



# **Alternative energy and greenhouse gas implications**

Information for the Wonarah  
Phosphate Project

Prepared for Minemakers Pty Ltd

**9 April 2010**



**ACIL Tasman**  
Economics Policy Strategy

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## A Alternative energy and greenhouse gas implications

This appendix provides a summary of the costs associated with using a range of alternative energy sources to reduce the diesel consumption and associated greenhouse gas emissions connected with the Wonarah Phosphate Project (the project) proposed by Minemakers Australia Pty Ltd. This appendix also provides some current cost estimates for voluntary greenhouse gas emission offsets and the cost of installing solar power for the accommodation camp or northern borefield.

### A.1 Renewable energy generation options

A key issue in relation to any decision by Minemakers to using renewable power generation at the project site is the reliability of supply associated with alternative energy technology options (i.e. solar or wind). As the mine will not be connected to an electricity grid, all power requirements must be generated on site. Renewable power sources such as wind or solar technologies only supply power intermittently. Intermittent generation from wind or solar technologies will therefore require investment in either energy storage or reliable backup generation technology (such as the currently proposed diesel generator set) and quite possibly both. Consequently, the use of renewable power at the mine site will require a significantly higher initial investment in the generation equipment. This higher initial cost will be offset to some extent by lower ongoing fuel costs and lower greenhouse gas emissions. This section provides some estimates of the costs associated with different generation options.

#### Solar power

As shown in Figure 1 there is a very good solar resource at the project site. The Office of the Renewable Energy Regulator has a zone rating of 1.536 MWh a year per kW of installed capacity (ORER 2010). This equates to a capacity factor of 17.5%. This is likely to be a conservative estimate of the annual electricity that could be generated from the solar resource at the project site. In the absence of more detailed information, this capacity factor has been used for all solar calculations in this section.

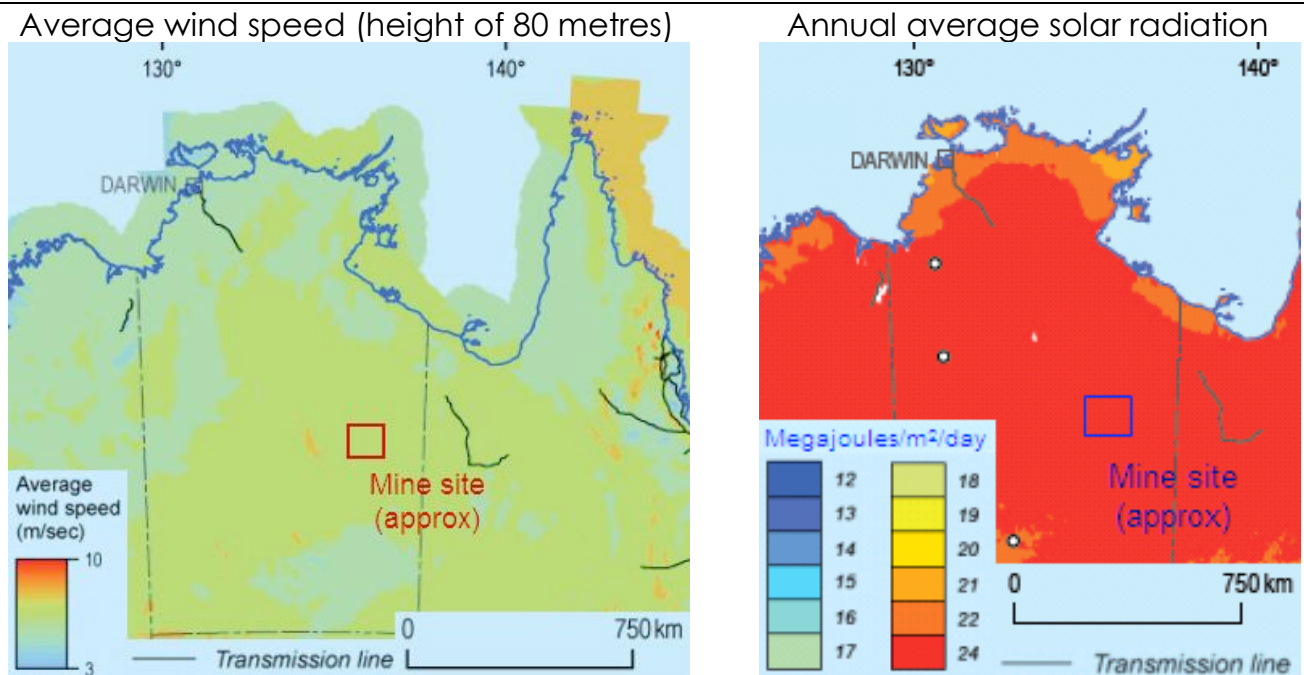
Electricity generation for the project using solar power would require a large land area. The currently proposed 4MW of diesel-fired generation capacity uses a land area of approximately 1 hectare. In comparison, 1 MW of solar photovoltaic (PV) panels will use around 12 to 15 hectares<sup>1</sup>. As the panels will be located on a mine site, they are likely to be affected by dust and may require regular cleaning to ensure that the generation efficiency is maintained. This cleaning will increase the water requirements of the project.

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<sup>1</sup> Land area calculations are based on the dimensions of Sanyo HIP-210NKHE5 and Yingli YINGLI-175 panels and assume a panel density of 50% of the land area.



Figure 1 Potential wind and solar resources at the Wonarah mine site



Data source: Adapted from Figures 9.8 and 10.1 in Geoscience Australia and ABARE (2010).

It is estimated that every MW of solar PV capacity that is installed will reduce annual diesel requirements by 398 kL and reduce the annual greenhouse gas emissions from the project by 1,068 t CO<sub>2</sub>-e (carbon dioxide equivalent). Further, installing a 1 MW solar generation facility would enable the project to create 1,536 renewable energy certificates (RECs) per year, which can be sold to provide an additional revenue stream.

Table 1 presents the implied emissions abatement cost associated with installing 1 MW of solar generation capacity under alternative diesel prices. The implied emissions abatement cost is very sensitive to the future price of diesel with a 15 c/L change in the price of diesel changing the calculated cost of abatement by \$40/t CO<sub>2</sub>-e.

Assuming a 10 per cent real discount rate on the debt and equity invested in the capital, it is estimated that the additional upfront cost associated with a solar PV system should breakeven with the net ongoing cost savings for an average real diesel price of \$1.75/L excluding GST and fuel excise (over a 10 year planning horizon). For comparison, the average delivered price of diesel that would have been paid by Minemakers over the past two years (had the project been operating) would have been around \$0.85/L. Consequently, based on a proposed mine life of 10 years, installation of a solar PV system to reduce diesel consumption is not economic in the absence of a large and sustained increase in the future real price of diesel.

Table 1 **Implied abatement cost associated with installing a 1 MW solar PV system (in addition to the current diesel generation system)**

	Units	Diesel price (real 2010 terms excluding GST and fuel excise)				
		\$0.85/L	\$1.00/L	\$1.15/L	\$1.30/L	\$1.45/L
Up-front capital cost <sup>a</sup>	\$m	5.12	5.12	5.12	5.12	5.12
Annual electricity produced <sup>b</sup>	MWh/year	1,536	1,536	1,536	1,536	1,536
Fuel savings	kL/year	398	398	398	398	398
Reduction in annual greenhouse gas emissions <sup>c</sup>	t CO <sub>2</sub> -e/year	1,068	1,068	1,068	1,068	1,068
NPV of fuel savings	\$m	2.42	2.84	3.27	3.70	4.12
NPV of REC credits <sup>c</sup>	\$m	0.44	0.44	0.44	0.44	0.44
NPV of additional operation and maintenance costs <sup>a</sup>	\$m	0.27	0.27	0.27	0.27	0.27
<b>Total NPV of installing 1 MW</b>	<b>\$m</b>	<b>2.53</b>	<b>2.10</b>	<b>1.68</b>	<b>1.25</b>	<b>0.83</b>
<b>Implied emissions abatement cost</b>	<b>\$/t CO<sub>2</sub>-e</b>	<b>237</b>	<b>197</b>	<b>157</b>	<b>117</b>	<b>77</b>

<sup>a</sup> Source: AEMO (2010) for fixed flat solar PV plate.

<sup>b</sup> Source: Calculated using ORER (2010) zone rating for solar power.

<sup>c</sup> Does not include land clearing emissions associated with the land area required for the solar panels. Emissions calculated using stationary emission factors presented in Table 3.

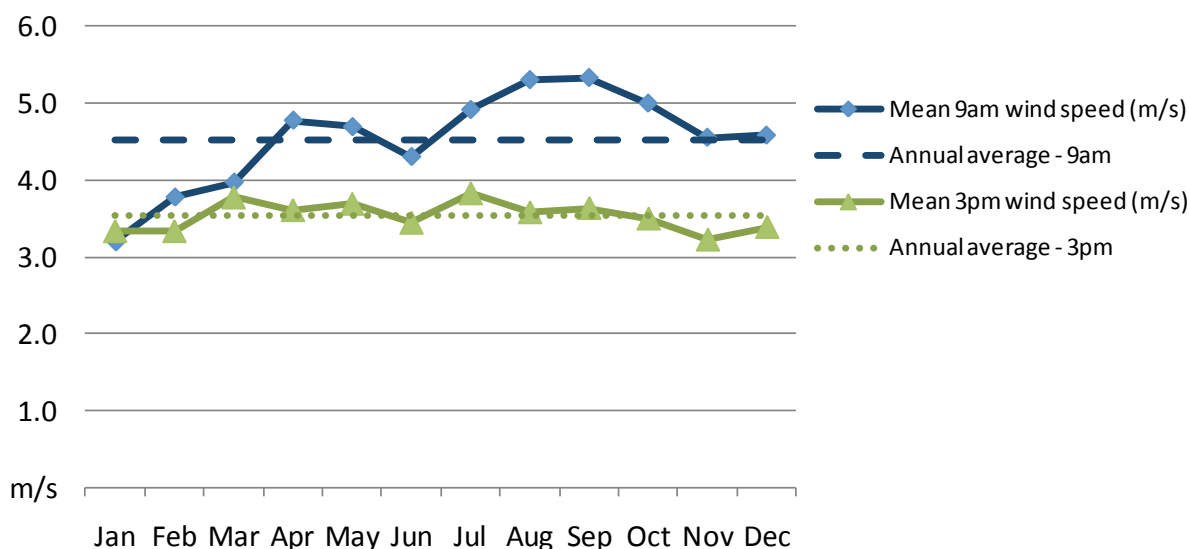
<sup>d</sup> Assuming an average REC price of \$40 per certificate per year (in real 2010 terms).

Notes: NPV = Net present value. The net present value was calculated over 10 years as per the current proposed mine life. If the mine life is extended to 20 years the breakeven diesel price is estimated to be \$1.30/L. NPV calculations assume a 10 per cent real discount rate. Installation of solar generation capacity should reduce the operation and maintenance costs associated with the diesel-based generation but have not been included in these calculations.

## Wind power

In the absence of a detailed study of the wind resource available at the Wonarah mine site, we have relied on the estimated wind resource presented in Figure 1 and Figure 2. Based on Figure 1, the average wind speeds in the region of the mine are around 4 to 6 m/s while based on Figure 2 the average annual wind speeds at 9am and 3pm are 4.5 and 3.5 m/s, respectively.

Figure 2 **Average monthly and annual wind speed for Wonarah**



Note: The Wonarah weather station is no longer operational. The data presented is the average for each month over the period 1957 to 1974.

Data source: Bureau of Meteorology. On line climate statistics for the Wonarah weather station (site number 015034). Available at [http://www.bom.gov.au/clim\\_data/cdio/tables/text/IDCJCM0038\\_015034.csv](http://www.bom.gov.au/clim_data/cdio/tables/text/IDCJCM0038_015034.csv).

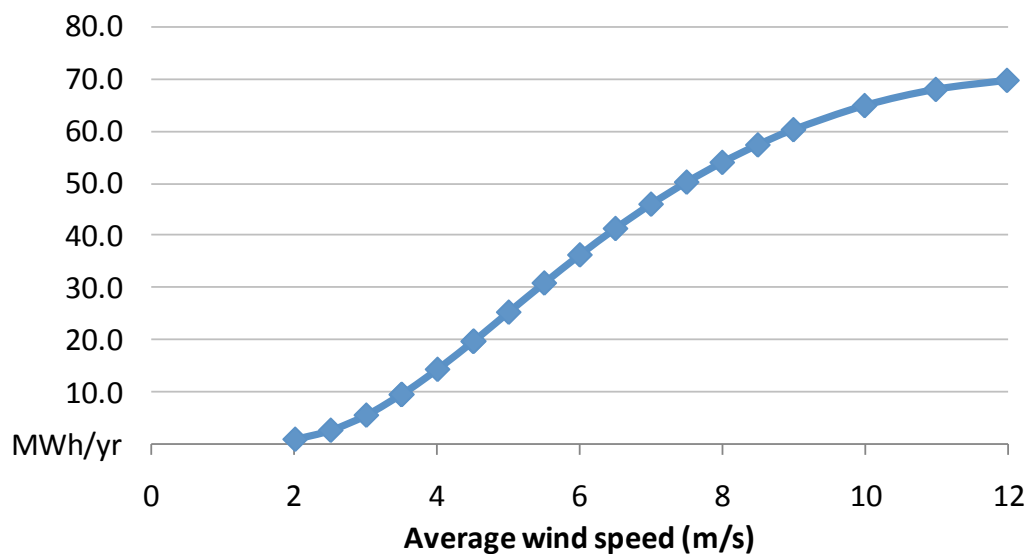


Some micro-wind turbines suitable for generation to meet small scale power demands can generate power from wind speeds as low as 1-3 m/s (the Windside turbine<sup>2</sup>, for example). However, most modern large scale wind turbines start producing energy at 4 m/s and reach maximum energy output at around 12 to 14 m/s (Geoscience Australia and ABARE 2010). This suggests that while generating power using wind at the site is certainly possible, the cost would be significantly higher compared to power generated from current Australian wind farms, which tend to be situated in areas where the average wind speed is greater than 8 m/s (and generally are closer to 10 m/s).

The low wind speeds indicate that multiple small to medium scale wind turbines of 0.3 to 25 kW that can generate electricity at low wind speeds will be more suitable for power generation at the site than, say, a single large 1 MW turbine.

The annual wind production from a Proven Energy 15kW wind turbine is provided in Figure 3. As can be seen, the annual electricity generated by the same turbine varies dramatically based on the average wind speed. For example, an average annual wind speed of 4 m/s will generate approximately 14.3 MWh/year while an average wind speed of 6 m/s will generate approximately 36.3 MWh/year.

Figure 3 **Example annual electricity generation for different average wind speeds (15kW wind turbine)**



Note: Data based on the performance of the Proven Energy 300Volt 15kW wind turbine with a 15m tower.

Data source: Graph produced from data supplied on the Proven Energy website: <http://www.provenenergy.co.uk> (accessed 8<sup>th</sup> March 2010).

The capital cost associated with small scale commercial wind farms of around 50 MW is around \$3,500/kW of installed capacity (AEMO 2010). In Minemakers' case, however, installing 1 MW of wind capacity using multiple small turbines which are capable of generating electricity at lower wind speeds is likely to have a much higher cost. For example, the cost of the Proven Energy 15kW turbine with a 15m tower is around \$6,700/kW excluding

<sup>2</sup> See <http://www.windside.com/products.html>.



installation costs. For this analysis, it is assumed that the installed cost for up to 1 MW of capacity is \$7,000/kW.

Table 2 presents the implied abatement cost associated with installing 1 MW of wind generation capacity under alternative future diesel prices. The implied abatement cost is very sensitive to the assumed average wind speed as well as to the future price of diesel. For example, a 15 c/L change in the price of diesel changing the estimated emissions abatement cost by \$40/t CO<sub>2</sub>-e, while changing the assumed average wind speed from 4 m/s to 5 m/s reduces the estimated emission abatement cost by \$480/t CO<sub>2</sub>-e.

Assuming a 10 per cent real discount rate on the debt and equity invested in the capital, it is estimated that the additional upfront cost associated with a wind electricity generation system should breakeven with the net ongoing cost savings for an average wind speed of 6.0 m/s and a real diesel price of \$1.75/L (excluding GST and fuel excise).

Consequently, based on a proposed mine life of 10 years, installation of wind turbines to reduce diesel consumption is not economic if the average annual wind speeds at the project site are 6 m/s or less, and even then, only in the presence of a large and sustained increase in the future real price of diesel.

Table 2 **Implied abatement cost associated with installing a 1 MW wind turbine system (in addition to the current diesel generation system)**

	Units	Diesel price (real 2010 terms excluding GST and fuel excise)					
		\$0.85/L			\$1.30/L		
		Average wind speed			Average wind speed		
		4 m/s	5 m/s	6 m/s	4 m/s	5 m/s	6 m/s
Up-front capital cost	\$m	7.0	7.0	7.0	7.0	7.0	7.0
Annual electricity produced	MWh/year	952	1,684	2,418	952	1,684	2,418
Fuel savings	kL/year	247	436	626	247	436	626
Reduction in annual greenhouse gas emissions <sup>c</sup>	t CO <sub>2</sub> -e/year	662	1,171	1,681	662	1,171	1,681
NPV of fuel savings	\$m	1.50	2.65	3.80	2.29	4.05	5.82
NPV of REC credits <sup>b</sup>	\$m	0.27	0.48	0.69	0.27	0.48	0.69
NPV of additional operation and maintenance costs <sup>a</sup>	\$m	0.30	0.30	0.30	0.30	0.30	0.30
<b>Total NPV of installing 1 MW</b>	<b>\$m</b>	<b>5.53</b>	<b>4.17</b>	<b>2.80</b>	<b>4.74</b>	<b>2.77</b>	<b>0.79</b>
<b>Implied emissions abatement cost</b>	<b>\$/t CO<sub>2</sub>-e</b>	<b>836</b>	<b>356</b>	<b>167</b>	<b>716</b>	<b>236</b>	<b>47</b>

<sup>a</sup> Source AEMO (2010)

<sup>b</sup> Assuming an average REC price of \$40 per certificate per year (in real 2010 terms).

<sup>c</sup> Does not include land clearing emissions associated with the land area required for the turbines. Emissions calculated using stationary emission factors presented in Table 3.

Notes: NPV = Net present value. The net present value was calculated over 10 years as per the current proposed mine life. If the mine life is extended to 20 years the breakeven diesel price is estimated to be \$1.30/L, but only if the average wind speed at the project site is 5.5 m/s. NPV calculations assume a 10 per cent real discount rate. Installation of wind generation capacity should reduce the operation and maintenance costs associated with the diesel-based generation but have not been included in these calculations.





## A.2 Use of biodiesel in the transport fleet

Minemakers may also reduce the emissions associated with the combustion of diesel by using a biodiesel blend. Biodiesel can be used in modern engines (i.e. those suited for using ultra-low sulphur diesel) with little impact on operating performance. Using 100 per cent biodiesel can cause issues in cold climates (due to gelling at low temperatures). However, it appears that Minemakers could use pure biodiesel instead of conventional mineral diesel subject to checking with equipment manufacturers.

The high degree of substitutability between biodiesel and conventional diesel means that the products are typically comparable with respect to price. Consequently, Minemakers should not need to pay a higher Terminal Gate Price (TGP) for biodiesel (blended or pure) compared to conventional diesel (from suppliers in the same region). Further, there are currently no taxation implications of Minemakers using biodiesel instead of conventional diesel. In particular, Minemakers should be able to claim the same fuel tax credits using either fuel.

As shown in Table 3 using biodiesel instead of conventional diesel would reduce the on-site emissions by approximately 96 per cent.

Table 3 Greenhouse gas emission intensity of alternative biodiesel blends

Technology	Conventional diesel	20% biodiesel blend (B20)	50% biodiesel blend (B50)	100% biodiesel (B100)
	kg CO <sub>2</sub> -e/L	kg CO <sub>2</sub> -e/L	kg CO <sub>2</sub> -e/L	kg CO <sub>2</sub> -e/L
Transport energy purposes	2.692	2.177	1.405	0.118
Stationary energy purposes	2.683	2.148	1.346	0.009
<b>Mine average @ 3.0 Mt/year</b>	<b>2.691</b>	<b>2.174</b>	<b>1.398</b>	<b>0.105</b>

Notes: All emissions calculated according to the National Greenhouse Gas (NGA) emission factors (DCC, 2009). Euro IV diesel emission factors have been used for transport emission factors. 'Mine average' is based on annual consumption of 13.5 ML for transport energy and 1.8 ML for stationary energy.

Ensuring access to a reliable supply of biodiesel is a key barrier to its regular use at the project site. Although there is a biodiesel refinery located at East Arm in Darwin, it was mothballed in early 2009 due to it being uneconomic to operate (principally due to high feedstock prices). There is no indication that it will reopen.

The closest operating biodiesel refinery identified that has sufficient capacity to supply some or all of Minemakers diesel requirement is the Australian Renewable Fuels refinery in Adelaide. Discussion with the refinery's Plant Manager indicates that a pure or blended biodiesel product of sufficient quantity could be provided at an equivalent TGP to conventional diesel (ex-Adelaide).

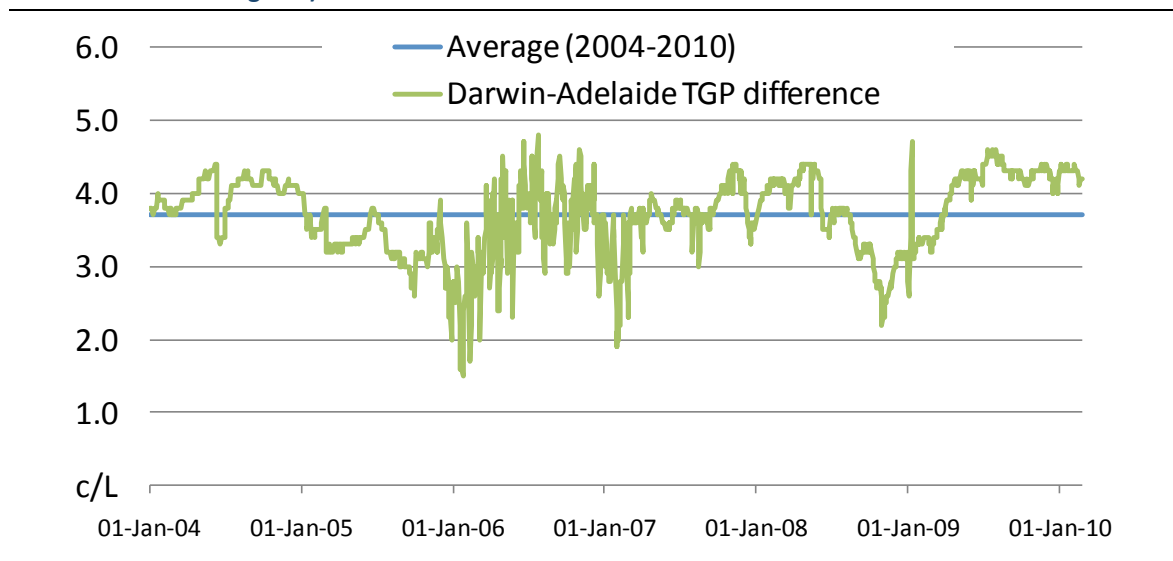
Until biodiesel can be sourced from Darwin, the cost to Minemakers of using a biodiesel blend is the difference in transporting conventional diesel from Darwin and the price of transporting a biodiesel blend from Adelaide (approximately 1,100 km additional distance). Based on the Australian transport market, it is estimated that this cost would be in the order of 6 to 7 c/L excluding GST.





In estimating the cost to Minemakers it is important to note that the Terminal Gate Price (TGP) from Darwin has historically been more expensive than the Adelaide TGP (see Figure 4). Over the past six years the TGP from Adelaide has been approximately 3.7 c/L cheaper than the TGP from Darwin (including GST). Assuming that Minemakers can take advantage of this price differential, the net additional cost to Minemakers of sourcing biodiesel from Adelaide compared to conventional diesel from Darwin would therefore be around 3 to 4 c/L.

Figure 4 **Difference in the Terminal Gate Price of conventional diesel in Darwin versus Adelaide (daily average including GST)**



Data source: Australian Institute of Petroleum online data ([www.aip.com.au](http://www.aip.com.au)). Downloaded 4<sup>th</sup> March 2010.

If the additional cost of sourcing biodiesel is 4 c/L, then the cost of reducing the projected onsite emissions is estimated to be approximately \$93/t CO<sub>2</sub>-e for a B20 blend, falling to around \$15/t CO<sub>2</sub>-e if pure biodiesel is viable (Table 4). A lower additional cost will result in a lower estimated emissions abatement cost. If the Darwin biodiesel refinery reopens at some time in the future, then the additional cost of using biodiesel will be close to zero (assuming it remains at price parity with diesel).

Table 4 **Emissions abatement cost of using various biodiesel blends (ex-Adelaide)**

	20% biodiesel blend (B20)	50% biodiesel blend (B50)	100% biodiesel (B100)
	\$/t CO <sub>2</sub> -e avoided	\$/t CO <sub>2</sub> -e avoided	\$/t CO <sub>2</sub> -e avoided
Net additional cost = 3 c/L	69.7	24.2	11.6
Net additional cost = 4 c/L	93.0	32.3	15.5

Source: ACIL Tasman estimates using emission factors from Table 3. Includes emissions associated with the additional transportation distance. Transport emissions calculated assuming an average fuel efficiency of 0.83 MJ/tonne-km with the truck using the same biodiesel blend.

These abatement estimates are based on the combustion emissions resulting from Minemakers' use of liquid fuel for on-site energy requirements as well as the emissions associated with additional transportation distance. They do not take into account the life cycle



emissions associated with each fuel (e.g. upstream emissions associated with the feedstock production and refining processes).

### A.3 Use of LPG for stationary electricity generation

Liquefied Petroleum Gas (LPG) is a mixture of light hydrocarbons (mainly propane and butane) which are gases at normal temperatures and pressures but which liquefy at moderate pressures or reduced temperatures<sup>3</sup>. LPG occurs naturally in oil and gas fields but also can be produced when refining oil.

The lower carbon content of LPG compared to petrol or diesel results in lower greenhouse gas emissions when combusted. According to DCC (2009), greenhouse gas emissions associated with the use of LPG for stationary energy purposes are 59.90 kg CO<sub>2</sub>-e/GJ, which is approximately 14 per cent lower than emissions associated with conventional diesel (69.50 kg CO<sub>2</sub>-e/GJ).

#### A.3.1 Benefits and issues of using LPG

In addition to having lower greenhouse gas emissions, LPG is a 'cleaner' burning fuel compared to diesel and undergoes more complete combustion. Although it is possible to buy generators which can run solely on LPG, they are more expensive compared to diesel generators. A generally accepted approach is to utilise the existing diesel generators but substitute LPG for some of the diesel. Discussions with the engineers at Origin Energy suggest that substituting 30% with LPG is a generally accepted maximum blend.

When blended with diesel, LPG acts as an accelerant which results in a higher percentage of the fuel in the combustion chamber being combusted — releasing more energy per unit of fuel with less residues. According to industry suppliers, customers who use a 30% blend of LPG with diesel experience longer service intervals on their machinery compared to using straight diesel due to the 'cleaner' combustion characteristics. Importantly, however, the different combustion characteristics of an LPG blend require consumers to retune their engines to take advantage of the improved efficiency.

A key issue when comparing LPG and diesel is that the energy content of LPG is significantly lower on a per litre basis compared to diesel. In particular, the average energy content of Australian LPG is 25.7 MJ/L while the energy content of diesel is 38.6 MJ/L (ABARE 2009; DCC 2009). Hence, all else being equal, replacing 1 litre of diesel requires 1.5 litres of LPG to obtain the same energy content. However, it is possible that the improved combustion properties of a diesel-LPG fuel mix can translate into a higher generation efficiency that may partially offset the lower energy content of the LPG.

We have not identified any definitive literature surrounding the magnitude of such an efficiency improvement but a preliminary estimate from a major LPG supplier estimated it

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<sup>3</sup> LPG Autogas Australia <http://www.lpgautogas.com.au/index.cfm?Action=About>.



would be in the order of 14-20%. Consequently, we have assumed that 1.3 litres of LPG will be required to replace 1 litre of diesel, which would result in a 25% reduction in greenhouse gas emissions.

Finally, it should be noted that transportation and storage costs of LPG are significantly more expensive than for diesel. LPG must be pressurised to keep it as a liquid during transportation. LPG is transported in relatively small and specialised vehicles and ships which translates to a higher delivery cost compared to diesel (ACCC 2009).

Minemakers will need to allow for dedicated LPG storage tanks to be placed onsite. Although Minemakers will not need to purchase the storage vessels they will need to ensure that there is appropriate tanker access, water supply, fire protection equipment and to meet any other statutory requirements.

### A.3.2 LPG pricing

It is not possible to provide a simple estimate of the cost of using a LPG-diesel mix relative to the cost of using only diesel. It is generally recognised that LPG is significantly cheaper than petrol or diesel. Unfortunately it is quite difficult to undertake a simple comparison, particularly for Minemakers, largely due to a lack of suitable data but also because LPG and diesel are fundamentally different, albeit related, commodities. The following discussion attempts to draw out what Minemakers could expect to experience with respect to the average cost of using a LPG-diesel mix compared to using only diesel.

As with most other refined products, LPG is an internationally traded commodity and its domestic price is therefore influenced by the international price of LPG. Since around 1994, Australian producers tend to use the Saudi Aramco Contract Price (Saudi CP) as the benchmark upon which to set their wholesale domestic and export prices. The Saudi CP price is typically used because Saudi Arabia is the major supplier of LPG to buyers in the Asia-Pacific market, including Australia, and there are few other quoted prices. On the first day of each month, Saudi Aramco sets and publishes the price to be paid by 'term contract buyers'. Typically domestic contracts use an average exchange rate for the preceding month to determine the Australian dollar price for purchases in the current month<sup>4</sup>. The Saudi CP is quoted in US\$ per tonne of propane or butane.

As shown in Figure 5A, historically the Saudi CP price has broadly tracked the crude oil price. This is encouraging as it indicates that, over time, any price differential between LPG and diesel should be roughly constant. Interestingly the LPG did not experience the large rise in the crude oil price between January and June 2008 (from approximately \$100/bbl to \$140/bbl) and instead the LPG price was relatively flat during this period at around \$1,000/tonne. The authors of this report are unaware of the reasons for this but it would be interesting to see if the underlying supply and demand characteristics precluded the LPG

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<sup>4</sup> BP Australia <http://www.bp.com/genericarticle.do?categoryId=9008033&contentId=7017886>

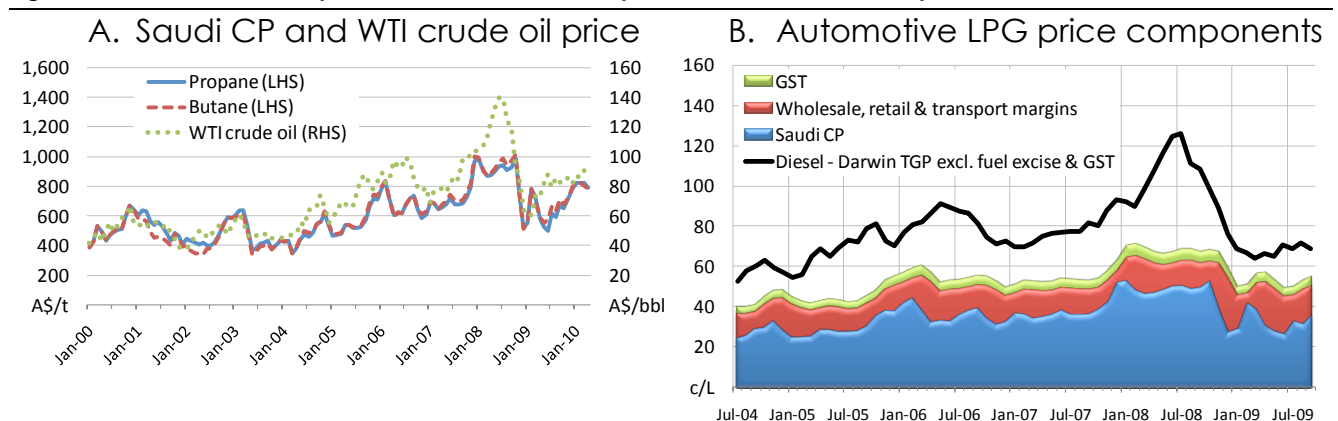


price rising beyond \$1,000/tonne and, hence, whether LPG provides a natural hedge against very high oil prices.

It is difficult to obtain LPG price data at the wholesale level which is equivalent to the publically available diesel TGP. Figure 5B, however, presents the historical retail price of LPG used for general transport purposes (typically called LPG Autogas or Autogas). As can be seen, the price from LPG producers comprises approximately two-thirds of the retail price, GST comprises 9% of the retail price while a range of wholesale, retail and transportation margins account for the remaining 25%. Importantly, it is evident from Figure 5B that there are could be substantial cost savings associated with LPG compared with diesel, but any savings are highly dependent upon the costs of supplying the remote mine site.

With respect to fuel excise, LPG is currently excise free but is (currently) planned to be gradually introduced from 1 July 2011 in annual increments of 2.5c/L until it reaches 12.5 c/L in 2015. The current taxation legislation states that Minemakers is eligible to receive fuel tax credits for “All taxable fuels” (ATO 2009). Although LPG is currently ineligible (since it is excise free) presumably it will become eligible for a fuel tax credit if an excise is introduced<sup>5</sup>.

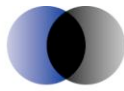
Figure 5 **Historical LPG prices versus WTI crude oil price and diesel wholesale price**



Data source: ACIL Tasman calculations using ACCC (2010), Australian Institute of Petroleum online data ([www.aip.com.au](http://www.aip.com.au)), LPG Australia ([www.lpgaustalia.com.au](http://www.lpgaustalia.com.au)) and RBA exchange rate online data ([www.rba.gov.au/statistics/hist-exchange-rates/index.html](http://www.rba.gov.au/statistics/hist-exchange-rates/index.html)).

The authors of this report have sought quotes from a number of major Australian LPG suppliers for supplying sufficient LPG to replace 30% and 100% of Minemakers anticipated annual diesel consumption associated with on-site electricity generation. To date, two preliminary quotes have been received from two major industry suppliers. For commercial reasons we have chosen to keep the names of the entities confidential and instead we refer to them simply as Supplier 1 and Supplier 2. Supplier 2's pricing structure is based on the assumption that the on-site storage tanks are purchased and owned by the Supplier with the capital cost of the tanks rolled into the contract price. In contrast, the pricing structure of

<sup>5</sup> Although this will require a (minor) modification to the legislation since, in Minemakers case, all taxable fuels are eligible for a fuel tax credit of 38.143 c/L which is higher than the planned excise rate.



Supplier 1 separates the fuel cost from the capital cost of the tanks and has assumed a larger amount of on-site storage in order to allow for deliveries of maximum load in order to minimise delivery costs. The quotes are discussed separately in the following sections. Both Suppliers propose to primarily source their LPG from the Santos Port Bonython refinery.

### Supplier 1

Supplier 1's quotation is based on the assumption that they will make dedicated supply runs using large tri-axle 21 tonne tankers (or larger 30 tonne B-Doubles). The current delivered price to the mine site is 63.2c/L. Assuming that 1.3 litres of LPG are required to replace 1 litre of diesel this equates to an effective price of approximately 82c/L of replaced diesel.

After the first year Minemakers will also be required to pay an annual rental fee of \$12,000 per 30 tonne of on-site storage. Based on a replacement of 540kL of diesel per year this rental equates to an additional charge of 2.2c/L of replaced diesel implying that the cost to Minemakers will be around 84c/L — approximately 4c/L cheaper than the equivalent cost of diesel.

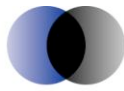
### Supplier 2

Based on the current market price of LPG, delivery costs and overheads, if Minemakers were to replace 540kL of diesel using LPG, Supplier 2 quoted an indicative delivered price including all necessary capital installation and ongoing maintenance costs of 85c/L. Assuming that 1.3 litres of LPG are required to replace 1 litre of diesel this equates to an effective price of 102c/L of replaced diesel. For comparison, the current Darwin diesel TGP (excluding fuel excise and GST) is 80c/L, with a delivered cost to the mine site of approximately 88c/L. Hence, using LPG to replace 30% of the anticipated annual diesel use for electricity generation will incur an additional cost to Minemakers under this pricing model.

Supplier 2 has indicated that larger volumes will significantly reduce the delivered cost. For example, if LPG were to be used to replace the entire 1,800kL of diesel, a discount of approximately 10% should be possible. Such a discount would equate to a delivered price of approximately 92c/L of replaced diesel. The greater volume however, would require Minemakers to use a gas-fired electricity generator set instead of a diesel generator set, which is likely to incur a higher upfront capital cost.

A benefit of using Supplier 2 is that they have a LPG depot at Alice Springs, which provides regular deliveries to the region around the Wonarah mine site. Consequently, Supplier 2 can readily supply the LPG requirements of the mine by simply hooking a second trailer to the truck on its regular run. This capability may provide Minemakers greater flexibility in their week to week use compared to Supplier 1's solution.

It should be noted that the indicative quote from Supplier 2 is based on all deliveries and support being supplied from their Alice Springs depot. This option may be more expensive compared to Supplier 1's solution of transporting LPG in full loads from Port Bonython and, if



Minemakers wishes to proceed further with the option of using LPG, it is recommended that a second quotation using the same delivery solution should be sought.

### A.3.3 Summary

Based on the estimated annual diesel demand of 1,800kL for on-site electricity generation purposes, a saving of 4c/L on 540kL (i.e. 30% of 1,800) equates to an annual fuel saving of \$21,600 per year. Over the currently assumed mine life, the ongoing fuel savings would justify any additional upfront capital costs associated with using LPG (e.g. pad preparation for storage vessels, tanker access, water supply, fire protection equipment and any other statutory requirements) of up to approximately \$150,000<sup>6</sup>.

Greenhouse gas emissions associated with the fuel combustion for the purposes of on-site electricity generation are estimated to fall by 7.6 per cent, or 368 t CO<sub>2</sub>-e per year as a result of substituting 30% of the estimated diesel use with LPG.

## A.4 Cost of installing solar power for the northern borefield and accommodation camp

The potential cost to Minemakers of using solar power to operate the northern borefield and/or the accommodation camp is dependent on the size of the generation capacity that is installed on the project site as a whole. If a large solar PV array is installed in addition to the proposed diesel generator sets similar to that discussed in Section A.1, then the costs and benefits will be similar to those presented in Table 1.

However, if a small scale, stand alone solar PV system is installed to provide power to the northern borefield or to the accommodation camp, then the cost of the PV array is likely to be per kW and will also require the use of battery storage to allow for night time electricity use or to compensate for extended cloudy periods. Based on estimates from industry suppliers, the cost of the components required for a standalone 10 kW solar PV power system with three days of battery storage is around \$16,000 to \$18,000 per kW. This costing does not include installation. Around half of the cost is related to the battery storage capacity. Reducing the need for the battery storage capacity by connecting the system to a backup generator would substantially reduce the upfront capital costs, but will result in some diesel use during extended periods of low sunlight.

Under the current<sup>7</sup> rules for generation of renewable energy credits, a 10 kW solar PV system is eligible to receive 368 RECs, while a 12 kW system is eligible for 414 RECs. Assuming a REC

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<sup>6</sup> This estimate is determined by calculating the net present value of the fuel savings over a 10 year mine life and assuming a 10 per cent real discount rate.

<sup>7</sup> A joint media release by Senator Wong and Minister Combet on the 26<sup>th</sup> February 2010 announced changes to the current scheme titled the 'Enhanced Renewable Energy Target Scheme'. The proposed legislation will not be considered until mid-2010, however. It is likely that the proposed changes will not alter increase the value of the RECs generated by a small solar PV system.





price of \$40, this equates to an up-front subsidy of around \$14,700 to \$16,600 — approximately 9 per cent of the estimated capital cost of a standalone system.

## A.5 Potential emission offsets

As stated in the EIS, Minemakers has already taken a number of steps to ensure that the emissions associated with the project are minimised. These include to:

- Develop and apply policies and procedures for efficient mine operation that will ensure fuel use is minimised.
- Minimise haul distances to minimise diesel use in vehicles and subsequent combustion emissions.
- Monitor energy consumption (e.g., diesel and electricity) and calculate greenhouse gas emissions. This data can then be used to identify and address any key opportunities to reduce greenhouse gas emissions.
- Identify and assess economically viable opportunities for reductions in emission rates, e.g., reducing areas of vegetation clearance and exploring opportunities to use more efficient fuel technology such as natural gas.
- Use renewable energy sources where available and viable (e.g. solar hot water systems, monitoring systems powered by solar energy).
- Ensure that vehicles and equipment are mechanically sound, serviced regularly and fitted with appropriate emission control equipment.
- Use energy efficient lighting in all accommodation and office areas.
- Use 5-star appliances in accommodation and offices where available (e.g., refrigerators, air conditioners and cookers).
- Continue to pursue opportunities to reduce combustion emissions from ore transportation through development of a rail link between the mine and Tennant Creek.

In addition to reducing greenhouse emissions by becoming more energy efficient and making smarter equipment choices, it is also possible to reduce net emissions by using offsets.

To offset its own emissions an organisation can pay someone else to reduce their emissions or sequester carbon already in the atmosphere such as by planting and maintaining a forest plantation that absorbs CO<sub>2</sub> from the atmosphere. Total CO<sub>2</sub>-e emissions for the Minemakers project at full production are estimated at 41,228 t/year. Based on a Carbon Conscious calculator, fully offsetting this amount of emissions would require planting of about 206 thousand trees, at an approximate cost of \$1 million or about \$24/t CO<sub>2</sub>-e offset.<sup>8</sup>

The Government is developing a National Carbon Offset Standard (NCOS) to ensure there are clear criteria regarding how offsets are generated, verified and calculated. The NCOS is intended to come into effect on 1 July 2010. It is designed to ensure the integrity of the carbon

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<sup>8</sup> Carbon Conscious web site, <http://www.carbonconscious.com.au> accessed 2 March 2010.





offset and carbon neutral products available for purchase and provide consumers with confidence in the voluntary carbon offset market. The Standard specifies:

- the types of carbon offsets that constitute genuine, additional emissions reductions in the context of the CPRS
- the general principles and requirements for calculating the carbon footprint of a product or organisation
- requirements for transparent recording of the carbon footprint, measures taken to reduce emissions and the amount reduced and the emissions amount offset and the type of carbon offsets purchased and retired
- requirements for auditing the veracity of carbon footprint calculations and offset claims.<sup>9</sup>

According to the Department of Climate Change, the following units are currently accepted under the NCOS for the purposes of voluntary carbon offsetting:

- CPRS permits, which are known as Australian Emissions Units (AEUs), including those issued for forestry projects and any offsets allowed under the CPRS.
- Other units accepted for compliance under the CPRS which include the following units generated under the United Nations Framework Convention on Climate Change (UNFCCC) flexible mechanisms:
  - Certified Emissions Reductions (CERs), excluding temporary (tCERs) and long term (ICERs) CERs
  - Emission Reduction Units (ERUs)
  - Removal Units (RMUs).
- Voluntary Emissions Reductions (VERs) issued by the Gold Standard.
- Voluntary Carbon Units (VCUs) issued by the Voluntary Carbon Standard, including credits issued for agriculture, forestry and other land use (AFOLU) and reduced emissions from deforestation and degradation (REDD) projects, where they apply methodologies approved by the Department of Climate Change.
- Offsets generated from emissions sources in Australia not counted toward Australia's Kyoto Protocol target and using a methodology that has been approved by the Department of Climate Change.

The offset units accepted for compliance under the CPRS are backed by domestic regulatory and compliance frameworks and international treaty obligations, and are subject to rigorous accounting and audit protocols providing a high level of integrity. The Gold Standard and Voluntary Carbon Standard together accounted for 60 per cent of over-the-counter transactions in international voluntary carbon markets in 2008.<sup>10</sup>

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<sup>9</sup> National Carbon Offset Standard, <http://www.climatechange.gov.au/government/initiatives/carbon-offset.aspx>, accessed 2 March 2010.

<sup>10</sup> Ecosystem Marketplace and New Carbon Finance (2009) Fortifying the Foundation: State of the Voluntary Carbon Markets 2009, p. 11



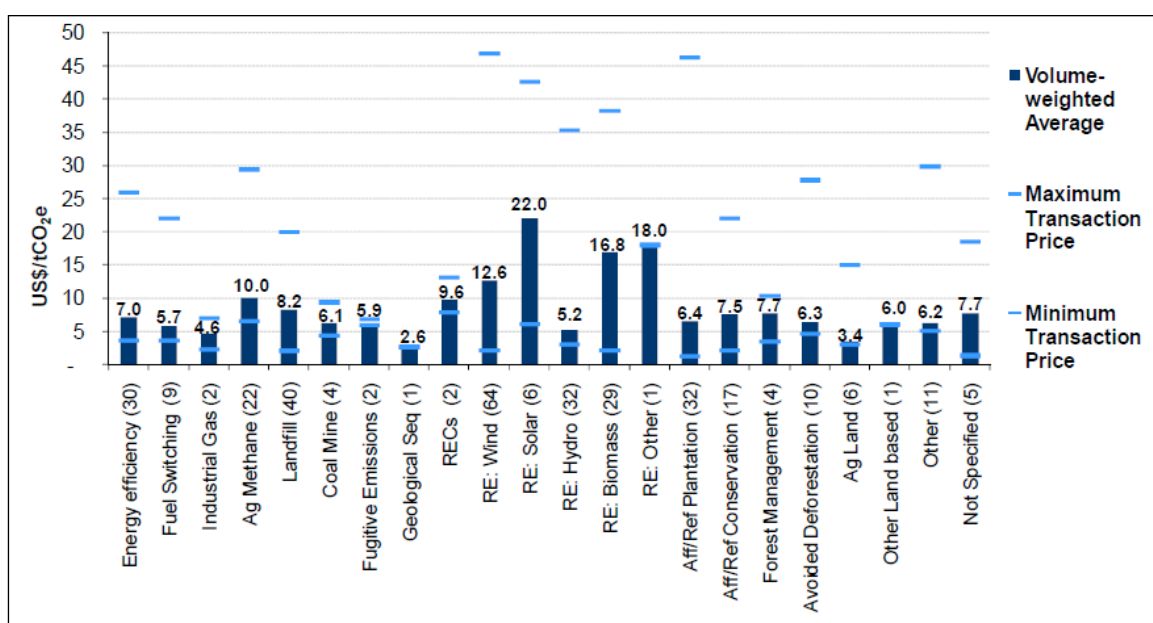
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Economics Policy Strategy

Gold Standard and Voluntary Carbon Standard offsets are traded on the over the counter (OTC) market<sup>11</sup> and the Chicago Carbon Exchange (CCX). The average price of an offset on the CCX in 2008 was US\$4.43/t CO<sub>2</sub>-e. On the OTC the average price paid for an offset in 2008 was US\$7.34/t CO<sub>2</sub>-e.

There is a wide range of different projects that can be used to generate offsets. The price per tonne of CO<sub>2</sub>-e varies considerably between different projects. Figure 6 illustrates how the volume weighted average price of an offset in 2008 in one market varied from as low as US\$2.60/t CO<sub>2</sub>-e to a high of US\$22/t CO<sub>2</sub>-e.<sup>12</sup>

Figure 6 Credit Price Ranges and Averages by Project Type, OTC 2008

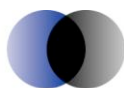
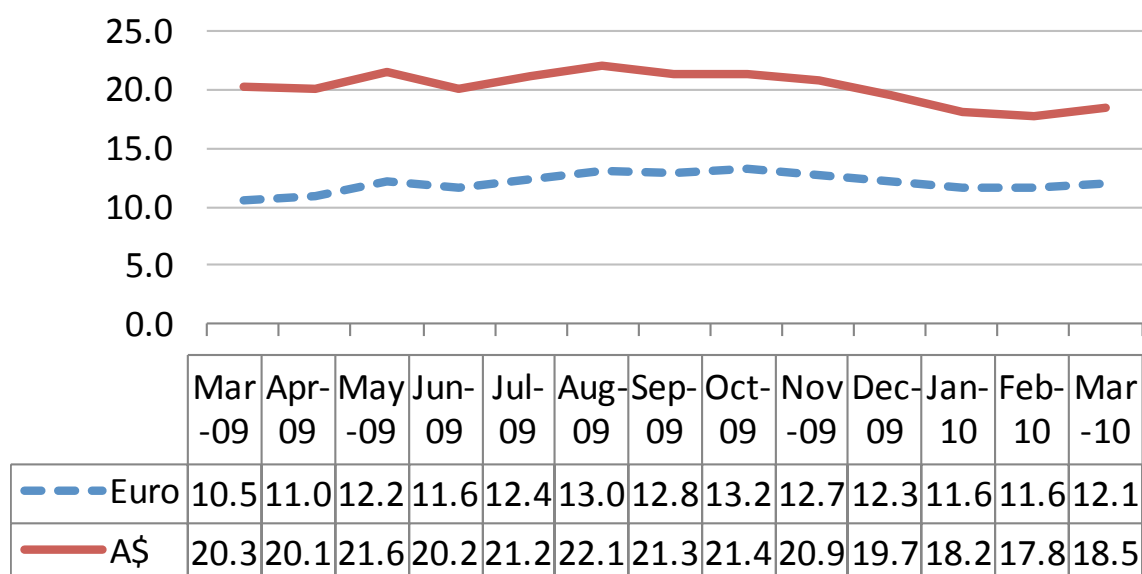


Data source: Ecosystem Marketplace, New Carbon Finance. Note: Numbers within parentheses indicate number of observations

Another potential mechanism for offsetting emissions would be to purchase Certified Emission Reduction (CER) permits on the European Climate Exchange (ECX). The average spot price of a CER permit in the last year has been around €12 (or A\$18.50 at an exchange rate of A\$1=€0.65). The price trend for CER permits over the last year is shown in Figure 7.

<sup>11</sup> The OTC is based on bilateral deals and operates largely outside of exchanges.

<sup>12</sup> Ecosystem Marketplace and New Carbon Finance (2009) Fortifying the Foundation: State of the Voluntary Carbon Markets 2009, p. vii

Figure 7 CER daily futures – spot contracts. Price per CER (in t CO<sub>2</sub>-e)

Data source: EUA & CER daily futures. Retrieved March 2010, from European Climate Exchange: <http://www.ecx.eu/EUA-CER-Daily-Futures>. Australian exchange rate from Reserve bank of Australia, retrieved March 2010 from <http://www.rba.gov.au/statistics/hist-exchange-rates/index.html>.

The estimated annual emissions of just over 41 kt CO<sub>2</sub>-e associated with a production level of 3 Mt of ore implies that each tonne of ore mined leads to an emission of 13.7 kg CO<sub>2</sub>-e. This implies that purchasing CER offsets for the emissions associated with one tonne of ore would cost approximately 24.5c. Based on the average price in 2008 the cost of buying an offset on the OTC market would be around 11 c/t of ore. The equivalent price if the offset had been purchased on the CCX in 2008 would have been closer to 7 c/t of ore.

NCOS also allows firms to propose methodologies for offset projects and develop offset projects within Australia from emissions sources not counted toward Australia's obligations under the Kyoto Protocol target. Eligible activities for the generation of domestic offsets under the Standard are:<sup>13</sup>

- Forest management (forests established before 1990);
- Revegetation (establishment of woody biomass that does not meet forest criteria); and
- Cropland and grazing land management (net greenhouse gas emissions from soil, crops and vegetation).

<sup>13</sup> National Carbon Offset Standard, <http://www.climatechange.gov.au/government/initiatives/carbon-offset.aspx>, accessed 2 March 2010, p. 4



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