THE UNIVERSITY OF MELBOURNE

Department of Economics

Working Paper Series

Should Households and Businesses Receive Compensation for the Costs of Greenhouse Gas Emissions?

John Freebairn

May 2009

Research Paper Number 1071

ISSN: 0819-2642
ISBN: 978 0 7340 4035 0

Department of Economics
The University of Melbourne
Parkville VIC 3010
www.economics.unimelb.edu.au

Should Households and Businesses Receive Compensation for the Costs of Greenhouse Gas Emissions?

John Freebairn
The University of Melbourne

Abstract: Arguments for, and then the form and level of, compensation of households and businesses for the additional costs of an emissions trading scheme to lower greenhouse gas (GHG) emissions are evaluated. With most of the costs passed forward to households as higher consumer prices, a sequential set of direct income transfers to all households is proposed to meet equity and macroeconomic stability objectives. In the event that Australia proceeds with a scheme before some of the other global polluters, to avoid carbon leakage and unnecessary industrial restructuring a consumption base system of taxing the GHG component of imports and compensating the GHG component of exports is proposed.

1. Introduction

Auctioning the scarce rights to emit greenhouse gas (GHG) emissions will provide a net increase of government revenue, and effectively an increase in indirect taxation. The broad aim of the Australian Carbon Pollution Reduction Scheme (CPRS) is to reduce GHG emissions to 60 per cent or less of the 2000 level by 2050. The current proposal described in the Green Paper (Department of Climate Change, 2008) is for electricity generators and wholesalers of petroleum products to purchase permits from July 2010. For an indicative starting value of around $20 per tonne of CO2, the permit auctions would yield revenue of about $8.5 billion a year. As the revenue base is expanded to include most of the remaining 30 per cent of GHG emissions, and as the CO2 price increases over time as projected (Garnaut, 2008, and The Treasury, 2008) (and making the assumption of an inelastic marginal abatement cost function to be explored further), the permit auction revenue will increase in the future. The objective of this paper is to evaluate the arguments to use the windfall government revenue gains to compensate households and businesses.

The arguments for and against using some, all, or even more than all of the government revenue windfall gain from auctioning tradable permits to reduce GHG emissions will be evaluated against the criteria of efficiency of production, consumption and investment decisions, equity relative to the pre-CPRS base case, and macroeconomic stability. Both Garnaut (2008) and the Green Paper (2008) propose a one-off package of lump sum compensation of households via the income transfer system, and mainly those on lower incomes for equity reasons. This paper argues that in addition, compensation should be provided to all households in a sequential package to meet a macroeconomic stability outcome. In the likely event that Australia proceeds with its CPRS some years before other large GHG emitters introduce policy interventions to internalise the external costs of emissions, there are compelling arguments to compensate the trade exposed energy intensive (TEEI) industries to reduce "carbon leakage" and costly industry restructuring. Both Garnaut and the Green Paper propose a system of compensation for the export and import competing industries, but with different details. This paper argues that these proposals will distort choices between the traded and non-traded sectors. Instead, it proposes a GHG consumption base with exports exempted and imports taxed. For the GHG emission intensive non-traded sector, and in particular coal-fired electricity generators, the Green Paper, and especially industry, argue for a package of temporary assistance. Both Garnaut and this paper argue against compensation, and this paper argues that the logic for temporary assistance sets an unfounded precedent for further rounds of special assistance.

The remainder of the paper is organised as follows. Section 2 assesses the economic incidence of the increase in production costs that are inherent with an explicit cost on GHG emissions. Consideration is given to both conceptual models and available empirical evidence for petroleum products and electricity directly covered under the CPRS, to products in most of the rest of the economy which use electricity and petroleum products as business inputs, and the traded sector. Sections 3, 4 and 5 consider the arguments for compensating households, the TEEI industries and the GHG intensive non-traded black coal electricity generators, respectively. Where compensation is warranted, the different forms and levels of compensation are evaluated. A final Section 6 provides conclusions.

2. Economic Incidence of Permit Cost

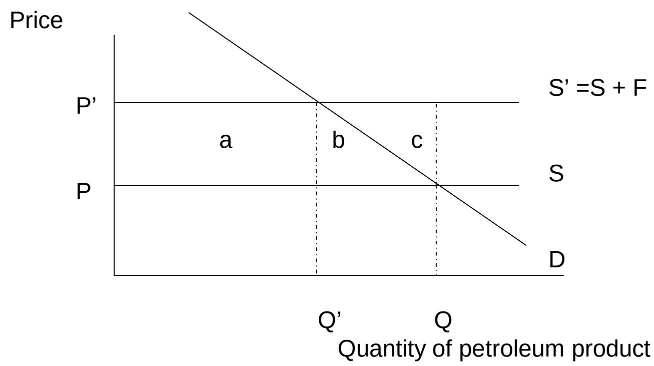
A market mechanism, both the initial auction and a secondary market, will set an opportunity price for the scarcity value of the limited supply of required government permits to emit GHG, initially CO2 arising from the combustion of petroleum products and fossil fuels used in electricity generation. The required permit and its price becomes an additional variable cost of production. The initial cost increment per unit of output will vary with the CO2 intensity of the production process. As with most other variable costs, including labour and material input costs, businesses will seek to pass forward to buyers the additional production costs as higher sales prices. The extent of price pass-forward will depend on the relative elasticities of product supply and demand, which in turn vary with such market circumstances as industry technology, industry structure and conduct, and trade status. In addition to the direct purchases by households of electricity and petroleum products, most other businesses in the economy require electricity and petroleum products as business inputs. The additional input cost will vary with the input mix across products and production processes. In this way the GHG emission permit costs flow through to higher costs for most other products purchased by households.

2.1 Petroleum Products

Australia is a small country net importer of petroleum products who has to pay the world price net of charges. Government charges, including the already levied petroleum products excise and the GHG emission price will be added to the world price, plus any costs of refining and distribution, to determine the domestic retail price. Then, for petroleum products there will be a 100 per cent pass through of the additional cost of CO2 tradable permits to households and business petroleum product input buyers.

A simplified model illustration of the price, quantity and distributional effects of tradable permits placing an explicit additional cost for the GHG emissions involved in the combustion of petroleum products is provided in Figure 1. In the current situation where the GHG emissions are dumped for free, the supply curve for petroleum products to Australia is the perfectly elastic S, and demand is given by D. This results in a quantity of product Q, and also of associated GHG emissions, and market price P.

Figure 1



Then, in Figure 1 introduce a tradable permit scheme with an associated market or opportunity cost of F per unit product consumed. The relative cost increase, or size of F, will vary from product to product, but it will be larger the more GHG-intensive the product. The supply curve is shifted upwards to S'. As a result, product price rises from P to P', that is by F, reflecting the 100 per cent pass forward of the extra production cost. Production and consumption of the desired petroleum products fall from Q to Q', and with the fall in production of the goods, also there is a fall in the quantity of GHG emissions as desired.

2.2 Electricity

The story for the rate of pass through of costs for GHG emissions to buyer prices is more complicated for electricity. In particular, in the production of electricity by generators there are a number of different technologies, each with different characteristics in terms of CO2 intensity per unit electricity output, mix of variable and fixed costs and their levels, and ease of turning on/off at short notice. With current technology and prices, at one extreme of the characteristics profile, coal fired generators, which provide over 84 per cent of the current capacity, have lower costs but are costly to turn on/off, and they are GHG emissions intensive (with an average of 1.26 tonnes of CO2 per KWh for brown coal and 0.9 tonnes of CO2 per KWh for black coal); gas fired generators, which provide less than 8 per cent of current capacity, have much greater flexibility to turn on/off, they are more expensive, but they have a lower rate of emissions (of between 0.4 and 0.6 tonnes of CO2 per KWh); and the renewables, with hydro being the most important, involve negligible CO2 emissions, but with current technology further increases in capacity are relatively expensive[1]. The opportunity cost of GHG emissions under a CPRS add to variable and marginal costs, but at different levels for the different technologies.

There are a number of other characteristics of the demand, supply and industry structure of electricity which are important to assessing the effects of additional costs for GHG emissions on electricity market outcomes. On the demand side: electricity is a homogeneous product, with the exception that some buyers are willing to pay a premium for "green" electricity; it is extremely costly to store; the demand curve shifts significantly over the day and between seasons; and, over time the demand curve is expected to shift outwards with the growth of population, real income, and the likely emergence of electricity as a major source of energy for transport[2]. On the supply side: for all generation technologies, investments in capacity are large and lumpy to capture economies of scale, they have economic lives in the decades, fixed costs are an important share of total costs and once incurred these fixed costs are sunk costs with a very low salvage value. Prices for the key fossil fuel inputs of black coal, gas and oil, but not brown coal, are largely determined by world energy markets, although there are a number of current contracts which serve to insulate some generators from world price fluctuations in the short run. The future paths of technology, particularly as they relate to the feasibility, effectiveness and costs of carbon capture and storage, and of social attitudes to nuclear energy, will be important determining forces on electricity supply, prices and returns, but there is considerable uncertainty about

[1] Data from ESAA (2004) as presented in Simshauser and Doan (forthcoming)
[2] MMA (2008) and the Treasury (2008) in their modelling project of the CPRS project contend that an additional 700 MWh of capacity each year will be required from 2009-10 under business as usual, and nearly this much under the different GHG emission reduction scenarios.

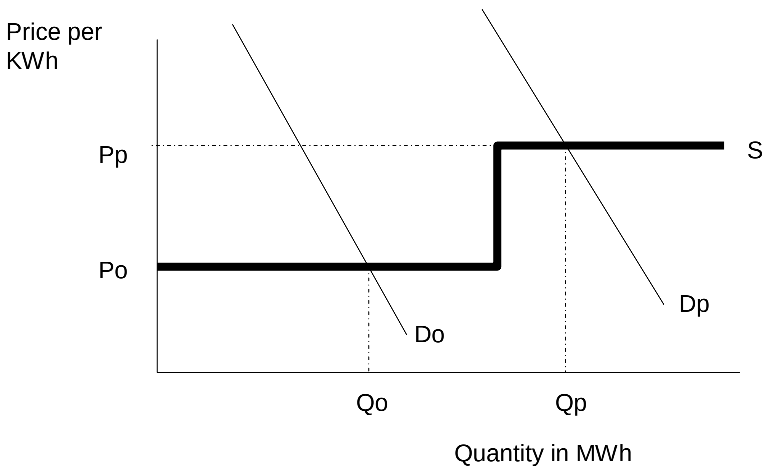
both[3]. The electricity industry is a vertically integrated industry with sectors for generation, transmission and retail distribution. The transmission and distribution sectors are characterised by natural monopoly characteristics. As a result they are either government owned and operated, or subject to extensive price regulation, with the CPI-X rule being a favoured Australian intervention.

For most of the time the electricity generation market appears to operate as a competitive market with the wholesale price close to the marginal cost of the marginal supplier at any point of time. More formally, with a homogeneous product and at most times with excess capacity, the relatively small number of generator companies and government owned authorities act much as a Bertrand oligopoly for a homogeneous product, wholesale electricity. Scrutiny by the Australian Competition and Consumer Commission, and regulation by the various state authorities, provides a regular oversight and an additional form of deterrence on any exercise of monopolistic behaviour. In practice, and as illustrated by the operation of the National Electricity Market Management Company (NEMMCO) for the eastern states, the different generators are ranked in terms of short run marginal production costs with the price set for each five minute interval at the marginal cost of the marginal generator. In the absence of a cost for GHG emissions, base load power is provided by the relatively cheaper and inflexible coal fired generators at a relatively low price during the off-peak parts of the day; and the more flexible and costly gas fired and hydro provide additional supplies during the peak demand parts of the day, with the price rising to their higher marginal cost. In periods of extreme demand shifts and/or of plant unavailability where capacity constraints are reached, the wholesale price of electricity rises even further. In these capacity-constrained circumstances the appropriate marginal cost is not the short run marginal production cost, but rather the much higher opportunity cost of electricity to the next consumer. These periods of high prices provide most of the surplus to cover the sunk costs of investments in generators under a marginal cost pricing framework.

[3] It is clear that one or both of carbon capture and storage and nuclear electricity generation will be required if Australia is to meet its 2050 target of a 60 per cent reduction in GHG emissions. Treasury (2008) and Garnaut (2008) in their modelling effectively assume that carbon capture and storage technology at ruling CO2 permit costs will be cost effective for use from about 2025.

A simplified version of the operation of the wholesale electricity generation market is shown in Figure 2. We have two generation technologies, coal with a relatively low marginal cost and gas with a higher marginal cost, which when stacked in ascending order of marginal cost give the supply curve S. There are two sets of demand for peak and off-peak, and assume excess capacity. In reality, the marginal cost curve has a large number of steps to reflect different technologies, vintages, resource costs, etc, and the demand curve shifts with a much larger number of time intervals over the day. Under competitive behaviour as described above, during the off-peak period, coal would provide all the power, Qo, at price, Po, equal to coal short run marginal cost; during the peak period, gas becomes the marginal supplier with cost rising to Pp equal to the gas short run marginal cost and quantity supplied increases to Qp. Note that in the peak period coal earns a surplus above variable costs and the surplus becomes a contribution to its fixed costs and profit.

Figure 2



Suppose we introduce an emissions trading scheme, with the permits auctioned as proposed[4]. Consider first operating decisions with existing capacity. In Figure 3, which adds to Figure 2, the cost of the permits raises production costs by Fi per

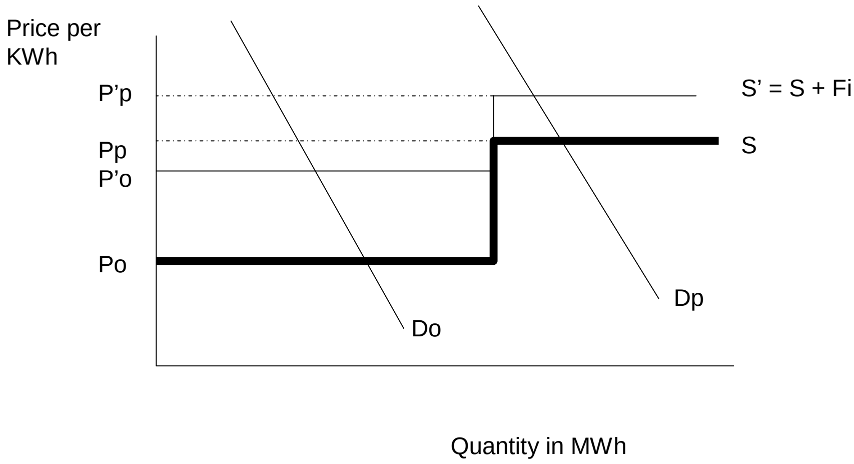
[4] The story told here is much the same as given in Box 10.3 of the Green Paper (Department of Climate Change, 2008).

unit of electricity generated (equal to CO_2 emissions per KWh times the CO_2 permit price) with i=c for coal and g for gas, and the supply curve shifts upwards from S to S' = S + Fi. The marginal cost increase per MWh is much larger for coal, the pollution intensive technology, relative to gas, but not so much as to reduce the cost superiority of coal over gas. With the new and higher cost structure, the off-peak price rises by the extra costs of coal fired production to P'o = Po + Fc, and production and consumption (not shown) of off-peak electricity, and of GHG pollution, falls. The peak period price rises to P'p = Pp + Fg, a smaller increase than the rise in price of off-peak, and output (not shown) of electricity and emissions fall. Note that the gas producers continue to cover their marginal costs as before the tradable permit scheme, and the coal producers also cover marginal costs and earn a surplus, but a smaller surplus than before. In this later sense, coal producers are unable to pass forward 100% of the extra costs, and the loss of surplus will be greater the larger the market price of the permits. However, coal generators continue to operate because marginal costs are at least covered, and there is some contribution to fixed costs.

In the Australian context where coal currently has over 84% of the capacity, for most of the time coal will be the marginal supplier and so in the early years of a tradable permit scheme most of the cost increase will be passed forward to buyers as a higher price[5]. The higher price associated with the rising price of the required GHG permits, together with the price responsive demand, leads to a reduction of electricity consumption and of GHG emissions relative to the business as usual scenario. This is the story told by Garnaut (2008) and the Treasury (2008) up to around 2025.

[5] The Australian situation is different to that in Europe. In Europe, coal represents about 28.6 % of electricity generation compared with 84 % in Australia. The smaller coal share in Europe then is not inconsistent with the finding by Sijm et al. (2005) that between 60 and 100 % of the European permit cost was passed forward and the argument made here, and by Garnaut, that for most of the time to 2020 coal will be the marginal supplier for the next few years and hence the pass through rate will be closer to 100%.

Figure 3



At some point the cost of the permits to emit pollution may rise to a level at which the ranking of the technologies change. Garnaut (2008) and the Treasury (2008) in their modelling assume the permit price rises about four per cent real per year based on the Hotelling rule. For example, in the simple case of the two technologies shown in Figures 2 and 3, gas becomes a lower cost first choice over coal. McLennan Magasanik Associates (2008) indicate a tipping permit price of around $40 a tonne of CO2-e, and Simshauser and Doan (forthcoming) indicate the tipping point for Victorian brown coal to natural gas combined cycle generation at around $17.50 a tonne[6]. For the technology cost ranking change context, three further interesting questions arise.

First, with a limited supply capacity for gas, and recall that gas represents less than 8% of current capacity (and if we add the renewables less than 16% of current capacity), coal likely would continue to be the marginal supplier for both the peak and off-peak periods for much of the time. While this outcome ensures that coal generators cover all marginal costs, the shift from being an inframarginal supplier to being a marginal supplier means no surplus as a contribution to fixed costs is earned. Instead, the gas generators as the new inframarginal suppliers earn

[6] A part of the difference is that the former use a export parity price for gas, whereas the latter appear to hold gas prices at current contract levels which are some way below export parity.

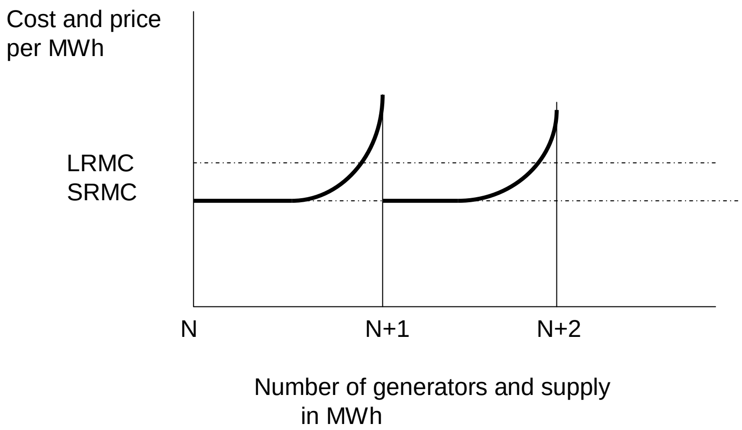
a surplus. Aggregating across the electricity generators there will be less than 100 per cent price pass through of the extra costs of the pollution permits.

A second issue derives from the high cost of operating coal fired generators as an opportunistic supplier by time of the day relative to a base load supplier when the GHG permit price re-ranks the technologies by short run marginal cost. Supposing the coal generator is the marginal peak supplier, but because of the technology it in practice operates 24 hours a day. To cover its marginal cost of operating over the 24 hour period, coal would set a relatively high price for peak period supply above its average over the 24 hours marginal cost, and it would set a relatively low off-peak price below the average over the 24 hour marginal cost but which (for market reasons) matches the lower gas marginal cost gas generator; and in aggregate it collects enough revenue to cover at least the 24 hour average marginal cost. Compared with the inframarginal supplier position of Figure 2, while coal generators pass forward the extra marginal costs of production as higher wholesale prices, and so continue to operate, they earn no surplus, and in aggregate there is less than a 100 per cent pass forward of the extra costs.

The third issue in assessing the effects of a carbon cost on the returns to incumbent generators concerns the relevant marginal cost. With reference to existing plant and with excess capacity, the relevant marginal cost is the short run variable operating cost including the permit price, with capital costs being sunk costs. But, when it comes to installing new capacity, including with new generators and with major but optional maintenance programs for existing plant, the relevant marginal cost and market price is a long run marginal cost which includes an expected per unit output capital cost plus the variable operating cost and permit cost. With the expected outward shift of the demand for electricity with population growth, GDP growth and perhaps the substitution of electricity for petroleum as a motor vehicle energy input, the higher long run marginal cost provides an additional capacity for the short run marginal cost increase pass through for incumbent generators.

In fact, as argued by Ng (1987), a limited capacity price premium necessary to induce new investment in generating capacity expansion provides both the incentive for investment in the new plant and the funds to cover the fixed cost component of the investment. The result is a cyclical saw tooth pattern of price movements illustrated by the broad line in Figure 4. As each large, lumpy capacity expansion output comes on stream, price falls to short run marginal operating cost, then with outward shifts of demand when capacity is reached price rises to allocate the scarce capacity, and ultimately the price becomes sufficiently high, and above long run marginal cost, to induce the next investment. Ng shows that this short run marginal cost pricing strategy ensures the financial viability of the generator for a world of constant costs, and it results in above normal profits in a situation of increasing long run marginal costs.

Figure 4



There are some other important considerations to the pass through of the extra costs of generation to retail prices of the introduction of a tradable permit scheme on the Australian electricity sector. Particularly over the interim period, any long term contracts and government imposed price ceilings on retail prices should be revised to recognise the change in costs and wholesale prices.

2.3 Other Industries

Most products use electricity and petroleum products as intermediate inputs in their production processes. For the reasons described in the preceding subsections, the costs of these inputs will increase to reflect the cost of permits to emit CO2 in their production. Then, the production costs of all products will increase to reflect both the direct and the indirect intermediate input GHG content.

Consider then the situation in which all countries adopt a common set of schemes to reduce GHG emissions in the sense of imposing a common cost on producers per unit of GHG emissions, or the more restricted case of Australian non-traded goods and services in a world where Australia implements its CPRS before some of the other countries join a global scheme.

For most of the Australian non-traded goods and services industries using electricity and petroleum products as business inputs it is reasonable to assume a constant returns to scale production technology at around current output levels and that individual firms and industries are price takers in the input markets. For example, one more food processor, truck transport and supermarket to process, transport and distribute food is close to a clone of the previous one. As a result, marginal costs are close to constant. Under most business price setting models, including perfect competition, cost mark-up pricing, and most of the imperfect competition models with a constant returns to scale technology, on average 100 per cent of a variable cost increment, including for electricity and petroleum inputs, will be passed forward as a higher buyer price (for more a more detailed set of arguments see, for example Freebairn, 2008). Figure 1 illustrates the situation. The cost mark-up component F includes the direct and intermediate CO2 emission costs, and this will vary across different products depending on their carbon intensity. For the assumptions made, there is a 100 per cent pass forward of the extra costs to consumers as higher prices.

There is supporting empirical evidence that most to 100 per cent of the cost of GHG emissions captured in the opportunity cost of tradable permits will be passed forward to consumers of non-traded products as higher market prices. These are studies of tax incidence, and the experience of the GST package of tax reforms introduced in Australia in 2000 and in New Zealand in 1985. Studies of the distributional effects of Australian indirect taxes, including the petroleum products excise which can be considered in part a selective carbon tax (and also in part a tax to fund road construction and maintenance and perhaps a tax on congestion) and taxes on motor vehicles, assume 100 per cent pass through to the consumer for both the direct effects and the indirect effects through intermediary inputs. These include studies by ABS (2007), and by Warren and NATSEM (for example in Warren et al., 2005).

A related practical experience of an emission taxes or tradable permits scheme to reduce greenhouse gas emissions is the GST package of reforms introduced in Australia and New Zealand. The 2000 Australian reform package involved using revenue from eight of the ten percentage points of the GST to replace other indirect taxes, including the wholesale sales tax and several state stamp duties, with revenue from the remaining two percentage points, plus some budget surplus, to fund lower income taxation and an increase in social security payment rates. The net incidence of the reform package of indirect taxes on product prices was modelled on the assumption of 100 per cent pass through to consumers (for example the study by Dixon and Rimmer, 2000). The Australian Competition and Consumer Commission (ACCC) used these numbers with effect to monitor business pricing, and the actual numbers revealed corresponded almost one to one with the model estimates (see for an assessment Treasury, 2003). Earlier experience with New Zealand tax reforms in 1985 conformed with a 100 per cent pass through of indirect tax changes to consumer prices (Stephens, 1989).

2.4 The Traded Sector

It is likely that Australia will introduce its CPRS some years before some of the large GHG emitting countries introduce similar charges on emissions, including the US and the developing countries. With a relatively small share of world trade in both export and importing competing products, most Australian producers of traded products are price takers with little ability to pass on the higher production costs of Australia's CPRS in the first instance. Unlike the situations for petroleum products and for non-traded products, including electricity, described above, almost 100 per cent of the costs of GHG emissions for the traded industries will be born by the producer side of the market. However, as elaborated in Section 4 below, this is not an equilibrium and there will be a round of market readjustments including a currency depreciation.

3. Compensating Households

As argued in the preceding section, households ultimately will bear most of the costs of policy interventions to internalise the costs of GHG emissions. Effectively, the interventions act as an increase in indirect taxation that falls more heavily on the more GHG pollution intensive products and production processes, with the explicit task of providing incentives to choose less GHG pollution intensive products and production processes. If Australia embarks on a CPRS before many of the other countries, these changed price outcomes will be restricted largely to non-traded goods and services, and only as the rest of the global economy follows will they encompass also traded products.

Arguably, the complete picture of distributional effects on households of policy interventions to internalise the social costs of GHG emissions and any claims for compensation should factor in also the benefits of lower adaptation costs of less climate change resulting from the fall in GHG emissions. After all, the policy intervention to correct a market failure is warranted as a positive sum outcome only if the benefits exceed the costs. Ultimately the benefits of less climate change would come back to households as lower costs of food and water, less damage to buildings and infrastructure, a higher level of protected biodiversity, and so forth, than without the intervention. Granted the in principle argument of these compensating benefits to households, in the context of Australian policy in practice the in principle argument may be heavily discounted. First, until other countries embark on similar schemes the actual benefits to Australians of the Australian CPRS will be negligible. Further, these benefits to Australian households are very uncertain if the argument is made that early action by Australia will speed-up adoption of a global scheme. Second, while the benefits of reduced climate change will accrue mainly to future generations, the current generation faces costs described in Section 2 above. Third, the CPRS provides a windfall revenue gain and the capacity for the government to fund compensation.

Both the Green Paper (Department of Climate Change, 2008) and Garnaut (2008) propose that households, and especially low income households, be compensated for equity reasons. In particular, they propose that the net increase in the cost of living effects of an explicit charge on GHG emissions be compensated with an increase in social security payment rates and a decrease in income tax rates. This lump sum compensation would retain the changes in relative prices and encourage changes in household consumption away from GHG intensive products. Given the findings in earlier studies, including Cornwall and Creedy (1996), and their own more recent estimates, of the likely regressive incidence of the CPRS, both the Green Paper and Garnaut focus their household compensation to lower income households.

A potentially more powerful and additional argument for using the government revenue windfall from the auctioning of the permits to pollute is a macroeconomic stability argument to avoid wage inflation and increases in nominal interest rates. Neither Garnaut nor the Green Paper considers this argument. A CPRS means that households on the same nominal wage and capital returns experience a fall in real purchasing power with the increase in consumer prices. Normally, they would seek compensation via an increase in nominal wages and interest rates to maintain real wages and returns on saving. If households are successful in negotiating higher nominal wages and interest rates, and this outcome seems plausible based on the usual operation of the economy, the introduction of a tradable permit scheme without compensation for the loss of real purchasing power could kick-off a wage-price inflation spiral. Alternatively, as with the 2000 GST tax reform package, which involved a net increase in indirect taxes (much as a tradable permit scheme would), government paid compensation (and essentially as lump sum payments via the income tax and social security systems which would not change the increase in relative prices of GHG intensive products) to households as income tax reductions in exchange for no compensating increases in wages and interest rates. This happened and macroeconomic stability was maintained (see, The Treasury, 2003).

Re-inspection of Figure 1 provides useful insights on the level and form of required household compensation and the revenue implications. Compensation based on an estimated increase in the CPI would involve a compensation payment of areas a+b+c since the CPI has base period quantity weights. In terms of equity measured as maintaining utility, compensation based on the estimated net increase of the CPI due to the CPRS overcompensates by area c, as households substitute out of the relatively more expensive GHG intensive products. On the other hand, the net revenue windfall of area a is not sufficient to fully offset the loss of consumer surplus, area a+b.

Garnaut (2008) argues that only a one-off compensation package will be required. Yet, he argues, and I would agree correctly, that as the aggregate permit quota to meet a 2050 target of GHG emissions at around a 60 per cent reduction on 2000 levels is to be reached, the price of the permits can be expected to rise over time, with an indicative number of four per cent real per year. If the marginal abatement cost function (MAC) is inelastic, the government revenue collection on the auctioning of the permits, and the effective increase in the indirect tax burden on households, also will increase over time; of course, if the MAC function is elastic, the indirect tax burden effect of the tradable permits scheme will decline in importance. Using data from the Treasury model simulations (The Treasury, 2008, Table 6.1) for the period 2010 to 2020, the estimated elasticity of the MAC at between -0.1 and -0.5 is very much in the inelastic zone[7]. In addition, as other countries join a global agreement, the case for compensation of the TEEI declines and the household buyer prices of products of these industries rises, with the effect of an increase in the set of activities required to purchase without compensation GHG permits[8]. Together, this means an increase over time in the indirect tax burden falling on households. Then, macroeconomic stability and equity will require a rolling system of lump sum transfers to households, rather than a one-off package.

4. Compensating the Trade Exposed Energy Intensive (TEEI) Industries

[7] Over the ten year period the permit price is estimated to rise by four per cent real per annum, or 48 per cent. The percentage reductions in emissions over the 2010 through 2020 period shown in Table 6.1 range from -5 to -25 per cent for the four scenarios modelled.

[8] This argument is the flip side of the point made below with respect to (2) that the Garnaut and Green Paper proposals to compensate the TEEI effectively narrows the tax base.

Current proposals under discussion are for the tradable permit scheme to take the form of a production base, or in taxation design analysis an origin base. The price or opportunity cost of the permits will increase the cost of all production processes resident in Australia that directly produce GHG emissions or use Australian made inputs which directly or indirectly produce GHG emissions. Using the national income accounting identity, the production base is

$$Y = C + I + X - M \tag{1}$$

where, Y is production or GDP, C is consumption, I is investment, with both C and I covering the private and government sectors, X is exports and M is imports. That is, such a scheme would tax exports and exempt imports.

Then, what are the implications for Australian TEEI, both exporters and import competitors, if Australia implements a scheme before our main trading partners? Suppose initially that there is no compensation for the additional costs associated with the scarcity value and market price of the limited GHG permits. Against the elastic demands, profits will be squeezed, and the TEEI will reduce output, investment and employment. The changes in relative costs and prices will result in:

- More imports, and especially of the energy intensive products.
- Less exports, and especially of the energy intensive products.
- An increase in the current account deficit and pressure for a currency depreciation to restore the balance of payments equilibrium[9]. The output price increase effects of the currency depreciation will offset the increase in costs for the relatively low GHG intensive exports and import competitors. However, for the relatively energy intensive TEEI products the currency depreciation will not be large enough to offset the cost increases from the required permit purchases.
- A change in Australia's comparative advantage away from its energy intensive industries, and a loss of national income. This makes little sense if down the track a global agreement is reached, the current comparative advantage of Australian TEEI industries is restored, and we subsequently re-invest in such import competing and export industries.

[9] The Business Council of Australia (2008) analysis, and others in business, overestimates the extent of adverse effects on the TEEI because it assumes a constant exchange rate.

- The shift to overseas of many energy intensive industries, so that the global reduction in GHG emissions is heavily muted (and some would argue reversed). This is referred to as "carbon leakage."

The last two points, rather than concerns about equity, alone are sufficient economic arguments for providing compensating assistance over the short term to the TEEI, and in determining the level of assistance.

Both Garnaut (2008) and the Green Paper (Department of Climate Change, 2008) propose a system of compensation of the TEEI to reduce carbon leakage and unnecessary restructuring of the Australian economy base over an interim period while other countries introduce their own GHG emission reduction schemes. After this interim period, with all the major countries involved in a global scheme, all sectors of the Australian economy become much as described for the non-traded sector in Section 2.1 above. The basic compensation scheme proposed is to compensate export and import competing industries for the additional direct and indirect costs of the GHG emission impost on Australian production. Imports would continue to be exempt as under the production tax of (1). Then, in the context of the national income accounting identity, the Garnaut/Green Paper restricted production tax base, Y – TEEI, is

$$Y - TEEI = C + I - (X + M + \text{import competing}) \qquad (2)$$

where all the terms are defined as above. There is no comparable tax base concept in taxation theory, and there is no market failure argument for this tax base. Before considering the rate of compensation for the TEEI, there are several problems with tax base (2).

First, tax base (2) is a very much reduced tax base relative to (1), and relative to a consumption base (3) below. Tax base (2) either reduces the capacity of Australia to meet a country target to reduce GHG emissions or it requires a much higher burden on the remaining non-traded sector. To some extent, and pragmatically, minimum thresholds for assisting TEEI as proposed by both Garnaut and the Green Paper contains these trade-offs, however this means some industries will not be fully compensated. Even then, both indicate that around 30 per cent of the government windfall revenue windfall gain from the sale of tradable permits in the early post 2010 period would be used to compensate TEEI.

Second, and more importantly, a GHG tax base of the form of (2) results in distortions and associated efficiency losses when due recognition is given to the multi-stages in the production of most traded and non-traded products. On the production side, there will be a bias against Australian produced inputs relative to imported inputs. For example, with an export aluminium smelter, the cost impost of an Australian tradable permit system would vary depending on whether the smelter uses as its input Australian produced alumina (which has embedded costs for Australian GHG emission costs unless it is compensated as an import competitor industry) or imported alumina from a non-signature member (which has no embedded GHG emission costs). A similar story of source of input distortions applies to an import competing car assembler choosing between Australian made or imported car components. In terms of consumption decisions, while non-traded products will bear a cost impost for GHG emissions, traded products consumed by Australians will be exempt, with a distortion in consumption between non-traded and traded goods and services for no market failure reason.

A logical solution is to move from the proposed production or origin base to a consumption or destination base. That is, exempt exports and tax imports. In terms of the national accounting identity, the tax base would be expenditure, E,

$$E = C + I + M - X \qquad (3)$$

Such a system internalises the external costs associated with Australian consumption of products which generate GHG emissions (whether produced in Australia or overseas) and contribute to the higher costs of adaptation to climate change. Then, imports, including on business inputs and on final consumer goods, will carry a tax approximating their GHG emission cost. As a result, the import competing and foreign sources are treated similarly in multi-stage production processes, and consumer decisions to purchase an import product, a domestic produced substitute or an export good are not distorted. Both import competitors and exporters have incentives to reduce their GHG emissions via lower required purchases of GHG emission permits in much the same way as they have an incentive to reduce other costs. At the same time, this consumption base tax application of compensation of the TEEI provides a large and comprehensive tax base, and it minimises distortions to the geographical location of GHG intensive export and import competing industries.

Whether one follows tax base (2) or (3), a practical policy question concerns the rate of compensation to be applied. Garnaut proposes what seems to be the ideal benchmark in reducing carbon leakage, providing longer term investment incentives, and formally phasing out the interim assistance. As a guiding principle, he says (p. 345)

"For every unit of production, eligible firms receive a credit against their permit obligations equivalent to the expected uplift in world prices that would eventuate if our trading partners had policies similar to our own."

Formally, using a competitive model of product demand and supply, the expected world price increment for a commodity if all countries participated, ΔP, would be

$$\Delta P = [\sum w_i \Delta C_i F_i] / [\sum w'_i E_i + \sum w_i Fi) \qquad (4)$$

where, w_i is the production share weight given to each trading country i and w'_i is the consumption weight given to each trading country, ΔC_i is the increase in cost in country i if a global agreement equivalent to Australia to reduce GHG emissions was applied, Fi is the elasticity of product supply in country i and Ei is the (absolute value) elasticity of product demand in country i.

Formula (4) has some nice properties. With a less than a perfectly elastic supply, the price increment will be less than the cost increase, and smaller than a half if supply is less elastic than demand. This point is noted informally by Garnaut (2008). In almost all cases the supply elasticity will be less than infinite because different countries have both different technologies and different relative factor prices (as compared with the case for non-traded products in a single country), and for agricultural and mineral commodities there are natural resource inputs with different properties affecting costs. As Garnaut notes, as more countries join an international agreement to reduce GHG emissions, the expected uplift in world prices would converge to zero (as the ΔC_i term goes to zero). To simplify the operation of the TEEI compensation, Garnaut proposes its operation on an industry by industry basis, but does not specify the level of aggregation, and that compensation be paid only when the cost impost exceeds a threshold.

A less principled and more ad hoc approach to determining the rate of compensation of the TEEI is contained in the government Green Paper (Department of Climate Change, 2008). The objective is an interim system of support to TEEI to reduce "carbon leakage." Specifically, the Green Paper proposes compensation based on some industry average with TEEI industries classified by tonnes of CO2-e per $ million revenue with a sliding scale. The high GHG intensive polluters defined as greater than 2000 tonnes of CO2-e per $ million revenue would receive compensation for around 90 per cent of the cost increment, medium GHG polluters with between 1500 and 2000 tonnes of CO2-e per $ million would receive a 60 per cent compensation, and no compensation would be made for smaller polluters. Interestingly, at a carbon price of $20 per tonne of CO2-e, combined with the three per cent price increase threshold suggested by Garnaut, corresponds to the Green Paper 1500 tonnes of CO2-e threshold.

The logic of compensation to the TEEI to avoid "carbon leakage" and some of the costs of economy restructuring and then its reversal when most trade competitors later join a global agreement is best met by shifting the base to a consumption or destination base involving taxing the GHG component of imports and exempting the GHG component of exports. Clearly this proposal involves challenges on accounting and monitoring, and perhaps also agreement with the WTO principles. The Garnaut principle for the expected world price, with assistance less than the Australian cost mark-up, is intuitively attractive and amenable to calculation by an independent authority. From a practical and simplicity perspective, the Garnaut and Green Paper proposals to use industry averages and with a minimum threshold seem sensible compromises.

5. Energy Intensive Non-traded Industries

The coal-fired electricity generators in particular, but also some other energy intensive non-traded industries, have lobbied for interim compensation for the additional production costs of a CPRS. The Green Paper (Department of Climate Change, 2008) provided some support for further investigation and consideration of the claims, while Garnaut (2008) explicitly argued against compensation. This section considers the arguments for compensation of the coal fired generators in terms of production decisions using installed capital, investment decisions in new capacity and technology, and equity.

A key finding of the market effects of a CPRS on production decisions and market outcomes in the wholesale electricity market of Section 2.2 was that the incremental costs to the marginal producer of purchasing GHG permits would be passed forward to buyers as higher market prices, and that the production choices of the generators would accord with society efficiency decisions on levels of production and consumption of electricity and on the choice of production technology. At the same time, the relative GHG intensive coal fired generators will experience some fall in the surplus available to cover sunk capital costs.

A second set of decisions concern the effects of the additional cost of the required permits to emit GHG emissions for decisions on investment on replacement and additional capacity and on R&D. In particular, as the cost per unit of GHG emissions increase over time the relative attraction of relatively lower GHG emission technologies and of investment in these technologies increases. This includes the choice of gas over coal through to renewables, lower pollution technologies using fossil fuels, the timing and form of major refurbishments versus decommissioning of existing plant, and enhanced incentives and rewards for R&D to find production methods involving less GHG emissions through to carbon capture and storage technology. Also important to investment decisions is the anticipated continued outward shift of the electricity demand curve with population and real per capita income growth, the likely increase in demand for electricity as an energy input for transportation, and so forth. Given the long lives of electricity generation investments, such investment and R&D decisions will take into consideration the perspective price paths of costs and electricity prices over the life of each investment. Electricity prices will have the saw tooth pattern described in Figure 4.

Given the number of current players, and perspective new players in what is a global investment market, new investments can be anticipated when the present value of the expected marginal returns cover the present value of the expected long run marginal costs, including a risk premium for uncertainty about the future price path of the tradable permits, construction costs and input fuel prices. Expected production costs over the prospective economic lives of the alternative generator investment options will include the anticipated paths for the cost of the tradable permits, the costs of capital fuels and so forth. So long as the short run marginal cost of existing technologies, including the costs of permits to pollute, are less than the long run marginal cost of investments in new generators, existing generators will continue to rank ahead of new investments and win market share, and they will make a non-zero contribution to sunk costs and/or profits.

It seems arguable that the additional uncertainty associated with the Australian and other country policies and institutions to place a price on GHG emissions, and the future price paths of tradable permits, will increase the required risk premium on new investments to expand electricity generation capacity. Clearly, the future price path for tradable permits to emit GHG emissions is an additional element of uncertainty. However, it has to be considered along with other elements of uncertainty including fuel prices, technological change, and demand volatility. The Green Paper (Department of Climate Change, 2008, chapter 10.4), Simshauser and Doan (forthcoming) and many in industry argue that in addition, any loss of above marginal cost surplus revenue on existing infrastructure will be reflected in both a loss of ability and of confidence of existing investors to fund capacity expansion in electricity generation.

The strength of concern for any reduction in funding capacity by incumbents for investment in new generator capacity on aggregate industry investment in the future will depend in part on the likelihood of entry of other global, and domestic, investors. To the extent that investment in electricity generators in Australia is part of a much larger global investment industry, as has been illustrated in recent years post privatisation of generators in some states, eager global investors will place additional funds in Australia if the prospective returns exceed the prospective costs. This criterion is consistent with efficient investment decisions from the Australian efficient investment principles. Further, it applies to the transfer of ownership of existing assets sold at distressed prices, as well as to investment in new assets.

Then, this analysis provide no support on efficiency grounds for providing compensation to the capital side of the coal fired electricity generation industry. Also, it provides little support, if any, for compensation on equity objectives. In this respect the paper agrees with Garnaut (2008). Garnaut advances a further argument against compensation to current generators. While there may be a case for supporting the labour side, there is no Australian policy precedent to support the capital side.

Further, even if one accepted the equity side argument made in the Green Paper (Department of Climate Change, 2008) for compensation, almost certainly this becomes an argument for a long period strategy of special assistance. The price of the CO2 permits will increase over time as the permit quantity is targeted to meet the target of a 60% reduction of emissions by 2050. The story of less than 100 per cent pass through of the extra costs to producers, and the associated claims of loss of surplus returns to cover sunk capital costs, will not be a "once and for all" transition event, but rather a recurring event.

6. Conclusions

A CPRS to increase the relative prices and costs of GHG intensive products and production processes involves large redistributive effects. Government revenue gains are matched by higher prices paid by households, a squeeze in returns to the TEEI industries if Australia proceeds before other countries and some loss of surplus to sunk investments in the electricity generator and other industries. Along with equity arguments, there are good economic efficiency arguments for using most of the government windfall gains from what is an increase in indirect taxation for the compensation of households and some businesses. However, a roughly aggregate revenue neutral package that contributes to economic efficiency, including a reduction in GHG emissions, requires a different package of compensation payments than proposed by Garnaut (2008) and the Green Paper (Department of Climate Change, 2008).

Compensation to households via reductions in income taxation at all levels and increases in social security payments can be justified to provide for macroeconomic stability as well as for maintaining the current pattern of distribution. Importantly, as both the price of the permits to emit GHG and the effective size of the GHG tax base rise over time, a compensation package of direct income transfers in exchange for lower nominal wages and interest rates, much as was negotiated with the GST reform package of 2000, will need to be negotiated every year or two, rather than as a one-off interim measure.

In the likely event that Australia implements a CPRS before other countries, as Garnaut and the Green Paper argue, there is a compelling case to compensate the TEEI industries to minimise carbon leakage and to reduce unnecessary industry restructuring which would in part be reversed when at a later date all (or most) countries join a global agreement to reduce GHG emissions. The Garnaut and Green Paper proposals to compensate the export and import competing energy intensive industries, and with imports unaffected by the scheme, results in a narrow tax base and with distortions to both production and consumption decisions between traded and non-traded sources. Rather, a scheme which taxes the GHG content of imports and exempts the GHG content of exports internalises for Australian consumption decisions the external costs of GHG emissions. Setting the rate of import tax and export compensation with reference to an estimated world price increment described by Garnaut has a desirable in-built property of falling to zero as most countries join and it minimises carbon leakage.

The coal fired electricity generators are unlikely to fully pass forward to consumers 100 per cent of the extra production costs involved in their purchases of permits to emit GHG. However, this effect should not lead the generators to make production or investment decisions which differ from those that are socially efficient. As a result, there is no strong case to provide interim compensation to this sector. Further, if such a case for interim compensation is accepted the same arguments support more interim compensation in the future as the permit price rises.

Compensation as proposed above for households and the TEEI will utilise all of the government revenue windfall revenue gain from auctioning the tradable permits, and likely more in a political context. Among other things, this means that the proposals to fund R&D and to assist low income households buy more energy efficient appliances and housing will require additional sources of government consolidated revenue.

References

ABS (2007), Government Benefits, Taxes and Household Income 2003-04", Catalogue 6537.0, Canberra.

Cornwall, A. and Creedy, J. (1996), "Carbon Taxes, Prices and Inequality in Australia", Fiscal Studies, 17(3), 21-38.

Business Council of Australia (2008), How Emissions Trading Can Work for the Environment and the Economy, Melbourne.

Department of Climate Change (2008), Carbon Pollution Reduction Scheme: Green Paper, Commonwealth of Australia, Canberra.

Dixon, P. and Rimmer, M. (2000), "The Government/Democrats' Package of Changes in Indirect Taxes", Australian Journal of Agricultural and Resource Economics, 44(1), 147-158.

Energy Supply Association of Australia (2004), "Electricity Australia", ESAA Publication, Sydney.

Freebairn, J. (2008), "Some Sectoral and Global Distributional Issues in Greenhouse Gas Policy Design", Agenda, 15(1), 13-28.

Garnaut, R. (2008), The Garnaut Climate Change Review, Cambridge University Press.

Lineares, P., Santos, F., Ventosa, M. and Lapiedra, L. (2006), "Impacts of the European Emissions Trading Scheme Directive and Permit Assignment Methods in the Spanish Electricity Sector", The Energy Journal, 27(1), 79-98.

Mclennan Magasanik Associates (2008), Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets, Report to Federal Treasury, October.

Ng, Y-K (1987), "Equity, Efficiency and Financial Viability: Public Utility Pricing with Special Reference to Water Supply", Australian Economic Review, 3rd Quarter, 21-35.

Sijm, J., Neuhoff, K., Hepburn, C. Ward, J. and Grubb, M. (2006), "CO2 Cost Pass Through and Windfall Profits in the Power Sector", Climate Policy, 6, 49-72.

Simshauser, P and Doan, T. (forthcoming), "Emissions Trading, Wealth Transfers and the Wounded-Bull Scenario in Power Generation", Australian Economic Review.

Stephens, R. (1989), “New Zealand Tax Reform”, in J. Head (ed), Australian Tax Reform in Retrospect and Prospect, Australian Tax Research Foundation, Sydney.
The Treasury (2003), “Preliminary Assessment of the New Tax System”, Economic Roundup, Autumn.
The Treasury (2008), Australia’s Low Pollution Future: The Economics of Climate Change Mitigation, Canberra, October.
Warren, N., Harding, A. and Lloyd, R. (2005), “GST and the Changing Incidence of Australian Taxes: 1994-96 to 2001-02”, eJournal of Tax Research, 3(1), 114-115.