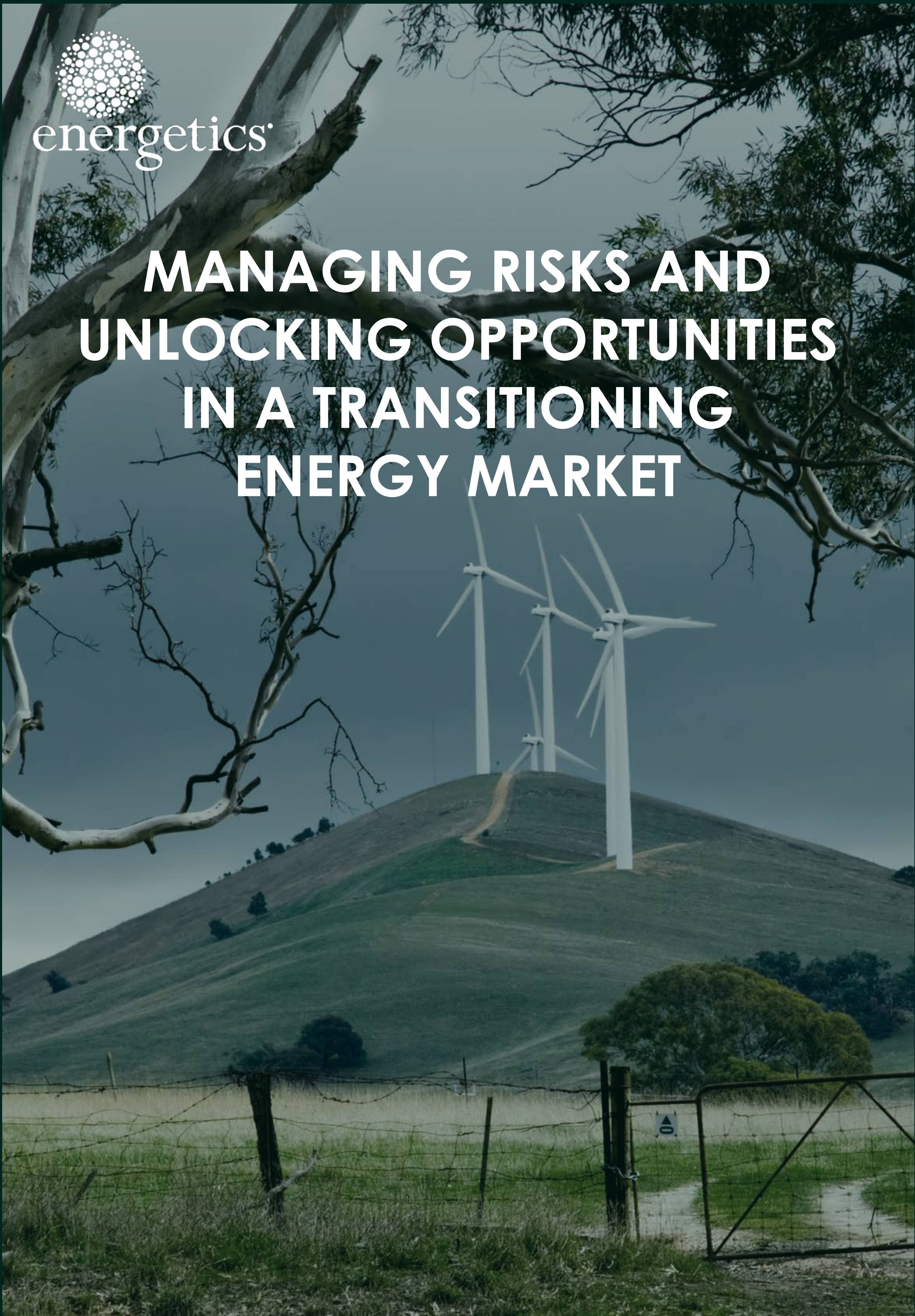
energetics

MANAGING RISKS AND UNLOCKING OPPORTUNITIES IN A TRANSITIONING ENERGY MARKET



ARTICLES IN THIS EBOOK

FROM THE CEO

With the majority of east coast coal fired power stations reaching the end of their asset life within the next two decades, and to be replaced by lower cost renewable energy solutions, Australian business is reliant on the federal and state governments to ensure an orderly, managed transition of our energy mix. However, the outlook is for electricity prices to remain high and the NEM to remain volatile, exposing large energy users to substantial risks, at least into the medium term. The good news is that there is a growing number of options available for taking back control of your energy spend and achieving energy budget certainty. In this ebook, we present a series of articles that explore the risks in detail and present the most effective approaches for mitigating those risks.

Businesses that can both contain and reduce their exposure to high energy costs, will obtain a competitive advantage. Should you have any questions, or would like to explore the suitability of options for your business, please contact me or the authors of the articles.

TONY COOPER
CEO, ENERGETICS

OUR EXPERTS

If you would like to connect with an Energetics' expert who wrote the articles in our eBook please follow the link to their LinkedIn profile. All authors are listed in order of article appearance.

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January 2018

Summer temperatures are rising. Will electricity prices in the NEM also soar?

Written by John Bartlett

When a new year begins, market speculators tend to reflect on the trends observed over the previous calendar year. For those engaged in our energy markets, we tend not to reflect on the experiences of the previous year overall, but instead prepare ourselves for the summer peak electricity period ahead. Some would say that nothing much happens in January, however historical data suggests that while temperature-driven electricity demand does not commonly peak until February, other environmental factors including droughts, floods and bushfires can all contribute to high spot prices independently of demand. In this article we will look at these and other drivers of price coming into the latter, hotter part of the summer.

Last summer saw significant price volatility, particularly in Queensland where extremely high demand during the December – February period resulted in an average pool price of $165/MWh, the highest in the National Electricity Market. As indicated in the table below, this compares with $71/MWh in the previous summer and $88/MWh in the summer period prior to that.

Table 1: Average NEM pool prices December – February 2014 to present

	Summer 2014/15	Summer 2015/16	Summer 2016/17	Summer 2017/18 to date
Qld	87.88	70.89	165.80	71.67
NSW	33.69	42.94	101.79	75.45
Vic	26.85	43.63	58.43	82.90
Tas	40.90	123.93	73.24	89.01
SA	35.76	52.86	118.49	83.30

This volatility triggered significant increases in futures prices, impacting customers seeking electricity contracts up to 2019.

Based on the historical relationship of spot market prices and futures prices, what should we expect when procuring energy agreements in 2018?

There are several key factors worth considering that may influence electricity prices over summer:

1. The impact of the Queensland government's intervention in directing Stanwell Corporation to **return the 385MW Swanbank E gas fired power station into service** in January (six months earlier than previously scheduled) as well as the direction to state owned electricity generators to modify pricing behaviour which, given their large market power, has been reportedly putting inflationary stress on electricity prices
2. Victoria's first summer **without the Hazelwood Power Station.** A 1,600MW brown coal fired power station which, while Australia's largest emitter of greenhouse gases, produced relatively cheap and reliable baseload power for the National Electricity Market.
3. AEMO's, ARENA's and select retailers'/aggregators' efforts in identifying, developing and implementing demand response capabilities and curb peak power consumption in times of system stress.

Downward price pressure
Starting with Queensland, introducing additional peaking generation will, in theory, put downward pressure on spot prices despite the higher cost of the fuel source. What remains to be seen, is the effectiveness of the government's direction to modify the pricing behaviour. This point is interesting as the state owned generators' profits go back to the state government - the same government who directed them to minimise behaviour aimed at maximising profits. If we trust that the State Government maintains this view and generators behave accordingly then we would expect reduced spot market volatility and as a result downward pressure on Queensland electricity futures market.

Upward price pressure
Victoria on the other hand is facing a summer without a significant amount of cheap baseload power, a gap which is mainly being filled with a large portion of more expensive gas power generation, ultimately setting a higher price. The step change has already been seen since Hazelwood came offline in March, with more electricity now imported from NSW. The real test this summer will be when both Sydney and Melbourne incur hot, high demand days, with prices likely to rise as both regions bid for power to meet local demand.

Improved security of supply
Finally, demand response could well be a quiet achiever. If executed it should help manage extreme demand and in turn help the states manage power flows across interconnectors. Focussing on NSW and Victoria, the level of interest in demand response has been unprecedented and this summer will be a real test of its effectiveness. Unlike the previous two points, while effective demand response would help minimise price volatility, its main focus is system security, so it will not be triggered solely by high prices.

When we consider the three points above, one could possibly see deflationary trends in Queensland and inflationary trends in Victoria, with NSW being influenced by the behaviours on each side of the interconnectors. The most significant of these changes is Hazelwood's closure, as it is a firm change to the supply demand balance. While this would mostly impact Victoria, NSW, Tasmania and South Australia will also be highly exposed to potential volatility.

Pricing in Queensland on the other hand, will be dependent on a change in corporate behaviour, as opposed to the clear shift in supply demand balance we note in Victoria. While some of the higher pricing coming out of Victoria can pass through to Queensland, if Queensland generators reduce their risk taking pricing behaviour we should see less volatility, and a reduction on the artificial price outcomes observed last year. If this does occur, one would expect pricing in Queensland to fall as the buyers fears, which pushed up the curve in the same period the year before, will be less relevant.

Our advice? Consider your individual circumstances

While these three factors are likely to have considerable bearing on pricing across the individual state jurisdictions in the NEM, the impact will vary according to your business' circumstances. If yours is a large energy using business investigating contracting options at this time, Energetics can help you assess the trends and assist with the development of a risk managed procurement strategy.

It's not just price. A corporate renewable PPA is a risk management strategy

Written by Gilles Walgenwitz

January 2018

In the past, the overwhelming majority of large commercial and industrial electricity consumers chose to hand the management of electricity market risks to their electricity retailers. The typical retail services agreement was a fixed price forward contract with some volume flexibility over the contract term. When wholesale futures contract prices were low and flat (around $35-$40 per MWh) such arrangements provided the most appropriate means of transferring risk for most end-users. After all, quantifying, managing and hedging volume and price risk is core business to energy retailers.

Today we see a very different landscape. With futures contract prices more than doubling across all market jurisdictions in the National Electricity Market (NEM) large customers have been reviewing their position and questioning the appropriateness of this simple risk transfer. More and more large electricity users are seeking to take back control and manage the cost of the retail energy component of their electricity bill differently. In doing so they need to weigh up the options against their business' risk profile and make risk/reward trade-offs.

In this article we look at the role corporate renewable power purchase agreements (PPAs)[1] can play in hedging against retail electricity price risks.

Mitigating price and volatility risks over the long term[2]

Consider the potential value of a corporate PPA to an end-user willing to source 20% of its load through a bundled supply arrangement from a renewable energy project providing power as well as Large-scale Generation Certificates (LGCs). Let's also include the cost of load balancing services from a retailer.

We then compare this retail PPA to the price of a business-as-usual retail arrangement, under which the price is based on a wholesale futures contract, retail contract premium and LGC pass-through charges. The following chart provides an indicative comparison over calendar years 2018 to 2020.

What we see from the comparison is that a PPA contract provides lower overall bundled prices. Across the three calendar years, the expected benefit narrows because of the current reduction in wholesale futures contract prices (base futures contract at $75 per MWh for delivery in 2020 vs $105 per MWh for 2018 in Victoria) and the expected reduction in the large-scale generation certificates (LGCs) pass-through charges applied by retailers in 2020[3].

Beyond its medium term attractiveness, a renewable energy power purchase agreement provides a long term hedge, with partially fixed or indexed prices for 10 years being typical. This is a much longer term than the conventional hedging strategy, which relies on entering into a fixed price forward contract with a retailer for the next two to three years. Electricity markets are not known for their liquidity and there is limited opportunity to secure a retail contract beyond a three year time horizon. Across all market jurisdictions in the NEM and across all exchange-traded futures products (base load strips, peak period strips), contracts are very thinly traded beyond two years.

The advantage of using a corporate renewable energy PPA as a hedge therefore lies in reducing long term volatility risk and removing the need to incur a liquidity risk premium and transaction costs on futures or forward contracts.

Renewable energy PPAs reduce the cost of green certificates

Under the Large-scale Renewable Energy Target scheme, wholesale purchasers of electricity, mainly electricity retailers, buy LGCs to meet their renewable energy obligations. The number of certificates each liable entity needs to source and then surrender is based on the Renewable Power Percentage (RPP) as set by the Clean Energy Regulator in each year, and applied to the amount of electricity acquired. This percentage is expected to increase from 14.22% in 2017 to around 20% by 2020. Currently these certificates are traded at around $85 by energy commodity trading firms. Retailers' offers to corporations for calendar year 2020 contracts include certificate prices at around $70 per certificate, leading to an expected additional $14 per MWh delivered.

The following chart shows the distinct price difference between LGC prices offered by retailers[4] for calendar year 2020 compared to the prices of separate forward contracts for LGC supply.

This material price difference (more than $10 per certificate on average over the nine month period of analysis) explains why an increasing number of corporations are looking into acquiring LGCs themselves, rather than bundling the purchase of certificates with a two or three year retail services agreement with their electricity retailer.

In addition, the bankability of a renewable energy project is influenced by the extent to which the project developer can secure firm pricing for both the power and LGC 'commodities'. The attractiveness of a bundled deal is such that a renewable energy project will typically sell bundled LGCs at a $10 to $20 discount compared to the price for LGCs where only LGCs are bought (known as an 'unbundled offtake'). As a result, when buying LGCs together with electricity via a renewable energy PPA, a corporation receives the benefit of the discount which is at a much lower cost than the environmental pass-through charges applied by retailers.

Beyond this ability to reduce the cost of mandatory LGCs, some corporations in Australia contract for a larger proportion of their load and get LGCs over and above the RPP requirements. Why? The objective is to leverage the green premium of the renewable energy project and secure a long term supply of high-quality voluntary carbon abatement permits to **meet a greenhouse gas emissions target or trajectory**. Some large end-users, especially Australian real estate investment trusts, also want to meet NABERS rating targets and source GreenPower through a PPA contract. They seek to contract with projects carrying a GreenPower Connect accreditation.

When assessing the value and options around corporate PPAs your business should also consider its climate change strategic intent. The treatment of LGCs and the value ascribed to these commodities needs to be clearly understood upfront taking into account the National Carbon Offsets Standard (NCOS). Your climate change strategy will impact decisions around the offtake volume and commercial terms you need to secure from a renewable energy PPA contract.

Clarify your risk capacity and appetite

In order to manage your electricity market and climate change risk exposure, there are a number of renewable energy PPA contracting and pricing arrangements. The model you choose needs to align with your business ' risk profile, noting that there is not a single, well-accepted PPA model that can cover all end-users' goals, risk capacity and risk appetite.

The following risks deserve special attention:

- **Partial spot market exposure**, especially the ability to deal with the lack of predictability of an annual energy budget and the capacity to alter consumption in response to market prices.
- **Additional corporate obligations**, such as hedge accounting treatment (hedge effectiveness testing) and the possible need to get an Australian Financial Services Licence if entering into an energy derivative contract.
- **Changes in law**, especially around the LRET and possible impact on the value of environmental tradeable certificates over a long term PPA contract.

When conducting a risk review, you will need to gauge your ability to implement and manage controls that can mitigate such risks, noting that there are many ways to reduce, transfer or avoid these and other risks.

Formulate your renewable PPA preferred model

Once options, risk capacity and risk appetite are well defined, your business has the basis upon which an informed decision can be made on the optimal level of risk to take, the preferred renewable energy PPA contract model and pricing model.

In instances where corporations want to remove some of the volatility from their electricity costs, they can enter into a long-term 'physical' PPA, which involves price firming by a retailer and integration, one way or another, of the renewable energy generation output into their retail services agreement[5].

Others, recognising the complexity of such tri-partite arrangements and likely additional contract premium, are prepared to enter directly into a long-term 'financial' PPA, which uses revenue from the spot market as a hedging instrument to offset changes to retail energy costs.

Table 1 below summarises the risk/reward trade-off. It is critical to understand how effective a renewable energy PPA arrangement can be in hedging your corporation's future electricity prices. The locational basis risk and the effectiveness of the hedge, i.e. the strength of the correlation between the price of your electricity supply and the price of a PPA contract, are two key elements to assess. Energetics can advise on how these factors can apply to the contracting structure and pricing arrangement your business pursues.

Finding the right risk-reward trade-off for your business

Over the last couple of years, Energetics has been approached by a number of corporations seeking advice on the attractiveness of a PPA price offer by a renewable energy developer. Every time we had to broaden the discussion beyond price, as the best PPA solution depends on both the proposed price and the level of risk tolerance within an organisation. The greater the aversion to risk the more the optimal approach moves from managing wholesale pass-through to transitioning to forward contracts on the retail side; and from a financial hedge to a retail 'physical' PPA on the renewable energy supply side.

By taking an integrated approach to managing risk, understanding the needs of the organisations involved and the range of contracting options available, Energetics has been successful in securing both financial and retail 'physical' PPA arrangements. Please contact us if you would like to understand more about where the opportunities may lie for your organisation.

Table 1: RIsk/reward trade off for PPA models

PPA model	Key benefit	Key risk
Enter into a financial PPA (derivative contract) to mitigate impact of shocks to energy prices	Low PPA rate and transaction costs	Partial hedge – needs active risk management
Enter in a retail 'physical' PPA to remove some of the volatility from energy spend	Firmer price with load balancing at retail rates	Market for sleeving services by retailer is still under-developed - comes at a cost but preserves upside potential while eliminating downside risk

Figure 1: Comparative analysis of retail contract with and without a renewable energy PPA

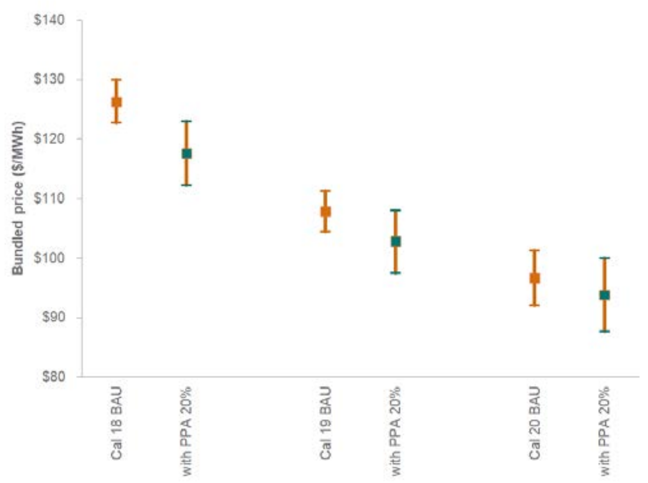


Figure 2: LGC pass-through charges vs LGC forward contract prices

Footnotes

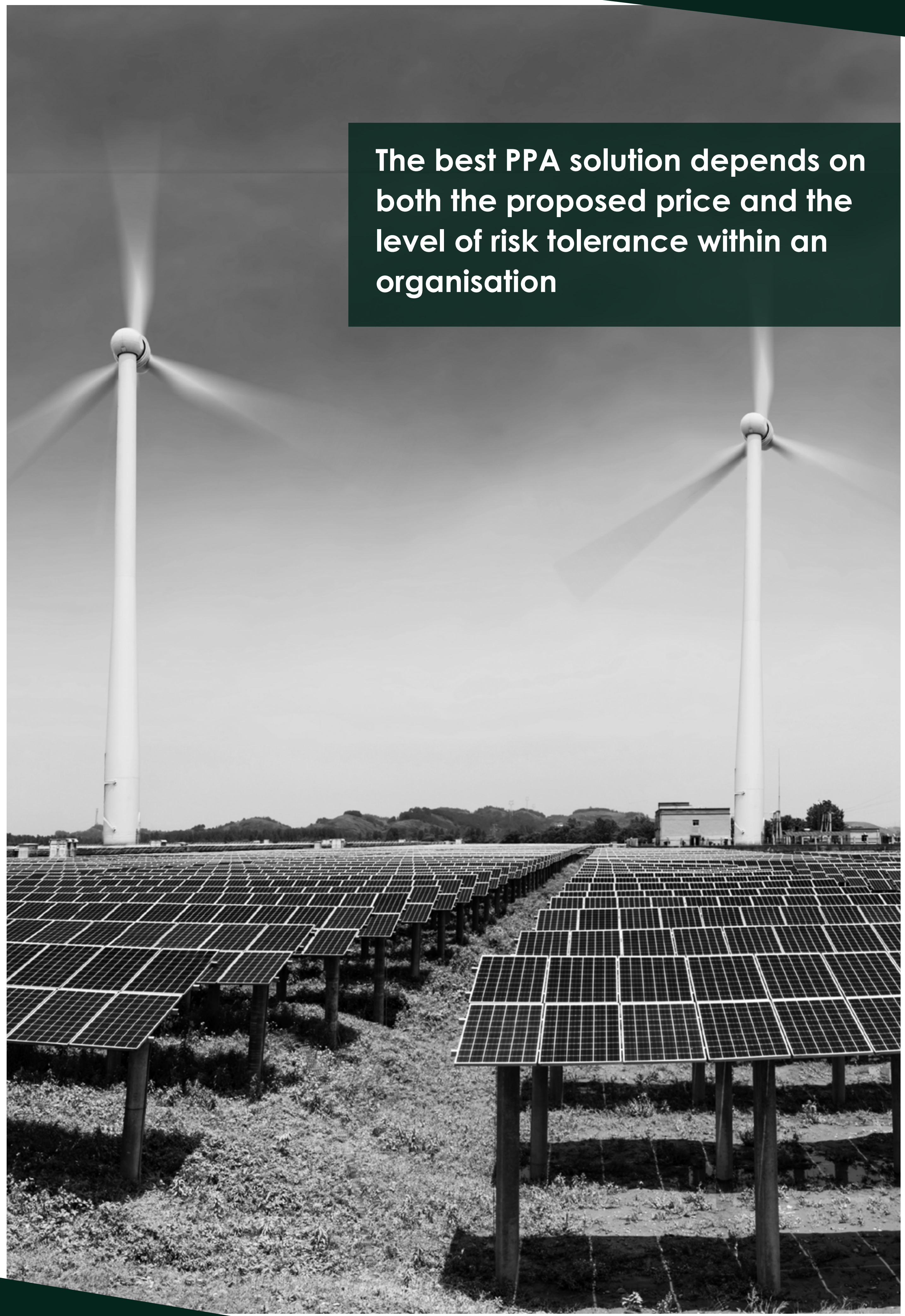
1 Power purchase agreement with a utility-scale, in front-of-the-meter, renewable energy generator (solar farm, wind farm, energy-from-waste power plant)

2 Consider as well your business ability and economic rationale to implement energy efficiency projects, on-site generation capacity and demand response capabilities

3 The expected reduction in pass-through charges in 2020 is in line with forward projections for this green commodity

4 Based on a sample of retail offers received by Energetics over the last nine months. Prices are averages of offers received. "Spot" prices represent actual trades for immediate delivery as reported by energy commodity trading firms

5 E.g. price reset mechanism, back-to-back electricity swap agreement



The best PPA solution depends on both the proposed price and the level of risk tolerance within an organisation

January 2018

Corporate PPAs took off in 2017 – who were the leaders?

Written by Anita Stadler

At the start of 2017, the rising costs of grid-supplied electricity, coupled with the falling costs of renewable energy production were narrowing the price difference between renewable and traditional energy sources. Energetics' advice (reported by the **Clean Energy Regulator**) was that contracting with a renewable energy generator to meet all or part of your energy supply needs was a **commercially viable proposition**.

Our advice still holds true in 2018 as outlined in the graph below. During competitive tenders for standard fixed term, fixed price Retail Service Agreements during 2017 we observed a softening in contract prices for delivery in FY2020 compared to FY2018. However, at $75/MWh for electricity and $65 for LGCs[1] there is still a significant premium on PPA prices. Although it is market practice not to disclose pricing details for PPA transactions, Origin mentioned in the media that it secured a PPA with Goldwind for the Stockyard Hill wind project in Victoria at prices closer to $50 than $60[2]. This was a large deal, with prices for corporate 'financial' PPAs typically higher due to differences in the scale and risk profile of these transactions[3].

This clearly illustrates that there is significant value at risk by continuing to treat electricity cost as an overhead, rather than an opportunity to add value to the bottom-line. It is therefore not surprising that many large energy users saw the opportunity and are now taking a more strategic approach to energy cost management.

Who led in 2017?

By mid-2017 Sun Metals, Telstra and had Sunshine Coast Council announced deals[4] in Queensland, with transactions also concluded by UTS[5] in NSW and Nectar Farms in Victoria[6].

In November, the Melbourne Renewable Energy Buying Group announced that it **became the first buying group in Australia to contract "firm supply" of electricity and LGCs** from a specified renewable energy project. Energetics was an advisor to the deal. The group consisted of 14 private and public sector organisations as listed in Figure 2.

In the second half of 2017 Adelaide Brighton announced a deal with Infigen[7], and in December 2017 a Telstra led buying group consisting of ANZ, Coca-Cola Amatil and University of Melbourne concluded a PPA transaction in Victoria[8]. By mid-January 2018 the University of NSW announced that it reached an agreement with Maoneng Australia and Origin Energy to have 100% of its energy supplied by solar PV[9].

Many other organisations have publically announced their active exploration of corporate PPAs as a risk management strategy, including Coles, Sydney Metro NorthWest[10], Monash University[11] and the Southern Shire Regional Organisation of Councils (SSROC)[12]. Others are pursuing this opportunity confidentially, many of which have engaged Energetics for strategic energy market advice, business case development and transaction support. Experience from these transactions demonstrates the importance of engaging the CFO and the board in developing and understanding the corporate PPA value proposition.

Given the broad spectrum of organisations that have successfully concluded transactions, using a wide range of contract and pricing models, we believe 2017 was indeed the tipping point for corporate PPAs in Australia. Based on the current market conditions, we expect this trend to continue in 2018 especially given the scale up in renewable energy project development over the last two years which provides a competitive pool of projects and counterparties.

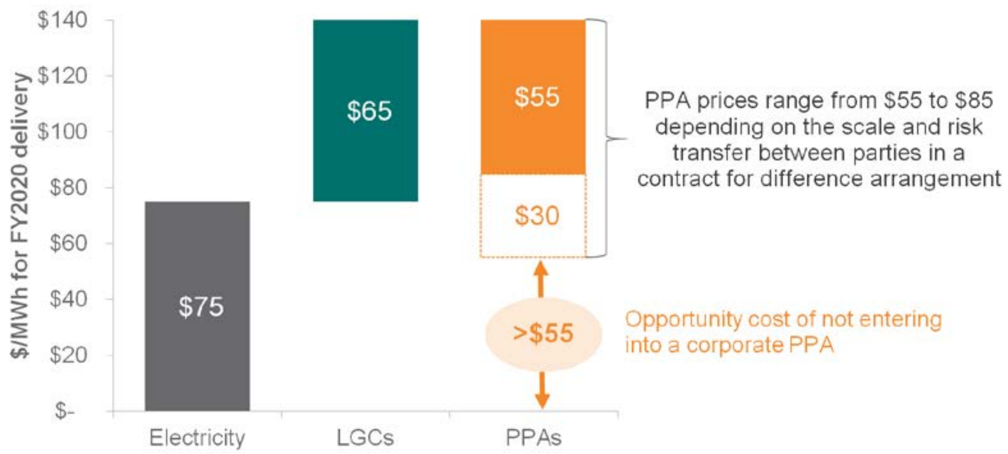


Figure 1: Cost per MWh for FY2020 delivery

Figure 2: Melbourne Renewable Energy Buying Group

Principal partners

Energy partners

References

1 Read **It's not just about price - corporate renewable PPAs are a risk management strategy** see in this article evidence of the premium extracted by retailers for LGCs

2 **http://reneweconomy.com.au/origin-stuns-industry-with-record-low-price-for-530mw-wind-farm-70946/**

3 Under a **'financial' corporate PPA**, the energy generated by a renewable energy project is not delivered directly to the corporate, but sold to the market. The market price received for that power may be different to the price agreed between the corporate and the generator. When the price the generators receives on the spot market is higher than the agreed PPA price, the generator will pay the **corporate the difference**, and vice versa. This is a contract for difference. Under this PPA model the corporate must continue to buy electricity consumed on its sites from a retailer.

4 **http://www.abc.net.au/news/2017-06-05/telstra-sun-metals-glencore-solar-energy-security/85892**

5 **http://newsroom.uts.edu.au/news/2015/09/uts-takes-lead-customer-led-renewables**

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Electric vehicles will change the world. What could it mean for your business?

Written by Matthew Sprague

January 2018

The hype around electric vehicles has been around for some years 'driven' in large part by Elon Musk and Tesla. Momentum has grown since the Tesla Roadster sports car was launched back in 2008, followed by the model S and the model X[1]. The Chevrolet Bolt was the first mass market electric vehicle released in 2016 and Tesla have since announced their Model 3 for broader markets. With the development of battery technology and falling costs, has the time for electric vehicles (EVs) arrived? What are the possible environmental and cost implications?

Over 2017, Energetics has seen interest from an increasing number of businesses and governments to understand not only the rate of growth in the EV market, but the implications for Australia's emissions eduction targets. In this article, we share our insights and analysis.

40-60% of the Australian car fleet is forecast to be electric by 2050

There are currently many competing EV technologies. The main three are the petrol hybrid, plug-in hybrid electric vehicle (PHEV) and battery electric vehicles (BEV). A battery electric vehicle (BEV) uses rechargeable battery packs and have electric motors connected directly to the wheels instead of an internal combustion engine to power the vehicle. Whereas a PHEV has an internal combustion engine (ICE) to either recharge the battery or to provide extended range capabilities. PHEVs have the ability to be recharged from grid electricity to reduce the consumption of hydrocarbon fuels.

Based on the Bloomberg report **Electric Vehicle Outlook 2017**[2] we expect PHEVs to represent a major proportion of EV sales from now to 2025. However after this, BEVs should be the majority of EV sales. This is due to a number of factors and they're not just financial. Other compelling drivers include the lower engineering complexity, lower cost of ownership and higher emissions savings, and as the price of battery technology reduces, the cost of ownership of BEVs falls.

Furthermore, the International Council for Clean Transportation[3] compared the first-owner four year cost of operation for a medium passenger car. This analysis finds that the costs of owning and operating an EV becomes competitive with an equivalent ICE vehicle by the mid-2020s, after which point EVs are likely to be cheaper. Figure 1 shows the average cost of ownership for EV technology (of 100, 150 and 200 mile electric range) compared to an ICE vehicle.

Importantly, the upfront cost of an EV is also forecast to be less than that of an ICE vehicle by the mid-late 2020s. The forecast of a crossover in competitiveness by 2025 is shared by other analysts including Bloomberg New Energy Finance[4] and UBS[5]. Together, these forecasts suggest that the total cost of ownership and then the purchase price of EVs will fall below the corresponding figures for ICE vehicles within the next few years. Once this occurs the financial barrier to the uptake of EVs will fall away.

Globally, electrified alternatives to ICE vehicles are expected to approach cost competitiveness within the next decade[6, 7], suggesting that the switch does not have to impose significant consumer or economic costs. EVs are already cheaper to operate and maintain. When the purchase cost reaches parity we will see a large disruptive force in the transport market.

A range of predictions for the uptake of EVs in Australia are available, however **40-60% of new vehicle sales by 2050** seems a conservative estimate. With around 137 million cars being sold globally in 2050 and approximately two million in Australia, this **equates to around 800K-1.3M new EVs on Australian roads each year.**

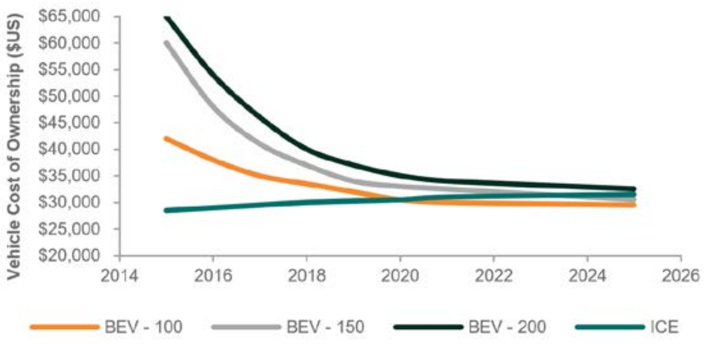

Figure 1: Cost of ownership of EVs[8]

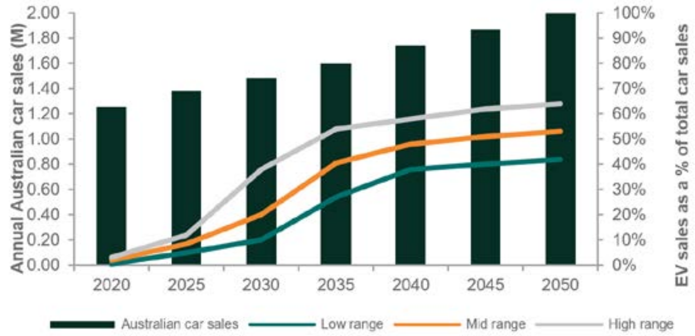

Figure 2: EV% of total car sales[9]

Watch for developments in China and India

India and China are growing their EV fleets, with the latter seeing EVs as an opportunity to leapfrog the traditional ICE manufacturers. As both nations have struggled with significant urban air quality issues, EVs offer a pathway to addressing this challenge. With EVs producing zero emissions at point of use, the air quality will be drastically improved in heavily populated cities such as Beijing and New Delhi. As these countries invest heavily in EV technology, the cost of EVs will drop further[13]. India is seeking to make all new cars electric by 2030[14]. With transition on this scale, increased demand and the entry into the market of non-traditional manufacturers, EV take-up globally, and in Australia, could occur more quickly than forecast.

What could EVs do for the task of reducing national emissions?

Life cycle assessments have shown that ICE vehicles produce most of their carbon emissions during their operational life. The EVs on the other hand have much higher start-up emissions due to the resources and energy required to produce the batteries.

The operational emissions from EVs are directly linked to the emissions intensity of the electricity used to recharge the battery. Australia's electricity system is slowly decarbonising[20] as renewable energy implementation increases. With recent renewable energy and battery projects announced, and the retirement of coal fired power stations, the emissions from EVs will drop significantly. Ultimately, the environmental case for high EV use will become undeniable. Increasing the use of renewables will further boost this case.

What roles could governments play?

Government readiness

The business case for EVs is compelling and potentially there is no need for additional resources or incentives from governments to accelerate EV take-up. However, the impacts on communities, work and the broader economy are potentially disruptive. Therefore planning and readiness for this transformation is essential.

Currently the roads and infrastructure budget is mainly funded through fuel tax, with other taxes including registration and licence fees.

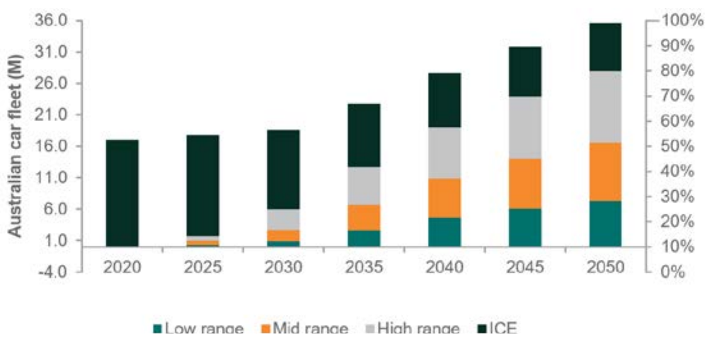

Figure 3: EVs in Australian car fleet[10]

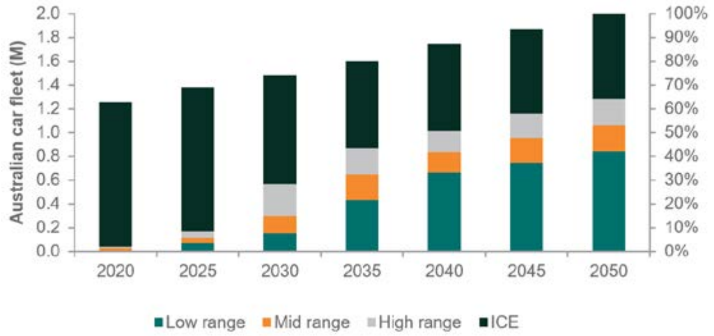

Figure 4: EV car sale predictions[11, 12]

However, as EVs become more wide spread, the reduction in revenue from fuel excise could cause a large budget 'black hole'. The shortfall is estimated to be billions of dollars and present a significant challenge for policy makers and infrastructure planners[21].

Governments also need to ensure that there are no barriers within their planning and legislation rules to restrict the implementation of charging stations and home based EV charging solutions. The infrastructure needs and implications of EVs are significantly different from those of ICE vehicles, suggesting that government approvals should be designed to smooth what could otherwise be a challenging transition. Certainly in the NRMA's 2017 report, The future is electric, we see six recommendations to Australian governments that include the establishment of an intergovernmental panel to manage the transition and support for the rollout of charging infrastructure, especially in rural and regional areas[22].

The reduction in ICE vehicles will have a significant impact on the traditional automotive industry. The employment of mechanics will reduce as more technical electronics knowledge is required. The skill base requirements will be disruptive to this industry. The NRMA is moving towards EVs[23] but small mechanic businesses throughout the country are unlikely to be prepared for a significant shift.

This change in the skills required and the impact on state and federal budgets means that different strategies will be needed to maintain and manage our future infrastructure and work force needs.

Increase in public charging stations

As with any disruptive technology a number of barriers have been identified that will impact the take up of EVs. The main concern is around the range and the charging time. With current, high end EVs having a range of over 500km[24], the issue becomes the time to charge. A network of charging stations that enables longer journeys is widely regarded as a pre-requisite for mass EV uptake. This is true even in markets where most vehicles' daily travel is far less than the maximum charge distance[25]. Hall and Lutsey[26] found that in high-EV-uptake markets the public provision of charging stations is much higher than in markets with relatively low EV uptake.

A second question is the type of charging station provided. 'Level 1' charging points provide less than 2kW of power, and so an EV needs to be connected for eight or more hours to fully charge. These are typical at-home chargers accessed by a standard power point. 'Level 2' charging stations provide power of 3.8-22 kW, charging at a rate of 18-40km/hour. These are significantly cheaper than DC fast charging stations, which operate at 50 kW or above and can recharge an EV in under an hour. The costs of charging infrastructure differ significantly across different markets.

However, we can also see a strong business case for enterprises such as shopping centres, parking stations and restaurants to offer charging facilities which in turn can encourage patronage. In capitalising on this business opportunity the required infrastructure for an EV fleet could grow considerably.

End of life recycling

With battery production costing a high proportion of the total energy consumption, a robust recycling model must be established. With high value materials a recycling scheme will not only reduce emissions but total cost of EV production. Currently around 80% of ICE vehicles can be recycled[30]. This level, if not higher, needs to be achieved for EVs. There is not a large enough EV retirement rate to merit a recycling system; however as the number of EVs increases, this scrappage will increase[31].

EVs are coming!

Transformational technology always takes time to gain traction in the market but the business case and environmental benefits point to a high uptake of EVs. Arguably consumers are likely to move towards EV ownership with or without Government intervention however opportunities exist for Government and business to lead by example by not only transitioning their own fleets to EVs, but by implementing the charge point model to offer greater value to customers and increased revenue.

The experience in other markets across the world

"Electric vehicle owners in California more frequently have access to home and workplace charging, and one public charger per 25 to 30 electric vehicles is typical. In the Netherlands, private parking and charging are relatively rare, and one public charger per 2 to 7 electric vehicles is typical." A similar range is found across multiple studies[27, 28]

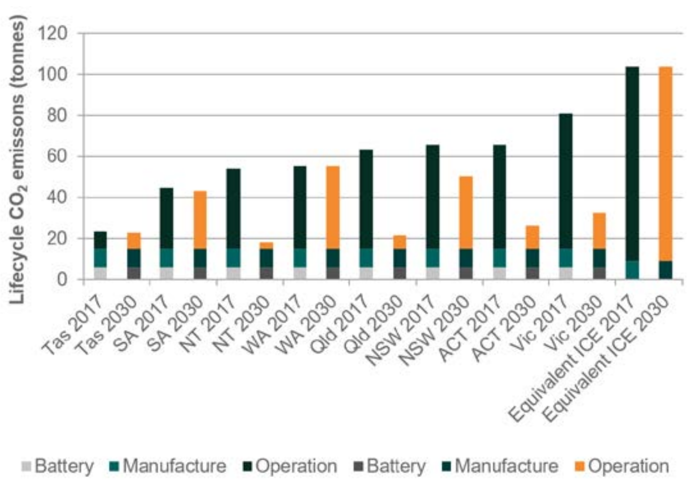

Figure 5: Life cycle carbon of EVs per state[15]

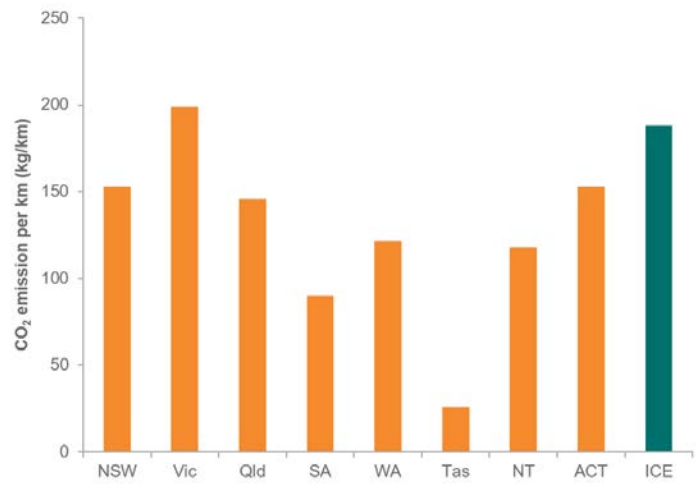

Figure 6: CO_2 emissions per km per state[16, 17, 18, 19]

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February 2018

Does your business spend more than $50m in electricity or gas? Could you participate in the wholesale energy markets?

Written by John Bartlett and Rebecca Harvey

With the outlook for energy in 2018 being one of persistent high prices on the east coast, industrial consumers are exploring the options available for taking back control of their energy spend. One option very large electricity and gas users can consider is to manage their own purchasing arrangements through the wholesale market. To do this they need to register as a 'Market Participant' with the Australian Energy Market Operator (AEMO). In this article, Energetics outlines the requirements.

What does being a 'Market Participant' allow my business to do?

The vast majority of electricity and gas consumers contract their energy supply through retailers who, with expertise and buying power, manage the market, regulatory and legal risks associated with being a Market Participant. If a business chooses to bypass an energy retailer and become a Market Participant they have the ability to directly negotiate electricity and gas contracts with a counterparty which is typically linked to a generator or gas producer. Energy users of significant size can potentially justify the additional risks and administration based on the potential savings that could be achieved by negotiating better energy rates. It is however, a large step to take which involves navigating numerous legal, regulatory and financial requirements.

Managing an energy portfolio is also time consuming, and while businesses may already hold expertise in trading commodities such as grain or oil, energy and in particular electricity, cannot be stored and therefore trades on a 24/7 spot market. This round-the-clock trading activity requires on-call support in case of market events which may impact the Market Participant.

Currently large consumers who are registered as Market Participants employ specialist staff to manage the risks as energy traders in the relevant gas or electricity markets. Depending on the nature of the business, these traders might also become sellers of electricity or gas and as a result make a profit through these sales without negatively impacting core business activities.

What does registration involve?

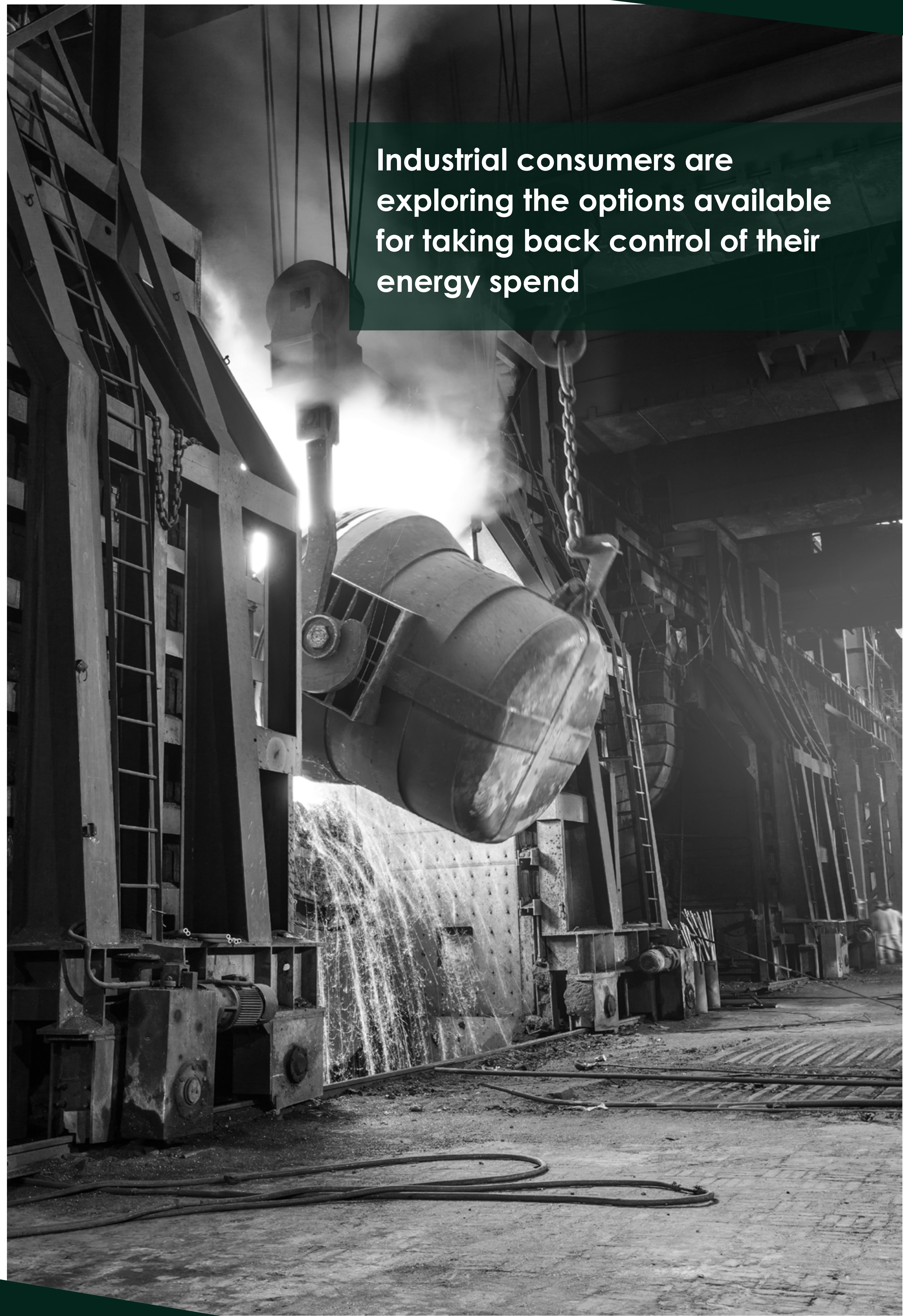
Navigating the often complex web of connecting, registering and accrediting with the AEMO can be capital and time intensive. The markets continue to change rapidly in terms of size, technologies, generation mix and policy direction, and in turn the requirements for participants are evolving. Also, as new players seek to enter the Australian energy markets, regulatory bodies are becoming more vigilant in assessing capabilities and eligibility criteria. In recent times, AEMO has deployed interim measures, particularly in the storage space, to update policy approaches quicker which has in turn impacted processes.

Renewable energy project proponents may also need to register with AEMO

On the generation side, some of the Government auctions and funding grants being offered in the market require proponents to be a Registered Participant or to have at least commenced the registration process with the AEMO. While these preliminary steps are often tackled by proponents later in their project schedules, they can be started much earlier.

Although registration requirements are set out in the various Rules and procedures governing each market, compiling an application and determining what level of supporting evidence is required, can be unclear. This may prolong commissioning dates for renewable energy projects and result in unplanned project costs.

Energetics can assist stakeholders, particularly renewable energy generators and end-users to fulfil the requirements for market participation. If you would like to speak to an adviser on registering with the AEMO, please contact: Rebecca Harvey or John Bartlett.



Industrial consumers are exploring the options available for taking back control of their energy spend

February 2018

2018: a buyers' market for corporate renewable PPAs

Written by Anita Stadler

The large corporate renewable Power Purchase Agreements (PPAs) announced in 2017 highlighted the range of cost, emissions reduction and community benefits that can come with such deals. Now in early 2018, we see more and more corporates investigating the opportunity as the business case for a PPA with a renewable energy generation project in the right location, and of the right type and size stacks up for most large energy users. In this article we discuss the factors that point to a buyers' market in 2018, the alternative procurement options and the flexibility in aligning a PPA with your energy market risk exposure.

Why now?

The rationale for using corporate renewable PPAs as a risk management instrument under current market conditions is compelling. Corporates that act in 2018 have a good buying opportunity. Interest rates, a key driver of PPA prices, are still low and there is intense competition amongst new renewable energy projects to secure PPAs in the period up to 2020, which is the target date for the RET. Such corporates will find that **60% or more of the value of a corporate PPA is likely to be realised well before 2025**. Delaying will reduce the financial benefit due to the higher LGC and electricity prices, especially in the period to 2021. The market prices for this period are known.

The NEM is complex. Understanding price drivers over the long term

Many corporates evaluating the corporate PPA opportunity have sought to understand the impact of of two major trends on a long term arrangement with a renewable energy generator:

- the predicted fall in Large-scale Generation Certificate (LGC) prices once the Renewable Energy Target (RET) is met around 2020, and
- the expectation that renewable energy technology costs[1] will continue to plummet, driving down market prices for PPAs and delivered electricity.

Why do gas prices impact electricity prices?

The wholesale market price per MWh paid to generators is determined by the bid price from the generator supplying the last unit of energy required to balance supply and demand during a supply period.
At times of high demand, open-cycle gas-fired power generators typically deliver the last unit of electricity (i.e. the system wide marginal cost generator). This is why the cost of gas has such a significant impact on electricity prices.

These are extremely relevant considerations and any assessment of a renewable PPA must take account of the expected drop in electricity and LGC prices from the current elevated levels.

However, the National Electricity Market (NEM) is a complex system with dynamic interactions between climate and energy policy, market regulations, cost of capital and physical system limitations to name a few. These relationships are not linear and the fall in LGC prices and renewable electricity technology costs in our assessment will not result directly in a corresponding fall in electricity prices over the period to 2030. Making an assessment of the relative strength of the drivers of electricity prices is challenging due to the unprecedented transformation of the NEM. However, we at Energetics are confident of three things:

1. The future demand and supply balance drives electricity contract prices. For example, the scheduled closure of the NSW Liddell Power Station in 2022 could see high futures contract prices in 2020/2021 for delivery in 2022/2023, even though AGL has provided much more advance notice than we saw with the closure of Hazelwood in 2017.
2. Renewable sources are now the cheapest source of new generation, filling the gap left by the closure of aging coal fired power stations.
3. The growing reliance on variable renewable sources in the supply mix places increased reliance on flexible, dispatchable sources to ensure system stability. Natural gas, hydro and storage will thus set the wholesale market price for electricity for an increasing proportion of time. The generation costs of all three sources are higher than incumbent coal[2].

The combined influence of the above factors, in our assessment, will result in prices dropping off moderately beyond 2020/21, but will not result in the major fall hoped for by many. In our assessment, the days of gas at \$4/GJ and electricity at \$40/MWh are well and truly in the past. The new norm is uncertainty and expected to persist over the medium and long term.

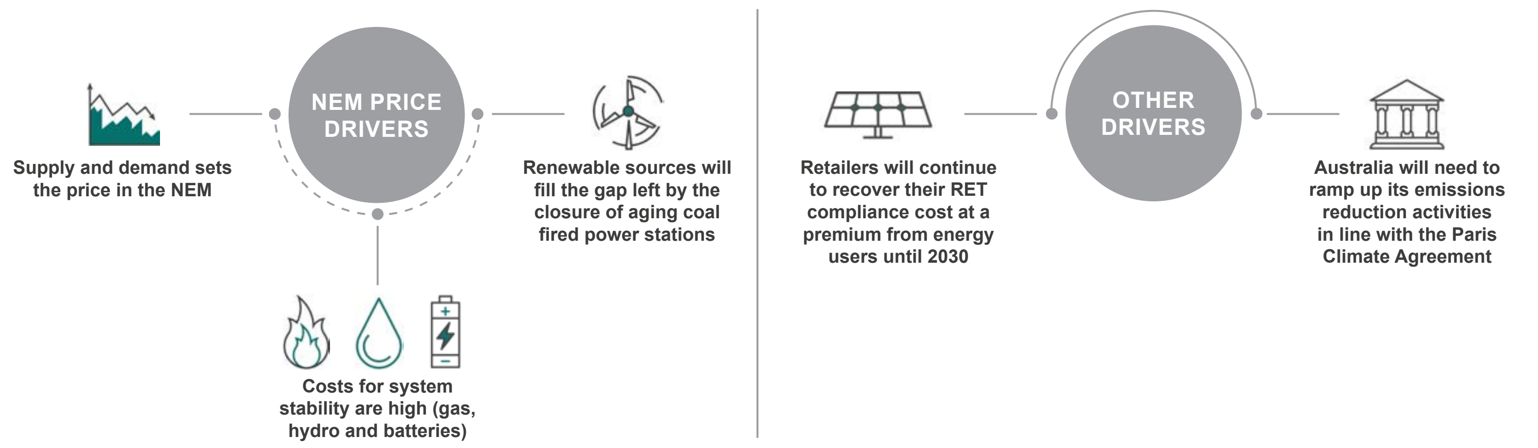


Figure 1: Factors leading to sustained high prices in the National Electricity Market (NEM)

Furthermore, beyond the dynamics of the NEM, we are confident that:

1. Market prices for LGC prices will drop sharply once the RET target is met, but retailers in all probability will continue to recover their RET compliance costs at a premium from electricity users until 2030 when the scheme is legislated to conclude. Energetics' analysis of 2017 tender responses showed this premium for 2020 to be close to 15%.
2. The global decarbonisation trend is likely to accelerate and as we approach the Paris Climate Agreement's target date of 2030. Australia will need to ramp up its emissions reduction activities to fulfil our international obligations.

What are your energy procurement objectives?

Each corporate's circumstances are unique, but the two key drivers are broadly:

1. energy cost savings and budget certainty
2. climate risk exposure and associated sustainability goals

Are you seeking to hedge against market price risks?

Some corporates are looking to the renewable PPA option to directly reduce or hedge their electricity costs, and may take, for example, a conservative position of committing 20% to 25% of their national electricity load. This provides a source of LGCs to displace mandatory RET compliance charges from retailers, as well as securing a partial shield against volatile and high electricity prices.

The rise of the buying group in 2018
At 20-25%, many corporates may lack the scale to secure very attractive PPA prices. We therefore anticipate that buyers groups will gain in prominence in 2018, at least for corporates that are willing to enter into financial PPAs (i.e. a pure financial arrangement for the value of the electricity, not the supply of electricity to a premise. Gains from this arrangement are anticipated to offset an increase in delivered electricity costs).

Are your energy procurement decisions influenced by your sustainability goals?

Many corporates have sustainability objectives and carbon reduction goals, driven by considerations ranging from sustainability leadership, social licence to operate and greening of supply chains. The value drivers and risk assessment frameworks used by these corporates will support the pursuit of renewable PPAs comprising as much as 100% of their load. Whilst buyers groups may be an option even for these large loads, we anticipate that many will prefer the flexibility of an individual PPA to secure additional value– adds in line with their objectives.

From a low percentage to 100% of your load - a corporate PPA can be designed to meet your needs

Corporates need to assess their electricity and environmental markets exposure and consider the optimal combination of risk retention and risk transfer. By taking a more direct role in managing their energy price risks, corporates are stepping into a new domain and are naturally risk adverse[3]. However, what many may not realise is the flexibility that can be achieved at the design phase of the corporate PPA to ensure that it meets your needs.

It is well worth understanding the value that a long term renewable PPA can create for your corporate, however you need to move quickly - 2018 is the time that this opportunity can be maximised.

Energetics can help large energy users understand the corporate renewable PPA opportunity and the options available. Please contact the author if you have any questions or comments.

Footnotes
1 Note that falling renewable energy technology costs do not translate directly to lower electricity rates as the cost associated with grid connection and generator technical performance standards are expected to increase, offsetting some of the gains from falling renewable energy technology cost. The prevailing low interest rate environment and equity return expectation of some project sponsors support low PPA prices. Upward adjustment in interest rates will push up PPA prices.

2 Domestic gas supply remains tight, whilst natural gas prices are partly linked to Australian Liquefied Natural Gas (LNG) prices, which are forecast to remain high. Storage will play an increasing role and with economies of scale costs will decline over time. However, it will be high in the medium term.

3 There are currently no retailers offering a 'commoditised' standard retail product offer linking a corporate PPA to power supply; nor do we expect to see one anytime soon.

How has the National Electricity Market handled the heat this summer?

Written by Alister Alford

January 2018 has been an exceptionally warm month for Australia. Temperatures in the eastern states ranked amongst the ten warmest on record for both monthly mean maximum and mean minimum temperatures. As a result, we have seen the third-warmest January monthly mean temperature on record[1]. December 2017 was also the fifth-warmest on record.

On the whole, the interconnected power system has not suffered a major incident this summer. Interruptions to supplies have been limited to localised blackouts associated with the failure of distribution network equipment. Following warnings from the Australia Energy Market Operator (AEMO) that the National Electricity Market (NEM) remains tightly balanced[2], the ability of the power system to reliably support peak demand for electricity during heatwave conditions has become a measure of success of the integration of increasingly geographically diverse and renewable generation sources. In this article we consider the value demand management measures have brought to the challenge.

The absence of major disruptions is not a particularly useful measure of the robustness of the NEM. Power markets are generally managed for the safe operation of the network without interruption of supplies should a generator or piece of transmission equipment fail. These so called ‘credible contingencies’ are managed by ensuring there is sufficient generation reserve and transmission capability to ‘ride through’ disturbances without load shedding.

The occurrence of ‘Lack of Reserve (LOR) events’ is a better measure of the NEM’s ability to respond to ‘credible contingencies’. If the market operator believes the occurrence of the largest relevant credible contingency event will result in load shedding, a LOR2 condition is declared prompting more direct intervention from AEMO to keep the power system secure. During extreme heat on 18 January AEMO declared a LOR2 condition in the Victorian region, however load shedding (LOR3) was avoided.

Are demand management initiatives keeping the air conditioners running through the summer?

To maintain adequate operational margins in both Victoria and South Australia, AEMO has drawn upon contracted reserves put in place as part of preparations for summer 2017/18. AEMO has sought responses under the Reliability and Emergency Reserve Trader (RERT) on three occasions and activated those contracts to reduce demand or increase available generation on two occasions this summer. Such ‘demand side’ responses have the potential to become an integral part of the market, and a more efficient use of resources given the short lived nature of extremes of demand. However, the ability to reliably deploy these often highly distributed resources in the Australian context is not fully understood. To narrow this knowledge gap the Australian Renewable Energy Agency (ARENA) and the NSW Government have awarded a combined $35.7 million to an initiative that will deliver 200 megawatts (MW) of capacity by 2020, with 143 MW to be available for this summer[3]. The diversity in programs awarded funding highlights the potential for all businesses to be engaged in demand management initiatives. While very large energy users may be able to contribute by suspending operation of key items of plant, other businesses are able to make more subtle changes such as altering air-conditioning set points that in aggregate make a measurable impact on demand.

What can demand management offer your business?

Commercial incentives such as those supported by ARENA are increasingly able to underpin a business case for participating in demand management activities. Market support for demand response activities has facilitated aggregators offering commercial terms that include participation and activation payments which reduce revenue volatility and enhance the value proposition. The growing diversity of programs is now able to meet the needs of more businesses by offering implementations such as:

- automatic curtailment
- SMS and email alerts for manual intervention
- control of building heating and cooling systems
- voltage control
- behavioural modification.

Energetics can work with you to determine which programs and technology are the best fit for your business.

A robust business case will generally seek to capture additional benefits. A successful demand management program is more readily achieved when:

- energy use is well understood and supported by data collection and analysis
- operational flexibility of business processes has been tested and refined
- insights gained are used to improve overall energy efficiency, lower network usage charges and shape electricity procurement activities
- management is able to demonstrate to stakeholders that the risks of any program are manageable and outcomes are aligned with business objectives.

Finding the right demand management program for your business

Innovation in demand management programs is rapidly expanding the range of options available. By taking an integrated approach to managing risk and understanding the needs of your business, Energetics can help you to assess the options best suited to meet your goals.

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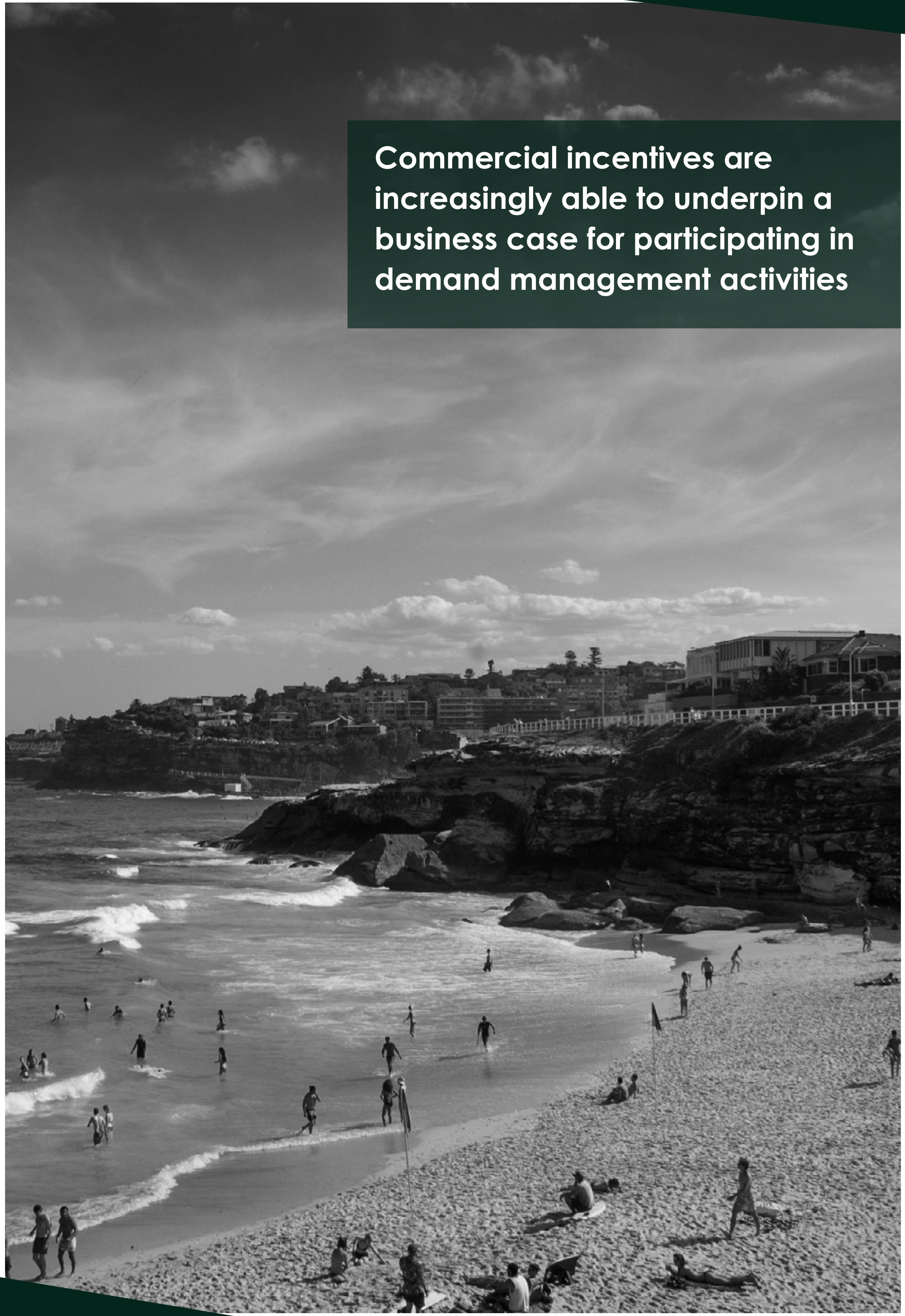

Commercial incentives are increasingly able to underpin a business case for participating in demand management activities

March 2018

The outlook for LGC prices from a corporate perspective

Written by Anita Stadler and Fadeela Saloojee

The Clean Energy Regulator (CER) announced in February 2018 that the Commonwealth's Renewable Energy Target (RET) of 33,000 GWh by 2020 is likely to be met[1]. This target is currently legislated to remain constant until 2030, with emissions reduction requirement contemplated as part of the National Energy Guarantee (NEG)[2] additional to this target.

This assessment is based on the CER's analysis of committed and probable projects in the development pipeline that are eligible for the creation of Large-scale Generation Certificates (LGCs). Delivery of these projects could be delayed for a range of technical and financial reasons. However, Energetics is in broad agreement that meeting the RET is within reach and that liable entities would be able to meet their obligations in the period leading up to 2020 and beyond. As observed for the 2017 compliance year, some liable entities (wholesale purchasers of electricity) may continue to rely on the carry forward provisions to defer their liabilities to future years.

This article looks at what this means for large electricity users and re-assesses available strategies to mitigate corporates' exposure to the compliance cost associated with the RET.

How does RET compliance cost impact large corporate electricity users?

Under the RET scheme liable entities (mostly retailers) must surrender LGCs equal to the MWhs consumed by their customers, multiplied by a percentage specified by the regulator every year to meet the RET. The standard practice is for retailers to on-charge this compliance cost to energy users.

The unprecedented surge in renewable energy investment in 2017 was driven by a recognition from major retailers and corporates that the Commonwealth is unlikely to rescind the RET. New renewable energy capacity was needed to meet the RET and avoid payment of shortfall charges after investment stalled for more than 18 months during the Commonwealth Government's 2014/15 review of the RET.

Recent price trends and premiums

Figure 1 illustrates the LGC price evolution over recent years and the trajectory of prices for the period to 2021.

In 2014 and 2015 many large energy users paid around $35 per certificate through their retail electricity bills, including the retailer's margin and administration cost. Following the 2014/15 RET review the price per certificate charged by retailers increased to as much as $93 during 2016/17.

In response to the expected oversupply of certificates by 2020, forward contract prices for delivery of LGCs in 2020 and 2021 have fallen sharply as illustrated below. This drop in prices is now flowing through in the quotations by retailers to corporate energy users. Nonetheless, throughout 2017 we continued to see a premium of about 15% charged by retailers for 2020 LGCs (see our January 2018 article[3] for a more detailed analysis) relative to forward contract prices.

What is an LGC and how much is a shortfall charge?

This is the certificate created by large-scale renewable energy generators under the RET Scheme.
One LGC = 1 MWh of renewable energy.

Ownership of a LGC is required to claim that a MWh of renewable energy has been supplied to the grid.

The Clean Energy Regulator (CER) annually specifies an increasing renewable power percentage (RPP) to achieve the RET by 2020. The RPP for 2017 was 14.22% and is expected to be above 20% between 2020 and 2030.

The CER imposes a shortfall charge on entities that do not surrender the required number of LGCs This charge is $65 per certificate. This cost is not tax deductable. The tax-effective shortfall rate is therefore about $93 per certificate.

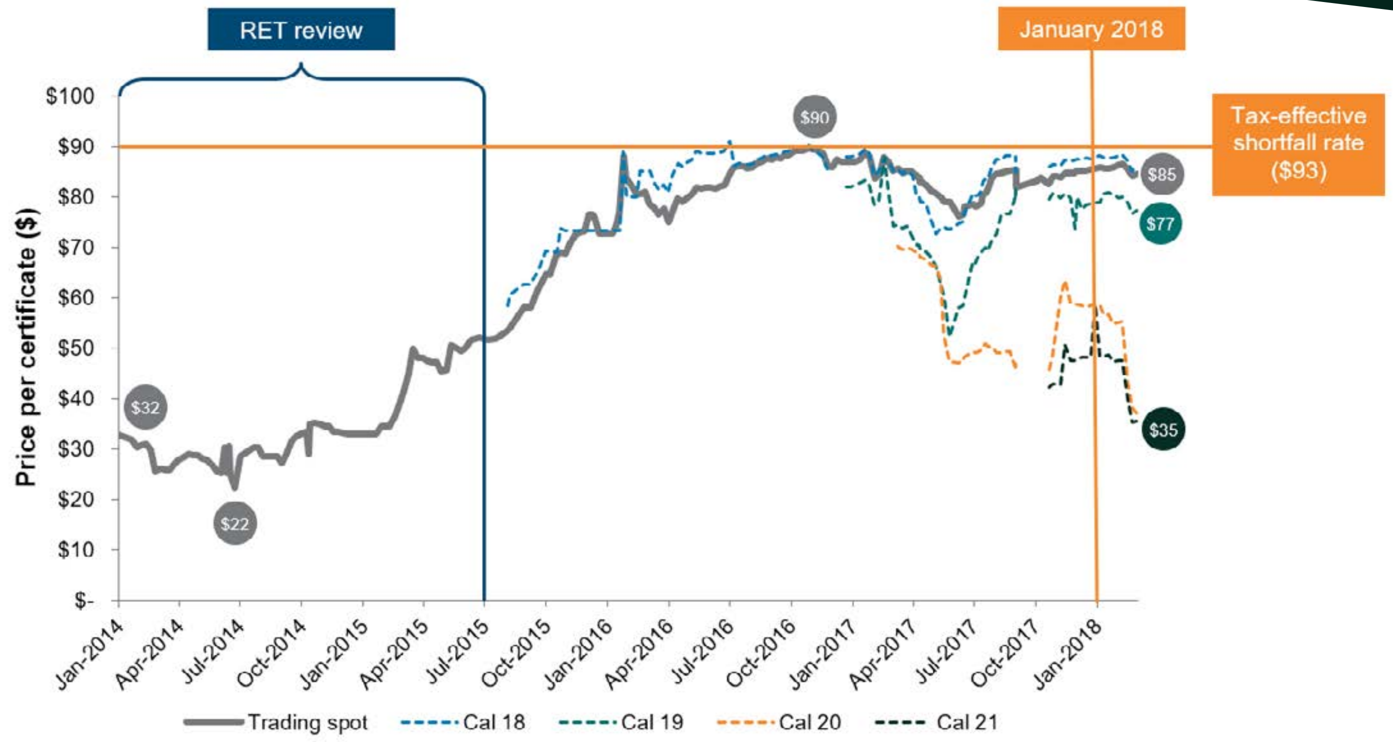

Figure 1: LGC price evolution (January 2014 – March 2018)

What price can corporates expect to pay for LGCs beyond 2020?

Some market commentators suggest that the expected over supply of LGCs in 2020 and beyond means that LGC prices will drop to zero[4]. Unfortunately, in Energetics' view, this assessment does not mean that electricity users will get a free ride. There are multiple markets for LGCs. When contemplating how to manage your exposure to LGC compliance cost we recommend you take into account the following supply-demand price drivers.

- Electricity retailers control much of the LGC supply and are expected to continue to recover their cost of compliance at a premium from customers[5]. The extent of the retailers' influence over LGC prices is illustrated by their holdings in the Renewable Energy Certificate Registry as at the end of January 2018. Note that the "other" group holding of 25% includes LGCs for voluntary surrender by institutions such as the ACT Government.
- Supply of LGCs eligible under the RET may be restricted if the NEG determines an alternative basis for assessing compliance with emission obligations. Or it may increase demand for LGCs if the certificates can be used / converted for use under the new policy to meet a higher emission reduction compliance obligation.
- An LGC has an emissions reduction value beyond the compliance market. It can be used to offset emission equivalent to the carbon content of one MWh of grid supplied electricity[6]. Holders of LGCs, in surplus to the RET compliance market, could therefore sell these certificates on the voluntary carbon market. The price of Australian Carbon Credit Units (ACCUs) does effectively set a floor price for LGCs. The price for ACCUs currently ranges between $12 and $18 per ton of carbon ($tCO_2e$)[7]. Recent trend has been driven by demand from 16 large emitting facilities that exceeded the emission baseline established under the Emission Reduction Fund Scheme (also referred to as the safeguard mechanism)[8]. In the long term the ACCU price is expected to increase in line with more aspirational targets to decarbonise the Australian and global economy.

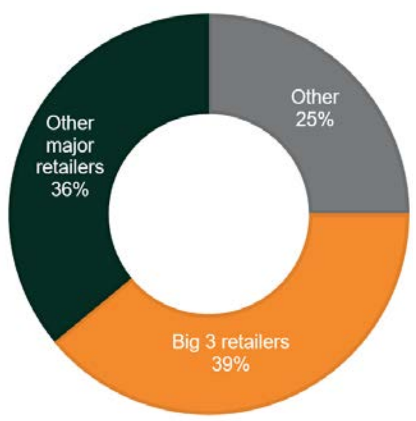

Figure 2: LGC holdings in REC Registry as at 31/01/2018

With forward contract prices for 2021 certificates trending towards $35 per LGC, it is conceivable that corporates may benefit from sub-$30 LGC prices in the period beyond 2021. However, we do not deem it a foregone conclusion that the LGC price passed through by retailers to electricity users would continue to drop off sharply after that. Even if 100% cost parity is achieved between renewable energy and incumbent coal fired generations, the concentration of market power amongst a handful of retailers and the increasing decarbonisation trend will result in LGCs retaining a market value, at least on par with ACCUs plus a retailer premium.

What can you do to mitigate your risk exposure?

Most large users of electricity continue to accept LGC compliance cost as a pass-through charge from retailers or self-source the volume of LGCs from the market as required, before transferring these LGCs to the retailer to meet its obligation associated with the corporate's consumption. With the RET scheme legislated to continue until 2030, it is worthwhile to consider options to reduce costs associated with this mandatory charge.

The main options available to corporates to reduce their exposure to LGC cost and price risks are summarised in the following table.

At a time of unprecedented market transformation, one may be tempted to “ride out” the storm. However, this will expose organisations to significant market risk as the electricity market transforms over the next 10 to 20 years. Now is not a time to be complacent. The sooner you take control of your LGC supply, the greater the opportunity to reduce cost over the medium term when prices are known and markedly elevated.

Energetics has a team of experienced energy and environmental market; as well as policy specialists that can guide you through an assessment of your risk exposure to mandatory LGC charges.

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3 **https://www.energetics.com.au/insights/thought-leadership/it-s-not-just-price-a-corporate-renewable-ppa-is-a-risk-management-strategy/**

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5 This cost is likely to be a blend of LGCs procured under long term contracts over the life of the scheme, and short term spot market purchases as buying opportunities emerge.

6 The emission intensity of 1 MWh of electricity varies depending on the State or Territory the renewable energy project is located in. However, the 2017 average emission intensity of 1 MWh of grid connected electricity was 0.8 tCO_2e per MWh. This will decrease over time in line with the increase in renewable energy in the supply mix (see: **http://www.cleanenergyregulator.gov.au/NGER/National%20greenhouse%20and%20energy%20reporting%20data/electricity-sector-emissions-and-generation-data/electricity-sector-emissions-and-generation-data-2016-17)**

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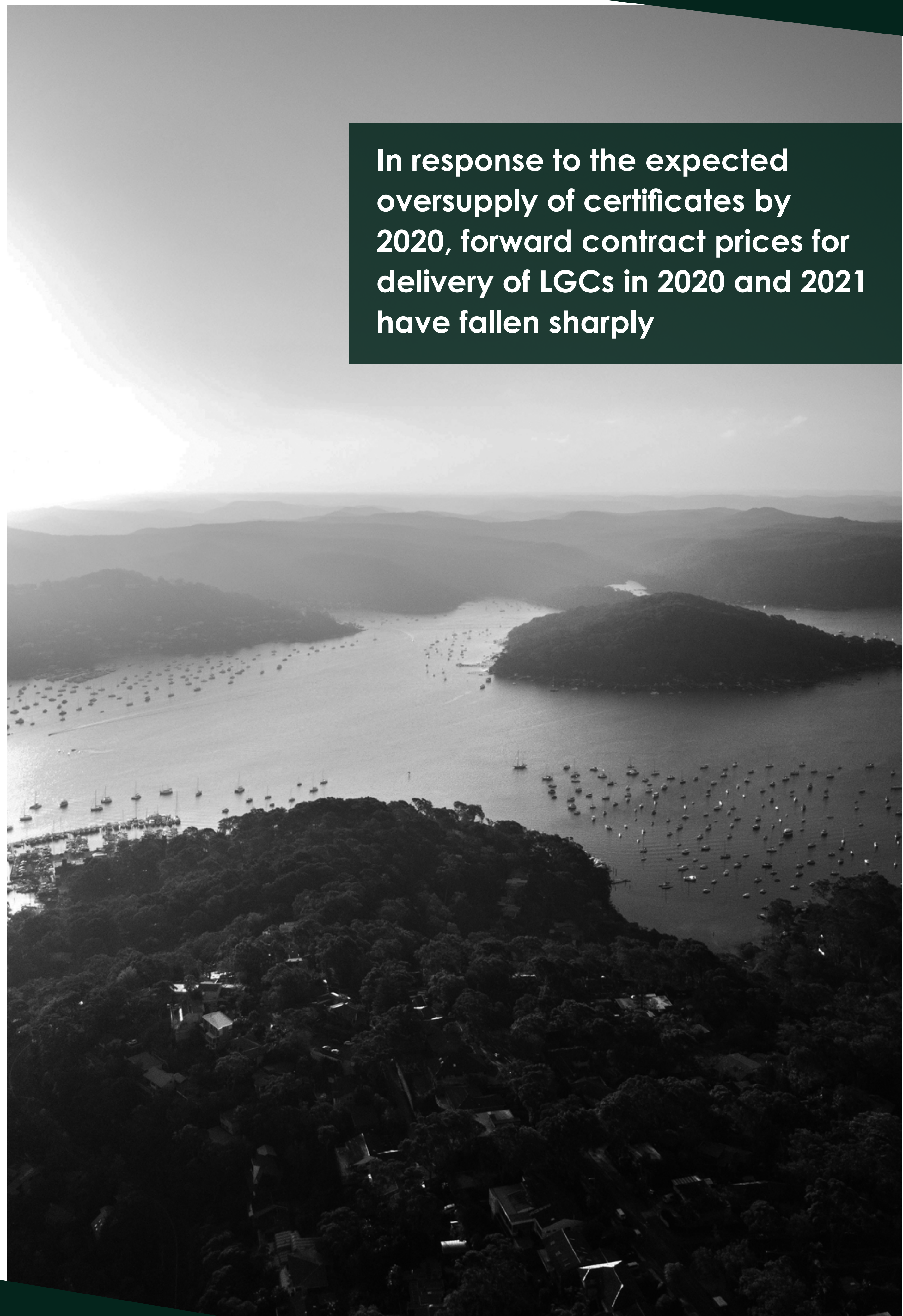
8 This scheme was introduced by the Coalition Government to replace the carbon tax introduced by the previous Labour government.

Option	Description
Generation of LGCs through on-site renewable energy projects larger than 100 kW	This option is viable if a suitable site is available for a large on-site project. The project can be financed though capital investment or an on-site Power Purchase Agreement (PPA). A key benefit of this option is the reduction in network costs associated with reducing consumption at a particular site.
Source LGCs directly from a renewable energy project under medium term contract to transfer to the retailer	Contract to purchase LGCs to meet the compliance obligation (e.g. 20% of the total load) and self-surrender these to the retailer. This could be a 3 to 5-year agreement. Savings of 20 – 30% on LCG costs is possible depending on the parcel size and duration of the agreement.
Enter into a long term renewable energy PPA for both electricity and LGCs	Significant savings is possible if you contract directly with a renewable energy project for both electricity and LGCs. This could be for a portion of your load, such as 20% to 25%, which will generate sufficient LGCs to meet the compliance obligation of the retailer associated with your total load. This is typically a 10-year agreement. However, it has an advantage over an LGC-only contract of also providing you with a partial hedge against future electricity prices increases and volatility.

Table 1: Options available to corporates to reduce their exposure to LGC cost and price risks

In response to the expected oversupply of certificates by 2020, forward contract prices for delivery of LGCs in 2020 and 2021 have fallen sharply



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Gas price shock drives interest in waste-to-energy solutions

Written by Fadeela Saloojee

During 2017 we saw a rapid increase in natural gas prices, with some large business users seeing a doubling of their gas bills. This drove industrial users to look at alternatives to natural gas to meet their heating requirements, particularly biomass and waste to energy. The result was a marketing drive from alternative fuel technology suppliers, breaking down the typical barriers to market entry for such technologies.

An interesting effect of this is that even customers who use other fuel sources such as LPG for their heating requirements are beginning to look into biomass options, especially in cases where LPG costs are high.

The gas price outlook and what this means for large users of gas

The wholesale East Coast gas market in Australia has undergone significant change since 2014, mainly due to the start-up of large-scale CSG (Coal Seam Gas) to LNG (Liquefied Natural Gas) export facilities in Gladstone, Queensland. Prior to the start-up of these facilities, overall gas consumption in the residential and industrial sectors was on a declining trajectory. The start-up of these facilities initiated a period of industry transformation, with domestic gas prices experiencing upwards pressure as a result of exposure to both international pricing and domestic supply constraints.

The gas price volatility has had an impact on the bottom line of large industrials with high heating requirements, and already tight profit margins. As a result, large consumers have increasingly been looking at alternative fuels, including coal and fuels derived from waste products.

Whilst coal-fired boilers might be the lower operating cost option, the associated emissions are sufficient to deter corporations from investing in these. On the other hand, technologies such as covered anaerobic lagoons provide the opportunity to capture biogas from waste streams and use this for heating, thus reducing costs and carbon emissions.

Traditional barriers to entry for alternative fuels, and how they have been broken down

Barrier	Recent market response
High installation costs	Equipment suppliers have been providing more competitive offers; Alternative financing options are available, such as Energy Services Agreement (ESA) (e.g. Build-Own-Operate (BOO) contracts) or corporate and energy efficiency loans (e.g. through the Clean Energy Finance Corporation). Grant funding, e.g. ERF or ARENA, may be possible 5 to 10 year lease and PPA packages including fuel supply.
Fuel supply issues, e.g. variation in supply volumes, quality or price	Some technology suppliers are willing to include a long-term contract for fuel supply. Flexible technologies have been developed, capable of handling a range of fuels with different properties. Regular fuel testing could ensure consistency of supply quality.

What are the alternative energy options for heating?

Alternative fuels for heating fall under the following broad categories:

- Biogas from on-site waste (both solid waste and wastewater)
- Biomass (wood waste or agricultural waste)
- Other waste to energy fuels, such as Municipal Solid Waste (MSW) or Processed Engineered Fuels (PEF)

Further, the types of technologies that can be considered are:

- Anaerobic lagoons
- Biomass boilers
- Gasifiers
- Pyrolysis

What should be considered in the business case?

When considering investment into alternative fuel systems, the following questions need to be asked.

1. Fuel supply
2. Technical feasibility
3. Potential savings
4. Environmental impacts

Fuel supply

- Is sufficient volume of fuel available at a good price (typically <$5/G)?
- What are the logistics of fuel delivery to the site?
- Alternatively, will biogas be generated at the site? If so, what are the additional costs?

Technical feasibility

- How well can the system be integrated with the site's current heating system?
- What is the required footprint and can the site accommodate this?

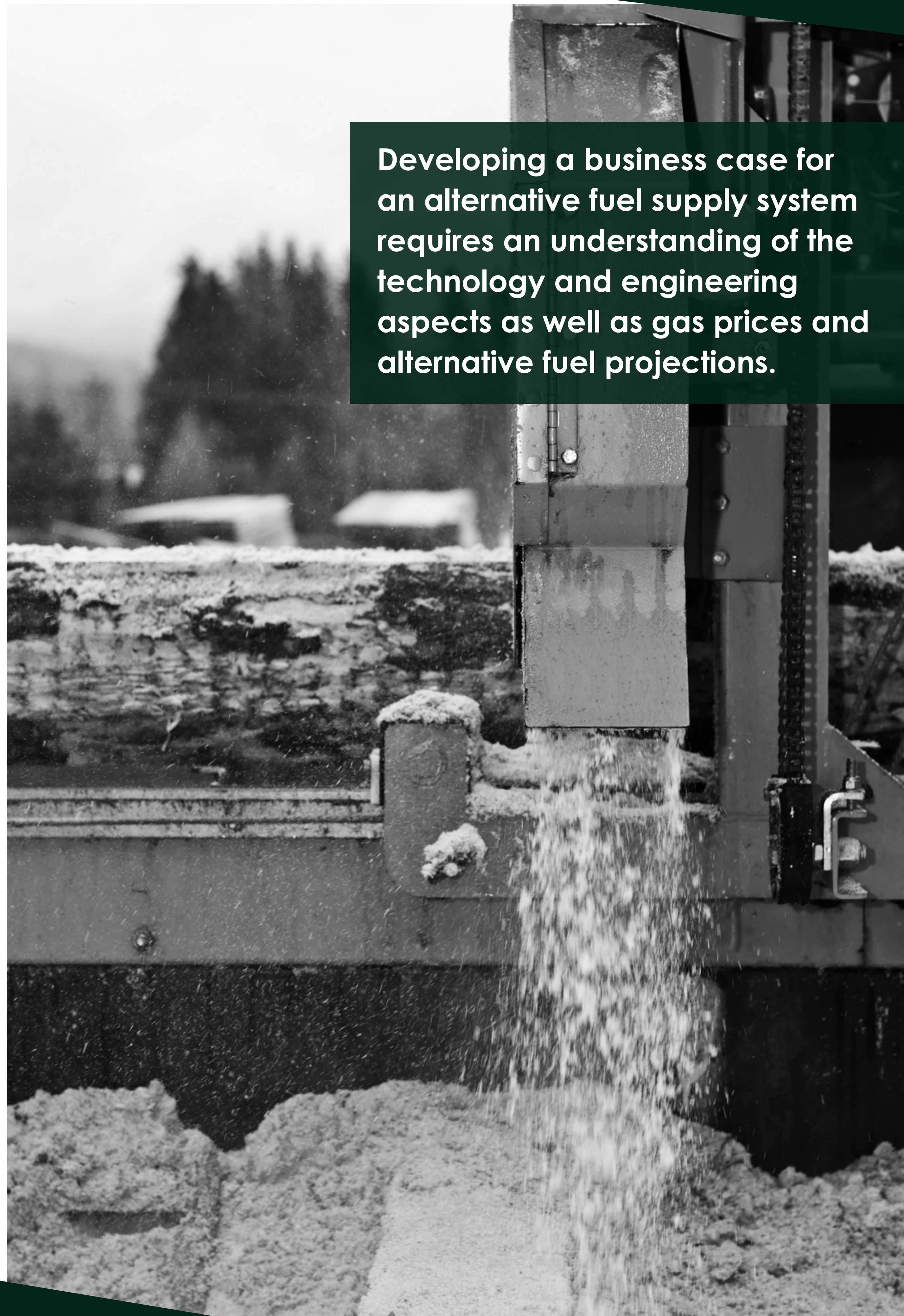
Potential savings

- Is the cost of natural gas high enough to justify the investment?
- What is the outlook for natural gas prices over the next 5 – 10 years?
- Can the fixed cost component of gas charges be reduced (e.g. different supply tariff)?
- Are there any additional benefits, e.g. reduction in waste to landfill?

Environmental impacts

- Is such a system compatible with the site's EPA requirements?
- What is the impact on the site's carbon emissions?

In summary, developing a business case for an alternative fuel supply system requires not only an understanding of the technology and engineering aspects of the proposed system, but also a robust view of gas price and alternative fuel projections over the life of the project.



Developing a business case for an alternative fuel supply system requires an understanding of the technology and engineering aspects as well as gas prices and alternative fuel projections.