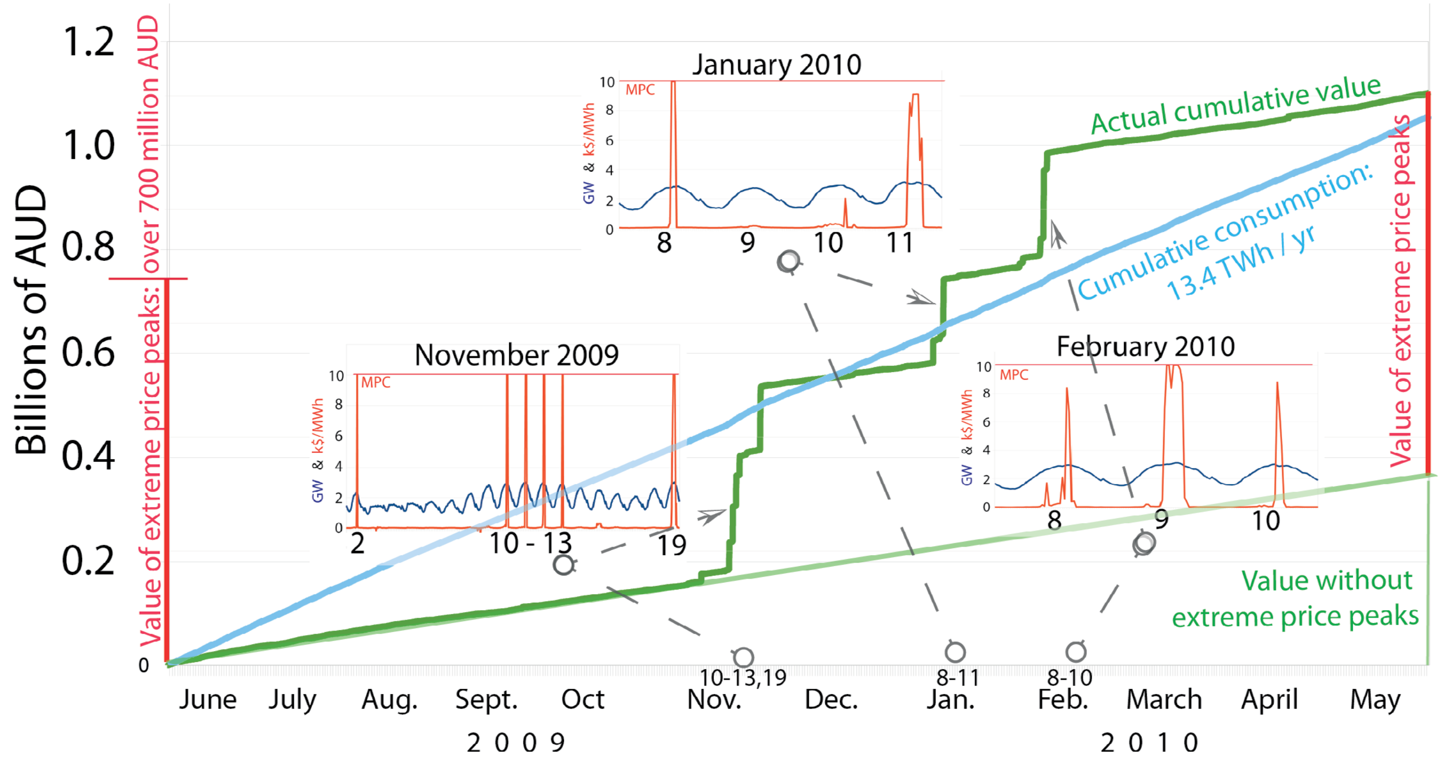


Fig. 6: The recent variation of South Australia’s Regional Reference Price, relative to the virtually linear cumulative growth of the market over the year in energy terms

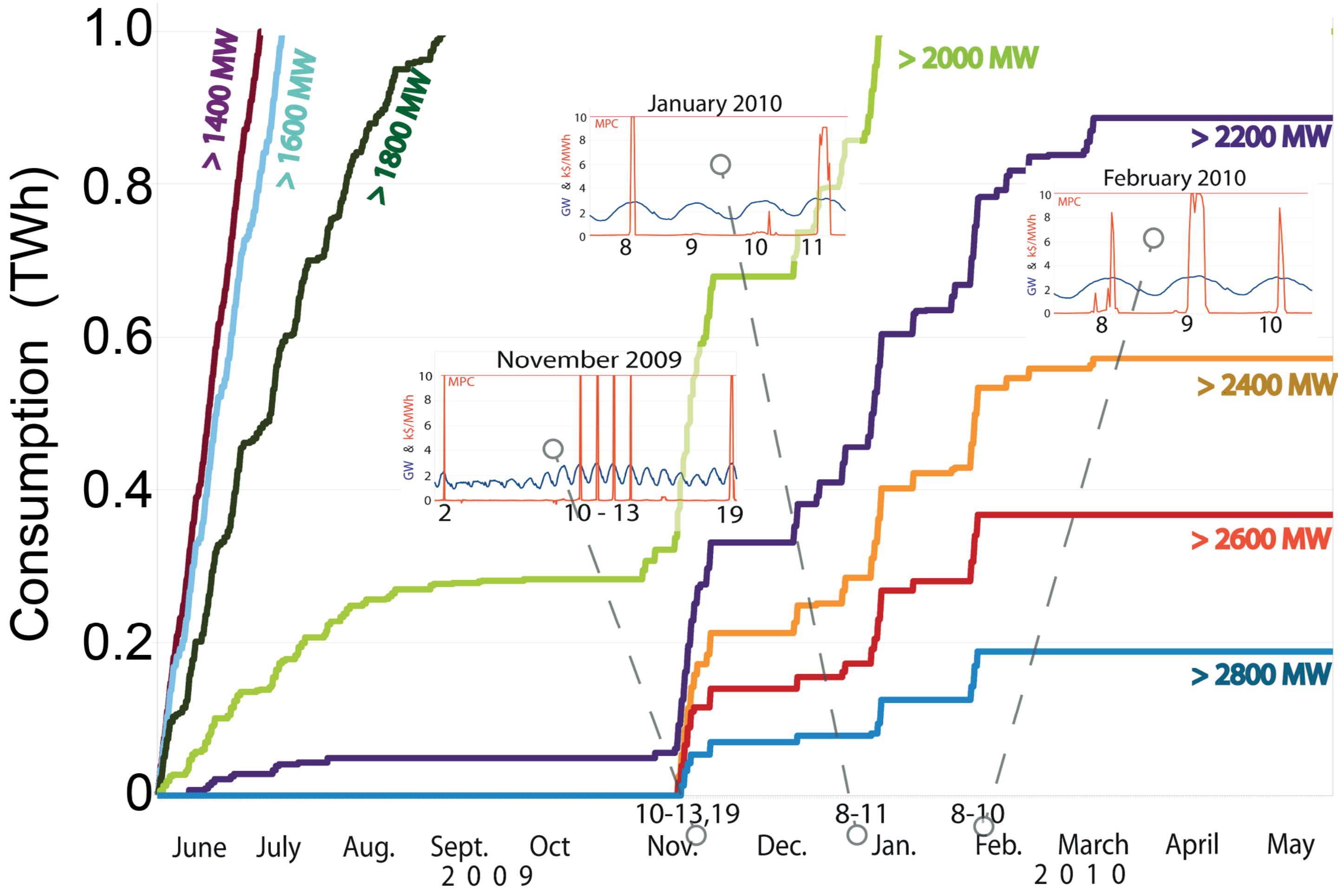


Fig 7: Cumulative South Australia electricity consumption. Each curve excludes all energy supplied during periods when SA demand is below the indicated threshold.

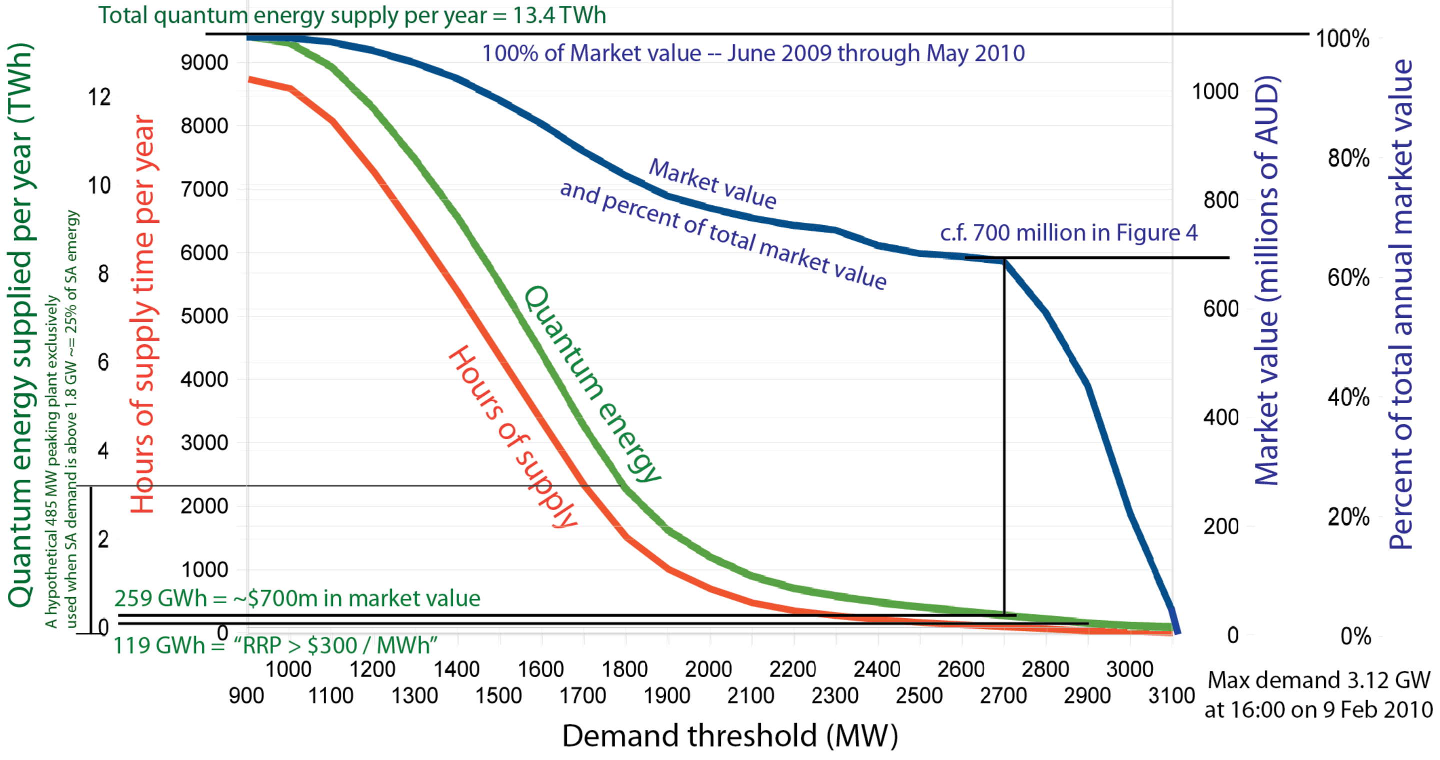


Fig. 8: The value of the SA market, the quantum energy supplied, and hours of supply per year, for a sequence of 0.1 GW SA demand thresholds above 1.4 GW

creasing demand (and supply) in MW, the fraction of the total market declines due to the decline in hours per year that demand (and supply) exceeds a given threshold.

The market value remains high up to about 2.7 GW. The top 259 GWh per year is presently worth about $700m. That is, 65% of the annual market value pays for delivering a mere 2% of the annual energy quantum! Again, this energy quantum is at the low end of the curve in Figure 5b), but would be worth at least an order of magnitude or two more if supplied to the grid exclusively during peak periods, relative to the value observed when demand is low. Hence it may be economically viable for the excess renewable energy to be stored and subsequently used to exclusively meet the peak demand. Importantly, this possibility is conditional on the availability of a suitable supply and intermediate storage business model, to exploit the high prices associated with the peak, thereby justifying the capital cost of systems to convert the excess energy to hydrogen, and of storing the renewable hydrogen until it is needed to contribute to supply during peak demand periods.

5. Energy storage economics to match high demand periods

The conventional approach to increasing electricity supply in South Australia in anticipation of shortfalls in supply during heat-wave afternoons, is to install a peaking plant, typically around 500 MW, using either an open cycle or a combined cycle natural gas-fired gas turbine generator. An example of the latter design is South Australia's 485 MW Pelican Point power station. Open cycle plants have a low capital cost, but also low efficiency, typically about 30%. Combined cycle plants have a high capital cost and high efficiency, in the range 50 – 60%. As shown in Figure 8, a hypothetical 500 MW peaking plant could provide 25% of the state's electricity needs if it were to only supply power when the state demand is above average (i.e. >~ 1.8 GW).

Extreme peak-demand periods (RRP > $300 / MWh)

Over the period June 2009 to May 2010, there were 43 hours in which the price exceeded $300 / MWh, with a total market value of $712m, and with a total of 119 GWh being traded, yielding an average price of $6,000 / MWh. Hence a 500 MW peaking plant supplying a mere 26 GWh / year of "top up" power over 43 hours would theoretically earn about $155m per year. However in practice, no system is likely to be viable if run exclusively for such a short period of time per year – the capital cost almost always needs to be paid off by selling power over much longer periods of time per year. For example, Pelican Point, despite being technically capable of operating as a peaking plant above 1.8 GW, is often operated at night as well as during the day, albeit usually being turned down to a lower output in the middle of the night (Figure 4).

A hypothetical option for supplying renewable "top up" power during extreme peak-demand periods (RRP > $300 / MWh) would be to blend "renewable hydrogen" and natural gas in a peaking plant during these periods. Most modern gas turbines operate in the lean-premixed mode. Accordingly, a fixed proportion of hydrogen is required to design for and control the resulting difference in flame speed (Dickinson et al., 2010). In turn, it becomes impractical to use a blended renewable fuel for supply exclusively during extreme peak-demand periods (RRP > $300 / MWh). If a blended fuel were to be used to all, it would have to used for all supply above about 1.8 GW (Figure 8) to be at least as economically viable as Pelican Point.

Table 1: An example financial calculation of electrolysis → fuelcell → grid supply above 1800 MW at a rate of 1% of SA market while up

			Basis of estimate
Capacity (number of 1 MW fuelcells)	18	Fuelcell MW	1% of 1800 MW @ 1 MW / fuelcell
Energy supplied per year (GWh)	27	GWh / year	(18 * 1508 hrs / yr (from Fig. 8))/1000
Excess renewable energy per year	80	GWh / year	27.15 / overall efficiency
Revenue from electricity sales	8.45	M$ / year	1% of 845 $m from Fig. 8 @ 1.8 GW)
Hours of excess production per year	1642	Hrs / year	4.5 * 365 (from Figure 5a)
Excess energy production rate	49	MW	
Number of 2.15 MW electrolysis units	23	units	
Total hardware amortization payments	8.39	M$ / year	Fuelcells: 15 yrs @ 7% Electrolysers: 25 yrs @ 7%
Revenue minus hardware payments	0.07	M$ / year	
Efficiency of electricity from fuelcells	0.5		Fuelcells: Ballard F C Gen , PEM
Efficiency of hydrogen from electricity	0.68		Electrolysers: Statoil Hydro 2.145 MW
Overall efficiency	0.34		

Above average demand periods (demand > 1.8 MW)

If the band of "peaking supply" is broadened to cover "above average" demand (> 1.8 MW) rather than exclusively targeting the extreme peaks, (RRP > $300 / MWh), then the renewable supply options are also broadened. For example, one option is to use decentralised large capacity fuelcells. The key advantage of fuelcells is that they are at least able to cost-effectively enter the market in modest increments, with each increment contributing to periods of above-average demand. Another advantage of this approach is that it would not require as much augmentation of the state's grid capacity.[2] Internal combustion engines are another option, but here we consider only the fuelcell option.

To assess the viability of market entry of fuelcells into South Australia, based solely on capital costs, we calculate net revenue as a function of energy supplied to the grid sourced from excess renewable energy, as presented in Table 1. For this calculation it was assumed that the excess renewable power is made available to the electrolysers without cost, (the wind farms receive substantial REC revenue relative to virtually zero marginal production costs).

The key benefit to note is that a positive return is likely to be possible from this market entry scenario, even without the fuelcell and electrolysis plant owners receiving a share of the REC revenues that the wind farms would receive. In summary, hydrogen as a storage medium for regeneration appears to be worthy of consideration when demand is above average (> 1.8 GW), but are not better suited than conventional alternatives for topping up supply in response to only peak demand (> 2.7 GW or > $300 / MWh). That is, all "exclusively top up" scenarios fail to provide enough revenue per year to pay off capital costs from supplying a mere 119 to 259 GWh / year.

6. Storage assessment

Low end: 18 x 1 MW fuelcells operating above 1.8 MW

For the "above average" supply scenario described in the previous section, the accrued energy is assumed to be produced from a 2.15 MW electrolyser outputting 485 Nm3/h over 4.5 hours, requiring an uncompressed storage volume of about 2.2 kNm3. The capital cost of 6000 psig compressors for applications of this scale range from about USD $ 40 – 100k (Drnevich 2003).

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[2] For centralised power stations, the peak power has to flow throughout the entire network in order to reach consumers, whereas for decentralised 1 MW supply units, the primary limitation becomes the Agreed Maximum Demand (AMD) used in network tariff arrangements.

Table 2: Computation of storage volume for accruing 119 – 259 GWh

Accrued turnover per year	119	259	GWh / year
Excess renewable energy per year	350	762	GWh / year
Hours of excess production per year	1643	1643	Hrs / year
Excess energy production rate	213	464	MW
Number of 2.15 MW electrolysis unit	99	216	units
Accrued volume per year	79	172	M Nm3

High end: 119 – 259 GWh of long term storage

As noted at the end of the previous section, all "exclusively top up" scenarios fail to provide enough revenue per year to be viable. Nevertheless, it is interesting to assess the hypothetical storage accrual required for the period between summer heat-waves: in the extreme, up to 12 months. Table 2 shows that 172 × 106 Nm3 of uncompressed storage would be required. Naturally this would significantly increase the capital cost of the plant and hence negatively impact the viability of this scenario, even if converted to liquid hydrogen and stored in sealed containment vessels to eliminate evaporative losses.

7. Market operation implications

A scheme to store energy such as that alluded to above cannot be established on the basis of existing market operational procedures alone, because there is presently no mechanism with which to account for and dispatch accredited excess renewable energy through the grid, in sync with dispatching accredited demand-side renewable energy consumption and/or storage components. The following discussion considers the need for such a mechanism, and how it might impact the operation of the market.

It is envisaged that, initially at least, excess renewable energy would be sold at near zero prices, but REC-accredited wind farms would remain viable by virtue of their REC revenue. In the longer term, REC revenue schemes will be supplanted by emissions cost recovery schemes of one sort or another (CPRS / ETS, tax at emissions source etc). By that time the cost of regenerated power would also become more competitive against emissions-intensive suppliers. Accordingly, no specific regulatory economics need be invoked to accommodate this part of the system.

The long term prospect for renewable hydrogen fuelled supply during peak periods looks promising. Even hydrogen fuelcells are likely to be able to enter the market without any special rules, providing that they are fuelled by hydrogen sourced from excess renewable energy. Hence no specific regulatory economics considerations are needed here either.

However, it should be noted that hydrogen can also be extracted from fossil fuels[3]. Even hydrogen from electrolysis cannot be labelled as "clean hydrogen" if the electricity is sourced from coal or natural gas. Hence, to achieve a clear and accountable net reduction in South Australia's carbon emissions from the approach alluded to in this paper, an overlay of both energy flow and price accountability is needed at the market operation level. This overlay would ensure that proposed consumption (and/or energy commodity conversion and storage) is dispatched when there is a substantial accountable excess of renewable energy supply. A software system for performing this task is the subject of another paper in preparation.

6. Conclusions

In conclusion, the emerging opportunity to exploit excess renewable-energy in South Australia is substantial. An economic analysis is presented to demonstrate that the option to exploit this excess energy in South Australia via hydricity is approaching viability. In this general scenario a new hydrogen market could be established alongside the present electricity and (emerging national) conventional-gas markets. The specific scenario in which accrued hydrogen is used solely to supply South Australia's peak-demand (> 2.7 GW) periods is found to be no more viable than other alternatives, all of which are unviable due to insufficient uptime per year. Further, even the "theoretical" potential of a new 500 MW generator to only supply South Australia's peak-demand (> 2.7 GW) periods, needs to be interpreted with caution: were a new generator of this size to be implemented, it would undermine the size of the extreme price market because available supply would no longer be as limited relative to demand.

More encouragingly, the specific scenario in which accrued hydrogen is used to supply above average demand (> 1.8 MW), is expected to become cost-effective in the near term, due to the mismatch of the relatively uniform supply of wind power over the course of the day and night, in comparison to the clear and substantial drop in demand during the night, and the limitations of other options to economically exploit this imbalance. Hydrogen generation offers the possibility to cost-effectively accrue energy at night, and supply it during the subsequent peak demand period about 12 hours later.

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[3] The most common hydrogen production method in use in Australia to date is steam methane reformation. This is used in chemical plants, steel making, petrochemical refineries and so on. It uses CNG as the source and emits carbon dioxide as a by-product.

Also note that the present analysis considers only one option to utilise the accrued excess energy. It accounts for neither other hydrogen use options, nor the wide range of broader societal and environmental benefits that would be derived from expanding the renewable energy generation in the state, nor the substantial fiscal value associated with improving the state's electricity network load factor by virtue of the exploitation of the network during periods when it is otherwise "idle". Hence, the potential to exploit excess renewable energy generally, is clearly worthy of further investigation.

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About

Hydricity SA provides energy systems design consulting services to South Australia's energy industry, and energy pipelines research community.

Its general focus is on the benefits of integrating alternative energy carriers. Its particular focus is on hydrogen and electricity (hydricity).

Application domains include harvesting excess renewable energy that is otherwise wasted, and enabling geothermal, solar and integrated solar-geothermal energy harvesting systems, to connect to gas pipelines for energy transport as a near term alternative to the eventual construction of high capacity long distance electricity transmission lines.

About Hydricity: dual and complementary clean energy commodities

*Renewable-energy traded as either **hydrogen** (stored fuel) or **electricity** (from load following harvesters).*