An assessment of the impact of proposed carbon tax legislation on Australian LPG and LNG markets

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Executive summary

This paper reviews the findings of the carbon tax impact assessment in light of key design principles required for an effective carbon pricing mechanism. In applying the principles to the draft exposure legislation, the following issues were identified.

1. INABILITY TO PARTICIPATE IN THE PROPOSED EMISSIONS TRADING SCHEME

Unlike the approach proposed for the electricity industry, the gaseous fuels industry will not have the ability to purchase cheaper permits in overseas markets, nor will it have the opportunity to apply trading and hedging practices to reduce the inherent carbon cost component of gaseous fuels.

2. DISPROPORTIONATE ADJUSTMENT COSTS FOR THE GASEOUS FUELS INDUSTRY

Locking the gaseous fuels industry out of an emissions trading scheme and collecting carbon tax by way of fuel tax will impose a transition burden on the gaseous fuels industry. This tax will be substantially higher than the tax for the electricity industry, which has the opportunity to defray the impact on operating cash flows by deferring purchase of permits until the surrender date.

3. INCREASED COST OF LNG FOR TRANSPORT RELATIVE TO DIESEL FUELS

Whether or not a carbon tax will apply to diesel fuels used in on-road transport in the future, the carbon tax is expected to result in an increase in the price of LNG relative to diesel for heavy vehicle operation as a result of the different levels of compensation afforded.

4. INCREASED COST OF LOW CARBON SOURCES OF LPG

The upstream GHG emissions intensity of LPG sourced from petroleum refineries is double that of LPG sourced from natural gas; however, the different levels of compensation afforded means that LPG from natural gas will have a carbon cost that is actually 9% higher than refinery-sourced LPG.

5. INCONSISTENCIES IN GHG EMISSIONS INTENSITIES CITED IN THE LEGISLATION

The draft legislation applies GHG intensity factors for gaseous fuels that are different to the GHG factors used in the National Greenhouse Accounts. In fact the intensity factors are not only different but are also higher, resulting in a higher carbon cost than would otherwise be the case.

6. DISPROPORTIONATELY LOW EMPHASIS ON THE ADOPTION OF LOW CARBON FUELS AS A BASIS FOR NATIONAL GHG EMISSIONS REDUCTION

While treatment of the electricity market is considered to be both comprehensive and appropriate, the treatment of alternative fuels is considered to be inappropriate. Given that gaseous fuels compete with electricity, the failure to place equal emphasis on availability of grant assistance has the potential to create a market distortion that will be detrimental to gaseous fuels in Australia.

1 About this paper

Following the July 2011 release of the draft exposure legislation for a carbon tax in Australia, LPG Australia commissioned Rare Consulting to undertake an assessment of the likely impacts of this legislation on the national liquefied petroleum gas (LPG) and liquefied natural gas (LNG) markets. Essentially, LPG Australia was seeking to understand the degree to which the proposed legislation will likely impact the future costs of production and the price competitiveness of low carbon gaseous fuels relative to electricity and other liquid fuels.

The scope of the assessment extended to a strategic review of the likely impact of the Australian change plan stakeholders with:

- an appreciation of the structure and key elements of the proposed carbon tax mechanism, and subsequent emissions trading scheme (ETS);
- an assessment of the likely direct and indirect impacts of the legislation on domestic LPG and LNG markets;
- the key issues for industry arising from the assessment and recommendations on the strategies that could be pursued by the gaseous fuels industry for the redress of these impacts.

The assessment in this paper evaluated the degree to which the proposed legislation satisfied the five core principles that LPG Australia believes are essential to the design and operation of any carbon pricing mechanism in Australia. These principles can be summarised as follows.

1. Any carbon pricing mechanism should advance a least cost solution to the reduction of greenhouse gas (GHG) emissions in Australia.
2. Any future mechanism should afford equitable access to a carbon trading market and the consequent industry benefits that accrue from participation in this market.
3. The GHG intensities used as the basis for carbon pricing of individual fuels or energy sources must be consistent with the intensities cited in other government legislation, policy and/or programs.
4. The mechanism should place equal emphasis on the encouragement of industry investment in low carbon fuels and energy efficiency as a means of lowering GHG intensity across the total supply chain.
5. Industry adjustment costs associated with a carbon pricing mechanism should be similar for competing energy and fuel sources, notwithstanding the need for compensation of energy-intensive trade-exposed (EITE) industries.

This paper concludes with a summary of the key adverse industry impacts and the actions that could be pursued for their redress.

2 Background

The design and operation of a carbon pricing mechanism in Australia has been debated by government and industry stakeholders for more than five years.

The first model was advanced by the Howard Liberal Government in a discussion paper released in May 2007. This model proposed the introduction of an ETS that incorporated coverage of greenhouse emissions generated within the stationary energy and transport sectors. The momentum towards the developed model was halted by a change in the federal government at the 2007 election.

A second model, known as the (CPRS), was announced by the Rudd Labour Government in 2009. Similar to the 2007 model, this scheme proposed the introduction of an ETS that included greenhouse emissions from the stationary energy and the national transport sectors with provisions for protection of EITE industries. The Carbon Pollution Reduction Scheme Bill was introduced into federal parliament in late 2010, following the release of a White Paper. The Bill was subsequently defeated, forcing the government of the day to revise its approach.

The ensuing political dynamic saw a change in both the Federal Opposition Leader and the Prime Minister, culminating in the election of a minority Gillard Labour Government in August 2010. The Gillard ability to form government was secured via a formal agreement with the Greens and three Independents.

On 27 September 2010, Prime Minister Gillard announced the formation of a Multi-Party Climate Change Committee (MPCCC). This committee operated under the auspices of a formal agreement known as the Clean Energy Agreement (DCCEE 2010), and comprised the following members:

- The Prime Minister, the Hon. Julia Gillard MP (Chair)
- The Minister for Climate Change, The Hon. Greg Combet MP
- The Leader of the Australian Greens, Senator Bob Brown
- Senator Christine Milne (Australian Greens)
- Tony Windsor MP (Independent member for New England).

Throughout its eight months of deliberations, the Committee was assisted by Adam Bandt MP (Australian Greens) and Mark Dreyfus (Federal Parliamentary Secretary for Climate Change and Energy Efficiency).

The work of the MPCCC culminated in the release of the Clean Energy Plan on 10 July 2011 (DCCEE 2011). This plan included an announcement of a new carbon pricing mechanism that has three stages of evolution, namely:

- an initial three-year period comprising the introduction of a carbon tax of $23/t, with annual escalation;
- transition to a carbon trading market that is controlled by the imposition of a price floor (and a price ceiling for three years);
- removal of the price controls to facilitate unconstrained operation of a carbon trading market.

On 28 July 2011, the Federal Treasurer and the Climate Change Minister released the draft exposure legislation for the proposed carbon trading mechanism. This package comprised four main Bills:

- Clean Energy Bill 2011 (which sets up the carbon price mechanism);
- Clean Energy Regulator Bill 2011 (which establishes a regulatory body to administer the mechanism);
- Climate Change Authority Bill 2011 (which establishes a new authority to advise the government on the future design of the carbon price mechanism);
- Clean Energy (Consequential Amendments) Bill 2011.

In addition, the draft legislative package included proposed amendments to the following existing pieces of legislation:

- Fuel Tax Act 2006
- Excise Tariff Act 1921
- Customs Tariff Act 1995.

Following the release of the draft legislative package, LPG Australia commissioned Rare Consulting to undertake an assessment of the direct and indirect impacts on the domestic markets for LPG and LNG, noting that the legislation essentially impacted on the sale of fuels for non-transport applications only.

This paper details the findings of the assessment, which sought to consider the potential impacts of the legislation on the industry as it stands today and the likely impact of the legislation on recent industry strategies prepared in relation to:

- Autogas use in Australia to 2030 (LPGA 2010)
- non-transport use of LPG in Australia to 2030 (Rare 2011).

3 Key elements of the proposed carbon pricing mechanism

Any assessment of the impact of a carbon pricing mechanism should be developed from an appreciation of its architecture. The architecture of a carbon pricing mechanism can typically be characterised as comprising six discrete elements, namely:

- **COVERAGE.** This refers to the greenhouse emissions that will be included in the carbon pricing mechanism. Typically, these emissions are categorised by the industry in which they are generated (e.g. energy generation sector). The majority of schemes effected to date have been limited to coverage of emissions generated by the electricity sector, with a small number proposing inclusion of transport sector emissions.
- **PRICING MECHANISM.** An examination of carbon pricing mechanisms introduced around the world suggests that the pricing mechanism is typically portrayed as a choice between the imposition of a tax or the operation of a market-based trading scheme. Any assessment must therefore consider the starting price, the nature of price escalation and the imposition of any caps on carbon price.
- **POINT OF OBLIGATION.** In simple terms, the point of obligation refers to the point in the supply chain where the responsibility is assigned to a party for (a) reporting the quantum of emissions, and (b) payment of the carbon price. The party to which the point of obligation is assigned is also generally the party that would naturally be directly involved in any trading market. Some schemes assign a primary point of obligation but provide mechanisms for the transfer of the point of obligation to a third party.
- **CARBON TRADING LIMITATIONS.** In cases where the proposed mechanism involves the operation of a carbon trading market, the legislation often includes a series of limitations on how the market will operate. Typical restraints include the imposition of a cap on the purchase of carbon permits outside the primary market, price caps, and limitations on the quantum of offsets that can be applied by liable entities.
- **COMPENSATION.** Every carbon pricing scheme effected to date has included compensatory measures for market participants. These measures typically seek to ensure that the impact on different industries is equitable, and often include free participation in the market for industries that are trade exposed.
- **TRANSITION ASSISTANCE.** Transition assistance can take many forms, including capital grants, low carbon innovation programs or staged implementation. These measures are generally designed to reduce the adverse market and industry impacts that inevitably arise from the transition to an economy where a price is assigned to carbon.

The following subsections summarise each of the above elements as they apply to the carbon pricing scheme detailed in the Clean Energy legislative package released by the Australian Government in July 2011.

3.1 Coverage

The recently released Clean Energy Bill 2011 (exposure draft) indicates that emissions from gaseous fuels are not directly covered under the proposed carbon pricing scheme, with the government instead opting to indirectly include these fuels through changes in the remission of fuel excise (DCCEE 2011, Schedule 1, sec. 43-1).

While this approach may be perceived as easier to administer from a government perspective, it has the unintended consequence of promoting unequal and inequitable treatment of gaseous fuels relative to natural gas and electricity.

The legislation does not propose to include gaseous transport fuels in the scheme but does foreshadow the inclusion of diesel from 2014, subject to the passing of separate legislation in the future. The

is premised on the fact that these fuels will be subject to an implicit carbon price by way of the imposition of excise on alternative fuels.

It should be noted, however, that the inclusion of on-road diesel is by no means certain, with the accompanying materials clearly stating that this action was not agreed by the members of the MPCCC. This observation raises the obvious question of whether any future failure to incorporate diesel fuels in the scheme should trigger a proportional reduction in excise on alternative fuels for transport to take account of the implicit carbon price.

A summary of the degree to which the proposed carbon pricing mechanism will extend to gaseous fuels used for transport and non-transport applications is provided in Table 3.1.

Table 3.1 **Coverage of gaseous (and liquid) fuels under the carbon pricing scheme**

Exemptions	Coverage	
	from 2012	from 2014
▪ Light commercial vehicles (< 4.5 t) ▪ Agriculture, forestry and fisheries (off-road fuel consumption) ▪ Household vehicle fuel (including petrol and LPG)	▪ Off-road transport and stationary energy (diesel, LPG and LNG) ▪ Rail, domestic aviation and marine	▪ Heavy on-road transport (diesel)*

* pending future legislation

3.1.1 Transport applications

The degree to which the proposed carbon pricing mechanism will incorporate coverage of transport fuels can be summarised as follows.

- Petrol and diesel passenger and light commercial vehicles are not covered by the scheme, but could incur a small carbon cost pass-through if domestic upstream emissions are not fully offset with compensation. In comparison, LPG, compressed natural gas (CNG) and electric vehicles will face higher relative price changes due to fuel excise and/or carbon cost pass-through.
- LPG and LNG used in heavy on-road transport will not face a carbon price as their eligibility for fuel tax credit (FTC) is reduced to zero as excise is less than the road user charge.
- There is uncertainty about the inclusion of diesel for heavy on-road transport as inclusion from 2014 was not agreed by MPCCC and will require new legislation.
- All fuels used for off-road transport will be included in the scheme from July 2012 via a reduction in the 100% remission of fuel tax by an amount equivalent to the carbon price for the respective fuels.

3.1.2 Non-transport applications

The degree to which the proposed carbon pricing scheme will incorporate coverage of gaseous fuels in non-transport applications can be summarised as follows.

- LPG, LNG and CNG will be progressively brought into the fuel tax system over a transitional period from 1 December 2011 to 1 July 2015, with an excise remission available for non-transport use.
- From 1 July 2012, non-transport use will be provided with only a partial fuel tax remission so that a small (but increasing) amount of excise is imposed as an effective carbon tax.
- LPG, LNG and diesel used in agriculture, forestry and fisheries will be exempt from the scheme, while both natural gas and electricity use will face a carbon price.

3.1.3 Emission factors

For the coverage of GHG emissions to be effective, the associated emissions must be assessed accurately and consistently. In the case of LPG, the legislation indicates that an emission rate of 0.0016 t of carbon emitted per litre will be applied. This factor, however, is different to the factor cited in the National Greenhouse Accounts (NGA).

Transport and non-transport GHG emissions and LPG combustion are 0.00158 t and 0.00153 t respectively (DCCEE 2010). The 4% difference between the two NGA figures is attributable to the inclusion of butane in LPG Autogas, compared to stationary LPG which is generally propane only.

In the case of natural gas, CNG and LNG are assigned the same GHG emission rate, which is 0.0029 t of carbon emitted per kilogram. While this appears odd given the different upstream intensities of the manufacture of these two fuels, it should be noted that the proposed scheme considers the embodied energy of the fuels on a post-combustion basis (i.e. consideration of upstream emissions is excluded in the intensity factors applied in the legislation).

In transport applications, the quoted emissions factor should change depending on the combustion technology adopted. In the case of stationary energy, CNG and LNG emissions are lower at 0.00262 t and 0.00279 t of carbon emitted per kilogram respectively.

Overall, if the interpretation of emissions factors is correct, the factors applied under the legislation appear to be simplifying the carbon price estimation by adopting slightly higher emission rates to account for all LPG and gaseous fuels used for both transport and non-transport purposes. It is also noted that upstream emissions from the production of gaseous fuels will still attract an additional carbon impost which may be passed on to consumers.

3.2 Pricing mechanism

The proposed scheme comprises a staged approach to the introduction of a carbon price in Australia. A discussion of the three stages is provided in the following subsections.

3.2.1 Fixed price start (2012–2015)

During the fixed price stage of the scheme (2012 2015), annual adjustments to FTC and excise will be in line with the carbon price which is set at the start of the year (i.e. \$23/t CO_2-e in 2011 2012).

The fixed price will escalate at 2.5% p.a. above average annual inflation during the three-year fixed period. Assuming an inflation level of 2.5%, the carbon price will increase from \$23/t in year 1 and climb through \$24.15/t in year 2, to \$25.40/t in year 3.

The starting price of \$23/t CO_2-e is considerably higher than current prices in international markets. The E

3.2.2 Price constrained ETS (2015–2018)

In an effort to manage the risk associated with price volatility in the transition to an ETS from the initial carbon tax, the government legislation proposes an intermediate stage that will see the introduction of a carbon trading scheme with price containment measures (i.e. price floor and price ceiling) between 2015 and 2018.

The transition will occur in the three-year period immediately following the fixed price period. The proposed floor price will be set at $15/t rising by 4% p.a. between 2015 and 2018. The price ceiling will be set at $20/t above the international price. (This price ceiling of $20/t will increase by 5% p.a.)

3.2.3 Full ETS (2018 and beyond)

The final stage will involve removal of the price containment measures and the free market operation of an ETS (although there is potential for extension of the price caps by government if considered prudent).

Essentially, the price trajectory beyond 1 July 2018 is likely to be defined by the pressure for permits created by application of national greenhouse reduction goals. The relatively modest reduction goals of 5% by 2020, for example, mean that the annual rate of retirement of permits will be modest, resulting in relatively gentle increases in permit prices.

In the period between 2020 and 2050, the stated emissions reduction target increases above the previous 50 80% reduction. The achievement of this target will require a more severe rate of retirement of permits that will likely see a significant increase in market prices beyond 2020.

It is worth noting that the government has not flagged any intermediate targets, which makes it difficult to comment on whether the rate of retirement of permits will be linear from 2020 (with commensurate linear increases in unit carbon prices) or will continue to be modest in the first 15 years and more aggressive in the latter 15-year period to 2050.

3.3 Point of obligation

3.3.1 Production

LNG and LPG producers with operational control over a facility that emits more than 25 kt CO_2-e p.a. (i.e. emissions arising from process emissions and energy usage during production) will incur direct permit liability under the proposed scheme. As such, they will be required to surrender permits to meet their obligation for each compliance year.

During the fixed price stage, large emitters (> 35 kt CO_2-e) will be required to surrender 75% of their liability by 15 June, with the balance to be surrendered by 1 February the following year. Post-2015, for all liable entities will be 1 February after the end of the compliance year. Liable fuel suppliers will need to understand which category they fall into and plan accordingly to prevent stress on cash flow.

The penalty for non-compliance during the fixed price period will be 130% of the fixed price during that compliance year. Post-2015, this penalty will rise to 200% of the benchmark average auction price during a particular compliance year.

The Clean Energy Bill also makes provisions with respect to the use of obligation transfer numbers (OTNs) for the production of LPG and LNG using natural gas (DCCEE 2011, sec.
OTN Use of natural gas in manufacturing CNG, LNG or LPG). Accordingly, licensed manufacturers of these fuels who pay excise can use an OTN to avoid direct carbon liability (i.e. netting out of embedde

3.3.2 Point of use

Under the previous carbon legislation in Australia (i.e. CPRS), the point of obligation rested with LPG and LNG marketers, as opposed to gaseous fuel producers. The rationale for this approach was understood to be recognition that fuel suppliers did not have adequate information about the nature of downstream use of LPG and LNG (i.e. the capacity to differentiate between end-product use). Under this original arrangement, LPG marketers were required to use an OTN when purchasing fuel, and to manage their permit liability requirements. Large users of LPG or petrochemical companies using LPG as a feedstock (e.g. plastic resin production) were able to use an OTN to manage their own liability.

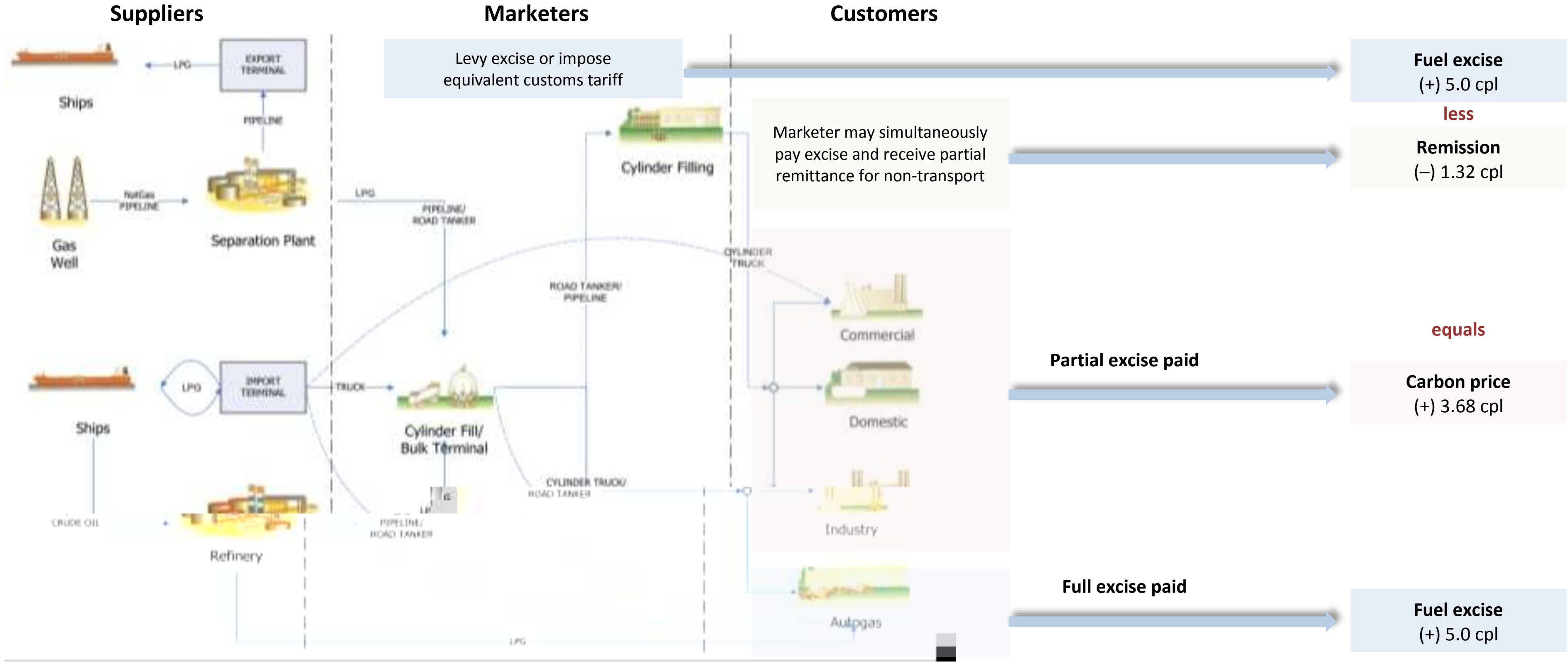
While the problem of differentiating between end-product use (i.e. between transport and non-transport applications) and characteristics of users (e.g. agricultural users compared to residential and leisure users in regional areas) remains, the new legislation reverses the previous approach and proposes to make the fuel producer liable for the carbon price through changes to excise remission.

The operation of the carbon pricing mechanism, as interpreted from the Clean Energy draft exposure legislation, is shown in Figure 3.1. The foreshadowed changes in excise and excise remission during the first three years of the carbon pricing scheme is shown in Figure 3.2.

Beyond 2015, the changes to the excise remission are likely to be less significant when the proposed alternative fuels excise attains the maximum levels identified under federal fuels taxation legislation. Figure 3.3 illustrates the expected changes over time based on the low carbon price outlook escalating to approximately $54/t in 2030.

3.4 Carbon trading limitations

As the indirect carbon liability of LPG and LNG use is covered through changes to excise remission, large users will be unable to take part in the carbon trading market as their liability is linked to the prevailing domestic carbon price. This places these industries at a disadvantage as they cannot capitalise on carbon cost saving opportunities by using trading and hedging practices. Further, the design of the scheme does not allow LPG and LNG users to benefit from potentially cheaper international credits, which can be used for compliance by all other entities with direct liability under the carbon pricing scheme.

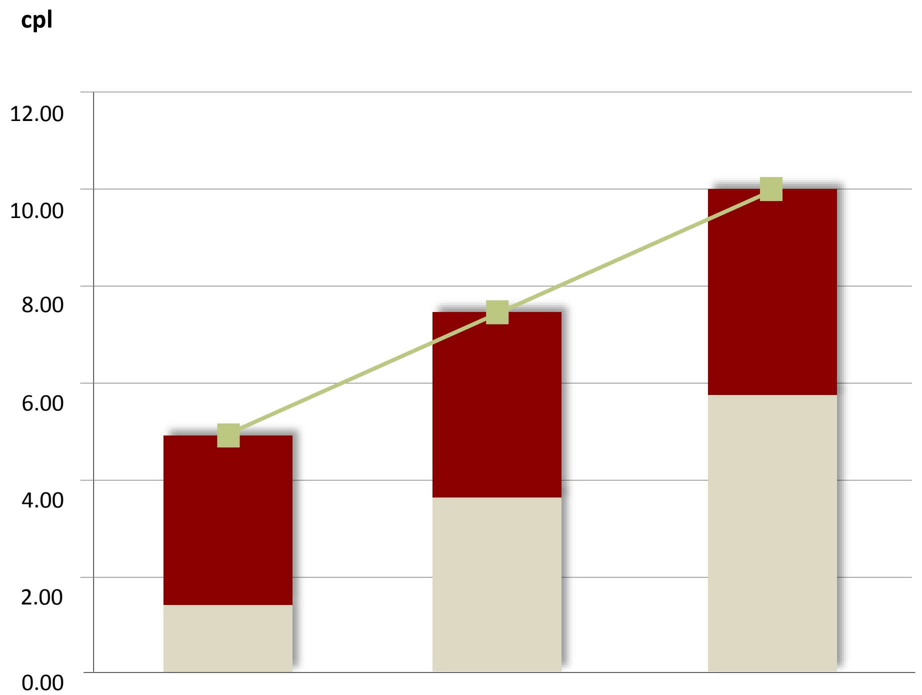


Adapted from LPGA (2008)

Operation of the carbon pricing mechanism

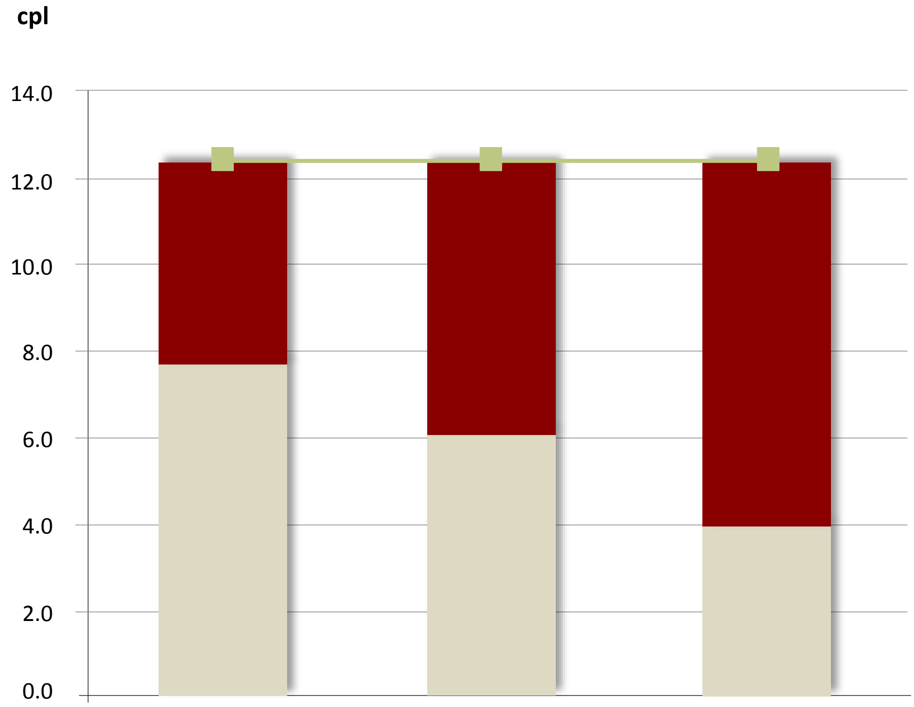
This is in contrast to electricity and gas supply, which may benefit from lower prices and a longer timeframe in which users must purchase and surrender permits. For example, carbon liability associated with electricity sold in July 2015 could be met with permits purchased in January 2017 and surrendered immediately. This discrimination can therefore enable a lower level of carbon cost pass-through compared to LNG and LPG suppliers who are carbon

Based on the carbon price outlook developed by Treasury under various global mitigation targets, and , there will be significant uncertainty with respect to the likely long-term carbon price trajectories and price elevation levels (i.e. post-2018). This is illustrated in Figure 3.4. This uncertainty also exists with respect to the difference between domestic carbon prices and international regimes. Overall, the proposed legislation locks the carbon price in as tax for all time.



	FY13	FY14	FY15
Carbon price impact	3.68	3.86	4.06
Excise remission	1.32	3.64	5.94
LPG fuel excise	5	7.5	10

Excise remission and carbon price FY13 – FY15



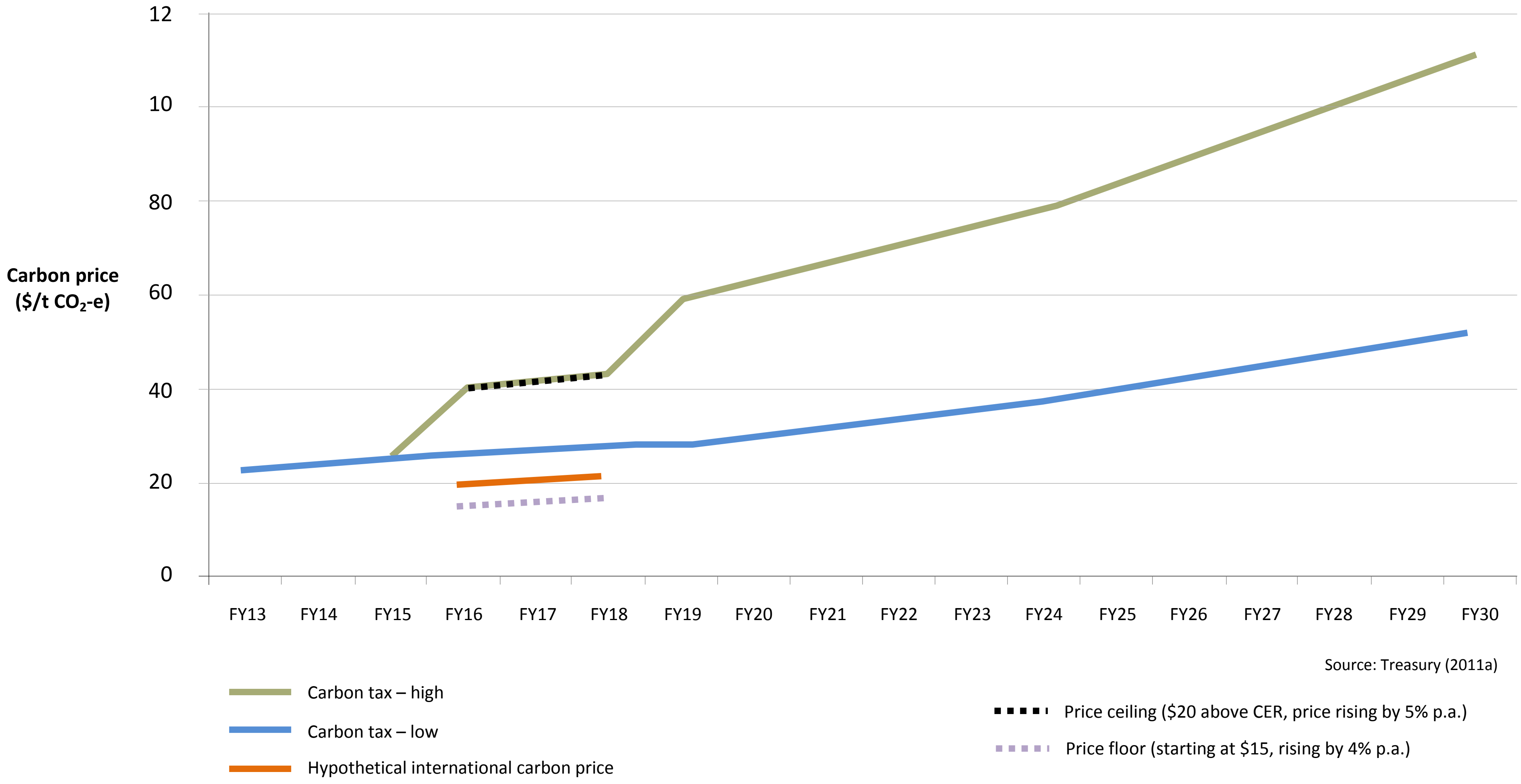
	FY20	FY25	FY30
Carbon price impact	4.70	6.30	8.42
Excise remission	7.80	6.20	4.08
LPG fuel excise	12.50	12.50	12.50

Excise remission and carbon price to 2030

3.5 Compensation

An analysis of the potential impacts of carbon pricing on energy sources requires careful consideration of the ability for a carbon price to be applied to both combustion and production (i.e. upstream supply chain coverage). Downstream emissions are well recognised and are specifically targeted under the proposed legislation; however, the amount that upstream emissions will be covered under a carbon pricing regime is not well understood.

The most effective carbon pricing regime would apply a carbon cost that accounts for all life cycle emissions. This would provide an accurate price signal in proportion to the total emissions contribution of each energy source. However, it is not possible to pass through all carbon costs. This is due to some upstream activities being located outside Australia (i.e. imports), and the limitations to coverage of emissions under the proposed carbon pricing regime. For example, some LPG is imported, while onshore production of LPG from petroleum refining will be supported with compensation.



Australian carbon price trajectory

The Jobs and Competitiveness program has been designed to (a) alleviate adverse competitive impacts his program is very similar to the EITE assistance, and strongly affected industry packages under the

summarised as follows.

- The highest emissions-intensive activities (i.e. those for which emissions exceed 2000 t CO_2-e per million dollars in revenue or exceed 6000 t CO_2-e per million dollars in value-added) such as aluminium smelting, will receive free carbon permits sufficient to cover 94.5% of their average emissions, initially decreasing at the rate of 1.3% p.a. Conventional fuel production is classified as a high emissions-
this level of compensation.
- Moderate emissions-intensive activities (i.e. those for which emissions are between 1000 and 2000 t CO_2-e per million dollars in revenue or between 3000 and 6000 t CO_2-e per million dollars in value-added) such as ammonia manufacturing, will receive free carbon permits sufficient to cover 66% of their average emissions, initially decreasing at the rate of 1.3% p.a. LNG production is classified as a moderate emissions-intensive activity and would therefore qualify for 66% compensation.

Eligibility for assistance under this program is based on an assessment of all entities conducting the relevant activity during an historic baseline period. Trade exposure will be assessed through both quantitative and qualitative tests, while emissions intensity assessment will be based on average emissions per million dollars of revenue or million dollars of value-added across the entire industry (as opposed to individual facilities).

Activity assessments and definitions that have been performed under the CPRS will remain valid. The relevant EITE activities for the LPG and LNG industries relate to the upstream production of these fuels.

3.5.1 LPG extraction from natural gas

The proposed treatment of LPG extraction from natural gas under the draft legislation can be summarised as follows.

- The activity is unlikely to receive EITE assistance for direct liability.
- The carbon cost impact on production from upstream emissions will (at the option of the producer) be passed through to customers (e.g. marketers or retailers).
- The liability for embodied carbon emissions will be transferred to the end-user via proposed excise remission arrangements.

3.5.2 LPG from petroleum refining

The treatment of LPG sourced from petroleum operations under the draft legislation can be summarised as follows.

- Given the size of Australian refineries, LPG production will, on average, receive 94.5% of permits for free in the first year (declining at 1.3% p.a. in subsequent years), with the impact of declining assistance contributing to a progressive increase in the upstream carbon cost component.
- The liability for embodied carbon emissions will also be transferred to the end-user via proposed excise remission arrangements.

3.5.3 LNG production

The treatment of LNG production under the draft exposure legislation can be summarised as follows.

- LNG producers will receive free carbon permits sufficient to cover 66% of the average emissions intensity of production, initially decreasing at the rate of 1.3% p.a.
- Supplementary credits will be provided to top up the allocation for individual producers who do not receive sufficient compensation to cover at least 50% of their relevant emissions related to production.

3.6 Transition assistance

The government has outlined how it plans to distribute the revenue raised from sale of permits as well as the revenue raised from application of an indirect carbon price (e.g. FTC reductions) which totals approximately $8 billion p.a. in the first three years of the scheme (Table 3.2). Revenue will go towards household assistance measures (50% of revenue raised), the Jobs and Competitiveness program, the energy security and transformation package (i.e. loans to power generators), and land and biodiversity measures as well as funding for clean technology and business energy efficiency measures.

Table 3.2 **Forecast revenue from carbon scheme**

	2011–2012	2012–2013	2013–2014	2014–2015
Revenue from sale of permits	0	7740	8140	8590
Revenue from application of carbon price via other measures[1]	0	290	320	320
FTC reductions[2]	0	570	620	670

[1] Includes revenue from synthetic GHGs and changes to aviation excise

[2] Ongoing FTC reductions with permanent shielding for heavy on-road transport, agriculture, fisheries and forestry

3.6.1 Major funding opportunities

The major funding opportunities can be divided between two principal assistance mechanisms: (a) Jobs and Competitiveness program (compensation for EITE, etc.), and (b) energy security and transformation packages (i.e. power generators and steel).

The energy security and transformation packages are complementary measures intended to provide funding for liable parties and affected industries to enable investment in low carbon technologies, products and processes.

The $1.2 billion Clean Technology program will support businesses with funding on a co-investment basis. It has three elements:

- $800 million Clean Technology Investment program which provides grants to manufacturers (with facilities that use > 300 MWh of electricity or 5 TJ of natural gas a year).
- $200 million Food and Foundries Investment program which provides $150 million to the food processing industry and $50 million to the metal forging and foundry industries.
- $200 million Clean Technology Innovation program which supports business investment in research and development in the areas of renewable energy, low-pollution technology and energy efficiency.

In addition, a new $10 billion Clean Energy Finance Corporation will invest in renewable energy, low-pollution and energy efficiency technologies. It is recognised that the broad investment mandate also includes low-emissions cogeneration technology. This opportunity is particularly relevant to natural gas, LPG and LNG. It is also noted that renewable investment will need to be supported by low carbon electricity to back up intermittent power supply. In this case, LPG and LNG have a clear capability and proven track record of remote generation.

3.6.2 Minor funding opportunities

A number of business energy efficiency measures are also targeted for support. While electricity use is a major driver that needs to be tackled by increasing the productivity of energy use through energy efficiency, the focus on electricity will deprive businesses and households of potential options to lower GHG emissions. For example, limited options exist to obtain an improvement in the energy efficiency of electric hot water systems that would offset the current GHG saving in the vicinity of the 60% reduction that LPG hot water systems deliver (Rare 2011).

The provision of grant funding under the Clean Energy package should therefore focus primarily on GHG outcomes, rather than on specific technologies such as solar for hot water (as was the case under the current federal and state incentive schemes). The government should therefore ensure that monies available for the Energy Efficiency Information Grants program ($40 million), which assists in providing information to SMEs and the community on practical measures to reduce energy costs, includes low carbon opportunities. This program could then be more effectively targeted through industry associations (including LPG Australia) which have established relationships with small businesses and households.

The Clean Energy Skills program ($32 million) should also support the educational needs of industry to develop the materials and expertise to promote clean energy skills of plumbers and installers of low carbon technology (e.g. gas-powered air-conditioners and heavy vehicle modifications to use LPG and LNG).

4 Industry impact assessment

The purpose of a carbon price is not to drive significant and immediate change. Rather, it is designed to gradually transform the economy by encouraging investment in low carbon innovation, energy efficiency and adoption of energy sources and fuels that produce lower GHG emissions than incumbent sources. While energy price differences have historically been driven by rent-seeking goals and underlying market forces, the imposition of a carbon price has the potential to progressively change the price differential between high GHG energy sources in favour of lower GHG energy sources over a sustained period of time.

Given that the imposition of a carbon price has the potential to affect the entire economy, it is vital that the design and operation of the scheme take due account of any unintended adverse consequences for individual industries, businesses, households and the community at large. These impacts are generally managed during the transition to a carbon economy by the provision of government support and compensation to vulnerable elements of the economy.

This section provides a discussion of the likely impacts of the proposed carbon tax legislation on the operation of the domestic LPG and LNG markets in Australia, recognising that these impacts will likely be both direct and indirect.

4.1 Direct pricing impacts

In order to understand the relative impact of carbon prices on the competitiveness between alternative energy sources, the expected escalation in the underlying price must first be considered. For the purpose of this study an energy price outlook derived using the electricity and gas price trajectories applied by the Australian Treasury was used to model the impacts of a carbon tax on the Australian economy (Treasury 2011b). These trajectories assume that there will be a near-term reduction in the annual growth of electricity prices, and significant growth of natural gas prices over the short to medium term.

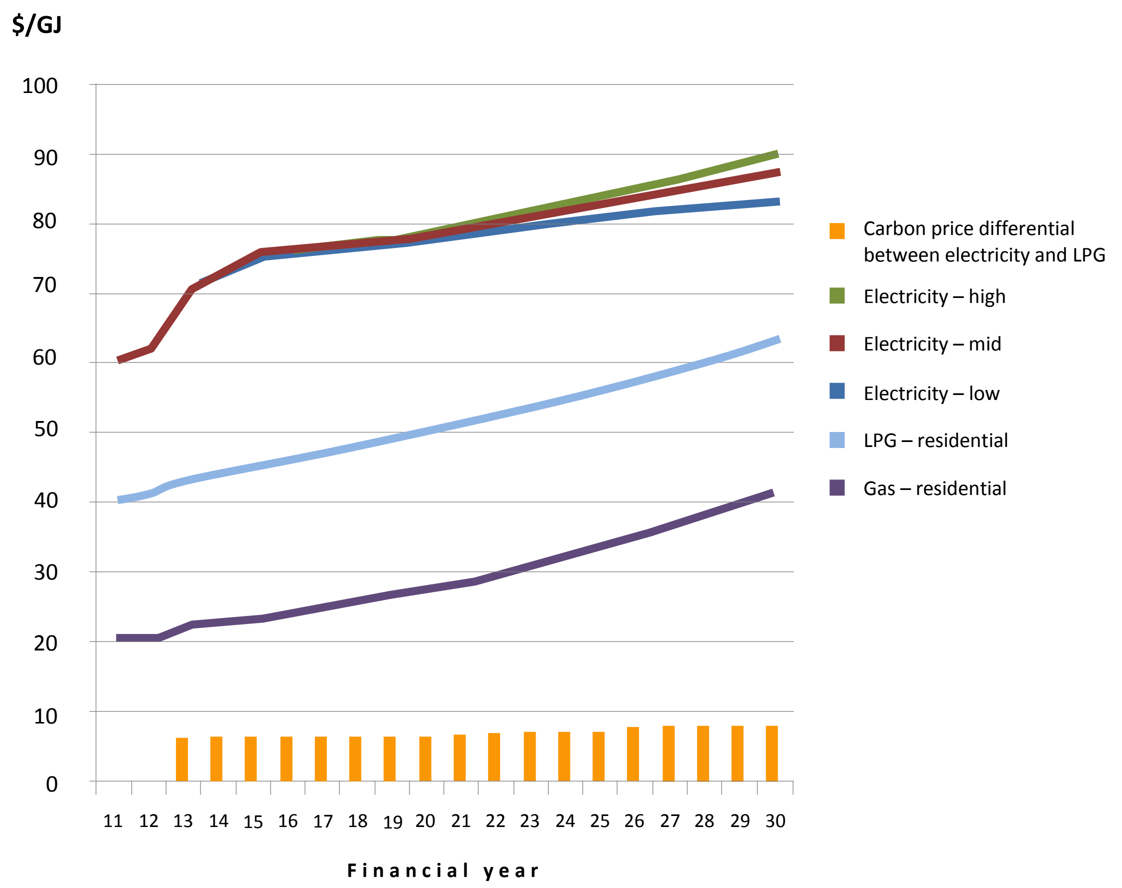
Unfortunately, the Treasury modelling does not appear to have explicitly considered fuels for stationary energy applications. As a result, additional price forecasts had to be developed for the fuels that are used in stationary energy applications (i.e. LPG, diesel and LNG). These forecasts were developed around the forecasts constructed by the International Energy Agency in its 2010 assessment (IEA 2010). The underlying cost of LPG is based on the Saudi Aramco contract price (quoted monthly) for propane and is closely linked to oil price as it shares a common use as petrochemical feedstock.

The energy price outlook for LPG was constructed by assuming that LPG prices would continue to scenario which predicts an annual average escalation of crude oil prices of 2.15% p.a. (The mid-price scenario was discounted owing to the fact that the projected escalation of 1.3% was below the long-term inflation forecast for Australia, essentially suggesting that oil prices [and therefore LPG prices] would fall in real terms over the coming 20 years. It was also noted that IEA forecasts have historically been well below actual oil prices over the past 10 years.)

The resultant energy price forecast for households is shown in Figure 4.1.

4.2 Indirect pricing impacts

An analysis of the potential impacts of carbon pricing on energy sources requires careful consideration of the ability for a carbon price to be applied to both combustion and production (i.e. upstream supply chain coverage). While downstream emissions are well recognised, and are specifically targeted under the proposed legislation, the amount that upstream emissions will be covered under a carbon pricing regime is not well understood.



Expected energy prices

The most effective carbon pricing regime would apply a carbon cost that accounts for all life cycle emissions as this approach would provide an accurate price signal in proportion to the total emissions contribution of each energy source. The complexity of accounting for the total supply chain of many fuels, however, makes it difficult to apply a carbon cost across the total supply chain on a direct basis. This difficulty is principally due to the fact that some upstream activities are located outside Australia (i.e. imports), making it impossible to incorporate total coverage of the supply chain for these fuels.

In considering the validity of the approach proposed by the legislation of only taking account of the downstream emissions of fuels in the derivation of the carbon price (i.e. embodied emissions per energy unit of fuel), it is worth noting that the upstream emissions of hydrocarbon-based transport fuels constitute an additional 10 20% of downstream GHG emissions. As a consequence, the government approach of considering only downstream emissions for fuels is seen as both valid and practical.

That said, the assessment compiled for this study was conducted on the basis of full life cycle emissions to determine whether the proposed legislative approach would create any distortions in the carbon price relativities. Full life cycle emissions were constructed using the SimaPro life cycle analysis tool (SimaPro 7.2). The assessment included consideration of both upstream and downstream inputs thereby enabling assessment of the carbon intensity on a full life cycle basis.

All energy sources were assumed to be representative of the Australian average stocks (as contained in the SimaPro database). The only exception to this approach was the treatment of large-scale LNG production which was derived by using a lower specific power consumption per tonne of LNG produced than domestic LNG production. The following key assumptions were made with regard to upstream emissions estimates for the different feedstock energy sources.

- **ELECTRICITY**. Electricity consumption was modelled as an average supply, composed of a range of coal, gas and renewable sources as per the Australian grid feedstock.
- **NATURAL GAS**. As for other fossil fuels, the SimaPro model derived estimates of the average emissions arising from natural gas exploration and extraction in Australia from the Australian

  submitted by their members (APPEA 2007).
- **DIESEL**. Upstream emissions for diesel were derived from the 2006 Australian average crude blend composed of 31.6% domestic crude blended with 68.4% imported crude (ABARE 2006). Emissions from crude oil exploration and extraction were based upon figures for the 2006 production year presented by APPEA to the Greenhouse Challenge Plus program (APPEA 2007).
- **LPG**. As per diesel, LPG upstream emissions were sourced from APPEA 2007. LPG production was based on Australian production figures of 3929 ML LPG from natural gas, and 1477 ML from refineries (ABARE 2010).

- **LNG.** LNG is derived by cooling natural gas to between 140° and 160°C and then storing and transporting the fuel in cryogenic cylinders. Small-scale/micro-plant calculations were performed using Australian averages for natural gas production (contained within the LCS database), and subsequent consideration of liquefaction of the gas using energy derived from (a) grid electricity and (b) natural gas. Large-scale (export) plant calculations derived a lower specific power consumption per tonne of LNG produced based on estimates, or on existing and planned projects.

Boundaries of the life cycle GHG assessments were the same for all energy sources, commencing at the exploration and extraction stages of the product and concluding at the point of use. GHG emissions associated with development of infrastructure or end-of-life of products were not considered by the assessment. The outcomes of the subsequent analysis are shown in Table 4.1.

Table 4.1 **Relative GHG upstream compared to total life cycle emissions**

kg CO_2-e per unit	Upstream			Point of use (transport)			Point of use (stationary)			GHG upstream (%)
Where applicable	GJ	L	kg	GJ	L	kg	GJ	L	kg	
Electricity	267	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**100**
Natural gas	6.08	n/a	0.31	57	n/a	2.91	51.33	n/a	2.62	**11**
Diesel	13.6	0.525	0.62	69.81	2.69	3.18	69.5	2.68	3.17	**16**
LPG (refinery)	13.3	0.341	0.66	60.2	1.58	2.99	59.9	1.53	2.97	**18**
LPG (natural gas)	6.21	0.16	0.308	60.2	1.58	2.99	59.9	1.53	2.97	**9**
LNG (small scale)*	16.4	0.41	0.892	53.33	1.35	2.9	51.33	1.29	2.79	**24**
LNG (large – export)	5.466	0.136	0.297	53.33	1.35	2.9	51.33	1.29	2.79	**10**

* based on SimaPro 7.2 averages

4.2.1 LPG supply chain

Examination of the analysis presented in Table 4.1 gives rise to the following observation in respect of the treatment of the LPG supply chain under the draft legislation.

- The upstream GHG emissions for LPG sourced from natural gas fields (i.e. natural gas separation) are less than 50% of the upstream emissions for LPG sourced from a petroleum refinery.

Despite LPG sourced from a refinery having higher upstream emissions, the nature of the proposed compensation mechanisms is such that the indirect carbon price component on this source of LPG will actually be lower than for LPG sourced from natural gas fields (i.e. refinery compensation starts at 94.5% in year 1, while compensation for LPG production facilities in Australia will be 66%). In effect, the differences in proposed compensation for the two sources of LPG mean that the total carbon cost imposed on the low carbon source (i.e. sourced from natural gas) will actually be higher than for the higher carbon source (i.e. LPG sourced from a refinery as shown in Table 4.2).

Table 4.2 **LPG supply chain – impact of $23/t CO_2-e**

	LPG (refinery)	LPG (natural gas)
Upstream emissions (kg CO_2-e/L)	**0.34**	**0.16**
Potential carbon cost – upstream (cpl)	0.784	0.368
Expected compensation (%)	94.5	0
Expected carbon cost pass-through (cpl)[1]	0.043	0.368
Point of use emissions (kg CO_2-e/L)	**1.6**	**1.6**
Potential carbon cost – point of use (cpl)	3.68	3.68
Total expected carbon cost – LCA less compensation (cpl)	**3.72**	**4.065**

[1] Upstream costs may be able to be passed into price

4.2.2 LNG supply chain

Examination of the analysis presented in Table 4.1 gives rise to the following findings in respect of the treatment of the LNG supply chain under the draft legislation.

- The indirect cost impact associated with the upstream emissions intensity of the LNG supply chain will likely vary according to the size of the plant, feed gas specification and the specific power consumption (per tonne of LNG) of the production facility (Table 4.3).
- Small-scale domestic LNG production plants are likely to receive the minimum level of compensation due to higher emissions relative to the industry baseline, which incorporates export facilities. It is likely to require a top-up of supplementary pe
emissions intensity of production.
- Export-scale plants (approximately 2500 tpd or above) will receive free carbon permits sufficient to cover 66% of the average emissions intensity of production, initially decreasing at the rate of 1.3% p.a. The compensation awarded to individual facilities will vary either side of this average level of permit allocation according to specific production characteristics, but they will receive at least 50% compensation due to the support of supplementary credit allocation if required.

Table 4.3 **LNG supply chain – impact of \$23/t CO_2-e**

	LNG (small-scale domestic)[1]	LNG (export scale)[2]
Upstream emissions (kg CO_2-e/kg)[3]	**0.41**	**0.41**
Potential carbon cost – upstream (cents per kg)	0.94	0.31
Expected compensation (%)	50	66
Expected carbon cost pass-through (cents per kg)[4]	0.47	0.11
Point of use emissions (kg CO_2-e/kg)	**1.35**	**1.35**
Potential carbon cost – point of use (cents per kg)[5]	3.11	3.11
Total expected carbon cost – LCA less compensation (cents per kg)	**3.58**	**3.21**

[1] Small-scale domestic plants typically have production levels of less than 200 tpd
[2] Export scale relates to large production volumes greater than 2500 tpd (approximately 1 Mt p.a.)
[3] Production assumes black coal–produced electricity (gas generation will reduce upstream GHG intensity)
[4] Upstream costs may be able to be passed into price
[5] Potential carbon cost related to point of use will depend on whether LNG is used for non-transport purposes

The above analysis reveals that the small-scale domestic LNG plants will need to rely on the supplementary allocation of permits. This will have implications for the use of LNG in both transport and non-transport applications.

The consequence of the lower level of compensation for small-scale facilities will mean that the cost of LNG relative to diesel used for transport will increase by 0.8 cents per diesel litre equivalent (DLE), despite LNG being a fuel with a lower GHG intensity.

4.3 Competitive considerations

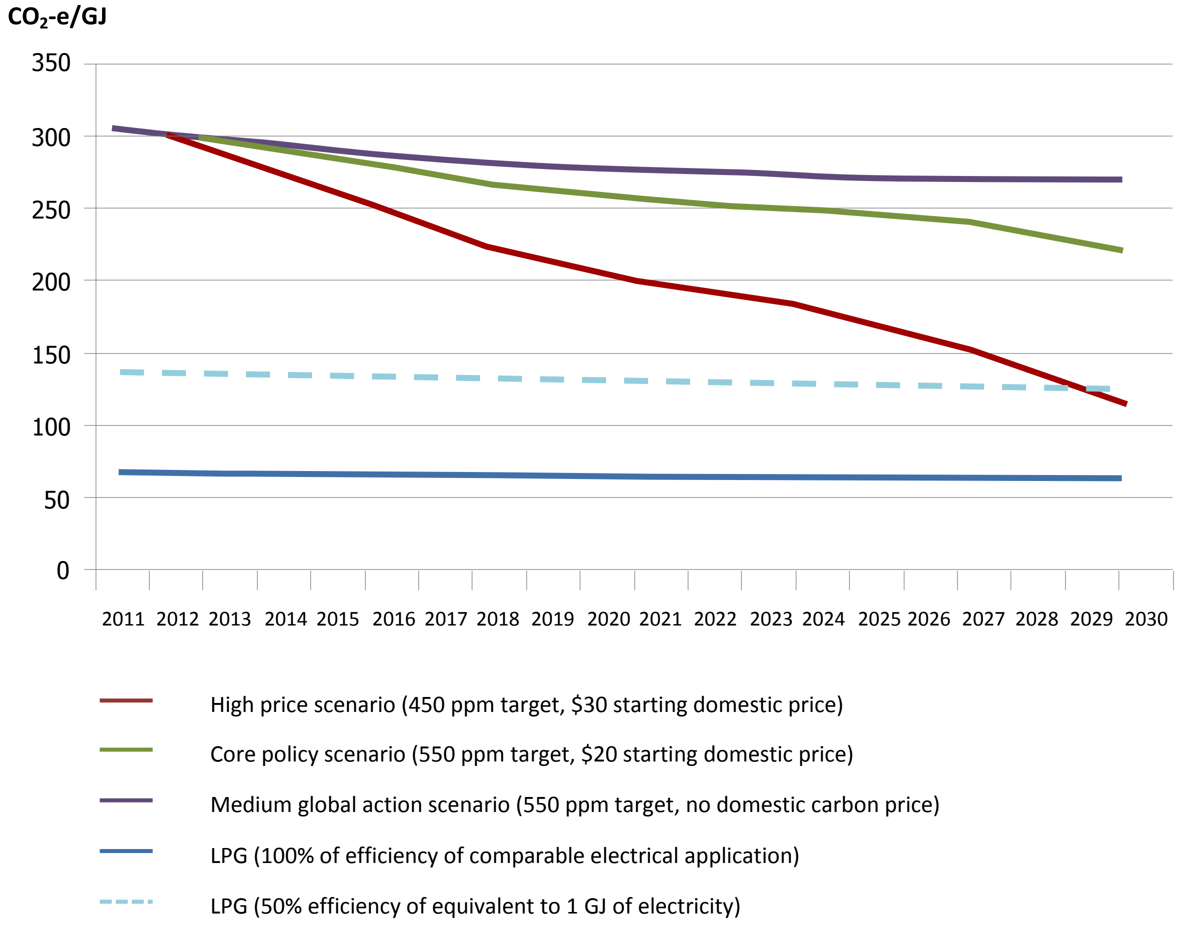
4.3.1 Stationary energy – electricity vs. LPG

The electricity sector has a significant opportunity to reduce greenhouse emissions intensity over time. The combination of the Renewable Energy Target, and the inclusion of a carbon price in the wholesale electricity price, will drive investment in renewable/gas-fired generation and the closure of brown coal power stations (e.g. 2000 MW mandated through the Clean Energy Future legislation). These measures could halve the GHG intensity of electricity by 2030.

While carbon prices are expected to rise as emissions caps are lowered, the decline in greenhouse intensity will help offset the increase in the carbon price. Figure 4.2 illustrates the expected decline in the average GHG intensity of electricity to 2030. This has been based on three separate global mitigation and domestic policy action scenarios derived by ROAM Consulting (2008) under the following three carbon price scenarios:

- **medium price:** global action for 550 ppm emissions target, without a domestic carbon price
- **core policy:** global action to achieve a 550 ppm emissions target, with a $20/t starting carbon price
- **high price:** global action to achieve a 450 ppm emissions target, with a $30/t starting carbon price.

In Figure 4.2, the two blue lines (solid and dotted) highlight the limited ability of LPG to reduce exposure to carbon prices over time. Based on the expected increase in supply of LPG from natural gas as opposed to petroleum refining, there is potential for the average life cycle emissions to decrease by between 2% and 3%. In comparison, the average GHG intensity of electricity in 2030 could be halved with adoption of the high carbon price scenario.



Declining GHG intensity of electricity under various mitigation scenarios compared to LPG

A separate but related issue is the energy efficiency of equipment that uses LPG or electricity. In the case of battery-electric forklifts, the greenhouse intensity of the different fuels is the reverse of the greenhouse intensity of the overall application (including equipment). The example above therefore demonstrates the impact of an application that uses twice the energy relative to electricity.

4.3.2 Stationary energy – electricity vs. LNG

The use of LNG in lieu of electricity (or LPG) for some manufacturing and industrial processes is becoming an increasingly feasible option for mid-sized and large industrial enterprises, including mining operations.

Analysis of the impacts of the proposed carbon tax legislation reveals that the legislation will not significantly affect the existing price differential where the LNG is sourced from larger scale plants that is, both energy sources will incur a similar carbon price component. In cases where the LNG is sourced from small plants (i.e. < 200 tpd), the cost of LNG will actually increase by approximately 5 cents per gigajoule immediately following the introduction of the $23/t carbon price.

4.3.3 Passenger transport and light commercial vehicles

The underlying price differential between transport fuels will be impacted by increased upstream costs of production due to the carbon price impost on upstream emissions and the different levels of compensation provided through the Jobs and Competiveness Program.

Fuel excise will be imposed on LPG over the next five years and will contribute to a weakening of the price differential with petrol. The potential adoption of electric and CNG vehicles will also be impacted by the upstream carbon costs of the respective energy retailers.

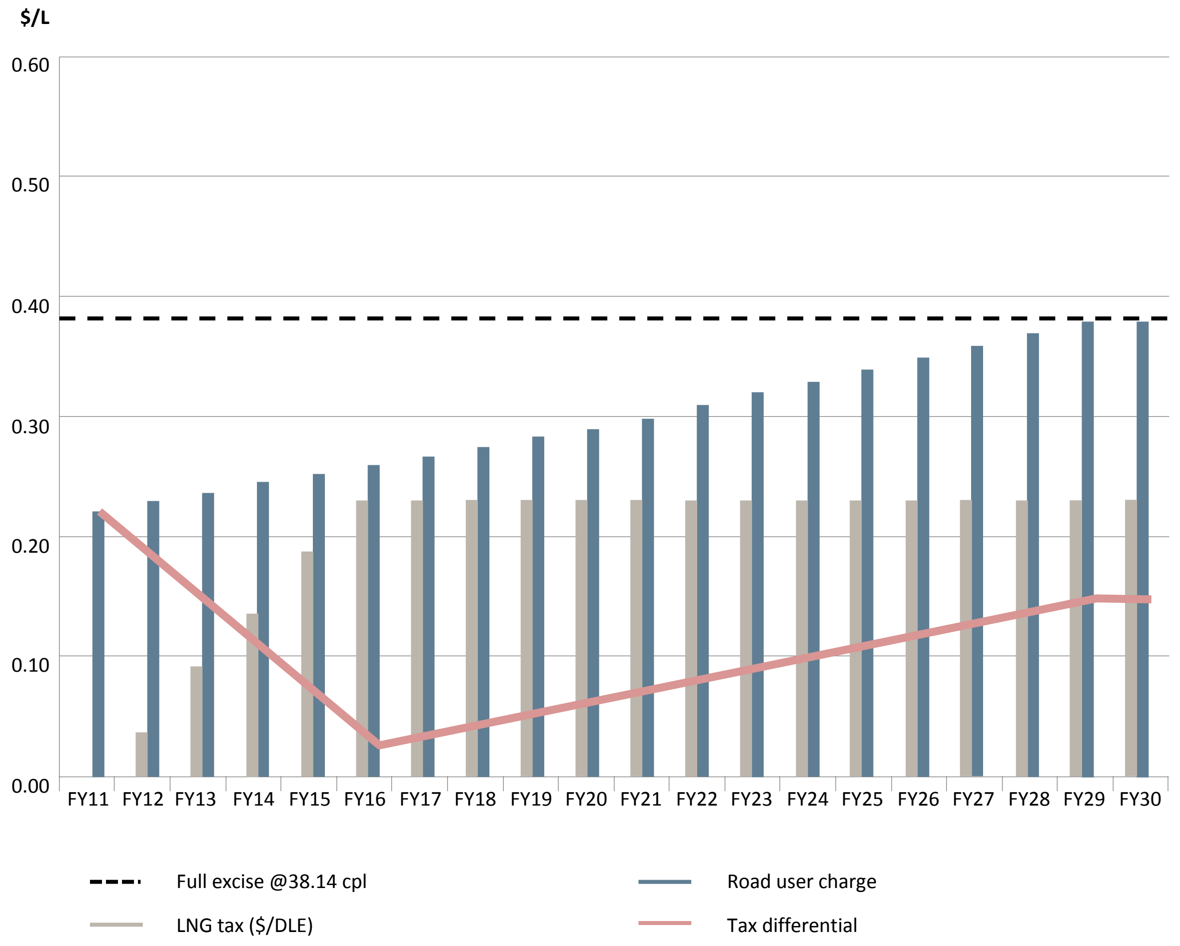
4.3.4 Heavy transport – diesel vs. LNG

Analysis of the impacts of the draft legislation on transport fuels gives rise to the following principal observations.

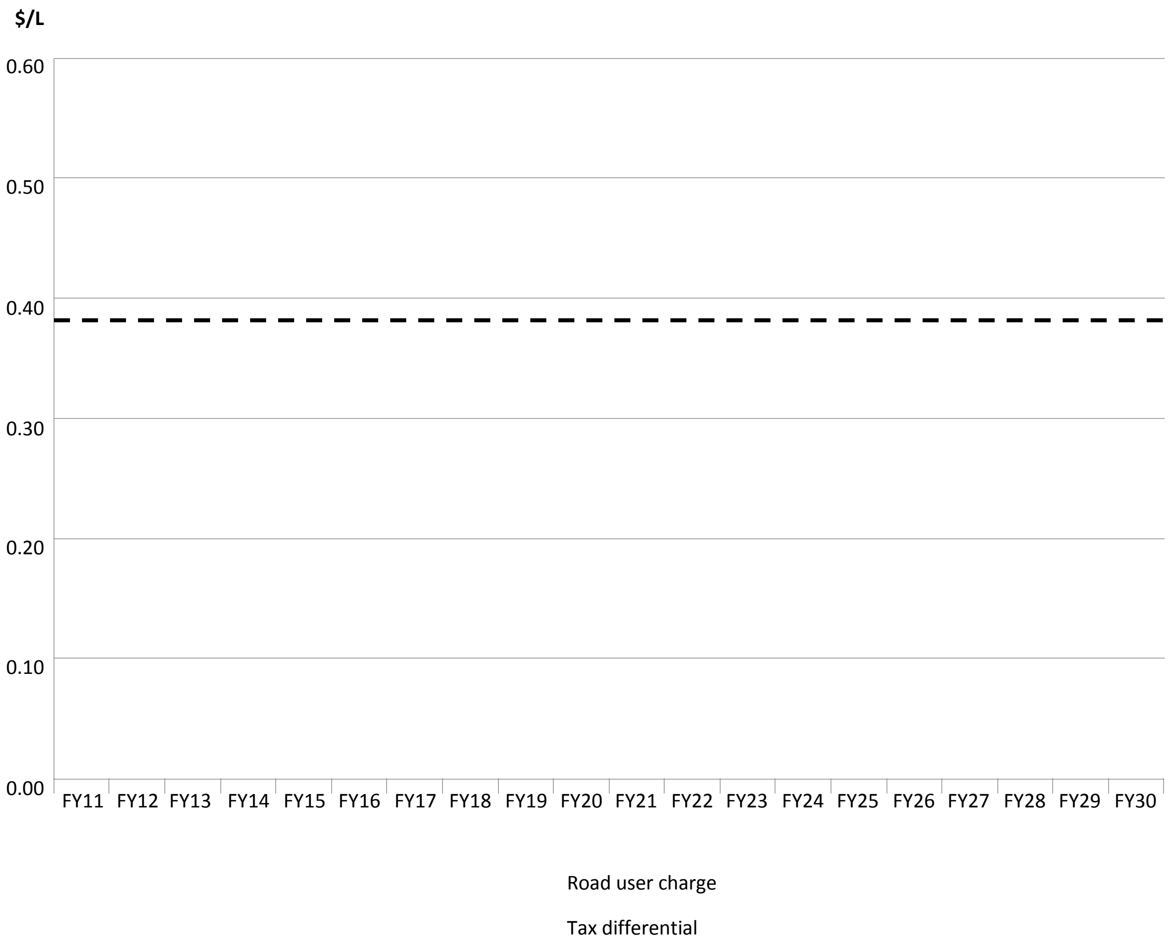
- Under the proposed carbon tax legislation, the current price relativity between diesel and LNG used in transport will not alter significantly in the near term, with the exception of LNG sourced from small-scale LNG plants (i.e. > 200 tpd). The apparent exclusion of these plants from compensation (i.e. they do not qualify as liable entities by nature of their emissions being below the 25,000 t CO_2-e p.a. threshold), means that the price of LNG will increase by 1.6 cents per DLE. This is despite LNG being less GHG intensive than diesel.
- Subject to the inclusion of diesel fuels for on-road transport being included in the scheme from 2014 under separate legislation to be passed in the future, the price of diesel will increase by the equivalent of the carbon price (around 6 cpl). Given that the proposed mechanism for collection of a carbon price will be by way of a reduction in the current FTC afforded to diesel users, the use of gaseous fuels for road transport will effectively be excluded from coverage under the scheme if this additional legislation was to be enacted.

The uncertainty surrounding the competitive position of LNG relative to diesel relates to the potential future inclusion of on-road diesel from 2014. If a decision is taken not to include diesel in the scheme from 2014, then the negative price impact associated with the introduction of excise on LNG from 1 December 2011 will not be recovered for more than 20 years, as shown in Figure 4.3.

Conversely, if future legislation was to include diesel in the scheme (and continue to exclude LNG as is stated in the exposure legislation), the imposition of the carbon tax would facilitate recovery of the price disadvantage for LNG (created by excise imposition) by July 2020, as shown in Figure 4.4.



Estimated tax differential for diesel vs. LNG, assuming that a carbon tax is not introduced on diesel (or LNG) from 2014


$/L
0.60
0.50
0.40
0.30
0.20
0.10
0.00
FY11 FY12 FY13 FY14 FY15 FY16 FY17 FY18 FY19 FY20 FY21 FY22 FY23 FY24 FY25 FY26 FY27 FY28 FY29 FY30
Road user charge
Tax differential

5 Key issues

The findings of the industry impact analysis presented in Section 4 were reviewed in light of the five assessment principles discussed at the beginning of this report, namely:

1. Any carbon pricing mechanism should advance a least cost solution to the reduction of GHG emissions in Australia.
2. Any future mechanism should afford equitable access to a carbon trading market and the consequent industry benefits that accrue from participation in this market.
3. The GHG intensities used as the basis for carbon pricing of individual fuels or energy sources must be consistent with the intensities cited in other government legislation, policy and/or programs.
4. The mechanism should place equal emphasis on the encouragement of industry investment in low carbon fuels and energy efficiency as a means of lowering GHG intensity across the total supply chain.
5. Industry adjustment costs associated with a carbon pricing mechanism should be similar for competing energy and fuel sources, notwithstanding the need for compensation of EITE industries.

By applying the above principles to the analysis of the draft exposure legislation, a number of issues were identified. These issues are summarised in the following subsections.

5.1 Inability to participate in the proposed ETS

The draft legislation proposes that the carbon tax on gaseous fuels be levied via a reduction of the current wholesale remission of fuel tax on gaseous fuels used in non-road transport applications. The only exceptions to this provision are the use of gaseous and other fuels in agriculture, forestry and fisheries. The net effect of this approach is that Australian LPG and LNG marketers will be responsible for the collection of fuel tax from customers on behalf of the Australian Taxation Office.

Unlike the approach proposed for the electricity industry, the gaseous fuels industry will not have the ability to purchase cheaper permits in overseas markets, nor will it have the opportunity to apply trading and hedging practices to reduce the inherent carbon cost component of gaseous fuels.

In essence, the proposed approach effectively penalises the gaseous fuels industry relative to the electricity industry an industry that competes directly with the gaseous fuels industry for customers in the residential, commercial and industrial markets.

Apart from the obvious consequence of limiting the ability of gaseous fuel enterprises to explore reasonable mechanisms for reducing the carbon cost component of their product, the proposed approach also poses significant short-term adverse consequences in relation to operating cash flows of gaseous fuels enterprises. Industry players will be required to remit payment of the carbon tax from the first week of the scheme, while competitors in the electricity industry will have the capacity to defer payment for carbon permits up to 20 months following commencement of the trading scheme.

Examination of the Regulatory Impact Statement (RIS) prepared by the Australian Department of Finance and Deregulation (DFD 2011) for the carbon legislation suggests that the rationale for adoption of the fuel tax approach for the gaseous fuels market was premised on the belief that this approach imposed lower costs on government (administrative burden) and industry (compliance burden). Interestingly, the RIS does not appear to have considered the substantial industry and customer downsides of the proposed approach compared with the inclusion of the gaseous fuels industry in an emissions trading market.

This issue is considered to be the single biggest issue for the Australian gaseous fuels industry in respect of the draft carbon legislation released by the government. As such, it is suggested that the industry should immediately seek amendment of the draft legislation to accommodate participation of the gaseous industry in the future emissions trading market.

5.2 Disproportionate adjustment costs for the gaseous fuels industry

This issue is related to the previous issue in that the net effect of locking the gaseous industry out of an emissions trading scheme and collecting carbon tax by way of fuel tax will impose a transition burden on the gaseous industry that is substantially higher than will likely occur for the electricity industry.

By requiring payment of the carbon price through fuel tax collections immediately following commencement of the scheme in July 2011, the gaseous fuels industry must immediately ensure that sufficient operating capital is in place.

The electricity industry on the other hand, has the opportunity to defray the impact on operating cash flows by deferring purchase of permits until close to the permit retirement date 12 months after the commencement of the scheme.

Following expiry of the fixed-term period, the advantage to the electricity industry over the gaseous fuels sector strengthens further, with electricity generators afforded the flexibility of being able to purchase permits when the market price is relatively low as opposed to the gaseous fuels industry which would be paying a relatively constant price for GHG emissions compliance.

This issue would be corrected by the inclusion of the gaseous fuels industry in the emissions trading mechanism. Alternatively, the difficulties could be corrected by requiring payment of fuel tax at the same time as the electricity generator is required to surrender its permits.

5.3 Increased cost of LNG for transport relative to diesel fuels

Diesel fuels used in on-road transport are explicitly excluded from the legislation, albeit that the government has foreshadowed the future introduction of legislation to expand the carbon scheme to incorporate on-road diesel.

Whether or not such legislation is likely to be passed in the future, given the nature of the likely federal political dynamic the carbon tax is expected to result in an increase in the price of LNG relative to diesel for heavy vehicle operation. This is despite LNG having lower GHG emissions than diesel.

This occurs as a result of the level of compensation likely to be afforded to the petroleum industry relative to the level of compensation afforded to small-scale LNG domestic producers. While the exact level of compensation afforded to individual LNG producers will need to be assessed, it is likely that small-scale LNG production facilities (Westbury in Tasmania, Dandenong in Victoria and Kwinana in Western Australia) will receive around 50% compensation in the first year of the scheme compared with 94.5% for diesel producers.

This difference in compensation is likely to see a negligible increase in the cost of diesel to cover indirect carbon costs (i.e. electricity used in fuel production) while LNG will increase by approximately one cent per DLE in 2012.

While this increase may be considered by government to be relatively modest, it is unclear why a carbon tax should effectively impose a higher cost on the fuel that has a lower GHG intensity. It should also be noted that this increase will come on top of the relative price increase associated with the imposition of excise on alternative fuels from 1 December 2011.

as opposed to a focus on full life cycle emissions. Accepting that the administration of the scheme on a full life cycle basis is impractical (given the inherent complexity of such an approach) there is a need for the government to consider an alternative means of redressing this perversity in pricing that effectively makes a low GHG emission fuel (i.e. LNG) less price competitive compared to diesel.

It is therefore suggested that the gaseous fuels industry should approach government with a view to seeking redress of the pricing imbalance by either (a) provision of the same level of compensation for LNG production of transport fuels as applied to diesel, or (b) reduction in the starting excise rate of LNG to compensate for the market distortion.

5.4 Increased cost of low carbon sources of LPG relative to high carbon sources

As discussed in Section 4, the upstream GHG emissions intensity of LPG sourced from traditional petroleum refineries is double that of LPG sourced from natural gas fields. Unfortunately, the different levels of compensation afforded to the petroleum industry (94.5%) and the natural gas industry (0%)

means that LPG sourced from natural gas fields will result in a carbon cost component that is actually 9% higher than refinery sourced LPG.

Again, this issue arises as a result of the failure of the scheme to take due account of differences in the upstream emissions of fuels. Nonetheless, this outcome is perverse and introduces a cost barrier to the achievement of the Australian LPG industry strategy of sourcing greater volumes of LPG from natural gas fields, given the GHG advantages of this source over traditional refinery sources of LPG (LPGA 2010).

While the quantum of the relative price penalty is likely to be fairly small, it is considered to be significant and imposes an unnecessary barrier on the sourcing of increased volumes of low carbon LPG. Consequently, it is strongly suggested that the LPG industry should approach government with a view to seeking redress of this issue. Possible remedies include:

- providing equal levels of compensation for LPG sourced from Australian refinery operations and natural gas fields;
- reducing the excise levied on LPG by an amount equivalent to the price distortion.

5.5 Inconsistencies in GHG emissions intensities cited in the legislation

As discussed in Section 3, the draft legislation applies GHG intensity factors for gaseous fuels that are different to the GHG factors used in the long established NGA. In fact the intensity factors are not only different but are also higher, resulting in a higher carbon cost than would otherwise be the case.

While this issue may at first appear trivial when considered in terms of the quantum of carbon price difference, consistency in the application of GHG is essential for the creation of a reasonable level of investment uncertainty for all industries in the face of a transition to a carbon constrained economy.

In view of the above, the gaseous fuels industry should seek alignment of the GHG intensity factors for gaseous fuels contained in the draft legislation with the NGA or at the very least, should seek an explanation as to why the factors contained in the legislation differ from those contained in the NGA.

5.6 Disproportionately low emphasis on the adoption of low carbon fuels as a basis for national GHG emissions reduction

By way of a general observation, the treatment of the electricity market under the proposed legislation is considered to be comprehensive and appropriate. Together with the various transition programs, the legislation seeks to encourage emissions reduction from the national electricity sector by:

- reducing the GHG intensity of electricity generation through the promotion of investment in renewable electricity generation activities;
- encouraging investment and innovation in energy efficiency practices and end-user technologies.

By comparison, the treatment of alternative fuels is considered to be inappropriate. The shallow emphasis on fuels used for non-road transport applications appears to be manifest in the assistance programs that have been foreshadowed as part of the Clean Energy Future legislative package. None of the programs explicitly supports the increased market adoption of low carbon fuels for non-transport applications, or promotes increased investment in low carbon transport fuels.

Given that gaseous fuels such as LPG and LNG will compete with electricity in many domestic markets (e.g. residential, commercial, industrial, resources), this failure to place equal emphasis on transition assistance to the gaseous fuels industry has the potential to create a market distortion that would be detrimental to gaseous fuels in Australia.

It is therefore suggested that the gaseous fuels industry should approach government seeking expansion of some of the associated assistance programs to explicitly incorporate adoption of low carbon gaseous fuels. Programs that could be specifically targeted for expansion to incorporate alternative fuels include the commentary for the $10 billion Clean Energy Finance Corporation and the $40 million Energy Efficiency Information Grants Program.

6 Conclusions and recommendations

The Regulatory Impact Statement prepared by the Australian Department of Finance and Deregulation states that Arrangements for non-transport use of gaseous fuels such as LPG are important for , p. 49).

In addition, the MPCCC identified five principles that would guide the development of any carbon price mechanism:

1. **ECONOMIC EFFICIENCY.** A mechanism to price carbon should harness the most cost-effective pollution reduction options and facilitate informed and efficient investment decisions. It should also minimise costs of our pollution reduction to the economy as a whole and be consistent with

2. **COMPETITIVENESS OF AUSTRALIAN INDUSTRIES.** The overall package of carbon price design and associated assistance measures should take appropriate account of impacts on the competitiveness of all Australian industries, having regard to carbon prices in other countries and maintaining incentives to reduce pollution.
3. **ENERGY SECURITY.** Introduction of the carbon price should be accompanied by measures that are necessary for maintaining energy security.
4. **ADMINISTRATIVE SIMPLICITY.** A mechanism to price carbon should be designed with a view to minimising both compliance costs and implementation risks.
5. **CLEAR ACCOUNTABILITIES.** A mechanism with transparent scheme rules and clear accountabilities will help promote business and community confidence in carbon pricing.

The impact analysis presented in this paper suggests that in respect of the Australian LPG and LNG market, the draft legislation fails both the RIS statement and elements of principles 1 and 2 cited by the MPCCC in December 2011.

Failure to include the gaseous fuels market is considered to be a major limitation in the existing legislation and, if left unchanged, has the potential to significantly distort market competition between electricity and gaseous fuels used in non-transport applications. The adverse consequences of excluding the gaseous fuels market from the trading scheme are multifaceted and present potential adverse consequences for both gas industry participants and end-users of gaseous fuels.

In light of the above deficiencies and the analysis presented in this paper, it is recommended that the Australian gaseous fuels industry approach the government with a view to seeking the following changes to the Clean Energy legislative package released by the government in July 2011.

1. Amendment of the proposed legislation and carbon tax collection mechanism to accommodate the full participation of the gaseous fuels industry in the future emission trading market from the scheduled commencement of the scheme in July 2012.
2. Amendment of the compensation level for LNG used in transport to reduce the additional cost imposed on small-scale LNG production (i.e. < 200 tpd) relative to diesel fuels used in transport. Alternatively, the price disadvantage of approximately one cent per DLE could be counterbalanced by a commensurate reduction in the excise to be imposed on LNG from December 2011.
3. Amendment of the compensation level for LPG sourced or produced from natural gas to the point where it is equivalent to that of LPG sourced from Australian refinery operations (i.e. 94.5%).
4. Amendment of the GHG intensity factors cited in the legislative package for LNG and LPG such that these factors are actually consistent with the intensity factors cited in the Australian NGA.
5. Expansion of the eligibility criteria and stated intent of associated industry assistance programs (e.g. The $10 billion Clean Energy Finance Corporation and the $40 million Energy Efficiency Program Information Grants Program) to explicitly incorporate potential provision of assistance for the market adoption of low carbon fuels as a means of achieving low cost GHG emission reduction.

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Glossary

ABARE	Australian Bureau of Agricultural and Resource Economics
APPEA	Australian Petroleum Production and Exploration Association
CER	Certified Emission Reduction
CNG	compressed natural gas
CO_2-e	carbon dioxide equivalent
cpl	cents per litre
CPRS	carbon pollution reduction scheme
°C	degree Celsius
DCCEE	Department of Climate Change and Energy Efficiency
DLE	diesel litre equivalent
EITE	emissions-intensive trade-exposed
ETS	emissions trading scheme
EU	European Union
FTC	fuel tax credit
FY	financial year
GHG	greenhouse gas
GJ	gigajoule
kg	kilogram
kt	kilotonne
L	litre
LCS	life cycle strategies
LNG	liquefied natural gas
LPG	liquefied petroleum gas
ML	megalitre
Mt	megatonne
MPCCC	Multi-Party Climate Change Committee
MW	megawatt
MWh	megawatt-hour
n/a	not applicable
NGA	National Greenhouse Accounts
OTN	obligation transfer numbers
p.a.	per annum
ppm	parts per million
RIS	Regulatory Impact Statement
sec.	section
SME	small to medium enterprise
t	tonne
TJ	terajoule
tpd	tonnes per day
>	greater than
<	less than