

Executive Summary

As the most carbon-intensive of the fossil fuels, this report focuses on thermal coal production subsidies and the key markets of the Powder River Basin (PRB) in the US and the Australian export market as an example in the overall World Export seaborne thermal coal market. Our analysis shows significant levels of subsidies present in these supply source locations¹.

Australian Coal Industry		
	Total Subsidy	Per tonne
Rehabilitation (2015)	A\$18bn capital subsidy	A\$2.05/US\$1.50
Tax deductions and direct spending (2005-2011)	A\$414m/US\$300m	A\$1.25/US\$0.91
Fuel excise exemption (2012-2013)	A\$767m/US\$560m	A\$1.92/US\$1.40
Total		A\$5.22/US\$3.81
Power River Basin, US		
	Total Subsidy	Per tonne
Tax subsidies ongoing	US\$1.3bn pa	US\$1.56
Tax subsidies phasing down	US\$2.4bn pa	US\$2.61
Rehabilitation and Self-bonding	A US\$2-4bn capital subsidy; US\$1bn pa	US\$0.78
PRB coal lease subsidy	A US\$30bn capital subsidy	US\$2.59
Total US		US\$7.54

¹ Unless otherwise noted within the text, weights are expressed in metric tons. Values can be converted into short tons (common in the United States) by multiplying by 1.1.

A Framework for Assessing Thermal Coal Production Subsidies

We set out to create a framework to assess thermal coal production subsidies and their impact in a 2035 framework.

The context is the CTI and IEEFA September 2014 Coal studies of demand and supply costs. We find:

- subsidies equalling US\$8 per tonne in the US Powder River Basin;
- of which US\$2.6 per tonne of subsidies already set to phase out;
- US\$4 per tonne in Australia, which we apply across the seaborne export markets.

In terms of a range of demand responses, the potential impact of removal is:

- 8%-29% effect to US PRB related demand; we estimate this equates to 0.7 to 2.5 GtCO₂ cumulative to 2035;
- 3%-7% effect on Australian Seaborne related demand..

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Coal subsidies can prop up uneconomic coal extraction and encourage new entry and expansion that would not otherwise occur. Both have the potential to increase carbon emissions worldwide. Quantifying the impact of subsidy removal on coal demand and GHG emissions requires a number of steps; gauging which substitutes in the relevant electricity market are likely to move in is a crucial one. The climate impacts will differ greatly if low carbon renewables or lower carbon gas is the marginal supply, versus other sources of high carbon coal. To avoid simple displacement by coal from other basins, subsidy removal would be best completed as part of a national and international framework. In the case of the US PRB, because US coal markets are somewhat isolated from global suppliers, removal of coal subsidies nationally would result in gas, and increasingly renewables, being highly competitive even against other sources of coal such as Appalachia, with resultant decreases in the carbon footprint of the PRB region. Australian exports are more exposed to inter-coal competition; unilateral reforms would be less likely to result in widespread fuel switching.

We note that fossil fuel production subsidies are complex to model, both in terms of identifying and quantifying them and then gauging their impact on demand. The IMF² has warned of challenges, claiming that 'producer subsidies do not lead to excessive consumption of energy,' but rather often supports inefficient domestic suppliers of the same fuels. However, they do incorporate available producer subsidy data from OECD into their "pre-tax" subsidy estimates. The IEA's price gap approach focuses on measuring pricing distortions between domestic and benchmark prices for specific fuels, whether the cause is on the producer or the consumer side. Many of the most heavily subsidized countries have clear consumer subsidies, with key fuels priced well below world prices; price impacts from producer subsidies are far more difficult to tease out. We seek to address this in our specific focus

The subsidies in detail

- **Australia – Proxy Seaborne markets:** Mine rehabilitation costs constitute a significant subsidy in the Australian coal sector. The problem has grown over time because mine company shareholders benefit by deferring the expenditure of hundreds of millions of dollars on mine closure for a decade or more, relative to having to fund mine closure immediately. While some rehabilitation is done progressively as coal is mined, the vast majority (upwards of 70%) is deferred until after the cessation of mining activity. Further, cost-deferral is not the only problem: political concessions routinely undermine adequate provision of funding or insurance for rehabilitation costs, resulting in inadequate accrual. For example, mine companies are often able to negotiate lower bonding than is realistically needed, or to underestimate the liability in other ways. Less reliable financial assurance mechanisms are also commonly deployed: bank guarantees, letters of credit, surety bonds or self-bonding assurances can be cancelled or not renewed when a mining company runs into financial distress, increasing the risk that rehabilitation costs are ultimately transferred from the mine owner

² <http://www.imf.org/external/np/pp/eng/2013/012813.pdf>

back to the general public.

We value rehabilitation costs at A\$4/tonne. This estimate is based on an independent analysis of Australian mine closure and rehabilitation liability published in May 2015 by Lachlan Barker. He estimated Australian mining has generated at least A\$18bn of rehabilitation liabilities, mostly unfunded. We converted this to a shortfall per ton of coal extracted, and conservatively treated half (A\$2.05/US\$1.50/t) as a subsidy, given the lack of adequate rehabilitation bonding and long history of deferral and externalisation of this cost.

- The OECD estimates that between 2005 and 2011 the Australian government provided a total of A\$1,150m (US\$840m) of financial assistance via tax subsidies and direct spending to the Australian coal industry. This included accelerated depreciation for coal mining buildings, capital expenditure deductions, immediate write-off of exploration and prospecting costs, government costs of the Clean Coal Fund and New South Wales Derelict Mines Program, among others. This is the equivalent of A\$1.25 (US\$0.91) for every tonne of coal sold over the data period.
- The Australian government also hands out over A\$6bn annually under its Fuel Tax Credits Scheme – an estimated 40% of which goes to Australia’s mining industry, and of this share, a third flows to coal mining. In comparison to prevailing tax levels on petrol and other fossil fuels within the OECD (aside from North America), this exemption for coal mining companies constitutes special treatment.
- The combination is total subsidy for Australian exports of A\$5.2/US\$3.8 per tonne.
- **US PRB:** OECD’s 2013 tally of US producer subsidies to coal identified aggregate tax and spending subsidies totaling US\$3.6bn annually. National supports were pro-rated to the PRB region based on its share of coal production. The OECD estimate comprises alternative fuel production credits; various tax concessions; accelerated amortization of certain pollution control technology investments used predominantly in the coal fuel cycle; and beneficial funding for R&D projects for coal fuel conversion or liquefaction. The OECD totals do not capture all state-level subsidies to coal; and do capture some state supports not relevant to PRB (and that were not included). We estimate total tax and spending subsidies benefitting PRB coal at US\$3.6bnbn/year during the period of analysis.
- Because subsidy policies do periodically change, we further split PRB supports to highlight the portion continuing versus those being phased out. We view this segregation conservatively, as it is likely that during the modeling period (to 2035), new subsidies will replace the ones phasing out.
- In addition, we found that PRB coal lease auctions over the past 30 years have often been uncontested – with but a single bidder. The impact of uncontested natural resource auctions is below-market leasing rates with high resultant lost income to taxpayers. We estimate that PRB bidding problems have transferred some US\$30bn from the US government to private coal companies during this time, equivalent to a subsidy of US\$2.59 per tonne.
- Both financial markets and US state regulators are belatedly grappling with another capital subsidy available to coal firms: ‘self-bonding’ for environmental rehabilitation liabilities. Similar to the situation in Australia, inadequate provision of financial assurance for mine reclamation is a growing problem. We estimate the current subsidy at US\$0.78 per tonne of coal produced.
- The combination is a total subsidy for PRB coal of US\$7.54 per tonne.

- **In addition to these quantified subsidies**, there are many more substantial subsidies in these regions that we were not able to quantify. These include the evasion of coal royalties, corporate tax avoidance through the use of transfer pricing and similar schemes, and other coal-specific tax deductions. ‘Coalgate’ and coal invoicing scandals in India and Indonesia also generate large subsidies to the coal sector. Furthermore, transport infrastructure subsidies are crucial ‘enablers’ to future coal production – these subsidies could be the difference between whether a fossil fuel project (and the resulting climate impact) goes ahead or not. As such, our per tonne subsidy estimates are significantly conservative and the resulting impact on demand should be seen in this light.

A case study framework for assessing the impact

Our assessment utilizes a supply-demand partial equilibrium framework to gauge the potential impact of these subsidies on a thermal coal supply curve and then, through estimating the elasticity, on demand in the relevant electricity markets. This allows us to broadly gauge the potential effects of subsidies on market structure, demand, and, to a lesser extent, carbon emissions. Our estimates assess first order effects on a long-term basis out to 2035.

We did not have access to a more detailed energy-optimization model such as MARKAL. Nonetheless, we believe that our approach explaining the key factors and drivers behind our estimates is valuable in showing the key assumptions which form the basis of more complex models.

One key issue for carbon and the climate becomes whether subsidies are considered as a cluster, or even globally, as opposed to a specific location or supply source. Removing the subsidies on a single location/source of supply could simply lead to substitution by other types of coal in that electricity market. For example, benefits of subsidy removal only in the PRB may be muted by an influx of coal from other (still subsidized) US based coal basins, such as Appalachia. Similarly, in World Export seaborne markets, other exporting countries and importantly domestic coal supply in India and China, can mute the fuel switching benefits of subsidy removal only in Australia. Where large new projects, particularly in environmentally sensitive areas, are prevented once subsidies are removed, there can be significant benefits even if coal from other existing locations moves in. However, the broadest benefits will be realized via more systematic removal of coal subsidies.

From the perspective of policy reform of coal subsidies, this dynamic raises a number of issues. The first is to shift from unilateral reform to a more globally-coordinated action, particularly in regions with significant coal trade. A second is to focus on the competitiveness of other lower carbon substitutes (renewables, natural gas, nuclear, and energy efficiency) in the relevant electricity markets. It may not make sense to ramp down renewable subsidies as quickly as is currently planned when the coal supports remain in place. Further, existing policies may inadvertently focus on supply resources – undermining low cost and rapidly-deployable options to boost efficiency. From a carbon/climate perspective this is crucial. Gas is less carbon intense than coal but renewables are better still and energy efficiency is quite often the quickest and highest value carbon reduction option.

To incorporate these interactions, we have conducted sensitivity assessments in the case studies we have set out. These assessments incorporate a range of values on both the level of subsidies and the

elasticity of demand (Ed). The elasticity range differentiates between removing specific subsidies at a location (generally a higher price sensitivity, but lower carbon benefits due to an influx of other coal) and coal subsidy removal over a wider geographic range. We look ahead to the likely trends in competitiveness of lower carbon fuel sources in particular – renewable costs should fall while in the US gas remains competitive.

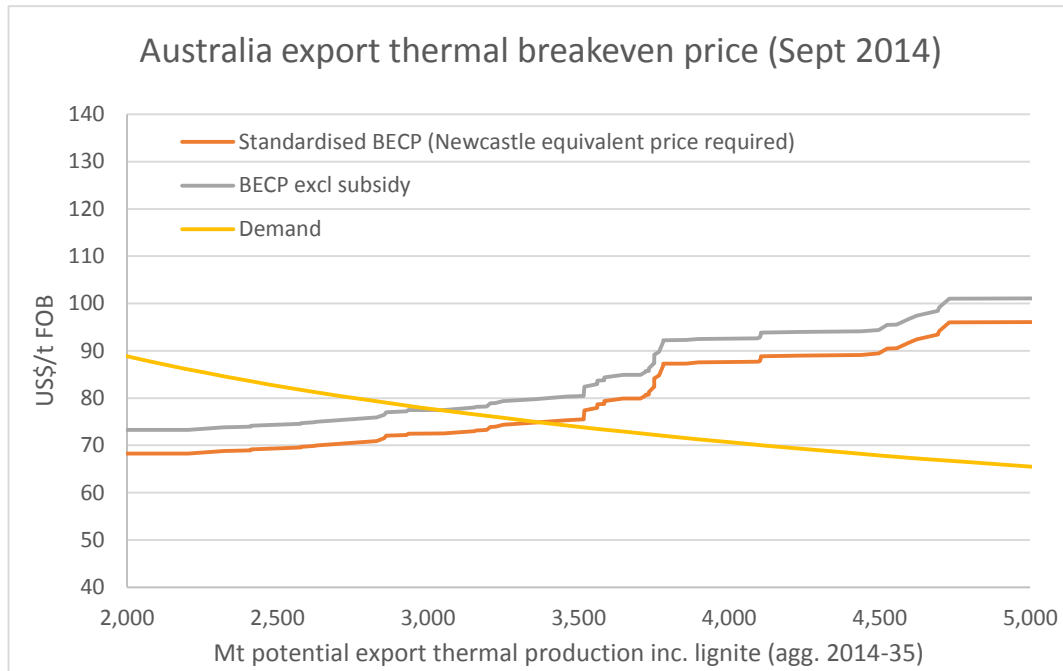
Section 3.3 tackles these issues in more detail.

Using a demand and supply curve framework

- As examples for generating charts, we adjust the supply curve of Australian seaborne coal up by US\$4/t from its original equilibrium break-even coal price (BECP) as published in Carbon Tracker's September 2014 coal study³ of US\$75/t and PRB by US\$8/t on a US\$36/t break even equilibrium (Note we adjust the PRB directly for domestic rail transport costs estimates from EIA compared to the September 2014 document).
- In order to illustrate the different effects of coal substitution, we derive demand curves where the slope is:
 - Ed of 1.5 for PRB coal, where we assume that all coal subsidies in the US are lifted on all sources of US supply, and there is limited import competition. As such, it is more related to coal overall against other low carbon sources which we see having increasing penetration for regulatory and cost reasons. Gas remains competitive and the surprise could be higher Ed based on more aggressive gas switching as subsidies are removed.
 - Ed of 3 for Australia where these subsidies alone are lifted much of the replacement supply is coal from other regions.
- The last step is to combine the revised supply curve with the elasticities of demand and calculate the estimated coal demand reduction and associated carbon impacts. The red line below shows the energy-adjusted price of coal needed for a mine to break even, if subsidies are in effect. If production subsidies are removed, the costs of the mine (and hence the required price of coal) are increased; the price of coal needed for a mine to break even without the cost benefit given to it by subsidies is shown by the grey line

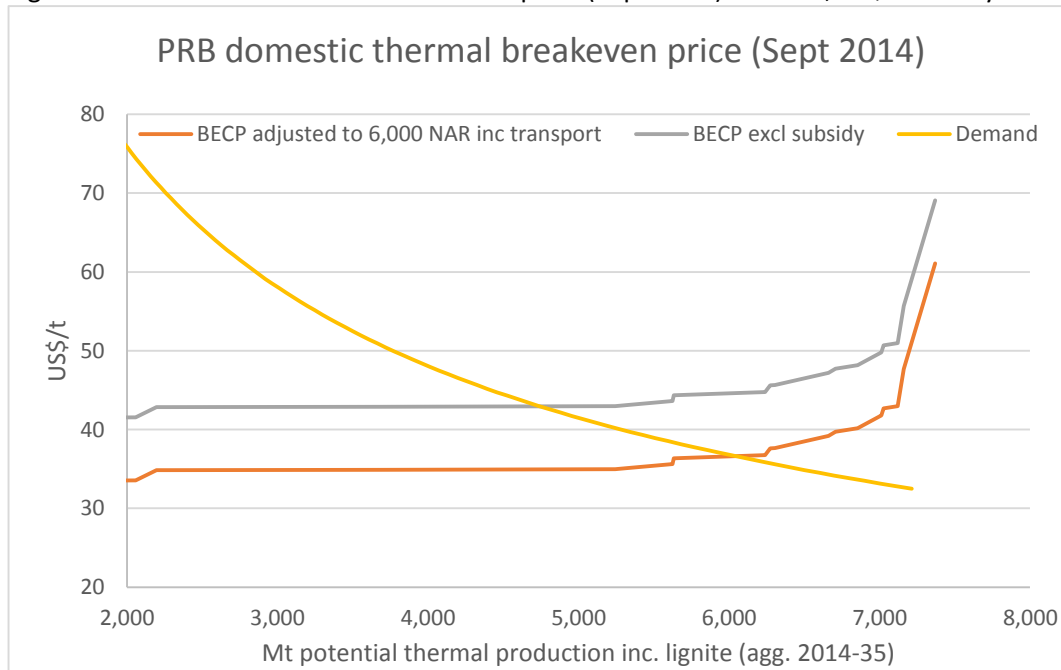
³ <http://www.carbontracker.org/report/carbon-supply-cost-curves-evaluating-financial-risk-to-coal-capital-expenditures/>

Figure 1: Australia export thermal breakeven price (Sept 2014)- 3.0x Ed, US\$4 subsidy



Note – based on September 2014 data. The break-even coal price (BECP) is based on a standardized energy content exported from Newcastle Australia. The supply curve has been adjusted for transport costs based on EIA estimates compared to the curve derived in September 2014. This is needed in a subsidy price effect analysis to derive a delivered price.

Figure 2: PRB domestic thermal breakeven price (Sept 2014)- 1.5x Ed, US\$8 subsidy



Note – based on September 2014 data.

- Note that the supply curve has been adjusted for transport costs based on EIA estimates compared to the curve derived in September 2014. This is needed in a subsidy price effect analysis to derive a delivered price.

Sensitivity analysis

To address key areas of uncertainty in our data, we present a set of sensitivity tables to illustrate the impact on demand of different subsidy levels and different Ed levels.

1. We consider the impact of pre-closure subsidies alone and then the impact of both pre- and post-remediation/closure subsidies. This acknowledges uncertainties around the manner and degree to which different types of subsidies will stimulate supply. In particular, investment decision-makers may attribute greater significance to subsidies coming at the project development stage (tax deductions and the like) relative to those at the end of the project life cycle (such as rehabilitation subsidies).
2. In the PRB, a number of subsidies are already phasing down, highlighting the importance to investors exposed to companies that might be affected in understanding the impacts set out in this work.

3. We consider a range of Eds reflecting the differing assumption on cross-coal substitution. Available fuel substitutes, as well as the scope of subsidy removal (specific policy, national, or global) affect relevant elasticities and the competitiveness of lower carbon options. These different estimates might reflect differences in market context, for example:
 - a. An Ed of 0.5 is more related to short-term effects from price rises in electricity markets. An Ed range of 1-2 would describe market responses to coal subsidy removal across a broader geographic market area, or globally where all subsidies are lifted at once. The upper end of this range would be more likely associated with increased low carbon fuel source penetration based on regulatory support and declining cost curves of substitutes. We see the higher Ed scenario as most relevant to the US PRB, as national removal of US coal subsidies, while not politically easy is also not impossible to envision. In this market, we see regulation and costs as increasingly making coal less attractive and with gas being an important potential driver on the upside to the Ed.
 - b. An Ed of 2-3 (ranging up to 4) would incorporate regions where other sources of coal can substitute more easily, allowing consuming industries to shift fuel suppliers while continuing to operate their existing capital. It is possible gas in the PRB could lift the Ed to this level even with other sources of coal constrained as aging coal plants need replacing. This range would apply at the higher end to Australian coal in isolation, and at the lower end if subsidies were tackled in world seaborne markets and India and China.

Effect on demand of removing subsidy US\$, % (based on supply - demand framework)

Market	Category	Subsidy (\$/t)	Elasticity					
			0.5x	1.0x	1.5x	2.0x	2.5x	3.0x
US PRB	Ongoing tax and lease	\$4.00	-5%	-8%	-11%	-13%	-16%	-20%
	Phasing out	\$3.00	-4%	-7%	-8%	-11%	-12%	-13%
	Remediation	\$1.00	-2%	-3%	-4%	-6%	-7%	-7%
	Total	\$8.00	-8%	-16%	-22%	-29%	-34%	-39%
Australian Export	Tax and fuel excise	\$2.50	-1%	-3%	-3%	-3%	-4%	-4%
	Remediation	\$1.50	0%	-1%	-1%	-3%	-3%	-3%
	Total	\$4.00	-1%	-3%	-4%	-6%	-6%	-7%

Note:

Australian export and PRB domestic demand impact rounded to nearest 50 mt coal

"Total" based on actual impact of total level of subsidy - sum of constituent parts may be different due to the shape of the supply curve

In terms of carbon impacts, without a detailed dispatch model to assess the penetration of particular substitutes, our analysis should be viewed as indicative. If we assume that it is at the lower Eds that lower carbon substitutes make their biggest impact, then it seems best to focus on the 1-2 Ed. However, this still leaves open the role of gas, particularly in the US PRB. For illustration we have assumed half of the substitution in the US is gas at a 40% saving of carbon (conservative) relative to coal.

CO₂ reductions from removing subsidy US\$, mtCO₂ (based on supply - demand framework)

Market	Category	Subsidy (\$/t)	Elasticity			
			0.5x	1.0x	1.5x	2.0x
US PRB	Ongoing tax and lease	\$4.00	432	720	936	1,152
	Phasing out	\$3.00	360	648	720	936
	Remediation	\$1.00	144	288	360	504
	Total	\$8.00	720	1,368	1,944	2,520

Notes:

PRB domestic demand impact rounded to nearest 50 mt coal

CO₂ calculated at 1.8 mtCO₂ per mt coal

50% of PRB impact on coal demand assumed to be into gas at 40% less carbon than coal

"Total" based on actual impact of total level of subsidy - sum of constituent parts may be different due to the shape of the supply curve

Conclusion:

We find production subsidies summing up to:

- US\$8 per tonne in the US Powder River Basin; and
- US\$4 per tonne in Australia.

The removal of these subsidies would result in:

- A 8%-29 % reduction in demand for US PRB coal, with associated cumulative reductions of 0.7 to 2.5 GtCO₂ to 2035.
- A 3%-7% reduction in demand for Australian Seaborne coal, though with smaller carbon reductions due to substitution of coal from other (often also-subsidized) producers.

Removing subsidies to coal extraction should be a central plank of any country's fiscal and environmental plan. Particularly as subsidies to renewable energy come under increasing pressure, subsidies to the mature coal sector should not be ignored. A broader geographic range for coal subsidy elimination will boost the carbon benefits, as the ability for coal supplies to move in from other subsidized markets will be constrained.

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1. Subsidies literature review

Governments introduce fossil fuel subsidies claiming they will achieve some mix of: i) reducing dependence on energy imports; ii) redistributing wealth domestically; iii) reducing the cost of energy to the poor; and iv) stimulating investments and jobs. The nature and scale of the subsidies governments choose to implement vary depending on the main objective they are trying to achieve, as well as the political dynamics of the subsidized industry.

Crucially, however, most energy analysts, investors and policymakers consider fossil fuel subsidies an inefficient and unnecessary state intervention. For free market adherents, subsidies are a drain on national budgets that stifle private investment into the energy sector and are ineffective in delivering on their stated aims - they are 'pervasive and impose substantial fiscal and economic costs in most regions' according to the International Monetary Fund (IMF).⁴ For advocates of a non-market, or planned economy, fossil fuel subsidies incentivise investment into carbon-intensive energy, thus posing a barrier to low-carbon development. The subsidies are not effective in supporting the world's poorest communities that governments often point to in order to justify their policies. The IMF estimates that the poorest 20% of households worldwide receive less than 7% of the benefits generated by fossil fuel subsidies. Although the subsidies undoubtedly provide some support to the poor, the majority of total support flows to wealthier segments of society due to their greater consumption of fossil fuels's services (referred to as subsidy "leakage").⁵

Most research on fossil fuel subsidies thus far has focused on consumption subsidies for two reasons. First, in terms of capital value, they are larger than those supporting fossil fuel producers.⁶ Second, they are relatively easier to measure. However, understanding the scope and incidence of fossil fuel production subsidies is equally crucial because they affect key decisions to build out future coal production, which, in turn, locks society into decades of associated carbon emissions.

Efforts to phase-out subsidies have been negligible

Amid a near consensus on the inefficacy of fossil fuel subsidies to achieve social policy goals, calls for fossil fuel subsidies to be phased out have been supported by governments internationally. In 2009, G20 countries agreed to 'rationalise and phase out over the medium term inefficient fossil-fuel subsidies that encourage wasteful consumption while providing targeted support for the poorest'.⁷ This commitment was made in light of the risks posed by fossil fuel subsidies, such as encouraging 'wasteful consumption, reduc[ing] our energy security, imped[ing] investment in clean energy sources and undermin[ing] efforts to deal with the threat of climate change'.⁸ An identical declaration was also made by leaders of the Asia-Pacific Economic Cooperation (APEC) forum in 2009 and was reiterated in the 2013 St. Petersburg G20 Declaration and within other international processes such as the UN Conference on Sustainable Development and the UNFCCC.

⁴ <http://www.imf.org/external/np/pp/eng/2013/012813.pdf>

⁵ http://www.wto.org/english/docs_e/legal_e/24-scm.pdf

⁶ (To provide context, Appendix 1.1 summarises estimates of total global fossil fuel consumption subsidies that range from approximately US\$500bn to US\$5.3trn per year as a result of different methodologies of what is included as a subsidy).

⁷ <http://www.ft.com/cms/s/0/5378959c-aa1d-11de-a3ce-00144feabdc0.html#axzz3Omm73aTX>

⁸ http://www.g20ys.org/upload/files/Pittsburgh_0.pdf

The New Climate Economy recently highlighted that 27 countries are now engaging in fossil fuel subsidy reform in one form or another.⁹ Appendix 1.2 provides details of a number of these actions. In spite of these positive trends, actions taken to phase out fossil fuel subsidies during the six years since the G20 declarations were made have been quite limited. Indeed, fossil fuel subsidies in most countries have continued to grow. Major obstacles preventing the shift to phase out fossil fuel subsidies include: a lack of information on subsidy magnitude and widely varying quality on subsidy reporting across governments; continued challenges on applying a consistent definition of subsidy across nations; and well-organised opposition to reform by subsidy beneficiaries. Although disagreements remain, there is a growing consensus on recognised subsidies and the core elements to be included in any subsidy review. Increasingly, institutions are collecting data on various forms of ‘support’. A framework is needed to help subsidy reporting, to track these records, and perhaps most importantly to implement sanctions for failing to do so correctly.¹⁰

Fossil fuel subsidies as an ‘enabler’

As this literature review demonstrates, the scale of total global fossil fuel subsidies is vast. While this financial contribution plays a significant role in the market fundamentals of fossil fuel supply and demand, subsidy support also needs to be considered in terms of how it affects the risk perception of actors within the industry. Even subsidy policies that may not involve immediate cash outlays can have significant distortionary effects on investment decisions by de-risking development decisions by capital providers and project developers for targeted activities. Credit subsidies, such as loan guarantees, commonly play this role. Unfortunately, this type of “risk-shifting” subsidy is often inadequately quantified in available studies, or missing entirely. Consider the decision-making point about whether to invest and move forward with a project or not. Without any subsidy support the decision-maker may not see the project in question as a viable investment. However, with a production or capital infrastructure subsidy, the cost of initial investment is reduced directly and the potential returns are derisked. Both shifts increase the expected value of the investment and increase the likelihood that the project will get the go-ahead. This single shift in calculations not only locks in large amounts of investor capital (and taxpayer risk), but can also trigger vast carbon emissions for decades to come. The subsidy fundamentally altered the final investment decision. It is in this context that this report frames fossil fuel subsidies, in particular production subsidies, as project and investment ‘enablers’.

⁹ <http://newclimateeconomy.net/content/press-release-renewables-are-safer-bet-price-volatile-oil-says-new-climate-economy>

¹⁰ <http://www.odi.org/sites/odi.org.uk/files/odi-assets/publications-opinion-files/8668.pdf>

1.1 Defining a subsidy

What is considered a subsidy has been a great area of debate. Broadly, the definition of a fossil fuel subsidy is agreed as any government action that raises the price received by fossil fuel producers, reduces the price paid by fossil fuel consumers, or reduces the costs incurred by either producers or consumers. While in theory this definition should capture the derisking element of subsidy support that is so crucial in investment decision-making (loan guarantees would reduce the cost of capital, which should show up in the numbers), in practice such interventions are rarely captured.

The most commonly reported fossil fuel subsidy metric is the price-gap approach. The metric compares the domestic market price of a fuel against a market benchmark price, typically the transport-adjusted market price for internationally-traded fuels. Differences or “gaps” between the two values are considered a subsidy, regardless of whether the support flows to producers or consumers. This definition, therefore, sees a subsidy as:

Subsidy = (benchmark price – end-user price) x units consumed.¹¹

This approach is utilised by the IEA and IMF. Subsidy definitions often focus more broadly on policy types and include interventions that may not show up in the market prices. The OECD, for example, states that the price-gap approach:

*‘... does not generally capture support to producers and most tax concessions to both producers and consumers, which account for much of the supported provided by developed countries, since such measures do not push final prices below the level of international reference prices but these policies can induce greater production or use of fossil fuels’.*¹²

The WTO’s 1994 Agreement on Subsidies and Countervailing Measures defines a subsidy as ‘any financial contribution by a government, or agent of a government, that confers a benefit on its recipients’, and details four transfer mechanisms where a benefit is thereby conferred and therefore constitutes a subsidy:

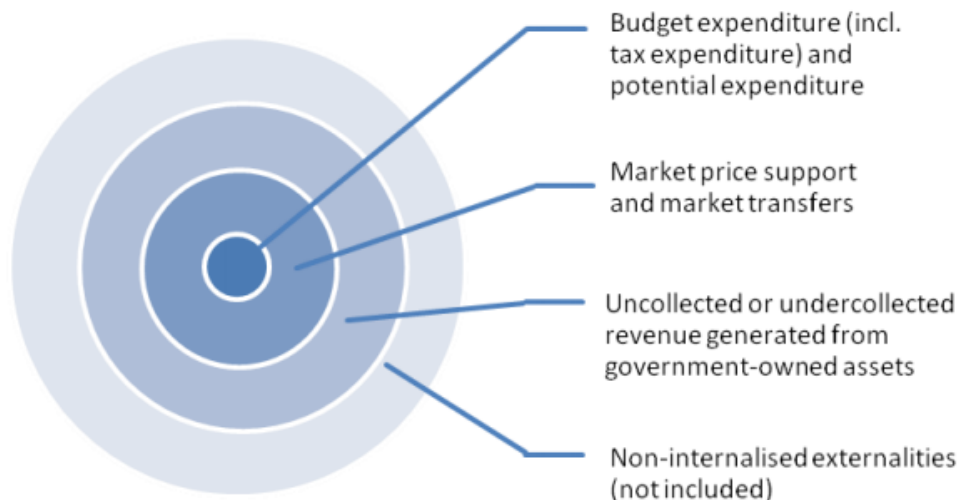
- i) A government practice involves a direct transfer of funds, potential direct transfers of funds or liabilities;
- ii) Government revenue that is otherwise due is foregone or not collected (e.g., fiscal incentives such as tax credits);
- iii) A government provides goods or services other than general infrastructure or purchases goods;
- iv) A government makes payments to a funding mechanism, or entrusts or directs a private body to carry out one or more of the type of functions illustrates in: i) to iii) above that would normally be vested in the government.¹³

Generally, what is considered a subsidy has become more complex with time as practitioners have developed greater expertise on the subject. Figure 3 from the OECD aptly summarises how improvements in understanding around subsidies has, and continues to, increase what this comprises over time.

¹¹ <http://www.iea.org/publications/worldenergyoutlook/resources/energysubsidies/methodologyforcalculatingubsidies/>

¹² OECD, 2013 inventory

Figure 3: The ever-widening content of a subsidy

Source: OECD¹⁴

Over the course of this evolution, what constitutes a subsidy has progressed from a narrow definition including only direct, budgeted expenditures to definitions that include non-monetised, non-internalised externalities. Not all assessments apply the same definition. OECD includes direct budgetary expenditures and tax expenditures that in some way provide a benefit or preference for fossil fuel production or consumption. They also include risk-shifting via credit or insurance subsidies within their definition, though have little associated data. The OECD also refers to such measures as 'support' rather than 'subsidies' per se. This rewording is effective in conveying the general message without the political overtones while 'subsidy' could be perceived to have negative connotations.

The absence of a globally-agreed definition, and hence the lack of harmonised/consistent (and transparent) data, inhibits the measuring of fossil fuel subsidies and analysis of the distortions subsidies impose on the economy beyond that.¹⁵ One important distinction that helped to achieve a greater level of data consistency, is between producer and consumer subsidies. Consumer subsidies are more prevalent in non-OECD states, due to a largely ineffective attempt to make energy access more affordable by providing it at below-market prices. Developed world subsidies to consumers also include low-income access programs, as well as energy exemptions from standard taxes levied on other goods. Quantified producer subsidies tend to be located in OECD nations, and are currently considered to be smaller in scale than the consumption side. Measurement challenges on producer subsidies suggest that they are larger than currently reported in both OECD- and non-OECD nations.

Fossil fuel production subsidies

Production subsidies are mechanisms that either artificially raise the price received by the producer for a good above the market rate or reduce the costs incurred by the producer such that producers

¹⁴ http://www.oecd.org/env/outreach/EHS%20report_20%20August%202013_ENG.pdf

¹⁵ <http://www.odi.org/sites/odi.org.uk/files/odi-assets/publications-opinion-files/8668.pdf>

are incentivised to increase supply more than would otherwise be demanded by the market. Subsidy support for producers can be provided to selected companies, to one sector, geographic region, or product in comparison to other sectors domestically, or to sectors or products nationally when compared internationally. These efforts can also be supported by foreign trade barriers, such as import tariffs, that further serve to protect domestic producers. Ultimately, someone has to bear the real cost of fossil fuel production subsidies; often it is the taxpayers who lose out. In other cases, the subsidies exacerbate environmental damages with costs borne by surrounding communities, or more broadly by society.

To date, far less effort has been invested into uncovering the scale of fossil fuel production subsidies compared with consumption subsidies. This is partly due to consumption subsidies being far larger, but also because there is less transparency around production subsidies. For example, governments may prefer subsidising an industry through price altering mechanisms because they do not necessarily show up on budgets, thus reducing their accountability. Only a small group of oil producing countries (Indonesia, Iran, Malaysia, Sudan, and Yemen are examples) explicitly include production subsidies in their budgets.¹⁶ Even where coverage of support at the national level may exist, significant subsidies at the state, provincial, or municipal levels may be missing. Clearly, a greater level of standardised reporting is required globally to include coal-producing countries.

More specifically, the IMF notes that identifying producer subsidies can be especially difficult because they often 'take the form of differential tax treatment and tax exemptions for specific sectors'.¹⁷ Given foregone government revenues is often one of the largest production subsidies, the need for standardisation is again clear. As GSI notes, 'more transparency and research are needed to measure the level and impact of production subsidies with regard to driving exploration, production, price and demand in fossil fuels globally'.¹⁸

There are a number of different possible fossil fuel production subsidies. Market price support mechanisms include government-brokered agreements that force utilities to buy domestic fossil fuels from producers at a higher price than market, as well as other market guarantees. Cost reduction subsidies include advantageous deductions in corporate income tax and direct financial transfers such as grants. The table below from the OECD presents an exhaustive list of these budgetary and tax support mechanisms available to fossil fuel producers.

¹⁶ De Mooij, R., Parry, I., & Keen, M. (2012) Fiscal policy to mitigate climate change: A guide for policymakers. Washington, D. C.: International Monetary Fund.

¹⁷ <http://www.imf.org/external/np/pp/eng/2013/012813.pdf>

¹⁸ <http://norden.diva-portal.org/smash/get/diva2:786861/FULLTEXT02.pdf>

Figure 4: Matrix of support measures for fossil fuel producers

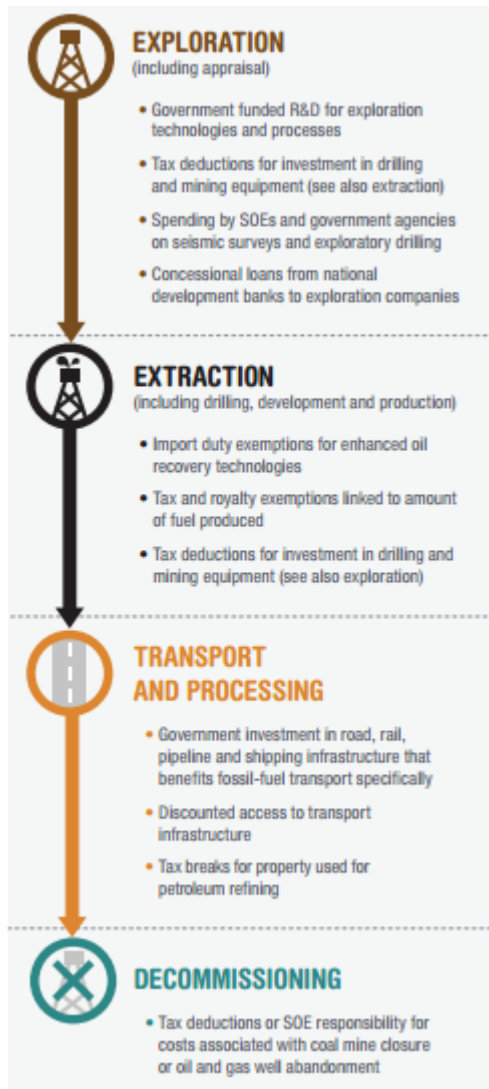
		Production						
		Output returns	Enterprise income	Cost of intermediate inputs	Costs of production factors			
					Labour	Land and natural resources	Capital	Knowledge
Transfer mechanism (how a transfer is created)	Direct transfer of funds	Output bounty or deficiency payment	Operating grant	Input-price subsidy	Wage subsidy	Capital grant linked to acquisition of land	Capital grant linked to capital	Government R&D
	Tax revenue foregone	Production tax credit	Reduced rate of income tax	Reduction in excise tax on input	Reduction in social charges (payroll taxes)	Property-tax reduction or exemption	Investment tax credit	Tax credit for private R&D
	Other government revenue foregone			Under-pricing of a government good or service		Under-pricing of access to government land or natural resources; Reduction in resource royalty or extraction tax		Government transfer of intellectual property right
	Transfer of risk to government	Government buffer stock	Third-party liability limit for producers	Provision of security (e.g. military protection of supply lines)	Assumption of occupational health and accident liabilities	Credit guarantee linked to acquisition of land	Credit guarantee linked to capital	
	Induced transfers	Import tariff or export subsidy	Monopoly concession	Monopsony concession; export restriction	Wage control	Land-use control	Credit control (sector-specific)	Deviations from standard IPR rules

Source: OECD

Outside of these more typical forms of subsidy, some of the more opaque mechanisms shown in the table illustrate the challenges in fully tracking subsidies. These include transfers of risk from producers to the government through instruments such as soft loans or loan guarantees, and the extent to which state-owned enterprises are excessively benefiting from government support.

Subsidies towards transport, infrastructure and decommissioning can also be significant, and important in assessing the extent to which subsidies have enabled fossil fuel producers to move forward on new projects, particularly those in remote or inhospitable (though often environmentally-important) regions of the world. Oil Change International and the Overseas Development Institute capture the full range of production subsidies by distinguishing them by supply chain stage (see Figure 5). Although government policies are often aimed at more than just one subsidy sub-category, overlaps often remain. Nonetheless, this simple grouping can help focus attention on specific subsidy policies that promote the further extraction of fossil fuels.

Figure 5: The four stages of fossil fuel production subsidy¹⁹



Fossil fuel consumption subsidies

The IEA defines a consumption subsidy as any government action that 'lowers the price paid [for energy] by energy consumers'.²⁰ Most types of consumption subsidy can also be applied to producers and so have been highlighted in Figure 5 - the primary forms of consumption subsidy are price controls mechanisms, direct financial transfers and tax concessions.

¹⁹ <http://www.odi.org/g20-fossil-fuel-subsidies>

²⁰ IEA WEO 2014

1.2 Fossil fuel production subsidies: How big are they?

As noted above, substantial differences in subsidy estimates across institutions arise from varying definitions and inclusion of types of policy supports. For instance, while the OECD estimates pick up an increasing share of grants and tax expenditures, investments from state-owned enterprises and public finance are not well captured. ODI reports do pick up the gross magnitude of credit support, though lacked the data to convert gross commitments into subsidy estimates. These types of analytic and coverage challenges are common, and lead to quite wide variation in estimates across institutions.

As mentioned earlier in the report, less effort has so far been invested in understanding the global scale and distribution of production subsidies. Oil Change International and the ODI recently estimated exploration and extraction fossil fuel subsidies, finding US\$88bn in annual spending that supporting the exploration and extraction of more coal, oil and gas.²¹ This total comprises three forms of support, as shown in Table 1 below. Investment into SOEs and public finance commitments are both gross supports rather than subsidies, since for both categories the supported activities will pay some funds back to the government. While more detailed data would allow an analysis of below-market conditions of these activities, even the overall spending levels illustrate the important role of government in directing and retaining large-scale fossil fuel extraction activities.

Table 1: G20 support for fossil fuel exploration and extraction

	Exploration (US\$bn)	Exploration and extraction (US\$bn)
National subsidies (direct spending and tax and duty exemptions)	4.1	22.7
Investment by state-owned enterprises (gross spending)	21.4	49.4
Public finance (domestic and international gross commitments)	14.7	15.9

Estimates of producer subsidies from other institutions differ quite widely, reflecting the breadth of approaches that can be adopted. The GSI estimated that producer subsidies globally equal US\$100bn²², while research from Oil Change International and the Natural Resources Defense Council (NRDC) posit producer subsidies in developing and emerging countries to range from US\$80 to US\$285bn annually.²³

These differences are likely due to variation in what is and isn't included as a production subsidy. For example, the ODI framed their research such that extraction subsidies were considered a group within exploration subsidies because they were fundamentally crucial to support future fossil fuel extraction. Subsidies to benefit transport, processing, and decommissioning could similarly be considered to fundamentally support and influence the decision to explore or not. Whichever

²¹ <http://www.odi.org/g20-fossil-fuel-subsidies>

²² <http://www.iisd.org/gsi/fossil-fuel-subsidies/fossil-fuels-what-cost>

²³ <http://priceofoil.org/content/uploads/2012/06/LowHangingfruit.pdf>

approach is adopted, institutional estimates thus far have highlighted the importance of being transparent about the methodology applied given the great scope for variation.

1.3 Coal subsidies

The OECD estimates budgetary support and tax expenditure coal subsidies at US\$11.7bn annually in the 34 OECD countries as of 2011.²⁴ Including the full spectrum of available subsidies will increase this total. For instance, a study conducted by the consultancy Ecofys found that in 2012, the EU28 nations provided just under EUR10bn (US\$11.4bn) in total coal subsidies.²⁵

Coal subsidies can appear small in scale because many coal extraction operations are less capital intensive than other fossil fuel sectors such as oil. The IMF finds coal subsidies are equal to only 1% of total global fossil fuel subsidies.²⁶ However, some caution is in order. First, these contributions can be significant as an ‘enabler’ to go ahead with a project, particularly given investor concerns over future market conditions for coal as a fuel. Further, coal support is sometimes understated – most commonly when coal-specific subsidies to coal power plants (subsidies to install pollution control equipment in power plants, for example) are captured in the power sector rather than attributed to the coal that is driving the need for the investment.

An OECD report uncovered by Reuters in February 2015 found that between 2003 and 2013 nearly US\$15bn of export credit support has been provided to fund coal-fired power plants and coal mining technology through Export Credit Agencies. Of this, US\$1.8bn went towards the extraction of coal and US\$829m of credit export value to mining equipment, most of which was for coal producers.²⁷ While the absolute monetary values of this support are not particularly large, the sheer fact that finance has been provided by governments, despite the concerns over carbon emissions, provides an important validation to other investors that the investment in question is a sound investment. This role of subsidies as a capital underwriter and hence project enabler is quite important in coal production though too often overlooked. The Abbot and Newman governments in Australia, for example, have promised material capital subsidies sourced from taxpayers to underwrite the required power, rail, water and port infrastructure needed to open up Galilee Coal Basin.

Climate impact

Coal is the most CO₂-intense of the conventional fossil fuels. Consequently, coal subsidies have the largest climate impact per dollar of any subsidy type and are, therefore, central to determining society’s success in mitigating climate change. This is reflected in subsidy analyses that factor in environmental and social externalities.

The IMF conducted such an analysis. Although IMF estimates direct subsidies to coal at only 1% of its total, their “post-tax” estimate (which includes any missing sales taxes as well as externalities) shows coal’s share of the total at 29%, equal to US\$539bn annually. This surge underscores coal’s

²⁴ http://www.keepeek.com/Digital-Asset-Management/oced/environment/inventory-of-estimated-budgetary-support-and-tax-expenditures-for-fossil-fuels-2013_9789264187610-en#page1

²⁵ https://ec.europa.eu/energy/sites/ener/files/documents/ECOFYS%202014%20Subsidies%20and%20costs%20of%20EU%20energy_11_Nov.pdf

²⁶ <http://www.imf.org/external/np/pp/eng/2013/012813.pdf>

²⁷ <http://priceofoil.org/content/uploads/2015/02/OECD-Leak-Data-on-export-credit-for-fossil-fuels-Oct14.pdf>

disproportionately negative environmental and health consequences.²⁸ The Ecofys study reaches similar conclusions, confirming coal to have the created externalities of all power sources, and attributing half of all coal’s external costs to climate change (see Figure 6). In addition to climate change impacts, external costs of coal burning include depletion of energy resources, human toxicity, particulate matter, and displacement of agricultural land.

Figure 6: External costs per technology for electricity sources across the EU28²⁹

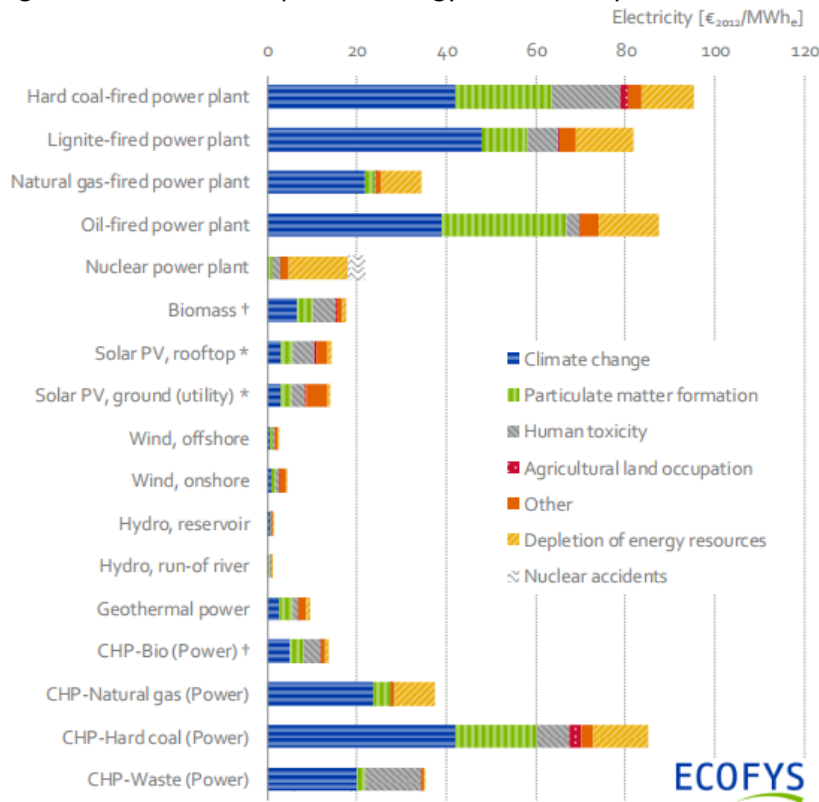


Figure 3-8: External costs per technology for electricity technologies, EU28 weighted averages (in €2012/MWh).

Including non-internalised externalities in this way remains a point of contention, in part due to methodological uncertainties and disagreements over its economic and political applicability. However, integrating an estimated cost of these externalities serves to better illustrate the full costs of coal fired electricity as compared to alternatives.

²⁸ <http://www.imf.org/external/np/pp/eng/2013/012813.pdf>

²⁹ https://ec.europa.eu/energy/sites/ener/files/documents/ECOFYS%202014%20Subsidies%20and%20costs%20of%20EU%20energy_11_Nov.pdf

2. What are the scale of subsidies applicable in the Powder River Basin and Australian coal exports (IEEFA)

The coal and coal-fired electricity industry benefits from a range of government subsidies and concessions that is both large and global. The supports substantially reduce the apparent costs of coal extraction, and artificially boost demand for coal by making it appear to be more cost-competitive relative to alternatives such as gas, hydro and renewables.

The [Africa Progress Report](#) of June 2015, produced by a committee chaired by Nobel laureate Kofi A. Annan, former secretary-general of the United Nations, is emphatic in its call for an end to subsidies that support the status quo:³⁰

“Cut the pro-rich subsidies. National strategies should include a roadmap and schedule for phasing out the US\$21 billion in energy subsidies geared towards the rich ... a comprehensive phase-out of all fossil fuel subsidies by 2025 ... with appropriate support for low-income countries. Eliminating subsidies for fossil-fuel exploration and production – especially coal – should be a priority. Developed countries should withdraw by 2018 all tax concessions, royalty relief and fiscal transfers, and all state aid to fossil-fuel industries by 2020. The G20 countries should set a timetable for acting on their commitment to phase out fossil-fuel subsidies, with early action on coal.”

The UN call for action flies in the face of deeply entrenched patterns of subsidy that keep the coal industry and the coal-fired power sector alive. Government-supplied subsidies even extend to providing capital that enables the fossil-fuel industry to expand. By subsidizing or by outright provision of capital for coal mining, associated coal rail and port infrastructure subsidies, and for general financial aid that promotes the continued expansion of coal-fired power plants, governments tap taxpayer dollars to prop up demand for thermal coal. They also undermine cleaner competitors such as gas, hydro and renewables.

The largest subsidies for the coal industry globally are the continued externalization of costs relating to air and water pollution; the resulting health impacts on communities; and compulsory land acquisition from private holders by the state for coal mines, often destroying the ability to support the original functions. This report does not delve into these costs. This report attempts to quantify coal sector related subsidies in terms of the narrow financial, tax and capital elements.

The subsidies detailed below encompass those that could be manageably quantified, and should be viewed as a conservative accounting of the full range of government subsidy provided to the coal fuel cycle. Many other coal subsidies are detailed in Appendix 2.

To summarize, we calculated the following production subsidies:

³⁰ http://www.africaprogresspanel.org/wp-content/uploads/2015/06/APP_REPORT_2015_FINAL_low1.pdf

Australian Coal Industry		
	Total Subsidy	Per tonne-year
Rehabilitation (2015)	A\$18bn/US\$14bn capital subsidy	A\$2.05/US\$1.50
Direct tax deductions (2005-2011)	A\$414m/US\$300m pa	A\$1.25/US\$0.91
Fuel excise exemption (2012-2013)	A\$767m/US\$560m pa	A\$1.92/US\$1.40
Total		A\$5.22/US\$3.81
Power River Basin, US		
	Total Subsidy	Per tonne
Tax expenditures and direct spending, ongoing	US\$1.3bn pa	US\$1.56
Tax expenditures and direct spending, phasing down	US\$2.4bn pa	US\$2.61
PRB coal lease and royalty subsidy	A US\$30bn capital subsidy	US\$2.59
Financing subsidy on funding for mine closure and rehabilitation	A US\$2-4bn capital subsidy	US\$0.78
Total US		US\$7.54

2.1 Australian coal industry

The OECD 2013 report into subsidies and other support for Australian coal miners chronicled some of the many ways mining energy is subsidized.³¹ The OECD report found that from 2005-2011 the Australian government provided a total of A\$1,150m (US\$840m) of financial assistance to the Australian coal industry via a range of tax deductions and benefits – see section 2.1.1. While some of these subsidies are no longer in effect, we note that the coal industry is relentless in its pursuit of both new subsidies and the maintenance of subsidies it has already garnered. It is reasonable to assume that the coal subsidies in effect over the period modeled to 2035 will include new supports that replace the programs that have been phased out. Relative to Australia’s total coal production of 2.3bn tonnes from 2005-2011, the subsidy amounted to A\$1.25/t (US\$.91/t) – not an insubstantial amount. Australia’s coal mining sector also receives a A\$1.92/t subsidy via the fuel-tax levy exemption – see section 2.1.2. In addition, the mining industry of Australia has been very effective at avoiding material rehabilitation bond requirements and at deferring mine rehabilitation costs beyond the end of mine life, with a regular externalization of this cost back to the Australian government. Assuming half the cost of coal mine rehabilitation is externalized, this equates to another A\$2.05 (US\$1.50) per tonne of effective subsidy, giving a total Australian coal subsidy of A\$5.22/t (US\$3.81).

2.1.1 Tax deductions and benefits

A breakdown of the OECD report findings:

³¹ <http://www.oecd.org/site/tadffss/>

- Accelerated depreciation for coal-mining buildings of A\$194m over 2005-2009, an average of A\$39m per year (this scheme allowed the depreciation of a building over 10 years or the mine life, whichever was shorter, and was in effect from 1982 till its phase out for new buildings in 2001. The concession still applied to existing buildings after 2001, and ran to 2009);
- Capital expenditure deductions for coal mining of A\$27m over 2005-2011, an average of A\$4m pa. This concession was phased out progressively after 2001;
- The immediate write-off of exploration and prospecting costs of A\$87m over 2006-2011, an average of A\$15m pa;
- The “National Low Emissions Coal Initiative” of A\$110m over four years to 2011/12;
- Government support of the Clean Coal Fund of A\$381m over 2007-2011, an average of A\$76m pa;
- Government costs of the NSW Clean Coal Fund of A\$61m over 2009-2011, averaging A\$20m pa;
- Government support for the NSW Derelict Mines Program of A\$9m over 2005-2011;
- Government support for the “Collingwood Park Mine Subsidence Package” of A\$19m over 2008-2011, an average of A\$5m pa. Normally subsidence is covered by the appropriate coal mining company responsible;
- The Australian government’s 2011/12 A\$219m “Coal Sector Jobs Package”,³² which aimed to provide up to A\$1.26bn over five years of funding for targeted transitional assistance to the most fugitive emissions-intensive mines to ease their transition to the introduction of a carbon price.³³ The repeal of the carbon price possibly saw this associated subsidy cut;
- Government support for the New Frontiers Program of A\$10m over 2006-2011, an average of A\$2m pa to expand Australian coal export markets; and
- Support for the Coal Industry Development Program of A\$33m over 2006-2011, an average of A\$6m pa (this scheme aimed to expand coal companies’ international market opportunities).

The Research & Development Tax Incentive is another tax support available to all Australian businesses.³⁴ No breakdown is made public on the use of this tax incentive by the coal mining industry, although we note that BHP Billiton reports an average global tax deduction for “investment and development incentives” of US\$235m annually over the three years to 2014 (for all businesses, not just coal mining). Rio Tinto has claimed aggregate tax deductions for “research, development and other investment allowances” of US\$65m annually over the past three years. We have not incorporated this given its hard-to-quantify nature.

The OECD-IEA report noted above also details how the Australian coal-fired electricity sector benefited from the “*Develop Australia Bonds*” program (tax deductible infrastructure bonds). This scheme was later replaced by the “*Infrastructure Borrowings Tax Offset Scheme*” that ran from 1997-2004. Given that coal-fired power plants have a useful life of 40-50 years (in the absence of appropriate emissions legislation), this tax subsidy for financing was utilized heavily by the very thermal power sector that now claims renewable energy should not be given any upfront capital subsidies. Again, due to quantification challenges, we have excluded it in terms of the per tonne benefit.

Australian funding of clean coal research, development and deployment (RD&D)

³² <http://www.pc.gov.au/research/recurring/trade-assistance/2011-12/trade-assistance-review-2011-12.pdf>

³³ <http://www.bulletpoint.com.au/coal-sector-jobs-package/>

³⁴ <http://www.business.gov.au/grants-and-assistance/innovation-rd/RD-TaxIncentive/Pages/default.aspx>

The state and federal governments of Australia have been handing out subsidies and grants for funding of clean coal for the past three decades. One example of the beneficiaries, Exergen, which has been exploring proposals for many years with the promise it has “developed a proven breakthrough clean-coal technology” that can dewater Victorian brown coal by up to 40%.³⁵

Despite many promises and multiple rounds of government grants and subsidies, these ‘clean coal’ technologies remain largely unrealized. The IEA’s 2015 Edition of “Projected Costs of Generating Electricity” report excludes CCS from its mainstream analysis, citing failure of the industry to advance commercial propositions in the last five years. In any industry, a going concern must invest some current revenues to develop new technologies that will generate its future revenues. When this responsibility is shifted to the government, it is properly counted as a subsidy. Whether or not the spending is productive is a secondary issue.

Victoria’s Advanced Lignite Demonstration Project

The A\$90m Advanced Lignite Demonstration Project in the Latrobe Valley of Victoria, announced in August 2012, is a partnership between the Australian and Victorian governments to subsidize the research, development and deployment of emerging technologies meant to improve the economic recovery of brown coal and to reduce emissions from coal-fired electricity generation. The program is administered by the Victorian Department of Primary Industries. The stated goal is to pursue the development of less emissions-intensive coal by upgrading technologies that include direct conversion, dewatering of coal, and conversion to higher-value energy products.³⁶

Australia’s Coal Mining Abatement Technology Support Package

In July 2012, the Australian Government commenced the “Coal Mining Abatement Technology Support Package” for a proposed A\$70m over five years to complement and support the coal industry’s research activities aimed at developing safe abatement technologies and processes to reduce fugitive methane emissions from coal mining. Funding will be directed at three elements:

- research, development and demonstration of technologies and processes associated with coal mining greenhouse gas mitigation including the measurement and monitoring of emissions, avoidance and abatement technologies;
- work to address safety and regulatory issues associated with the development and deployment of greenhouse mitigation related technologies, equipment and processes; and
- assistance to small coal sector participants for the development abatement strategies or the conduct of feasibility studies to reduce emissions from current and proposed mines.

While research does not always deliver the expected benefits in the expected timeframe, it is probably a good idea for the Australian government to re-evaluate the extent of its funding of multiple ‘clean coal’ proposals and to consider the actual progress delivered versus the promises made. As a general principle, a mature industry that has been around for a century should be funding its own research.

³⁵ <http://www.exergen.com.au/home.html>

³⁶ The Australian Productivity Commission [Report](#), 2011/12, page 49.

<http://www.pc.gov.au/research/recurring/trade-assistance/2011-12/trade-assistance-review-2011-12.pdf>

Australian government support for the Callide CCS Project

In December 2012, the Australian Minister for Resources and Energy announced an additional A\$13m of funding for the Callide Oxyfuel project.³⁷ The funding is intended to facilitate an extension of the demonstration phase of the project by 15 months. The Queensland-based project aims to demonstrate “how oxyfuel carbon capture technology can be applied to traditional coal-fired power stations to significantly lower CO₂ emissions” The retrofit technology is supposed to reduce carbon dioxide emissions on a 30MW pilot plant by 30%.

2.1.2 The Australian Fuel Tax Credit Scheme – a A\$2.4bn pa mining subsidy

The Australian government hands out more than A\$6bn annually under its Fuel Tax Credits Scheme, and an April 2015 report by ACF³⁸ estimates that the mining industry receives 40% of this subsidy, or A\$2.4bn per year. In 2012/13, coal miners got an estimated 32% of this, or A\$767m (US\$560m). Relative to total coal (thermal and coking coal) production in Australia over 2012/13 of 399Mt, this equated to A\$1.92/t (US\$1.40/t).

The private, mostly foreign-owned coal-mining industry operating in Australia argues that this isn't a subsidy. As noted in Figure 7, however, most OECD member countries levy considerable taxes on petrol use. Exempting Australian coal mining from paying a tax the rest of the developed world pays means Australian producers are getting special treatment. In arguing for a level playing field for fossil fuels to compete with renewables, removing a special interest group tax exemption seems like a sensible place to start. The Australian government is subject to intense annual pressure from mining companies to retain this subsidy.³⁹

The Fuel Tax Credit was the 15th biggest spending program of the Federal Australian Government.⁴⁰

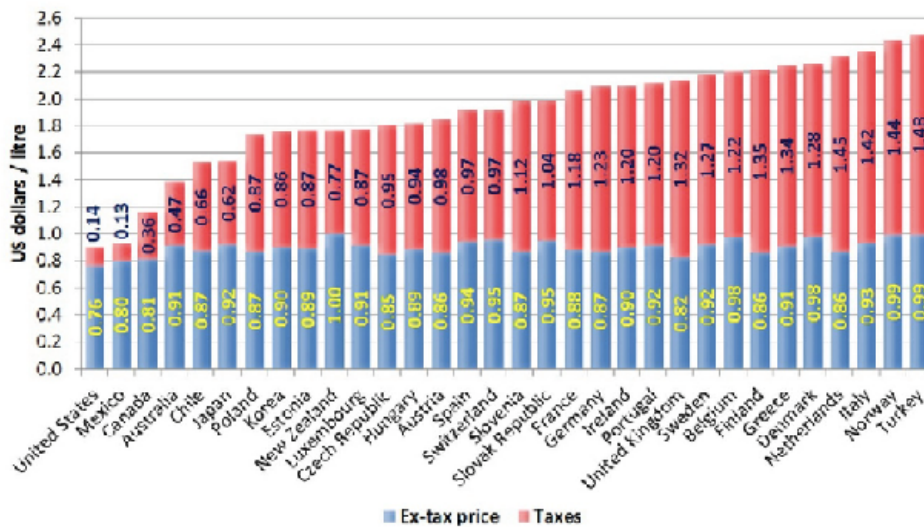
Figure 7: Petrol Taxes in the OECD

³⁷ <http://www.pc.gov.au/research/recurring/trade-assistance/2011-12/trade-assistance-review-2011-12.pdf>

³⁸ The Australian Conservation Foundation (ACF), “Subsidizing Big Coal: Handouts to Australia’s biggest coal mining companies through the Fuel Tax Credits Scheme”. April 2015.

³⁹ http://www.afr.com/p/national/worried_bhp_ceo_pressed_hockey_to_byOkNSIXbue5I2qIxnFZPP

⁴⁰ The Treasury, Budget 2014-15, Budget Paper 1, Statement 6: Expenses and Net Capital Investment, Table 3.1: Top 20 Programmes by expenses in 2014-15. http://budget.gov.au/201415/content/bp1/html/bp1_bst6-01.htm



Source: IEA second quarter 2014⁴¹

2.1.3 Mine rehabilitation

Another major form of coal mining subsidy stems from the general failure of the coal industry and regulators to properly reflect the impact of end of mine life closure and the associated rehabilitation costs.

While some rehabilitation is done progressively as coal is mined, the vast majority of rehabilitation work (upwards of 70%) is left until after mining ceases. The increasingly spurious logic behind this tradition is that if coal prices were to return to levels seen in 2010-2012, then mining companies could return to exhausted mine areas and to access hitherto uncommercial deeper coal seams. More to the point, putting an end of life mine on care and maintenance for a decade defers the expenditure of hundreds of millions of dollars that a mining company would otherwise have to spend on cleanup.

Given that governments are usually keen to attract new greenfield projects, and to also extend the life of existing projects, the approval process regularly sees concessions made to mining companies. One of the major concessions is in the upfront funding of rehabilitation bonds. These bonds are meant to serve as security to cover outstanding clean-up liabilities. The regulatory logic of an upfront bond is sound – the company is keen to access a public resource for private gain, and by any reasonable standard should factor in the clean-up cost. However, if a coal miner is able to negotiate a small bond, or alternatively underestimate the liability, or offer bank guarantees, letters of credit, surety bonds or self-bonding assurances in lieu of putting any real capital on the line, the cost of rehabilitation can be deferred and ultimately potentially transferred from the mine owner to the general public should the mining company fail.

Given that rehabilitation costs per mine often extend into the hundreds of millions of dollars (and a book value of liability of US\$2.5bn for a large coal company like Peabody Energy)⁴², the subsidies here are material. The taxpayer risks are further increased because end-of-life mines are generally put in care-and-maintenance mode for a decade or more, again with the view that possibly spending

⁴¹ <http://www.macrobusiness.com.au/2014/07/aussie-petrol-taxes-4th-lowest-in-oecd/>

⁴² Peabody Energy 2014 Annual Report <http://www.peabodyenergy.com/content/172/publications>

money in a decade's time is a much better deal for existing shareholders than the certainty of spending it immediately on mine closure and cleanup.

Leveraging the work of Lachlan Barker⁴³, IEEFA estimates opencut coal mine rehabilitation costs at over US\$2-3/t of product coal. Not overly material relative to the value of thermal seaborne coal at US\$60/t, but for a hypothetical large mine producing 15Mtpa over a 20-year life operating at a gross cashflow breakeven, this is a US\$600-900m cost in aggregate over the mine life. For an opencut mine with a strip ratio of 6 Bank Cubic Metres (BCM) per tonne of coal produced (a 6:1 BCM:t ratio), this 300Mt of coal involves the movement of upwards of 4bn tonnes of overburden (a BCM is a volumetric measure that equates to 2-2.5 tonnes). When mining experts like Wood Mackenzie model the gross cash cost of a tonne of coal, rehabilitation costs are generally not included. Like interest expense and corporate tax, this cost is deemed a financing corporate cost, not an operating cost. Regardless, this is a capital cost that is regularly externalized to taxpayers.

Rehabilitation cost issues are increasingly relevant to any evaluation of coal mining, however, given the size of costs that can be externalized to the public without careful oversight. The issue of "self-bonding" is being heavily debated as it relates to US coal majors like Peabody Energy, Alpha Natural Resources and Arch Coal, given their increasing evidence of actual or likely financial distress.⁴⁴ In Australia, attention is increasingly focused on the estimated 50,000 abandoned and un-rehabilitated mine sites across the country. With more than 20,000 coal miners retrenched since 2012 across NSW and Queensland, calls have grown to provide employment support for affected communities. If coal mining companies are held accountable for their mine-closure costs, coal miners can be redeployed to rehabilitation projects for upwards of a decade, facilitating the community transition needed.

Dr. Corinne Unger, a leading Australian mine rehabilitation expert, estimates that Australia has over 50,000 unremediated mine sites.⁴⁵

An independent analysis of Australian mine closure and rehabilitation liability published in May 2015 by Lachlan Barker estimated Australian mining has left taxpayers with at least A\$18bn of rehabilitation liabilities.⁴⁶ We have worked this through to put this in terms of a per tonne cash cost. Starting with the Australian average open cut coal mining stripping ratio of 6:1 BCM/tonne, this means that for 1,000t of coal produced, 6,000BCM are moved. With a single operator working at A\$375/hour fully loaded, and able to move 550BCM/hour, this means the cost to replace 6,000BCM is A\$4,100. This translates to A\$4.10/t. With rehabilitation bonding covering only a small percentage of the total rehabilitation cost (estimated at 10-20%), and most rehabilitation deferred by operating mining companies, the historic externalization of this cost is estimated at upwards of 50% of the total cost. Taking half as a subsidy translates to A\$2.05/t (US\$1.50/t).

Beyond the cost of straight filling final voids (Rio Tinto in March 2015 estimated the cost to fill its 950 hectare final void alone at A\$2bn (US\$1.4bn)), replacing topsoil and re-establishing vegetation and fixing subsidence, another key issue with rehabilitation is that 'acid mine drainage', where overburden and mining chemicals leach into the water table, and toxicity often remaining or re-emerging for decades post mine completion.

⁴³ <https://independentaustralia.net/business/business-display/who-will-pay-the-178-billion-mining-rehabilitation-bill,7772>

⁴⁴ <http://www.smh.com.au/environment/climate-change/peabody-shares-dive-after-moodys-cuts-biggest-us-coal-miners-credit-rating-20150628-gi05r5.html>

⁴⁵ https://www.churchilltrust.com.au/media/fellows/UNGER_Corinne_2009.pdf

⁴⁶ <https://independentaustralia.net/business/business-display/who-will-pay-the-178-billion-mining-rehabilitation-bill,7772>

The Queensland Department of Environment and Heritage Protection (EHP)'s published statistics show that 190,000 hectares have been mined, while only 66,000 hectares or 35% have been rehabilitated. That leaves 65% of all mining areas in Queensland unrehabilitated and 16bn cubic meters of overburden left in situ.

Another report, by Mike Seccombe in May 2014, detailed how Australian miners have for many decades kept regulators un-informed and incapable of regulating the industry, and didn't even properly track what little rehabilitations bonds were actually lodged.⁴⁷

In April 2014 Andrew Greaves, the Queensland Auditor-General, published a related report, effectively delivering an "F" to the State regulators involved in managing the mine rehabilitation process for their 15,000 unrehabilitated mine sites for which they are responsible.⁴⁸ The report concluded the following:

"EHP is not fully effective in its supervision, monitoring and enforcement of environmental conditions and is exposing the state to liability and the environment to harm unnecessarily... Environmental rehabilitation at the expense of those in the mining industry whose activities cause the damage continues to remain an unrealized aspiration."

The NSW Audit Office's 2012 Annual Report suggests that similar issues abound there, too:

"The Derelict Mines Program has many thousands of hectares of degraded and contaminated land where mining companies abandoned mines without cleaning up or stabilizing the sites."

Lanco Infratech of India owns the 3-4Mtpa domestic Griffin Coal Mine in Collie in Western Australia. The mine has operated for decades, producing well over 100Mt of coal, but has a remediation provision of a mere US\$0.1m. The mine has a long-standing, special dispensation under a Western Australia parliament action that exempts it from having to carry rehabilitation bonds. However, even senior management of Lanco admits the mine is probably not viable.⁴⁹ To complicate matters, the listed Indian parent entity has been in a corporate debt restructuring program since the end of 2013 due to extreme financial leverage and ongoing losses.

The sale of closed mining sites by global mining majors to private firms of unknown but limited financial capacity is the standard way to dodge the rehabilitation liability. The July 2015 "sale" of the closed Wilkie Creek coal mining site in Queensland for a reported US\$10-20m by Peabody Energy to the private Exergen Pty Ltd frees Peabody of an associated US\$55m liability relating to rehabilitation costs and take-or-pay infrastructure obligations.⁵⁰ The transaction should be reviewed by the Queensland government to evaluate the unfunded rehabilitation liabilities incurred by Peabody, but no such review process exists. For Australian readers, this practice is reminiscent of the famous and widespread bottom of the harbour tax dodge of the 1970s and 1980s by which company assets and accumulated profits were stripped prior to payment of taxes due; the entity sold to a shell corporation; and creditors left with nothing. It is notable that this type of transfer became a criminal offense in 1980.

⁴⁷ https://www.thesaturdaypaper.com.au/news/politics/2014/05/24/minings-multi-billion-dollar-black-hole/1400853601#.VZJ_Mtlw_Z4

⁴⁸ <https://www.qao.qld.gov.au/files/file/Reports%20and%20publications/Reports%20to%20Parliament%202013-14/RtP15Environmentalregulationoftheresourcesandwasteindustries.pdf>

⁴⁹ <http://www.colliemail.com.au/story/2807192/lanco-tells-indian-media-griffin-is-nearly-unviable/?cs=814>

⁵⁰ <http://www.smh.com.au/business/mining-and-resources/peabody-sells-shuttered-aussie-coal-mine-that-nathan-tinkler-had-failed-to-buy-20150708-gi87qm.html>

Mine rehabilitation case study: Australia - Hazelwood

In October 2014, Dr Nicholas Aberle of Environment Victoria released a report evaluating how the 2014 Victorian Hazelwood mine fire disaster occurred in an area of supposedly rehabilitated former brown coal mining lands.⁵¹

GDF Suez (now renamed ENGIE) of France is the owner and operator of this mine-mouth power generation facility. The overall cost of the fire was estimated at over A\$100m, even ignoring the long term community health issues that will arise. GDF Suez has also refused to pay even direct A\$18m fire-fighting bill that would cover some of the costs of deploying 7,000 firefighters working for 45 days straight to contain the fire.⁵² It is also very material that the rehabilitation bond held by the Victorian government is only A\$15m, a fraction of real economic cost. As seems standard regulatory practice, the Victorian government had not conducted any assessment of ENGIE's rehabilitation work nor even engaged in any substantive correspondence with mine management. The resulting litigation over cost recoveries is likely to provide a telling case study on this whole issue.

⁵¹ <http://environmentvictoria.org.au/newsite/sites/default/files/useruploads/Preventing%20the%20Preventable.pdf>

⁵² <http://www.businessspectator.com.au/news/2015/7/7/policy-politics/fire-fight-over-cost-hazelwood-mine>

2.2 Powder River Basin, US

This section reviews federal subsidies to coal in the United States, as well as those to activities specific in the PRB region in the states of Wyoming and Montana. By converting national subsidies to a value per ton of coal extracted, we are able to prorate the subsidies to the PRB region.

We have primarily used historical subsidies data as reported by the OECD (2013)⁵³, recognizing that individual subsidy items are phased in and out over time. Some additional support mechanisms were added where data were available. The supports are divided into four main categories: ongoing tax and general spending support to coal; tax and general spending provisions supporting coal that have phased down significantly since the data analysis period; leasing and royalty subsidies; and inadequate provisions for mine closure and rehabilitation.

We estimate that PRB coal benefited from US\$4.17 per tonne of annual production in tax breaks and direct spending over the period analyzed. This combines with a capital subsidy on self-bonding for rehabilitation costs of at least US\$0.78 per tonne and ongoing underpricing of PRB leases due uncontested lease sales – generating an annual subsidy of about US\$2.60 per tonne. Overall support levels are estimated to exceed US\$7.50 per tonne of PRB coal.

2.2.1 Ongoing tax subsidies and direct funding benefiting PRB Coal

Ongoing subsidies benefitting PRB coal include tax expenditures, direct funding of coal-related activities, and public funding of payments to coal miners afflicted with black lung disease. These are summarized below: (Lease and royalty subsidies to PRB production are also ongoing, and described in the section 2.2.3.)

A tax concession called the “excess of percentage over cost depletion” allows coal and lignite mines to claim a fixed depletion charge of 10% of gross income. Deductions for most industries are limited to the actual amount invested. With a coal mine, deductions can greatly exceed invested funds; indeed, the subsidy is estimated to have cost the US government US\$2.3bn over 2005-2011 or US\$327m annually. Tax expenditures vary year-to-year based on production levels and coal market prices.

A tax concession of US\$170m pa over 2007-2011 arises from the allowable credit for ‘clean coal’ facilities development, rising to US\$200m annually more recently.⁵⁴ The credit is available for investments in integrated gasification combined cycle or other advanced coal-based electricity generating technologies.

Accelerated amortization of certain pollution control technology investments by coal-fired power plants under the Energy Policy Act of 2005. The OECD estimated the tax break at US\$106m pa over 2008-2011.⁵⁵ Estimates for more recent years show higher values averaging about US\$360m/year.

Special tax rules allow fossil fuel producers, including coal mines, to deduct costs relating to mine exploration and development immediately. In most industries, these expenses must be capitalized into the cost of the productive asset and amortized over its productive life. This subsidy is worth

⁵³ <http://www.oecd.org/site/tadffss/USA.pdf>

⁵⁴ https://www.jct.gov/publications.html?func=download&id=4663&chk=4663&no_html=1

⁵⁵ https://www.jct.gov/publications.html?func=download&id=4663&chk=4663&no_html=1

US\$200m to the coal sector over the 2007-11 period, or about US\$40m annually.⁵⁶ Tax losses in more recent years are higher, at about US\$100m/year (JCX-97-14).

One of the most damaging legacies of poor coal mining practices is black lung disease, a debilitating illness all too common amongst coal miners. Two subsidies shift the cost of this disease from the mining companies onto taxpayers. While workers clearly need support, the subsidies contribute to understating the real cost of coal production and may also contribute to firms under-investing in better worker protection. In contrast, general disability payments from social security may be taxed as income.

Exemption of Benefit Payments to Disabled Miners out of the Black Lung Trust fund from income taxation. The resultant subsidy was estimated by the Environmental Law Institute at US\$460m over 2002-2010 (about US\$50m pa).⁵⁷ As miners continue to pass away (either from old age or from black-lung related complications), the public support needed has declined (to around US\$15m annually in the forward estimates from 2014).⁵⁸

While disability payments to black lung victims are supposed to be funded through an excise tax on newly mined coal, these collections have been insufficient to cover outlays. As a result, supplemental funding from the US Treasury has been common over the years. Indeed, a detailed review of the black lung program by National Public Radio found that the supplemental funding from taxpayers comprised a larger share of program financing than the fees on industry did, totaling US\$29bn over the 1970-2011 period. This translates to US\$500m annually, or roughly US\$0.55/metric tonne of coal produced over the last four decades.⁵⁹

State-level subsidies to coal are also common. Although many were tabulated in the OECD analysis, where the subsidies occur in non-PRB states, these have not been included. Though these policies certainly affect the basis by which the various US coal deposits compete with each other, they do not directly subsidize tonnage coming out of the PRB.

State-supports within PBR states have been included where data are available. For example, although Wyoming has a state severance tax on coal of 7% of gross value for surface deposits and 3.75% for underground mines, the maximum tax is capped at 60 c/shT and 30 c/shT respectively. This cap costs the state at least US\$80m in revenues (US\$0.22/t) every year.

Some tax breaks to coal are quite relevant to overall US coal production, but not to the PRB. For example, a tax concession to owners of coal deposits allows the coal royalties to be taxed at a much lower capital gains rate rather than incurring the higher rate normally paid on income. This subsidy was first introduced more than 60 years ago (1951) in an effort to boost domestic coal production. Revenue losses are significant: US\$103m annually from 2005-2011, and projected to reach US\$170m by 2024.⁶⁰ However, because only private coal owners face any tax at all on royalty payments, the subsidy is not relevant to federally-owned PRB deposits.

⁵⁶ p. 24 https://www.jct.gov/publications.html?func=download&id=1198&chk=1198&no_html=1

⁵⁷ Environmental Law Institute, September 2013, "Estimating U.S. Government Spending on Coal: 2002-2010, Sara Gersen, Nina Robertson, Sylvia Ghia et al: <http://www.eli.org/sites/default/files/eli-pubs/d23-10.pdf>

⁵⁸ page 26, item 143: <http://www.treasury.gov/resource-center/tax-policy/Documents/Tax-Expenditures-FY2016.pdf>

⁵⁹ <http://www.npr.org/2012/07/05/156302772/what-is-black-lung>

⁶⁰ Item 13, page 22: <http://www.treasury.gov/resource-center/tax-policy/Documents/Tax-Expenditures-FY2016.pdf>

In total, these tax and spending subsidies total nearly US\$1.3bn per year, or more than US\$1.50 per tonne of PRB production.

2.2.2 Expiring or sharply declining tax and spending subsidies benefitting PRB coal

Every subsidy has a political constituency behind it, and battles over subsidy initiation, continuation, or termination can be fierce. Two significant coal subsidies during the 2005-11 period have subsequently been downsized. While these trends can reverse quickly, we have broken them out for added clarity.

Alternative fuel production credits were a major subsidy to coal over the 2005-2011 time frame. OECD estimates total support of US\$9bn, an average of US\$1.3bn pa. The eligibility rules for the tax credits have changed over time, shifting which fuels benefited most. It was heavily utilized by the coal sector during the last portion of its existence – first for synthetic coal, and finally for coking coal (OECD 2013: 373). This subsidy has now been phased out.⁶¹

US government funding of energy-related R&D has been a constant for many decades. Research into fuel-conversion or coal-liquefaction has been ongoing since at least the late 1980s; however, the “2005 Energy Policy Act” and then the “2009 American Recovery and Reinvestment Act” significantly expanded the R&D support.⁶² The OECD estimates that this funding amounted to over US\$1bn annually from 2005-2011, with an acceleration in spending that peaked at US\$3.8bn in 2010. Levels have dropped since that time, with current coal-related R&D, including mostly coal-related CCS research, at about US\$500m/year.⁶³

2.2.3 US coal leasing and royalty subsidies – The Great Giveaway

IEEFA’s June 2012 report “*The Great Giveaway: An analysis of the costly failure of federal coal leasing in the Powder River Basin*” estimates that up to US\$30bn of taxpayer value was given away by the Department of Interior (DOI), through the US Bureau of Land Management (BLM), a DOI agency.⁶⁴ The program was similar in many ways to India’s Coalgate, with the BLM awarding coal leases at well below fair market rates, resulting in lost US government revenues.

A major “red flag” was in clear evidence in the US: since 1991, only four of 26 major Powder River Basin coal sales had more than one bidder, and the small handful that were ‘touted as competitive’ had only two bidders each. This situation arose due to a widespread failure in appropriate oversight: despite their scale, BLM coal-leasing activities were neither audited nor subjected to any publicly available external review for almost 30 years.

These lapses are particularly questionable given that a similar scandal had already erupted in 1982 over the same industry give-away practices. Clear, transparent reforms were laid out in the wake of that scandal by Congress, but were never adequately implemented.

The BLM is responsible for the sale of government-owned Powder River Basin coal. The US government holds an effective monopoly over western coal, which accounts for 40% of total US production. As a result, the DOI is extremely influential, shaping US annual coal production levels

⁶¹ <http://www.treasury.gov/resource-center/tax-policy/Documents/Tax-Expenditures-FY2016.pdf>

⁶² Department of Energy, Recovery Act, <http://www.fe.doe.gov/recovery/index.html>

⁶³ http://energy.gov/sites/prod/files/2015/02/f19/FY16_budget_rollout%202-2-15.pdf

⁶⁴ <http://ieefa.org/study-almost-30-billion-in-revenues-lost-to-taxpayers-by-giveaway-of-federally-owned-coal-in-powder-river-basin/>

and the market price of coal. An example of how the BLM program is disconnected from reality is in the “decertification” of the Powder River Basin, by which its status as an official “Coal Production Region” was annulled in 1990. This removed the requirement for the BLM to have a rational systematic management process for the region. The result has been lower lease prices, with a process where industry, rather than the government, proposes what land is put up for sale. Given that extraction rights for each coal tract sell for hundreds of millions of dollars, the deals are huge.

This is a textbook example of what happens when the government operates with almost zero transparency. As a result of policy choices, and an inherently subjective and flawed fair market value appraisal process, the US Treasury has lost an average of about US\$1bn annually through its coal leasing program over the past 30 years.

The coal boom in electric power generation in America has been fueled by artificially cheap coal from the Powder River Basin. Further, many US coal export programs are effectively being subsidized by US taxpayers because they are driven by underpriced coal taken from public lands. In 2012, the US coal industry projected 12bn short tons of exports by 2035, though current levels remain much lower.

The current BLM lease program allows coal producers to set the terms for the mining, distribution, and pricing of coal. Theoretically, the bid process should stimulate competition among coal producers and this competition should drive prices up to a fair market level. Competition is meant to both augment the valuation and serve as an independent check on BLM’s coal appraisals. Without competition, the appraisal process is inherently flawed. It is well known among industry officials that the BLM’s common practice is to allow lease applicants to buy up coal tracts simply to inhibit competition. Thus, competition between coal producers in the PRB is virtually nonexistent.

With 2012 production from the Powder River Basin of 426Mst, and an estimated US\$1bn pa subsidy evident, this equates to an effective production subsidy of US\$2.59 per metric tonne.⁶⁵

2.2.4 Mine Rehabilitation: ‘Self-bonding’ in America

Because coal mining revenues are often exhausted by the time most costs associated with closing the mine and managing and rehabilitating the site are incurred, the US and other countries have established requirements to ensure funds remain available for these purposes. The risk of producing corporations distributing out revenues via wages, dividends or other payments has always been high; and a corporate bankruptcy could leave the “long-tail” liabilities on the taxpayer, rather than on the company that benefitted from the sale of the coal.

There are a variety of allowable financial assurance models firms can use to comply with their reclamation obligations in the United States. While all create formal promises to cover these costs, the mechanisms vary widely in cost and security. Self-bonding, where a company points to its balance sheet as evidence it can self-finance mine closure and rehabilitation, is the least expensive compliance tool, and therefore usually industry’s preferred option. It is also among the least secure. Although firms must demonstrate adequate financial strength in order to use this approach, company fortunes can change quickly, and with it the viability of the self-bonding payment.

⁶⁵ <http://www.platts.com/latest-news/coal/washington/power-river-basin-producers-finding-it-more-costly-21402408>

Self-bonding has become an increasing worry for the US coal mining industry this year as coal prices have deteriorated and the industry faces extended commercial threats from multiple fronts. The declining fortunes of coal, driven also by top-of-the-cycle acquisitions, excessive financial leverage and unfunded pension liabilities, have led a number of state legislatures to move to enforce more secure funding mechanisms for mine rehabilitation liability. Major pure play coal companies such as Alpha Natural Resources, Arch Coal and Peabody Energy view enforcement of standing rules for them to secure their reclamation obligations as a potential catalyst for Chapter 11 bankruptcy proceedings.⁶⁶

The Wyoming Department of Environmental Quality's Notice in May 2015 that Alpha Natural Resources and its operating affiliate, Alpha Coal West, Inc. no longer qualified for the self-bonding program gave the company 90 days to provide substitute bonding. Self-bonding allows an operator to provide a promise to pay for reclamation costs, provided the company has sufficient tangible net worth. These self-bonding issues apply in at least 12 states, and proper enforcement of existing financial assurance requirements will have material adverse consequences for the companies involved, potentially dumping the liability on taxpayers.⁶⁷ The 2014 Report "*Undermined Promise II*" provides extensive detail on these issues.⁶⁸

The US Surface Mining Control and Reclamation Act of 1977 established requirements for companies to provide for the cost of reclaiming mining operations. In particular, to obtain permits, a bond (including in some states a self-bond) must be posted to cover future reclamation expenses. Bonding is only released once the permitting office is satisfied that no further reclamation is required. The Office of Surface Mining Reclamation and Enforcement (OSMRE) in June 2015 confirmed it was examining all aspects of bonding and self-bonding by coal companies.⁶⁹

In June 2015 Fitch Ratings reported the following: "*Tighter self-bonding requirements for distressed coal entities would reduce liquidity and could hasten restructuring. We anticipate further restructuring in the coal industry given unsustainably high debt balances over the near term.*"⁷⁰

Peabody Energy reported at the end of 2014 that it had US\$1.36bn of rehabilitation liabilities purportedly covered by self-bonding.⁷¹ If this liability were to be funded external to the company (a prudent approach that is used for nuclear reactor decommissioning, for example) Peabody would have to fund operations in another way. As the firm's current cost of borrowing is about 10% annually, the financing costs alone would be US\$136m annually of extra interest. On Peabody's 2014 US production of 178M metric tonnes, this is US\$0.78/t of coal sold.

In addition, Peabody had US\$1.12bn of surety bonds with third parties, bank guarantees and letters of credit covering various liabilities, unfunded retired worker pension liabilities of US\$0.84bn and net debt of US\$5.5bn. When put in the context of US\$1.9bn of net losses over 2012-2014 and a market capitalization of equity of only US\$323m,⁷² financial leverage combines with the reported losses to put the funding of rehabilitation liabilities at risk. Indeed, consistent with the warnings from Fitch

⁶⁶ <http://www.reuters.com/article/2015/04/16/alpha-ntrl-resc-bonding-idUSL2N0XD13E20150416>

⁶⁷ <http://ieefa.org/ample-evidence-in-at-least-12-states-that-coal-companies-are-in-no-position-to-meet-their-cleanup-commitments/>

⁶⁸ <http://www.underminedpromise.org/UnderminedPromisell.pdf>

⁶⁹ <http://www.reuters.com/article/2015/06/04/usa-coal-bonding-idUSL1N0YC17N20150604>

⁷⁰ <https://www.fitchratings.com/gws3.0/fitch-home/pressrelease?id=986698>

⁷¹ Peabody Energy 2014 Annual Report, page 24.

⁷² Calculated using Bloomberg at a share price of US\$1.16 on 13 August 2015.

Ratings, there is a real question as to whether Peabody even has sufficient access to capital markets to cover this liability.

Along with other problems, this calls into question the company board's fiduciary duty in continuing to pay almost US\$100m annually to its shareholders in dividends through November 2014.

In July 2015 the Wyoming Department of Environmental Quality ruled that it had somehow found that Peabody Energy still qualified for self-bonding, despite the company's 2014 consolidated annual report detailing US\$16bn of total liabilities outstanding.⁷³

IEEFA notes that Alpha Natural Resources likewise had an apparently unfunded US\$640m Asset Retirement Obligation outstanding in its 31 December 2014 balance sheet.

We have used this Peabody specific calculation of US\$0.78/t of extra interest costs as an estimate of this hidden and unfunded leverage that has in fact been a capital subsidy from the US government to coal mining company shareholders. For any business with front-loaded revenues and large end-of-life liabilities, this strongly suggests government regulations for the operation of an external sinking fund structure that will survive even a corporate bankruptcy. With the Office of Surface Mining and Reclamation now calling out this unfunded capital subsidy, the financial consequence for US coal mining companies is dire.

The issues relating to self-bonding of mine related entities has been long discussed. IEEFA published a report in October 2013 (with the Sierra Club and Public Citizen) detailing how US\$1bn of self-bonding was in place and clearly at risk in Texas with Energy Future Holdings.⁷⁴ In May 2014, the firm went into Chapter 11 bankruptcy as direct result of a failed 2007 leveraged buyout. If an appropriate rehabilitation bond program had been in place, these liabilities would not have been unfunded going into Chapter 11.

⁷³ <http://www.miningweekly.com/article/peabodys-wyoming-mines-eligible-for-self-bonding-subsidy-2015-07-08>

⁷⁴ <http://ieefa.org/press-release-energy-future-holdings-1-billion-bonding-for-texas-mines-doesnt-pass-the-smell-test-public-citizen-sierra-club-call-for-action-to-protect-taxpayers/>

Coal subsidies benefiting PRB coal production					
	Total Subsidy (millions USD)	Time unit	Total per year (millions USD)	Per tonne-year (USD) <i>Note 1</i>	Subsidy Trend
<u>Tax subsidies and direct funding, ongoing</u>					
<i>Federal tax expenditures related to coal</i>					
Excess of % over cost depletion for coal	2,288	2005-11	326.8	0.36	Fluctuates with production levels
Tax credit for investment into clean coal facilities	850	2007-11	170.0	0.19	Higher
Accelerated depreciation of pollution control equipment	530	2007-11	106.0	0.12	Higher
Federal - Expensing of coal mine exploration & development	200	2007-11	40.0	0.04	Higher
Per-ton caps on WY coal severance taxes		2013	80.6	0.22	Fluctuates with market price
WY Advanced coal conversion task force	33	2007-11	6.5	0.02	
<i>Subsidies to coal-caused health and environmental damage</i>					
Taxpayer funding of black lung costs		1970-2011	500.0	\$0.55	Long-term decline as miners die
Income tax exclusion, payments to disabled coal miners	460	2002-10	51.1	0.06	Long-term decline as miners die
<i>Total, ongoing tax and direct funding</i>			1,281.0	1.56	
<u>Tax subsidies and direct funding, phasing down</u>					
Alternative production fuel tax credits	9,050	2005-11	1,292.9	1.43	Expired
Federal funding of coal R&D	7,463	2005-11	1,066.2	1.18	Current funding about 1/2 this level
<i>Total, phasing down tax and direct funding</i>			2,359.0	2.61	
<i>Total, tax and direct funding</i>			3,640.0	4.17	
<u>PRB coal lease subsidy</u>	30,000	1983-2012	1,000.0	\$2.59	Stable
<u>Inadequate financial assurance mechanisms to cover mine closure and rehabilitation</u>					
Reduced cost of capital from self-bonding despite bankruptcy risks	2,000-4000	Multiple year period		\$0.78	Expected to rise sharply
<i>Total, all subsidies benefitting PRB coal</i>				7.54	
Notes:					
(1) Federal data converted into subsidies per tonne of PRB coal using national coal production values; WY and MT subsidies allocated to PRB using intra-PRB coal production. Coal subsidies in other states support continued use of coal in the country, but were not counted here.					
Sources:					
OECD (2013); Sanzillo; NPR black lung data analysis; Joint Committee on Taxation JCX-97-14.					

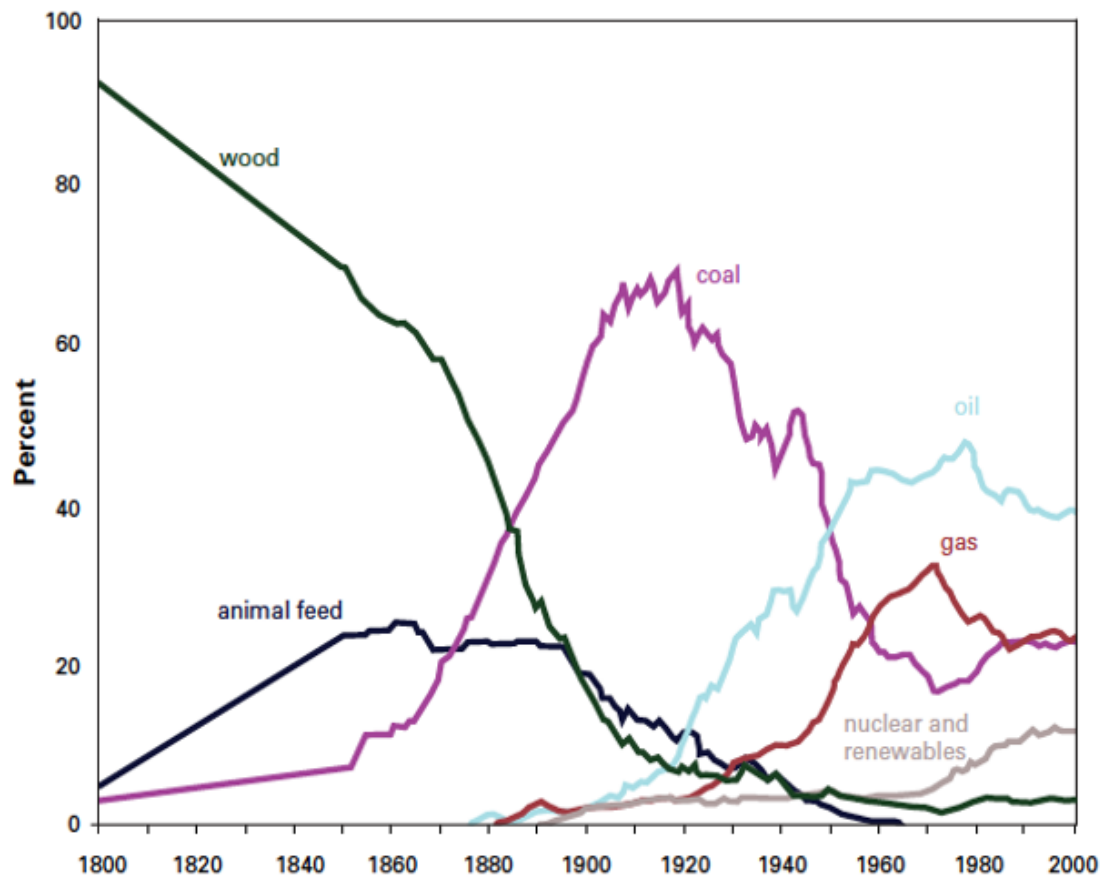
3. Looking at the impacts of subsidies on thermal coal demand using the price elasticity of demand

3.1 The Context – The Energy Transition

In many respects any analysis of the impacts of subsidies today on coal demand should be put in the longer-term context of energy transitions. Existing subsidies today are just one aspect of a 150 year story for coal – rising to a peak share of the energy system at the turn of the 20th century but then scaling up volume along with oil until present.

3.1.1 The historic context – Energy Transitions

Figure 8: The US energy mix over time



Source: Energy Bulletin; US EIA; DeAM analysis, 2008.

Here we see massive “substitution” as new technologies emerge and replace older ones. These are the mega infrastructure trends that were driven by infrastructure development, relative prices and many forms of subsidies, some which Section 1 touches on.

This also illustrates the issue of time frames that will become important when trying to estimate impacts.

3.1.2 Substitutes today

Indeed the simple idea of looking for the impacts of subsidies in coal uncovers a rich area of analysis that goes to the heart of the “energy transition”. One of the key drivers of the impact that we will look at is the “substitutability” of coal with other fuel sources. The more substitutes that are readily available and deployable at increasingly commercial rates, the more any increase in coal's price will reduce demand through substitution, which is what we are looking for in terms of impact analysis.

As a result we arrive back at the critical question of an energy transition in power markets. Thermal coal is essentially a power market fuel – electricity production dominates its use. The key new technologies that are in play to compete with and substitute for coal in electricity markets, which would lead to a higher price elasticity of demand relative to price, are:

- Wind power, both from onshore and increasingly offshore applications
- Solar Power – centralized and distributed
- Technologies to expand production of natural gas supplies
- Nuclear – controversial in many ways but still being considered
- Storage for intermittent power supplies – in many ways this is now seen as key to significant renewable scale up at the distributed level
- Smart grids to optimize the combination of technologies
- Energy Efficiency technologies to reduce end use of power – this impact cannot be underestimated

On top of technology, in the case of seaborne coal in the Indian and Chinese markets, domestic coal (while not climate friendly) is a key competitor.

This competition and substitution will be at the core of the impact on demand for any change in price. There will be rapid shifts in response in this environment. Indeed those shifts are also likely to be nonlinear – at the extreme the use of coal could simply diminish under regulation without a direct price signal.

3.1.3 The Role of Policy

Indeed, as is always the case in energy markets, regulation and policy play a key role. New technologies often need incentives to reach production scale and deployment, which lowers their cost. Old technologies, including coal, often continue to receive policy support on both the production and consumption sides of the market.

To better understand how substitute technologies can challenge coal we examine the incentive supports for those and the structure of the power markets they are being deployed in. However, this is a massive topic and evolving constantly. We can only focus on some key aspects in this study.

As mentioned above, the most fundamental regulation is one that essentially mandates the reduction of coal use in power markets. The closest we have for this is the New Source Performance standards of the US EPA. Essentially coal plants have to meet the emissions of natural gas plants or they can't be built.

3.2 The role of production subsidies in Australia and the US Powder River Basin (PRB) – a framework to assess the impact.

This section evaluates how the coal subsidies presented in Section 2 are likely to affect coal markets and carbon emissions. We focus on the impact of the subsidies for thermal coal in the PRB and how these interact with the US domestic electricity market; and those to coal in Australia as an example for export Seaborne coal markets and how these interact with their export electricity markets – with a focus on China, India and Japan to show their potential impact on thermal coal demand.

3.2.1 Two Approaches

There are two main approaches to assessing the impact of removing coal subsidies on demand of coal and within that context carbon as other forms of primary energy replace coal:

1. a detailed, bottom-up modelling of the electricity sector.
2. a broader, long-term focussed, demand estimation based on long-term elasticities of demand.

Each approach has its merits and this work lays out the methodology, benefits and drawbacks of both approaches.

Background

In the case of thermal coal, the end market is electricity so it is the dynamics of and within those electricity markets that determine thermal coal demand and emissions. The major issue for either approach is time frame. In the short term, the asset stock is fixed and focusing on this time frame would tend to miss the more important and impactful long-term dynamics of fuel switching, which often take more of a 20 year time frame to work through as the asset stock turns over.

Short-term impacts could surface via higher electricity prices, lower profits to generators and distributors and possibly a change in the merit order of coal plants. This would tend to have a lower impact on overall coal demand unless coal plants get pushed out far in the merit order, which in the case of the US for instance requires a large decrease in the ratio of natural gas to coal prices.

Longer-term impacts are showing the added flexibility of switching energy sources. Lower cost fuels and renewable energy sources will gain competitiveness when coal subsidies are removed and coal prices rise, which can lead to foregoing new construction, refurbishment or retrofitting of coal-fired power plants in favour of constructing new power plants relying on other fuels and renewables. This effect can be accelerated by increasing regulation, particularly environmental standards, covering coal-fired power plants as the timing of additional investment to retrofit is pulled forward. Removing subsidies today can therefore speed up the transformation of the power sector towards using cleaner fuels and more renewables, a trend that is already observed in US power markets in particular.

From a climate/carbon perspective it becomes critical whether substitution is for other types of coal, gas, or much lower carbon fuels such as renewables and nuclear. The focus here is on replacing coal with lower- and no-carbon alternatives. Energy efficiency will also play a role particularly in relation to the potential rise in electricity prices.

Detailed, bottom-up modelling approach

The first approach is a detailed dispatch model of the electricity system to evaluate the changes in the merit order of coal plants to identify which proportion of coal-fired capacity becomes more costly than alternatives including dispatch modelling. This would look at:

- The current status of the electricity markets for PRB and Australian coal to identify the merit order
- The current and predicted future of renewable and natural gas prices
- The coal-price increase induced by removing subsidies, including accounting for coal-on-coal competition if subsidies are not removed throughout the coal supply sources
- A stock-take of the need to upgrade, refurbish or retrofit existing coal-fired capacity, accounting for the age and environmental performance of the fleet and combining with existing and announced regulatory requirements, particularly environmental standards

The final step is to compare key price points of the various fuel supplies (which raises the issue of relating long-term Levelized Cost of Electricity (LCOE), which includes capital costs, to the actual marginal price used for dispatch which does not). This would capture increased coal costs and be most relevant for deciding if new coal-fired generation would be built and provides an overview of the coal-fired power plants that are at risk of being replaced by other generation capacity and the corresponding impacts on Australian and PRB coal-demand and emissions.

Dispatch models capture these interactions and can be used to compare the impacts on coal-fired generation and coal demand. Additional detailed modelling, energy-sector optimization models, such as MARKAL or PLEXOS, can be used to estimate the changes occurring in the electricity generation mix under different price and cost assumptions to evaluate how an increase in coal prices feeds through into demand changes. These models are available, and their calibration and estimation of impacts could form part of a more extensive modelling exercise. Depending on the exact methodology, combined with dispatch models to capture both the short-term and long-term impacts, these models can quantify the extent of coal substitution not only by alternative fossil fuels but also by renewables.

Long-term elasticity of demand (Ed) approach

The second approach is a general economic approach looking at the elasticity, frequently in terms of price elasticity of demand in relation to a supply curve. A body of literature from both academic and government sources uses this approach to account for the short-term impacts of price changes. The break-even price of the coal supply curve shifts by the impact of removing the subsidies as costs increase. Thermal coal demand is estimated in terms of a demand curve and is based on the evaluation of the underlying electricity market:

- The elasticity of demand will have to encapsulate the same forces that the dispatch model is also trying to deal with in electricity markets. This can be represented by varying the shape of the demand curve and, in particular, its elasticity
- Short term, the elasticity will be linked more closely to potential demand reductions from rising electricity prices. Elasticity will be lower, reflecting a more muted impact of price changes on coal demand
- Longer term the substitution/fuel switching is more relevant due to turnover of capital and contracts. This flexibility can be represented by using a larger elasticity; higher values for longer time horizons are the norm.

We have chosen to use this general economic approach. The analysis uses CTI's 2014 supply and demand analysis of coal; the work incorporates recent economic theory and empirical facts. This approach builds from coal supply curves estimating break-even prices and a starting estimate of coal demand developed previously by Carbon Tracker. These supply curves are estimated for the period 2014-35, a long time horizon in which the asset stock can turn over and fuel substitution options grow. Fuel switching and renewables become important as recent declining cost trends particularly in the renewables sector take hold, and a higher elasticity of coal demand is warranted. Our key task in this paper is then to estimate the range of elasticities of coal demand from the forces in the electricity markets to combine it with the estimated cost increase of removing subsidies.

The strength of this approach is the encompassing way in which the trends we set out are included in the elasticity and we can apply the framework to multiple markets covered in the 2014 supply study without the need to develop market-specific dispatch and electricity market models for each. There are trade-offs, of course. We acknowledge that a granular dispatch model approach would facilitate capture of those forces specifically in modelling terms and provide a more detailed quantitative estimate and could provide added detail when it comes to estimating carbon emissions avoided. However, our general approach is able to provide high-level estimates of the general trends and a range of impacts rather than point estimates that can be obtained from the first approach. Certainly a follow up study following the more detailed first approach could be useful to narrow down estimates and also distinguish the market impacts by generator and coal suppliers and their market and financial position.

Our results are case studies in terms of ranges of both subsidy removal and demand responses. The approach taken provides a high-level overview of the supply-demand relation in coal markets and a range for the demand reduction of thermal coal and corresponding emissions reduction when coal subsidies are removed and discusses the key drivers and their potential future development.

3.2.2 The starting point: supply and demand

Our focus to take a partial equilibrium approach, using our original work from 2014 on Demand and the Carbon Supply Cost Curve⁷⁵ for thermal coal and then derive an elasticity of demand (Ed) to estimate a demand change. This study focuses on two key thermal coal supply regions and used the supply curves associated with them:

- The US Powder River Basin (US PRB)
- The Australian Seaborne Export market

The partial equilibrium approach combines estimates of the thermal coal supply curve before and after removing subsidies with the long-term coal demand changes associated with thermal coal price changes, allowing for changes in the electricity generation capacity mix:

Supply

The unconstrained **supply curve** of thermal coal, used in the Carbon Supply Cost Curve, is based on the estimates by Wood Mackenzie Coal GEM. This provides the basis of the supply curve. This supply curve is adjusted to reflect removing subsidies, resulting in a new break-even price (BEP).

⁷⁵ <http://www.carbontracker.org/report/carbon-supply-cost-curves-evaluating-financial-risk-to-coal-capital-expenditures/>

Impact on demand

IEEFA long-term estimates for thermal coal based on relevant electricity markets are the starting point to arrive at a 20-year average demand estimate out to 2035. These “point” demand forecasts were then placed on long-term supply curves to 2035 to derive equilibrium break-even prices. The IEEFA demand forecasts contain an assumption on price elasticities of demand based on key assumptions of pricing and fundamental trends between the key fuel substitutes in electricity markets, including policy assumptions.

We follow the second approach outlined in the previous section using the Ed relating to the relevant electricity markets, which shows the % change in demand for a % change in price from removing the subsidies. This will give an impact on demand from varying the supply curve, with the steepness of the supply curve also influencing that result. The results are based on the IEEFA study and refine them to be an estimate of the average 2015-35 Ed to overlay the specific additional impact of varying the cost of subsidies. This relies on relevant literature and heat maps of key drivers in the demand forecasts.

The Ed reflects the significant and increasing impact of economically viable substitutes in electricity generation, including fuel switching (gas, possibly nuclear), renewables and energy efficiency. This work aims to modify the IEEFA demand estimates by the combined impact of the aforementioned substitutes to create an estimate of the changes in demand for thermal coal.

This adjustment depends on several factors:

- Are there other sources of coal readily available to substitute? This will tend to have a larger Ed – likely the case in export seaborne markets
- If there are fewer alternative sources of coal available, then a lower Ed
- The impacts assuming that all coal subsidies, even those not estimated, are removed simultaneously, so the response between different coal sources is restrained – a lower Ed

Section 3.3 examines these and other factors in detail, starting from a literature review to applying a heat map to illustrate the dynamics at play going forward in the next 20 years. This concludes with four case studies of the key drivers of the Ed of thermal coal in the US, China, India and Japan.

These scenarios are the heart of this paper. Assuming all subsidies are removed simultaneously in all coal markets would be considered a stretch in a practical sense. Yet were it achieved at a global negotiated level, such reform might not be impossible. Hence by looking at the incremental gains from broad-based subsidy elimination, we pose this as a policy challenge. Because most coal trade in the US is domestic, significant subsidy removal at the national level is also an important scenario to assess.

Further, we again note that a more comprehensive energy optimization model would attempt to look at all the various substitutes and so include a more comprehensive cost dispatch framework – we have not formally done this at this time. However a benefit of our approach is explaining the key factors and drivers behind our estimates, which we believe is valuable in showing the key assumptions that would underlie a more complex modelling approach

3.2.3 Sensitivity analysis.

Given the uncertainties around the subsidy levels and the Eds within a case study framework, we have also run sensitivity analyses where

- Subsidies are broken down to key levels
- Ed ranges from:
 - a low level of 0.5, reflecting very short-term effects,
 - to 1-2 that is more in line with a longer-term time frame where lower carbon fuels can substitute but there are few coal substitutes, or all coal subsidies are removed simultaneously,
 - up to 3 where other types of coal can also substitute in the long term.

3.2.4 Measuring Carbon – the gross or first order effect

Deriving the carbon impact becomes difficult without a more complex energy optimization model.

We can make a simple calculation of how much carbon is associated with the specific implied amount of supply in response to the Ed. But this is very much a “first order partial equilibrium” result and we do not explicitly model:

- the break down of what substitutes between other types of coal
- gas (around half of coal emissions if fugitive emissions managed)
- and energy efficiency and renewable energy (near zero and over next 20 years we expect the key substitute competitors).

However, in the case of assuming all coal subsidies are removed simultaneously, it might be fair to assume there is not much further coal substitution. Indeed the isolated subsidy effect we would expect might be mostly from gas and renewables – the low carbon options.

We have therefore chosen to show the estimated first order carbon effects relating to the case where all subsidies are removed simultaneously, meaning Eds of 1-2 and further to make an assumption about gas in the case of the PRB.

3.3 A framework for estimating Elasticity of Demand (Ed) and its key drivers

A number of key factors impact US PRB coal and Australian seaborne coal demand in the context of electricity markets. In the short run, changes to coal prices might pass through to electricity prices and reduce electricity demand and, in turn, coal demand, and provide an incentive for increasing energy efficiency.

The long term is the focus of this work and considers the structural changes in the electricity sector, including substitution away from coal. The figure below lists possible drivers of Ed, split into substitutes, regulatory impacts and industry structure.

Drivers of Ed
Substitutes
Other coal
Gas
Low Carbon
Wind
Solar PV
Solar CSP
Nuclear
Diesel
EE
Time
Regulatory
Industry Structure

For substitutes, a key issue is the availability of other types of coal. The most obvious substitute for a higher priced coal is another type of cheaper coal. Substituting one source of coal by another does not reduce emissions. However, thermal coal differs in quality, particularly sulphur content that reduces the degree of substitutability of coal from PRB and Australia for different thermal coal.

The high degree of substitutability across thermal coal also raises the point as to whether subsidies might be removed simultaneously on all types of coal that supply a particular market, up to the global level. Removing subsidies on all coal supplies leaves the relative demand for each type of coal unchanged and likely reduces overall demand for coal, as estimated later on. However, by changing the cost of only selected coal supplies, unaffected coal supplies might take up their market share, potentially reducing the emissions benefits of removing subsidies.

On top of the main focus on substitutes, we have threaded in the following aspects.

- **Regulatory and Policy.** Is coal being directly affected positively or negatively by policy? How are substitutes being treated?
- **Industry structures.** How are the power markets structured? As an example, more deregulated market with more companies active is likely to see more opportunities for substitution than a fully regulated market dominated by a few companies.

The drivers and trends of all of these were set out in great detail in the original IEEFA demand profiles from our study of 2014.

3.3.1 Quantitative studies of Ed – the starting point

Again, classic economic theory would argue for a quantitative analysis using an approach such as regression analysis and evaluating historic trends in the relationship between coal prices and demand. Better still, a complex energy optimization model could be used to integrate this data and illustrate second order effects as well.

Indeed, we started by looking at available studies of the specific markets we are interested in and classifying as to the time period and level of substitution they were looking at:

- PRB coal supplying both the north-eastern and south-eastern power markets in the US.
- Australian Seaborne coal using Chinese, Indian and Japanese electricity markets as key examples of demand sources.

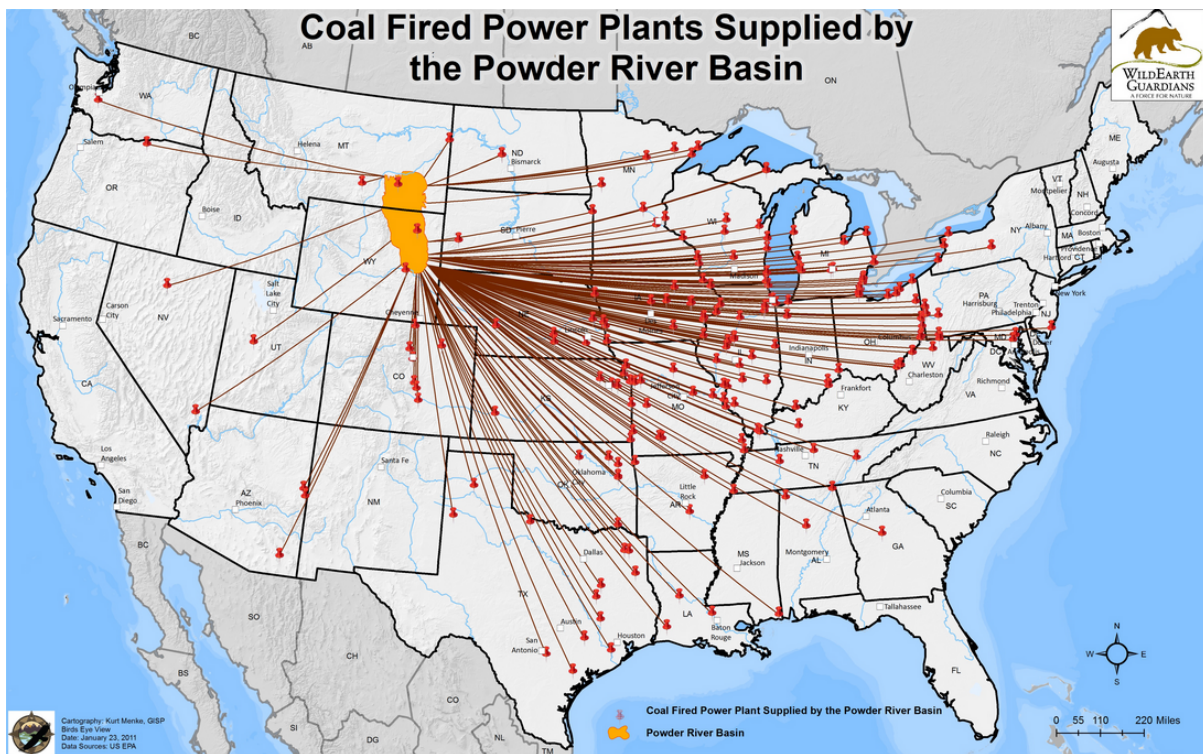
3.3.2 Elasticity of demand in the US Powder River Basin

The price elasticity of demand estimated in the literature often captures the short-term impacts only as the time horizons are insufficiently long to account for changes in the electricity generation mix based on asset turnover. A survey of the literature reveals a limited range of estimates of the price elasticity of demand for PRB coal in the electric power sector, some of which is fairly old and predates competitive pressure from comparatively cheap natural gas. It is important to understand the conditions that these studies take into account, in particular with regards their time frame and how much cross-substitution between coal sources they assume, and under what conditions.

Understanding the structure of PRB coal markets in the US is a first step in integrating the available PED estimates into our case studies.

The US is a ‘coal island’ in the sense that it generates its own supply of thermal coal and has no need to import coal. The PRB coal is shipped to almost all US coal plants, as shown in the figure below. The US has limited trade import and export capital infrastructure (e.g., coal terminals) and so the recent fall in the international coal price has had only a muted price impact on the US ‘coal island’. Nonetheless, trade capacity is rising and as such one should not assume the US market is forever isolated, and also focus attention on subsidization of export capacity that would artificially boost trade and expand domestic coal production.

Figure 9: Coal fired power plants supplied by the Powder River Basin



PRB, located in the US states of Wyoming and Montana, is the single largest source of US coal in the ‘coal island’. The PRB coal market has risen to supply upwards of 40% or more of US coal demand⁷⁶. Between 1990 and 2002 PRB coal more than doubled its output while Illinois Basin coal declined by

⁷⁶ Shelby Gerking and Stephen F. Hamilton, “What explains the increased utilisation of Powder River Basin Coal in Electric Power Generation?”, *Am. J. Agr. Econ.* (2008) 90 (4): 933-950.

42%. Sulphur dioxide emissions fell dramatically at a fraction of the expected cost by using lower sulphur PRB deposits.

Transport costs form a substantial part of the delivered cost of PRB coal at power generating plants. Two railroad companies originate coal from the PRB and ship it up to 1600 miles. At the generating plant gate the PRB coal (from multiple mines) competes with Illinois coal and Appalachian coal, as well as substitute fuel sources such as natural gas and renewables in the broader electricity generation market.

The generating plant coal buyer needs to consider the cost of British Thermal Units (BTU's) delivered per tonne of coal, trading off against heterogeneous variations in coal quality (sulphur content, sodium content and ash production). PRB coal has an advantage over Appalachian and Illinois Basin coal. Appalachian coal has a higher sulphur content (regulated under the sulphur dioxide emission cap with tradable permits) and Illinois Basin coal has a higher sodium content that makes it less attractive for use in some power plant equipment⁷⁷. PRB coal, by contrast, has a lower sulphur and sodium content and is cheap to access due to the open cut mining technique at scale in the PRB and favourable leasing terms with the US federal government. Ash content is another significant issue creating waste management costs, but is not examined in this work. The mine-to-mine variability of PRB coal across a number of key attributes (BTU's, sulphur, sodium and ash) makes it more difficult to manage as a feedstock for power plants compared to more homogenous coal fields⁷⁸.

Elasticity estimates

EIA studies show short-term elasticities ranging 0.3 to 0.5. These studies examine coal and electricity demand and prices over several years, during which the electricity generation capacity mix remains relatively constant. As such, the EIA studies produce short-term elasticities, which are lower than long-term elasticities.

Shelby et al⁷⁹ have attempted to understand the drivers of increased PRB coal demand between 1988 and 1999. Importantly, they documented the role of the transport link in the economics of PRB coal. At the time of their study, strong duopoly characteristics amongst shorter-haul rail lines (up to about 550 miles from the PRB) gave railroads market power over power plants and ultimately decided which coal sources will be used. For longer hauls, the PRB railroads supply coal in competition with coal from other sources and hence the coal market becomes more competitive with distance. Rail costs are up to 80% of the delivered cost of coal. The main reason for the increase in use of PRB coal is the very large fall in mine costs (50%) and rail costs (36%) in this period, extending the area serviced by rail.

Rail costs were influenced by rail deregulation reform, though at the same time it appears that some generators only had one rail supplier of coal, enhancing the effect of monopoly. In addition, generators began buying coal from multiple sources and mixing the coal to achieve their multiple goals of cost reduction, profitability, and emission management. Mixing the coal allowed marginal shifts in the mix of coal supply at each generator to reflect price changes from suppliers/railroads.

⁷⁷ Shelby Gerking and Stephen F. Hamilton, "What explains the increased utilisation of Powder River Basin Coal in Electric Power Generation?", *Am. J. Agr. Econ.* (2008) 90 (4): 933-950.

⁷⁸ Shelby Gerking and Stephen F. Hamilton, "What explains the increased utilisation of Powder River Basin Coal in Electric Power Generation?", *Am. J. Agr. Econ.* (2008) 90 (4): 933-950.

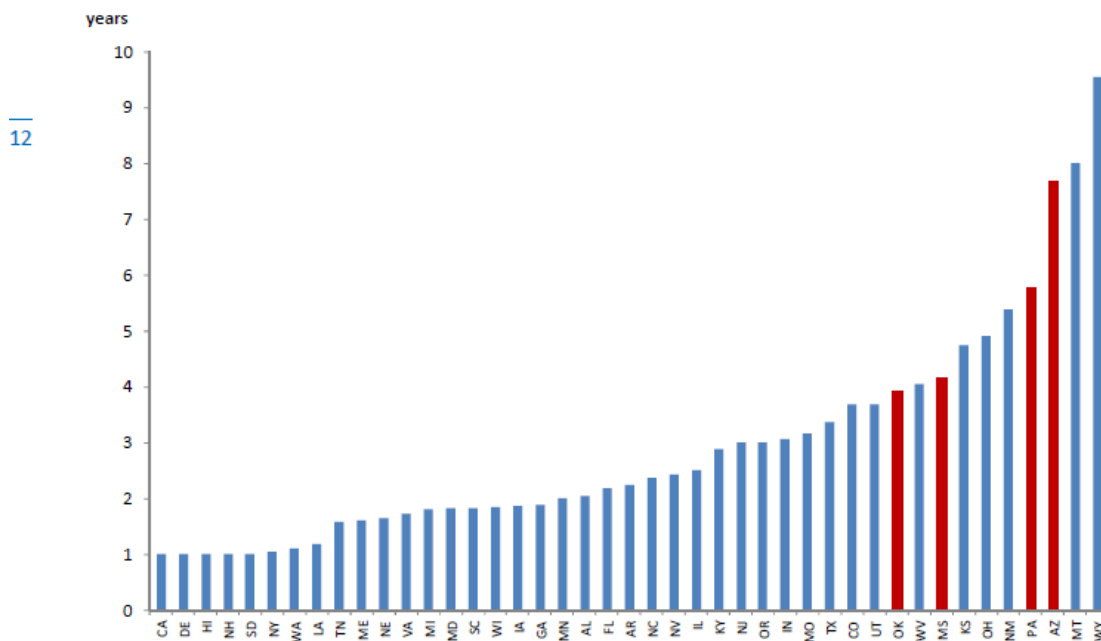
⁷⁹ Shelby Gerking and Stephen F. Hamilton, "What explains the increased utilisation of Powder River Basin Coal in Electric Power Generation?", *Am. J. Agr. Econ.* (2008) 90 (4): 933-950.

Simultaneously Shelby et al., argue that the high sulphur coal fell in price more than expected based on regulating sulphur content. The fall in costs and improved operational flexibility significantly lowered delivered prices received at the generator gate, and increased competition, despite the rail duopoly holding up prices at shorter distances and sulphur dioxide permits raising costs. Sulphur dioxide permit prices simply add another layer on top of this underlying market dynamic altering the relative distance at which the duopoly can extract rents from generators.

The use of long-term contracts also seems to have been part of this effort to get more leverage over feedstock costs: the states with the longest duration coal contracts were Montana and Wyoming. IEA notes that many of these contracts have “take-or-pay” clauses that commit the plants to accept a pre-determined amount of coal from particular mines years into the future.

Figure 10: Average length of US non-lignite coal contracts for power generation, by state

Figure 5 • Average length of US non-lignite coal contracts for power generation, by state



Note: Volume-weighted average, based on remaining terms on coal contracts from deliveries in 2011.
Source: EIA (EIA-923); IEA calculations.

US electricity demand is considered inelastic⁸⁰ but Shelby et al., note that demand for PRB coal is perfectly elastic with respect to other coals, in the distant regions where competition in coal delivery is dominant.⁸¹ This would also explain the elasticity of Appalachian coal that would presumably vary in a similar manner at distance on a competitive rail delivery network. In the regions where duopoly is stronger, the elasticity is significantly reduced as the monopoly railroad keeps prices relatively constant. Monopoly pricing comprises the underlying real cost, normal profit and a premium. All

⁸⁰. Source RFF paper

⁸¹ The general point is reflected as well in recent analysis of coal basin competition by investment banking firm Goldman Sachs. They argue the as large coal power plants closer to PRB mines continue to close, the competitiveness of PRB coal will continue to worsen. (Goldman Sachs Equity Research, Pavan Hoskote and Sairam Guthana, “Inter-basin coal competition debate heats up; Sell CLD, Buy FELP,” June 11, 2015).

else being equal, costs would rise with distance. Shelby et al., state “*The estimated elasticity of total variable cost with respect to ton-miles is 0.986*”.

A 2004 paper from the University of California Energy Institute⁸² estimated the price elasticity of demand for PRB coal in the context of a study examining how implementation of the Clean Air Act sulphur-dioxide permit trading program affected railroad freight charges on PRB coal. Using data from January 1990 to December 1999 on plants affected by the Clean Air Act’s sulphur-dioxide provisions, these authors estimated a long-run price elasticity of demand of -1.75. It is likely that the more detailed route based data set available to Shelby et al., has allowed them to see more deeply into the operations of PRB coal supply. Shelby et al., see the sulphur-dioxide cap has an influence but the drivers in change have been falling coal and rail costs.

Changing the sulphur dioxide permit price can increase or decrease rents received by the railroad owners. It follows logically from Shelby et al., that in a competitive railroad market for PRB coal the price would be more elastic, and probably lower, with larger volumes being sold, displacing even more coal from other sources, further lowering the cost of sulphur dioxide emission reduction. The existence of the ‘coal island’ effect, and the railroad duopoly should be considered carefully in the design of any carbon policies. The existence of the duopoly would have raised the average cost of delivered coal in the US eastern market, acting as a brake on coal expansion. It suggests that carbon pricing policies should consider the full suite of environmental impacts from coal such as extraction externalities, sulphur dioxide, ash etc. to avoid yet more distortions and unintended consequences.

Where coal is being substituted by alternative energy sources the elasticities are more muted. In 2014, a US study⁸³ calculated a matrix of elasticities of substitution *between coal, gas, petroleum, electricity, wood and waste for supply of electricity*. They calculated own price elasticities for coal and gas between 1970 and 2012, using state by state data provided by the US Energy Information Administration. They found that coal had an own price elasticity of -0.822, and gas had an own price elasticity of -0.903. However, looking ahead we see those rising as lower carbon alternatives become more competitive.

We conclude that structurally:

1. in the short term where electricity generation capacity does not change, the Ed is low, closer to 0.5
2. in the long term, as coal can be substituted and coal plants retired, the Ed is much higher
 - a. with comparatively cheaper gas and renewables and energy efficiency gathering pace (see below), the Ed is likely to increase

⁸² Meghan R. Busse and Nathaniel O. Keohane, “Market Effects of Environmental Regulation: Coal, Railroads, and the 1990 Clean Air Act”, CSEM WP 137, September 2004

⁸³ Yeboah et al (2104), Osei Yeboah, Saleem Shaik, Afia Fosua Agyekum, Julie Melikpor-Lee, Energy Substitution in U.S. Electricity Generation, North Carolina Agricultural & Technical State University, USA; 2. North Dakota State University, USA, Journal of Business and Economics, ISSN 2155-7950, USA October 2014, Volume 5, No. 10, pp. 1845-1853 DOI: 10.15341/jbe(2155-7950)/10.05.2014/010 © Academic Star Publishing Company, 2014 <http://www.academicstar.us>.

A list of further factors likely to increase and decrease the Ed is in the table below.

Factors likely to increase Ed	Factors likely to decrease Ed
<ol style="list-style-type: none"> 1. Higher value cargo options for railroads, such as oil (reduces incentive for rail operators to buffer coal sector from increased costs from subsidy removal in order to keep the business) 2. Variability of PRB coal across quality metrics (reduces incentives of buyers to keep buying PRB coal) 3. Increased availability of inexpensive wind, natural gas plants (reduces incentives of buyers to keep buying PRB coal) 4. Increased market exit of coal power plants in PRB region (increases relative market power of end user utilities) 5. Lack of export markets (increase market power of domestic end user utilities) 	<ol style="list-style-type: none"> 6. Long-term take-or pay contracts by power plants for PRB coal (utilities locked in to using specific coal for a number of years) 7. Rail market power (rails have the ability to protect their markets by buffering price changes to end users if in their interest to do so) 8. Low price at mine-mouth of PRB coal (makes product more economic, other things being equal). 9. Rising cost of alternative coal supplies such as in Appalachia, both from declining ore quality and rising labour costs

In order to further explore the long-term drives of the various Eds in the relevant electricity markets, we use a heat map based on the following key:

Little Effect on Ed
Moderate Effect on Ed
Significant Effect on Ed

3.3.2.1 Key Long Term Drivers PRB Ed

We foresee the natural gas sector continuing to take coal’s share of the energy market in the US. Increases in gas-fired power plants comprise the biggest contributor to a reduction in coal consumption in the US. Consequently, demand for coal from the PRB will fall. This includes several factors:

- The switch from coal to gas is accelerated by regulatory changes aimed at mitigating environmental and carbon related pollution.
- Emerging regulations will also serve to help promote renewable energy technologies, which also bite into coal’s share of the energy mix. Wind energy expands most rapidly, with solar energy also a significant growth market.
- Energy efficiency gains serve to reduce absolute power demand that subsequently serves to reduce coal demand from the PRB.
- With gas and renewables and efficiency gathering pace the Ed is likely to rise.

Elasticity of Demand Drivers for US PRB Coal in US Electricity Markets		
Substitutes		
other coal		Minimal
Gas		Strong - fracking, cost key, will tend to rise over time
Low Carbon		
Wind		Low cost in many regions
Solar PV		Costs falling, subsidies likely to end, storage break throughs possible
Solar CSP		Potential - costs need to fall
Nuclear		Unlikely, costs unsure, public resistance
Diesel		NA in US
EE		Significant policy support and cost effective with longer paybacks
Time		Renewable energy costs will keep falling, the aging US coal fleet encourages retirement
Regulatory		EPA pollution regulations assumed to continue to tighten. Renewable energy subsidies will decline. RPS likely to plateau
Industry Structure		Competitive and deregulated, leading to high flexibility in response to relative pricing

The conclusion is that, if all subsidies in the US were removed together, a 1-2 range of the Ed is plausible where cheap natural gas is the key driver to achieve higher levels of the Ed.

3.3.3 Elasticity of Demand for Australian Coal Seaborne Market

The studies we have found for Australia and which would influence other seaborne export suppliers are more related to changes in isolation in that particular market, where cross coal substitution is high.

The key countries whose electricity markets are being supplied at present by Australian coal are China, India and Japan. China and India also have large domestic coal industries that can potentially substitute.

The World Export seaborne coal market is supplied by at least three countries significantly including Australia and South Africa. De Wet (2003)⁸⁴ adopted a price elasticity of demand of -4 for coal. This follows the methodology used by the Australian ORANI-G CGE model for 'common' Australian export commodities where Australian exports, like 'common' South African exports, have limited influence over the international market price. This conveniently suggests that the price elasticity of demand for two of the major coal suppliers to the Indian seaborne market can be considered as -4.

Recent estimates of China's price elasticity of demand for all coal sources are in a range from -0.3 – 1.2. We highlight three such studies below. From the perspective of our case studies this shows how demand might react if all coal subsidies were removed globally.

Using annual time-series data from 1980 to 2006, Jiao, Fan, and Wei estimate a long-run demand price elasticity of -1.12 (and short-run demand elasticity of -0.067).⁸⁵ These authors note that China's coal demand underwent significant structural change during the period 1997-2000.

Burke and Liao took a different approach in using province-level data for the period 1998-2012; as of 2012, these authors estimate a demand price elasticity of -0.3 to -0.7 (when allowing two years for demand responses to occur).⁸⁶ These authors note evidence that China's provincial coal demand

⁸⁴ De Wet (2003), Section 8.3, sub-section vi, The Effect of a Tax on Coal in South Africa: A CGE Analysis, T.J. De Wet, PhD (Economics) in the Faculty of Economics and Management Sciences, Pretoria, October 2003 at the University of Pretoria.

⁸⁵ Jiao, J-L. Fan, Y. Wei, Y-M. "The structural break and elasticity of coal demand in China: empirical findings from 1980-2006. *International Journal of Global Energy Issues*. 31(3/4):331-344. 2009.

⁸⁶ Paul Burke and Hua Liao, "Is the price elasticity of demand for coal in China increasing?," CCEP Working Paper 1506, June 2015

“has become increasingly price elastic,” with potential explanations for this trend including greater implementation of market-based pricing mechanisms, increasingly availability of substitutes for thermal coal (e.g., nuclear power, natural gas, and renewable), as well as a rapid increase in coal prices during the 1998-2012 period translating into a higher coal price elasticity of demand.⁸⁷

Finally, employing a computable general equilibrium model, Lin and Jiang estimate a price elasticity for China’s electricity sector of -0.5. It is important to note, however, that (unlike in the US) the electricity sector in China is only one of several thermal-coal consuming sectors, meaning that an estimate of price elasticity in the power sector may not fully capture the price elasticity of demand for coal in China’s economy as a whole. Moreover, as with the power sector, the industrial sector in China is seeing the increasing emergence of fuel sources (chiefly natural gas) that can compete with coal.

3.3.3.1 Key Drivers for China Ed

- Arguably a slowing rate of GDP growth in China is the largest structural change that serves to reduce future coal demand growth as a result of lower power demand growth.
- Another characteristic of a developing economy is the shift from consumption-based industries to a service-based economy that is up to six times less energy intensive. Again, this has knock-on effects for coal demand in China.
- Aside from macro-level economic changes, the government in China is applying an ‘all of the above’ strategy towards future energy generation. As such, we foresee important growth in renewable energy technologies, hydropower, biomass and nuclear power in China. All serve to weaken coal demand growth.
- Domestic coal is also a key competitor.
- Finally, energy efficiency improvements are also expected to be significant.

Using the literature review findings and combined with the heat map below, we estimate an Ed relevant to a subsidy removal where only exporters remove them within a range of 2 to 4 on a 20 year average. This would drop to 1 to 2 if all coal subsidies removed globally as the cost differential would narrow.

Elasticity of Demand Drivers for Imported Coal in Chinese Electricity Market	
Substitutes	
other coal	Strong potential for domestic coal substitution
Gas	Supply constraints - tight gas hard to exploit, russian gas is being imported, LNG expensive
Low Carbon	
Wind	Targets that can be scaled up
Solar PV	Costs falling, subsidies likely to end, storage break throughs possible
Solar CSP	Potential - costneeds to fall
Nuclear	Announced program - not easy to scale up further
Diesel	Unlikely
EE	Significant policy attempts to encourage and cost effective with longer paybacks
Time	Renewable energy costs will keep falling, energy demand rising
Regulatory	"Anything but coal" policy - pollution focus
Industry Structure	SOE deliver efficient central planning outcomes

⁸⁷ Lin, B., & Jiang, Z. (2011). Estimates of energy subsidies in China and impact of energy subsidy reform. Energy Economics, 33(2), 273–283.

3.3.3.2 Key drivers for India PED

- We do not foresee India being the “great hope” of the export coal industry.
- Energy efficiency savings impact total electricity demand growth, an important factor being reduced grid losses. Currently transmission and distribution losses in India’s power sector stand at 25% - as such, there is huge potential for savings in electricity generation.
- We see the Government of India’s targets for a solar revolution being met so the contribution of renewable energy in India increases significantly.
- Domestic coal is also a key competitor.

Using the literature review findings and combined with the heat map below, we estimate an Ed relevant to a subsidy removal where only exporters remove them within a range of 2 to 4 on a 20 year average. This would drop to 1 to 2 if all coal subsidies removed globally.

Elasticity of Demand Drivers for Imported Coal in Indian Electricity Market	
Substitutes	
other coal	Strong potential for domestic coal substitution
Gas	Supply constraints - LNG expensive
Low Carbon	
Wind	Targets that can be scaled up
Solar PV	Targets. Debt funding getting more innovative
Solar CSP	Potential - cost needs to fall
Nuclear	Announced program - not easy to scale up further
Diesel	Can be complimentary with Hybrid coal PV
EE	Slow build up focus - plenty of room in the electricity system for improvement
Time	Renewable energy costs will keep falling, energy demand rising
Regulatory	" Saffron revolution" broad based but does encourage substitutes to imported coal across the range
Industry Structure	Oligopolies slowly unwinding.

3.3.3.3 Key drivers for Japan Ed

- Japan has made huge energy efficiency gains in the past and we foresee energy efficiency gains still outpacing GDP growth such that electricity demand continues declining
- We model Japan making substantial solar energy additions via its feed-in-tariff, in line with its published targets.
- We also model a small-scale restart of nuclear energy generation in the near-term. Each of these factors contributes to reducing demand for coal in Japan.

Using the literature review findings and combined with the heat map below, we estimate an Ed relevant to a subsidy removal where only exporters remove them within a range of 2 to 3 on a 20 year average. This would drop to 1 to 2 if all coal subsidies removed globally.

Elasticity of Demand Drivers for Imported Coal in Japanese Electricity Market	
Substitutes	
other coal	All imported
Gas	Major LNG importer who can switch on cost trends
Low Carbon	
Wind	Targets that can be scaled up
Solar PV	Targets. Solar PV Fit likely to still have big impact
Solar CSP	Unlikely
Nuclear	Announced program - not easy to scale up further
Diesel	Unlikely
EE	Very strong build up in Japan
Time	Renewable energy costs will keep falling
Regulatory	Expected to become more supportive
Industry Structure	Japanese "planned" system - could deliver strong substitution but still somewhat inflexible

Overall, for Australian exports, the Chinese, Indian and Japanese Eds imply a range of 3 to 4 over the coming two decades. If subsidies are removed globally, this might fall to a range between 1 and 2.

3.5 Measuring Carbon – the gross or first order effect

Deriving the carbon impact relies on estimates of the relative emissions intensity of coal compared with its substitutes. A conservative assumption replaces coal by natural gas and assumes the lowest emissions intensity differential between these two. A more refined analysis, using electricity sector-specific optimisation models, can provide further details on the emissions intensity of different fuels and the proportion of different substitutes for coal, highlighting, for example, what share of current coal capacity might be replaced by renewables.

This work provides an approximate calculation of how much carbon is associated with the specific implied amount of supply in response to the Ed. This is very much a “first order partial equilibrium” result and we do not explicitly model:

- the breakdown of what substitutes between other types of coal
- gas (around half of coal emissions if fugitive emissions are managed)
- and energy efficiency and renewable energy (near zero and over the next 20 years we expect the key substitute competitors).

However, in the case of assuming all coal subsidies are removed simultaneously, it might be fair to assume there is not much further coal substitution. Indeed we would expect the substitution might be mostly from gas and renewables – the low carbon options.

We have therefore chosen to show the estimated first order carbon effects relating to the all subsidies being removed simultaneously, implying Eds of 1-2 and to further make an assumption about the amount of gas in the case of the PRB.

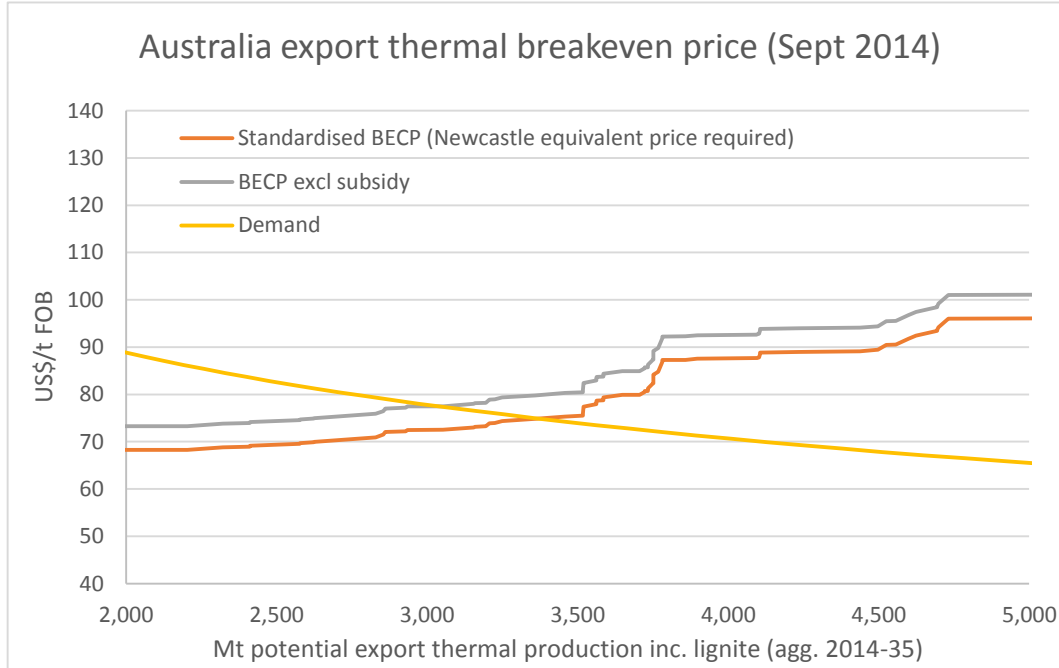
3.6 Gauging the impacts

- As examples for generating charts, we adjust the supply curve of Australian seaborne coal up by US\$4/t from its original equilibrium break-even price as published in Carbon Tracker’s September 2014 coal study⁸⁸ of US\$75/t and PRB by US\$8/t on a US\$36/t break even equilibrium (Note we adjust the PRB directly for domestic rail transport costs estimates from EIA compared to the September 2014 document).
- In order to illustrate the different effects of coal substitution, we derive demand curves where the slope is:
 - Ed of 1.5 for PRB coal, where we assume that all coal subsidies in the US are lifted on all sources of US supply, and there is limited import competition. As such, it is more related to coal overall against other low carbon sources which we see having increasing penetration for regulatory and cost reasons. Gas remains competitive and the surprise could be higher Ed based on more aggressive gas switching as subsidies are removed.
 - Ed of 3 for Australia where these subsidies alone are lifted much of the replacement supply is coal from other regions.

⁸⁸ <http://www.carbontracker.org/report/carbon-supply-cost-curves-evaluating-financial-risk-to-coal-capital-expenditures/>

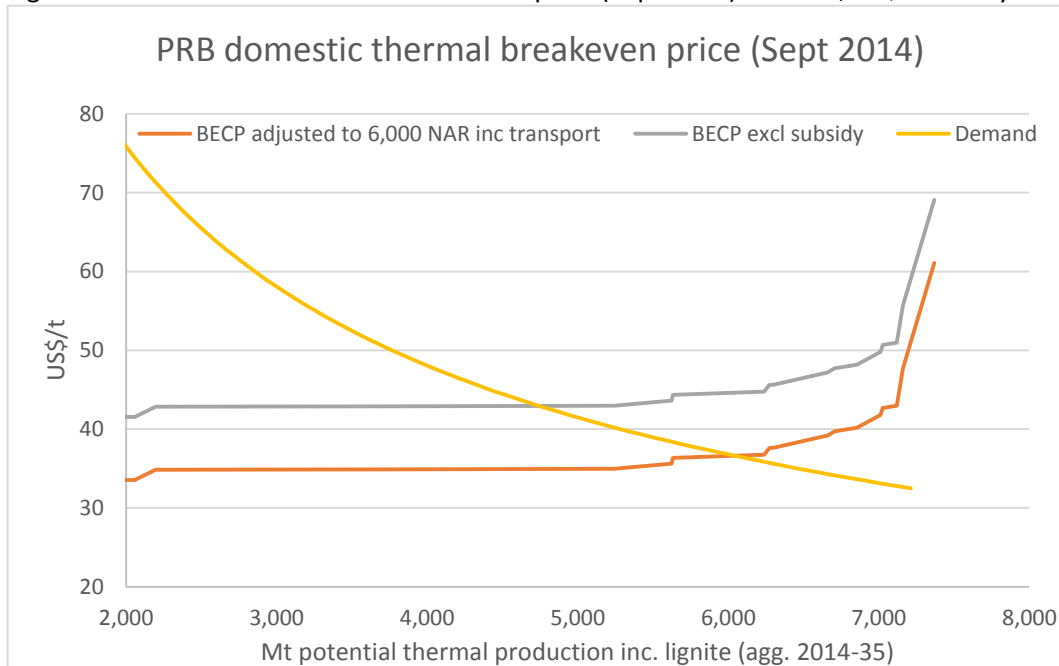
- The last step is to combine the revised supply curve with the elasticities of demand and calculate the estimated coal demand reduction and associated carbon impacts.

Figure 11: Australia export thermal breakeven price (Sept 2014)- 3.0x Ed, US\$4 subsidy



Note – based on September 2014 data. There have been significant changes in the interim, for example in exporter currencies and cost reduction initiatives which have lowered BEPs.

Figure 12: PRB domestic thermal breakeven price (Sept 2014)- 1.5x Ed, US\$8 subsidy



Note – based on September 2014 data.

- Note that the supply curve has been adjusted for transport costs based on EIA estimates compared to the curve derived in September 2014. This is needed in a subsidy price effect analysis to derive a delivered price.

Sensitivity analysis

To address key areas of uncertainty in our data, we present a set of sensitivity tables to illustrate the impact on demand of different subsidy levels and different Ed levels.

4. We consider the impact of pre-closure subsidies alone and then the impact of both pre- and post-remediation/closure subsidies. This acknowledges uncertainties around the manner and degree to which different types of subsidies will stimulate supply. In particular, investment decision-makers may attribute greater significance to subsidies coming at the project development stage (tax deductions and the like) relative to those at the end of the project life cycle (such as rehabilitation subsidies).
5. In the PRB, a number of subsidies are already phasing down, highlighting the importance to investors exposed to companies that might be affected in understanding the impacts set out in this work.
6. We consider a range of Eds reflecting the differing assumption on cross-coal substitution. Available fuel substitutes, as well as the scope of subsidy removal (specific policy, national, or global) affect relevant elasticities and the competitiveness of lower carbon options. These different estimates might reflect differences in market context, for example:
 - a. An Ed of 0.5 is more related to short-term effects from price rises in electricity markets. An Ed range of 1-2 would describe market responses to coal subsidy removal across a broader geographic market area, or globally where all subsidies are lifted at once. The upper end of this range would be more likely associated with increased low carbon fuel source penetration based on regulatory support and declining cost curves of substitutes. We see the higher Ed scenario as most relevant to the US PRB, as national removal of US coal subsidies, while not politically easy is also not impossible to envision. In this market, we see regulation and costs as increasingly making coal less attractive and with gas being an important potential driver on the upside to the Ed.
 - b. An Ed of 2-3 (ranging up to 4) would incorporate regions where other sources of coal can substitute more easily, allowing consuming industries to shift fuel suppliers while continuing to operate their existing capital. It is possible gas in the PRB could lift the Ed to this level even with other sources of coal constrained as aging coal plants need replacing. This range would apply at the higher end to Australian coal in isolation, and at the lower end if subsidies were tackled in world seaborne markets and India and China.

Effect on demand of removing subsidy US\$, % (based on supply - demand framework)

Market	Category	Subsidy (\$/t)	Elasticity					
			0.5x	1.0x	1.5x	2.0x	2.5x	3.0x
US PRB	Ongoing tax and lease	\$4.00	-5%	-8%	-11%	-13%	-16%	-20%
	Phasing out	\$3.00	-4%	-7%	-8%	-11%	-12%	-13%
	Remediation	\$1.00	-2%	-3%	-4%	-6%	-7%	-7%
	Total	\$8.00	-8%	-16%	-22%	-29%	-34%	-39%
Australian Export	Tax and fuel excise	\$2.50	-1%	-3%	-3%	-3%	-4%	-4%
	Remediation	\$1.50	0%	-1%	-1%	-3%	-3%	-3%
	Total	\$4.00	-1%	-3%	-4%	-6%	-6%	-7%

Note:

Australian export and PRB domestic demand impact rounded to nearest 50 mt coal

"Total" based on actual impact of total level of subsidy - sum of constituent parts may be different due to the shape of the supply curve

In terms of carbon impacts, without a detailed dispatch model to assess the penetration of particular substitutes, our analysis should be viewed as indicative. If we assume that it is at the lower Eds that lower carbon substitutes make their biggest impact, then it seems best to focus on the 1-2 Ed. However, this still leaves open the role of gas, particularly in the US PRB. For illustration we have assumed half of the substitution in the US is gas at a 40% saving of carbon (conservative) relative to coal.

CO₂ reductions from removing subsidy US\$, mtCO₂ (based on supply - demand framework)

Market	Category	Subsidy (\$/t)	Elasticity			
			0.5x	1.0x	1.5x	2.0x
US PRB	Ongoing tax and lease	\$4.00	432	720	936	1,152
	Phasing out	\$3.00	360	648	720	936
	Remediation	\$1.00	144	288	360	504
	Total	\$8.00	720	1,368	1,944	2,520

Notes:

PRB domestic demand impact rounded to nearest 50 mt coal

CO₂ calculated at 1.8 mtCO₂ per mt coal

50% of PRB impact on coal demand assumed to be into gas at 40% less carbon than coal

"Total" based on actual impact of total level of subsidy - sum of constituent parts may be different due to the shape of the supply curve

Conclusion:

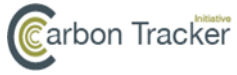
We find production subsidies summing up to:

- US\$8 per tonne in the US Powder River Basin; and
- US\$4 per tonne in Australia.

The removal of these subsidies would result in:

- A 8%-29 % reduction in demand for US PRB coal, with associated cumulative reductions of 0.7 to 2.5 GtCO₂ to 2035.
- A 3%-7% reduction in demand for Australian Seaborne coal, though with smaller carbon reductions due to substitution of coal from other (often also-subsidized) producers.

Removing subsidies to coal extraction should be a central plank of any country's fiscal and environmental plan. Particularly as subsidies to renewable energy come under increasing pressure, subsidies to the mature coal sector should not be ignored. A broader geographic range for coal



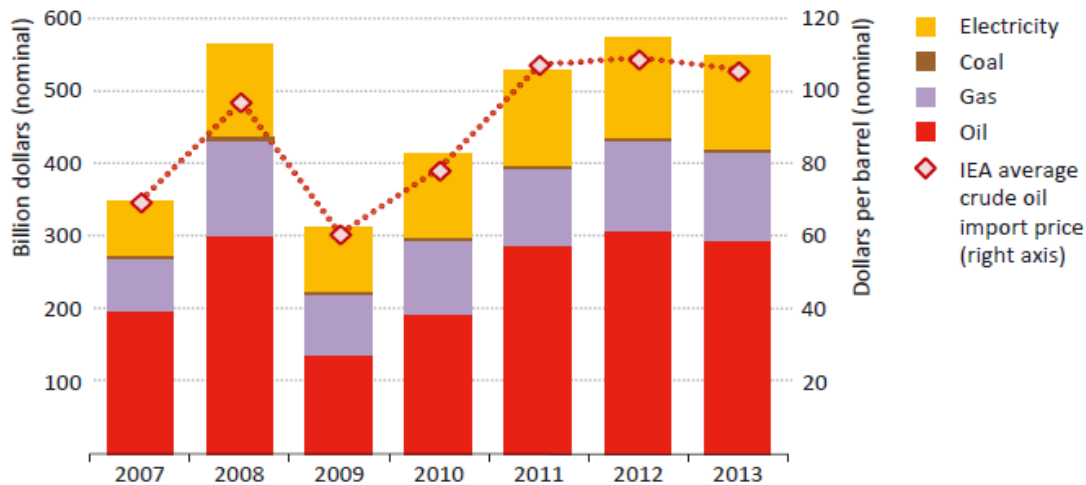
subsidy elimination will boost the carbon benefits, as the ability for coal supplies to move in from other subsidized markets will be constrained

Appendix 1: Fossil fuel consumption subsidies

A1.1 How large are they?

With regards to fossil fuel consumption subsidies, the International Energy Agency (IEA) estimates that fossil fuel consumption subsidies totalled US\$548bn in 2013. This figure is four times the value of the IEA's tally of renewable energy subsidies and the amount invested in improving energy efficiency respectively, though the renewable energy figure also picks up significant producer subsidies to renewables through feed-in tariffs and renewable portfolio standards.⁸⁹ Figure 11 shows that so far any efforts to phase out fossil fuel subsidies have failed since 2007 while Figure 12 reveals the top 25 countries in terms of economic costs of domestic subsidies. We do note that over 2014/15, the collapse in the oil price has allowed significant progress to phase down oil subsidies by select countries heavily exposed to the cost of oil imports (e.g., India, Egypt, Malaysia, Indonesia). India likewise over 2014/15 has made progress in using legal means to push back on cases of corruption-linked coal scams and under-pricing of coal deposit licences.

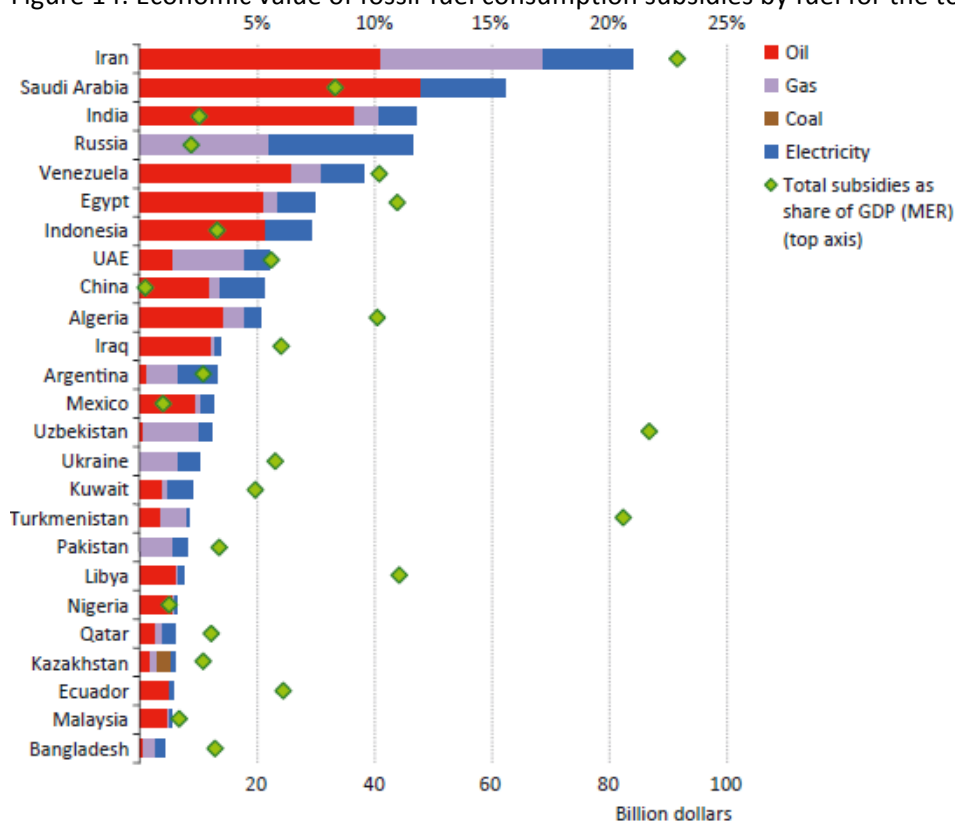
Figure 13: Global fossil fuel consumption subsidies, 2007-2013



Source: IEA

⁸⁹ IEA (2014) World Energy Outlook 2014

Figure 14: Economic value of fossil-fuel consumption subsidies by fuel for the top 25 countries, 2013



The Global Subsidies Initiative (GSI) puts a similar total on global fossil fuel consumption subsidies, estimating a total of US\$500bn being issued each year. In doing so, the GSI explains that ‘nobody knows the real number, however, because there is no international framework for regularly monitoring fossil-fuel subsidies’.⁹⁰

The International Monetary Fund (IMF) applies their own approach to estimating fossil fuel subsidies. They quantify support for 172 countries and present this as either ‘pre-tax’ or ‘post-tax’ estimates rather than consumer or producer subsidies. These estimates include oil consumption subsidies for all 172 countries, gas and coal consumption subsidies for the relevant 56 countries and production subsidies for 16 OECD countries. This approach puts the total for ‘pre-tax’ fossil fuel subsidies at US\$480bn in 2011, largely consistent with those studies cited already, but clearly difficult to compare accurately due to a different methodology.⁹¹

The IMF estimates for ‘post-tax’ fossil fuel subsidies factor in corrective taxes to account for the effects of fossil fuel consumption on global warming, human health through adverse effects on local pollution, traffic congestion and accidents and road damage. The addition of these externalities increases the scale of fossil fuel consumption subsidies from US\$480bn to US\$1.9trn in 2011.⁹²

The IMF updated this approach in 2015 with more refined estimates of the external costs of fossil fuel subsidies and the external costs of traffic-related accidents, road damage and road congestion for which it uses fuel taxes as a proxy for internalizing. As such, this methodology found that post-tax

⁹⁰ <http://www.iisd.org/gsi/fossil-fuel-subsidies/fossil-fuels-what-cost>

⁹¹ Two differences of note: while IEA’s consumer subsidy estimate includes exemptions from VAT, IMF picks these up in its post-tax number. In addition, IMF incorporates OECD’s producer support estimates where available; IEA’s price gap estimates do not.

⁹² <http://www.imf.org/external/np/pp/eng/2013/012813.pdf>

energy subsidies are dramatically higher than previously estimated – believed to be US\$4.9trn in 2013 and projected to reach US\$5.3trn in 2015.⁹³

Producer and consumer subsidies: Something of a false dichotomy

While this distinction is helpful in isolating subsidies and more accurately assessing their geographical distribution and scale, it also serves to create something of a false dichotomy. The production and consumption of fossil fuels represents two halves of the same whole supply chain. Decisions to produce are not made in isolation and no consideration of whether that fossil fuel is likely to be consumed. This inter-relationship is reflected in subsidies also, because while production subsidies are often crucial to tipping the balances of whether to invest in new fossil fuel production or not, this is but one of multiple factors driving decisions. Also of importance in the global fossil fuel markets is whether there are consumption subsidies being applied in the likely destination for that product that would provide important added security for the saleability of that product in that market. This interdependence means that it is important when estimating one half of fossil fuel subsidies to simultaneously be aware of support going to the other half of the supply chain. Price gap estimates pick up subsidies on both sides, though only if they affect market prices. As a result, this metric is often viewed as a lower bound value for total subsidies.

A1.2 Why fossil fuel subsidies need to be phased out

There is an almost universal consensus that phasing out fossil fuel subsidies will have a net-benefit effect on society. The IEA believe that ‘the market distortions created by fossil fuel subsidies...result in a longer-term economic cost. [They] crowd-out more productive and meritorious government spending and depress private investment’.⁹⁴ The World Bank has also reported that most fossil fuel subsidies are in effect a regressive use of limited public resources because they disproportionately serve the already wealthy sections of society. While this review has demonstrated that fossil fuel subsidies are at huge levels, there are signs of progress to move away from such pervasive policies. Driven largely by the drop in world oil prices, the IEA’s US\$548bn estimate for 2013 was the first fall for four years - leading the institution to scrap its 2011 prediction that fossil fuel subsidies will reach US\$660bn by 2020.⁹⁵ An analysis by GSI in February 2015 found that in 2014 almost 30 countries had delivered some form of fossil-fuel subsidy reform.⁹⁶

Low coal prices are an opportunity for a phase-out, just look at the oil price collapse

At the time of writing, international coal prices, as well as oil and gas, are at multi-year lows. This provides a golden opportunity for many nations to phase-out destructive subsidies. The rise in fossil fuel subsidies over the past few years has largely paralleled rising prices for these commodities. When such price trends reverse this compensation should be removed. Fortunately, when international coal (as well as oil and gas) prices are at a trough, phasing-out of consumer subsidies will be as painless as it ever can be, as overall supply costs of goods falls. *The Economist* argues that

⁹³ <http://www.imf.org/external/pubs/ft/wp/2015/wp15105.pdf>

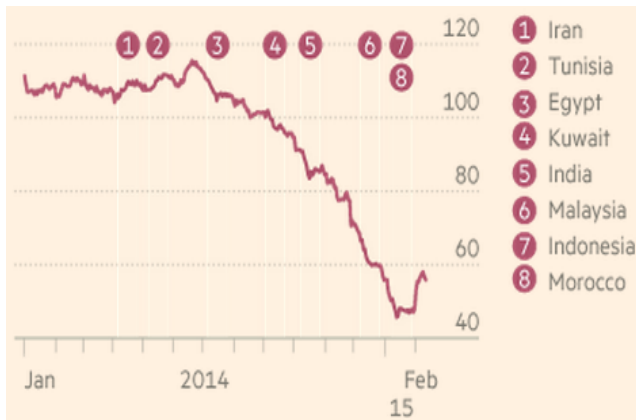
⁹⁴ IEA WEO 2014.

⁹⁵ <http://www.reuters.com/article/2011/10/04/us-iea-idUSTRE7931CF20111004>

⁹⁶ <http://www.iisd.org/gsi/news/fossil-fuel-subsidy-reform-can-reduce-greenhouse-gas-emissions-globally-6-13>

in this landscape, 'the excuse has gone' that the economy will suffer and that civil unrest will be created due to increasing costs.⁹⁷

Figure 15: Countries reducing fuel subsidies⁹⁸



Maria van der Hoeven, Executive Director of the IEA, states, 'low oil prices present an opportunity for policymakers to accomplish goals that would otherwise be more politically or economically difficult'⁹⁹; this perspective has also been articulated by the IMF and the World Bank. A number of countries have indeed taken the opportunity provided by the collapse in oil price to tackle oil subsidies, particularly on the consumption side. A few examples of countries taking action to reduce fossil fuel subsidies since the

price started falling are listed below:

- In October 2014, **India** raised excise duties on petrol by 2.25 rupees per litre and on diesel by 1 rupee per litre with immediate effect. This is set to raise US\$650m in the remainder of the fiscal year, with the 2014/15 year impact a 60% reduction in the Indian oil price bill;¹⁰⁰¹⁰¹
- Effective January 1 2015, **Indonesia** scrapped all petrol subsidies that were supposed to take up more than 13% of total expenditure in 2015 and will now save roughly US\$16bn.¹⁰² This will free up 7-25% of annual public spending that can now be spent on health, education and infrastructure;
- At the end of January 2015, **Egypt** announced its intention to cut fuel subsidies by US\$2bn in the next fiscal year. This builds on cuts Egypt has already made this current fiscal year that aimed to reduce the budget deficit from 12% of GDP at present to 10% (equal to US\$7bn). This was achieved by increasing the price of compressed natural gas by 144%, diesel by 64% and gasoline by an average 42%. These steps have been taken because Egypt's fossil fuel consumption subsidies are vast at US\$30bn, making up around one-fifth of total public spending – an amount seven-times larger than that spent on education and healthcare combined.¹⁰³

Mexico, Germany, Ghana, Morocco, Nigeria and Malaysia and other countries have made efforts to tackle fossil fuel subsidies.

⁹⁷ <http://www.economist.com/news/leaders/21639501-fall-price-oil-and-gas-provides-once-generation-opportunity-fix-bad?frsc=dg%7Cd>

⁹⁸ <http://www.ft.com/cms/s/0/b57011ba-b095-11e4-92b6-00144feab7de.html?siteedition=uk#axzz3SIIIGanf>

⁹⁹ [Low](#)

¹⁰⁰ <http://in.reuters.com/article/2014/12/02/india-tax-diesel-petrol-factory-gate-id!NKCN0JGONF20141202?feedType=nl&feedName=inmoney>

¹⁰¹ http://articles.economictimes.indiatimes.com/2015-01-18/news/58200783_1_fossil-fuel-subsidies-oil-prices-energy-subsidies

¹⁰² <http://www.economist.com/news/asia/21638179-jokowi-abandons-wasteful-fuel-subsidies-fiscal-prospects-brighten-good-scrap>

¹⁰³ IEA, WEO 2014

Taking the free-on-board Newcastle spot price as an example, international coal prices are down 50% on 2011 levels.¹⁰⁴ This presents an opportunity parallel to that beginning to occur with oil subsidies in some regions. It is, however, arguably more difficult to cut production subsidies than it is to cut consumption subsidies at a time of low prices. This is because low prices represent a time of particular hardship for producer companies who often turn to governments for help. Therefore, cutting or phasing-out production subsidies would in fact be antithetical to the typical government response during such a time – ‘there is little talk of trimming them [producer subsidies]’ in America according to *The Economist*.¹⁰⁵ The decision therefore becomes a trade-off between prioritising the least pain for consumers, while exposing fundamentally risky corporate business models, and avoiding the underwriting of new coal projects to deliver increased supply even as the seaborne coal markets enter structural decline. An effective transition would start by ceasing the subsidies available to new sources of supply, as well as improving rules regarding financial assurance for properly addressing the coal sector’s large closure and post-closure liabilities.

Additional fiscal budgets can be spent on the poor

For those governments phasing out fossil fuel subsidies, this significantly improves their fiscal balances. For nations dependent upon fossil fuel imports, reforms also serve to promote the relative merits of alternative domestic fuel sources such as renewable energy and energy efficiency. Such a shift not only helps reduce current account deficit pressures, it also has the potential to help improve that country’s currency stability, reducing inflationary pressures, and reduce upward pressure on interest rates. All these benefits have been seen in India over the last year on the back of lower oil prices and oil subsidies.

This reallocation of capital can be applied to benefit the country’s poorest communities effectively, unlike fossil fuel subsidies. Subsidies do not constitute an effective reduction in the cost of energy to the economy, more a redistribution of economic resources to the company while consumers and taxpayers pay the full cost of the energy plus subsidy. While this is the case, research shows that the poorest individuals end up paying the most of this cost. The World Bank found that the bottom 40% of the global population ranked by income distribution receives only 15-20% of the fuel subsidies.¹⁰⁶

The IMF estimates that the poorest 20% of households worldwide receive less than 7% of the benefits generated by fossil fuel subsidies.¹⁰⁷ Consequently, IMF Managing Director, Christine Lagarde, reiterated that ‘energy subsidies are enormous in scale, and they help the people who need them least’.¹⁰⁸ This is because higher income populations can afford to consume more of the subsidised fuels. Similarly, wealthier populations consume more goods and services that have fuel and their subsidies embedded in them.

Furthermore, fossil fuel production and their subsidisation do not support energy access for the poor. Firstly, there are a number of factors that could intervene between the implementation of producer subsidies and poor communities receiving increased energy access, e.g., exploration proves fruitless, fossil fuels are exported rather than consumed domestically or their consumption goes to

¹⁰⁴ <http://www.carbontracker.org/wp-content/uploads/2014/09/Coal-Financial-Trends-ETA.pdf>

¹⁰⁵ <http://www.economist.com/news/finance-and-economics/21639589-few-countries-are-taking-advantage-lower-oil-prices-cut-subsidies-pump>

¹⁰⁶ <http://www.oecd.org/env/45575666.pdf>

¹⁰⁷ http://www.wto.org/english/docs_e/legal_e/24-scm.pdf

¹⁰⁸ <http://www.bbc.co.uk/news/business-27142377>

the non-poor. Secondly, studies have shown that low-carbon energy proves a more appropriate solution than coal for the majority of the world's population in energy poverty.

For example, Carbon Tracker's research has shown that low-carbon energy solutions provide cheaper energy than coal for 84% of the rural population without energy access. Also, coal is not well distributed to serve the energy poor.¹⁰⁹ In sub-Saharan Africa for instance, only 7% of those without access to energy live in countries with coal producing assets.

Phasing out fossil-fuel subsidies would have significant carbon reduction impact

Fossil fuel subsidies mark a double-edged sword for the climate – firstly, they distort market fundamentals such that more fossil fuels are either demanded or supplied, depending on the type of subsidy, than would otherwise be the case. Inherently, this leads to larger carbon emissions relative to a no-subsidy baseline. Equally important, the fossil fuel subsidies disincentivise investments in low-carbon technologies. Phasing-out fossil fuel subsidies, therefore, will contribute significantly to mitigating the global threat of climate change.

Estimates have been made about the extent to which consumer subsidies have influenced carbon emissions. One academic study found that up to 36% of global carbon emissions between 1980 and 2010 were driven by consumption subsidies.¹¹⁰ The IEA says that phasing-out these subsidies between 2011 and 2020 would cut global energy-related carbon dioxide emissions by 6.9% by 2020.¹¹¹ In a 2015 report, however, GSI reported that this figure could be as high as 13% by 2050, based on IMF figures.¹¹²

The 2010 landmark joint report issued by IEA, OPEC, OECD, and the World Bank estimated that eliminating energy production subsidies by 2020 in OECD nations would lead to a 10% drop in greenhouse gas emissions by 2050.¹¹³ This gain is largely obtained at the expense of coal's share of the energy mix because it is assumed to have a much higher price elasticity than the supply of oil and gas.

As the GSI note, however, phasing out fossil fuel subsidies in isolation is not as effective in terms of GHG emissions reduction as pairing this effort with other appropriate policy targets. In particular, the GSI estimate that a cap on emissions in the OECD countries will achieve an additional 8-10% of emissions reductions on top of those from phasing out fossil fuel subsidies alone.¹¹⁴ This is because it cuts off the potential for significant 'carbon leakage' – the transfer of a greenhouse gas emitting process from one country to another for reasons of costs related to the implementation of climate policies.

Finally, fossil fuel subsidies serve to disincentivise capital from flowing towards low-carbon energy technologies and, therefore, delay the transition to a more sustainable energy system. The IEA describes fossil-fuel subsidies to 'rig the game against renewables and act as a drag on the transition to a more sustainable energy system'.¹¹⁵ They found that the total value of subsidies to renewables

¹⁰⁹ <http://www.carbontracker.org/report/energyaccess/>

¹¹⁰ <http://www.voxeu.org/article/inferred-fossil-fuel-subsidies-new-database>

¹¹¹ http://www.iea.org/files/energy_subsidies.pdf

¹¹² <http://norden.diva-portal.org/smash/get/diva2:786861/FULLTEXT02.pdf>

¹¹³ <http://www.oecd.org/env/45575666.pdf>

¹¹⁴ <http://norden.diva-portal.org/smash/get/diva2:786861/FULLTEXT02.pdf>

¹¹⁵ IEA WEO 2014

of all types equalled US\$121bn globally in 2013, roughly four times smaller than the financial support given to fossil fuels.

There are risks to phasing-out fossil fuel subsidies

Aside from the potential disgruntlement from producers and consumers who have been benefiting from fossil fuel subsidies, the phase-out of such support could have a number of disadvantageous fiscal, economic and societal implications that need to be considered and integrated carefully.

For instance, to the extent that subsidy reform drives up the cost structure of fossil fuel producers, some or all of the shift could be passed on to consumers. Such price increases can be difficult for the poorest citizens, both in the countries heavily subsidizing fossil fuel consumption, and also in the OECD nations where producer subsidies proliferate. Within the OECD, rising prices for electricity can be a problem since the elasticity of electricity demand to price tends to be low. Transitional support may be required in such circumstances, and often already exists in the OECD via discounted or free energy access for the very poor. But, by redirecting residual support narrowly only on the poor, both price signals and government finances are much improved.

APPENDIX 2: Non-quantifiable coal industry subsidies

A2.1: Corporate tax avoidance and tax breaks

There is a significant legal difference between tax avoidance and tax evasion. Our focus here is on avoidance, which relates to current legally acceptable strategies to structure business dealings in such a way as to minimize corporate tax payable.

Multinational mining companies have a myriad number of opportunities to structure their tax affairs in ways that allow them to avoid paying taxes in full tax rate jurisdictions and to avail themselves of tax havens. This includes the use of offshore “marketing hubs” in havens like Singapore, adding excessive financial leverage against subsidiaries with physical mining operations in full tax jurisdictions, related-party deals over technical and administrative services, the provision of self-insurance and utilizing accelerated depreciation allowances.

Offshore marketing hubs

In April 2015, an Australian Senate inquiry into multinational companies and tax avoidance focused on two sectors: technology and mining. Representatives of Glencore, BHP Billiton, Rio Tinto and Adani Enterprises all appeared at the inquiry hearings. A key finding from the inquiry was that all four of these coal companies operate “trading hubs” out of Singapore. Although Singapore has a corporate tax rate of 17%, foreign firms can negotiate with the government a concessionary tax rate of 0-5%. These four global coal majors have confirmed that they sell their Australian coal to a subsidiary company in Singapore and then on-sell their coal to end customers. IEEFA acknowledges that this practice is accepted under current Australian tax law. We recognize also that charging a marketing uplift in Singapore can be a form of transfer pricing, which is probably not in the best public interest.

BHP Billiton has disclosed it held A\$31.2bn in related party transactions with Singapore in 2014 alone.¹¹⁶ BHP disclosed that from 2006 to 2014, it booked profits of US\$5.7bn in Singapore and paid just US\$120,000 of tax in this period.¹¹⁷ Subsequent to the Inquiry, BHP revealed it has been charged A\$522m by the Australian Tax Office (ATO) relating to its Singapore marketing hub activities, including penalties of US\$221m for alleged tax avoidance. However, because BHP’s Singapore subsidiary is deemed a Controlled Foreign Company, and with BHP’s Dual Listed Structure, 58% of the profits BHP books in Singapore are then taxed in Australia (the other 42% is not taxable in BHP Plc’s UK books).

Rio Tinto Singapore Holdings has reported US\$3bn of profits since 2008, taxable in Singapore at a rate reported to be less than 5%.¹¹⁸ In 2014 Rio Tinto reported pretax profits in Singapore of US\$719m but paid only US\$44m tax (a 6% tax rate).¹¹⁹

¹¹⁶ <http://www.smh.com.au/business/the-economy/bhp-billiton-reveals-billions-in-relatedparty-deals-with-singapore-guernsey-20150518-gh4a37.html>

¹¹⁷ <http://www.afr.com/news/policy/tax/singapores-government-says-its-not-a-tax-haven-its-a-valueadding-hub-20150430-1mwvdu>

¹¹⁸ <http://www.afr.com/news/policy/tax/tax-office-pursues-bhp-billiton-and-rio-tinto-over-singapore-tax-shelter-20150406-1mezvh>

Glencore testified that more than half its Australian commodity exports are channeled through Singapore “trading hubs”.¹²⁰ It has also been reported that Glencore is under audit by the ATO for the low level of tax it pays within Australia. During the Senate inquiry, Glencore revealed it had a US\$1.4bn (A\$1.8bn) loss in Australia for the 2013/14 on revenues of A\$13bn, having moved US\$9bn (A\$11.3bn) in sales to “related parties” offshore from Australia in 2014.¹²¹ Glencore defends these actions stating that it pursues such strategies: “to the extent permitted by law can and do take into account the interest of the parent company to ensure that its commercial objectives, policies and interests are advanced.”¹²²

Allowance for Excessive Leverage – Thin Capitalization Rules

Australia has tried to enact solid rules against thin capitalization – rules that would prevent excessive leveraging of Australian subsidiaries by foreign multinationals, but moves to effect this legislative change have proven ineffective.

As an example, Adani Enterprises Ltd of India has invested more than A\$3bn in Australian coal mining and coal export ports since 2010. However, it has relied on debt as the predominate source of funding. Adani Mining Pty Ltd as of 31 March 2015 had A\$1.35bn of net debt against shareholder equity of negative A\$230m.¹²³ To the extent that can be determined by its annual accounts lodged with the Australian Securities and Investments Commission (ASIC), Adani Abbot Point Port (Australia) had consolidated net debts of A\$1.48bn in March 2015, and has reported aggregate net taxable losses over the past four years after interest and hedging losses.

Glencore is one of the five largest coal mining companies in Australia. Although Glencore advertises that its headquarters is in Switzerland (where the corporate tax rate is 15%), the company’s actual formal registered head office is in the tax haven of Jersey. This is very telling in that the company is operating largely outside the jurisdiction of the countries where its main operating assets are located, and that its operations are several steps removed from the corporate oversight that a BHP or Rio Tinto faces. Glencore also operates a multitude of subsidiaries across the tax havens of the British Virgin Islands, Bermuda, Singapore, the UAE, Jersey, and others.

Indeed, Glencore’s 2014 annual report refers to a strategy of “geographic arbitrage” and the company openly classifies its operations as either being marketing or industrial in nature, and applies an “estimated tax rate of 10% and 25% respectively.”¹²⁴ Glencore then allocates US\$35bn of debt to its industrial activities, representing 71% of its total debt. However, 84% of Glencore’s net interest expense in 2014 was allocated to industrial activities, which coincidentally happen to generally be in higher tax countries. The 2014 report also shows that whereas 83% of earnings before interest, tax depreciation and amortization were generated by industrial activities, yet the same industrial activities “generate” only 51% of the pretax profit. The bottom line: allocation of the

¹¹⁹ <http://www.afr.com/news/politics/moment-of-truth-does-rio-pay-less-singapore-tax-than-bhp-20150421-1mpkeg>

¹²⁰ <http://www.ft.com/cms/s/0/1d7cb368-df52-11e4-b6da-00144feab7de.html#axzz3YZPHNPqh>

¹²¹ <http://www.smh.com.au/business/mining-and-resources/worlds-top-commodity-trader-glencore-moves-to-reduce-coal-trading-20150622-ghu7vf.html>

¹²² <http://www.smh.com.au/business/the-economy/glencore-reveals-its-being-audited-by-ato-over-taxes-20150513-gh0g51.html>

¹²³ Adani Mining Pty Ltd, year to 31 March 2015 Annual Report, as lodged with ASIC 21 May 2015.

¹²⁴ Glencore Annual Report, 2014, pages 12 & 37.

majority of debt to the high-tax countries allows Glencore to arbitrage down its corporate tax rate considerably.

Glencore's submission to the Senate Inquiry states that the company paid a total of A\$2.07bn of corporate tax in Australia over 2007-2014, a tax expense averaging A\$258m per annum.¹²⁵ Against this, Glencore submits that it has invested A\$19bn in new projects in Australia since 2007 (with half of those in coal, and this figure specifically excludes acquisitions). If Glencore were paying a full 30% Australian corporate tax rate, this would imply an average return on equity of just over 3% after tax, hardly consistent with the 10-15% pa return on equity most resource companies' target.

By comparison, and probably by the very nature of BHP being an Australian domiciled company, BHP is the top Australian corporate tax payer and shareholders in Australia benefit as a result from fully franked Australian dividends, while foreign shareholders benefit to the extent they are liable for the 10% Australian withholding tax. BHP Billiton in the three years to June 2014 reported a very full average corporate tax rate of 32.3% overall, above its 30% corporate tax standard.¹²⁶

Australian corporate tax for multinational mining companies

In May 2010, the Australian Treasury released a paper¹²⁷ that evaluated the corporate tax ratio for various industries across Australia, concluding that: "... *the mining industry's average tax rate appears to be relatively low.*" It added that "*the industry receives generous deductions for the decline in value of depreciating assets, including the immediate expensing of exploration expenditure, certain infrastructure expenses and site rehabilitation.*"

The paper concluded that the Australian mining industry paid an average tax rate a third below the Australian industry average. With most Australian coal companies operating at close to, or below net cash breakeven, this corporate subsidy has no material value in the current market, but is worth in excess of A\$1-2/t over the last coal cycle. To be consistent with our view that coal has subsequently entered structural decline and profitability is unlikely to return anywhere near previous levels, we have not included this in our analysis above.

Within this sector, different companies have different domiciles and board attitudes towards fiscal self-responsibility.

The Minerals Council of Australia in multiple reports claims that Australia is a high tax country for the mining sector.^{128,129} Besides trying to confuse royalties with corporate tax by framing them together as a "Total Tax Take", the reports consistently assume that the companies' reported pretax profit is the correct base on which tax should be levied. By definition, this base is established after deducting

¹²⁵ <http://www.google.com.au/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0CB0QFjAA&url=http%3A%2F%2Fwww.aph.gov.au%2FDocumentStore.ashx%3Fid%3D9b835f76-1fe1-40a2-ab68-0b877a19b7a9%26subId%3D303104&ei=w6-PVbOVHqWlMQWk55hw&usq=AFQjCNGV1LZa0c0JRah>

¹²⁶ BHP Billiton 2014 Annual Report, page 239. IEEFA adjust the tax expense calculation to exclude royalties and pretax profit excludes profits from associates (given these are consolidated on an after tax basis).

¹²⁷ The Business Tax Division, Australian Treasury, Peter Greagg, Dean Parham and Pero Stojanovski, "Disparities in average tax rates of companies across industries", 24 May 2010. http://www.treasury.gov.au/~media/Treasury/Publications%20and%20Media/Publications/2010/Disparities%20in%20average%20tax%20rates/Downloads/PDF/Disparities_in_average_tax_rates.ashx

¹²⁸ http://www.minerals.org.au/file_upload/files/publications/DAE_Minerals_Industry_Tax_Survey_2014.pdf

¹²⁹ http://www.minerals.org.au/file_upload/files/submissions/MCA_SUBMISSION_-_Senate_Economics_Committee_-_corporate_tax_avoidance_inquiry_-_Feb_2015.pdf

profits shifted offshore into “trading hubs”, and is calculated after net interest expense where the interest allocations are those deemed appropriate by foreign directors choosing between low-tax and full tax jurisdictions. Starting with an understated pretax profit position and then calculating tax payable from there obviously supports the conclusion the minerals council seeks.

OCED Base Erosion and Profit Shifting

The Organization of Economic Cooperation & Development (OECD) Base Erosion and Profit Shifting project aims to eliminate the sort of tax avoidance that stems from base erosion and profit shifting (BEPS).¹³⁰ Base erosion and profit shifting are the various tax planning strategies that exploit gaps and mismatches in tax rules, making profits ‘disappear’ for tax purposes or shifting profits to locations where there is little or no real activity but where the taxes are low, a tactic that results in little or no overall corporate tax being paid.

The OCED action plan details the increasing need for BEPS rules to address globalization-driven corporate tax schemes that have adverse public consequences: “These developments have opened up opportunities for multinational enterprises to greatly minimize their tax burden”¹³¹ the OECD notes, adding that the trend serves to erode national tax sovereignty and that it puts an excessive onus on domestic firms and individual taxpayers to carry the country’s tax burden.

The OECD program is developing slowly, however, - so slowly that automatic exchange of tax information on Australian companies’ offshore activities will commence only by 2018 at the soonest. The program’s reach is also limited because it is aimed primarily at multinationals in the digital industry.

A further effort to improve tax disclosure and transparency can be seen in a June 2013 accounting directive adopted by the European Union (EU) that urges member country governments to oblige the extractive industry to publically disclose tax payments on an annual basis.¹³² The U.K. has implemented the EU Directive and requires relevant companies listed in London to publically report tax payments on a country-by-country and project by project basis from 2016. The action by the UK is a material step forward in disclosure and transparency and may well set an example for other countries to follow.

A2.2 Coal royalty minimization

Coal royalties charged for takings from public lands vary considerably from country to country.

In the US, the face value of such royalties is an impressive 12.5% versus Australia at 7-8% and between 5-13.5% in Indonesia. However, questions continue to be raised as to how much government review occurs into the commercial price at which the companies self-report the royalties they should be paying. Accounting procedures that include sales to subsidiaries in “arm’s length” transactions would be a logical starting point for reform. US law currently considers only the original sale between a company and a subsidiary as the base for royalty payments, allowing the subsidiary to sell such coal for a royalty-free higher price.

¹³⁰ <http://www.oecd.org/ctp/beps.htm>

¹³¹ <http://www.oecd.org/ctp/BEPSActionPlan.pdf>

¹³² <http://www.afr.com/opinion/columns/singapore-tax-structure-is-fair-for-bhp-20150628-ghzut6>

US Practices – Coal Royalty Fairness Act proposed

America's coal royalty is assessed at 12.5% for all coal taken from federal government leases under the administration by the Office of Natural Resource Revenues (ONRR). However, it has been shown recently that the rules as currently interpreted by ONRR and by US coal miners provide a loophole around this royalty. Alpha Natural Resources, Arch Coal, Cloud Peak Energy and Peabody Energy use this loophole, which does not require an "arms' length" transaction with a non-controlled or independent counterparty. For domestic coal sales, the 12.5% royalty has historically been applied by the companies involved at a domestic market sale. For exported coal, particularly coal exported through the Powder River Basin, the 12.5% has also historically been applied by the companies involved at a domestic market sale price. The extra revenue derived by coal producers from selling coal into the international market is not subjected to the royalty rate. In a robust market this can lead to a scenario where in excess of US\$20/t in revenue is not subjected to the 12.5% royalty rate.

This hidden subsidy does not appear on either corporate balance sheets or in the public reports of the US federal budget. IEEFA's 2012 report on the loophole documented how since the 1980's there has been no review by the federal government of the federal leasing program.¹³³ The IEEFA report and related Congressional inquiries has prompted the Government Accountability Office and the Department of Interior Inspector General to conduct reviews of the program. Both oversight entities have noted the lax treatment by the Department of the Interior of the coal lease program including export sales accounting. A subsequent expose by Reuters prompted a Congressional inquiry into the royalty issues.¹³⁴

This increased scrutiny, which has gained momentum over the past three years, has brought about some changes.¹³⁵ The ONRR has proposed reforms to close this loophole and to require royalties to be paid only once – only when an arms' length transaction actually occurs between unrelated parties. IEEFA's May 2015 submission to the ONRR describes the benefits and weaknesses of the proposed reform.¹³⁶

The coal industry's response to reform has been mixed. Peabody Energy has played down the impact of the regulations and Cloud Peak and the National Mining Association have criticized the proposed changes.¹³⁷ In January 2015 the ONRR promulgated new rules that would base the royalty revenue for export coal from federally owned deposits on the price paid when coal reaches a US port and is loaded onto a ship, rather than on the "mine-mouth" value, as has been the tradition.¹³⁸ The revenue derived from this "free on board" export coal would then be subject to certain reasonable transportation deductions approved by ONRR. The net value of the coal would be subject to the full 12.5% royalty, closing a loophole that amounts to a major US coal export subsidy.

¹³³ http://216.30.191.148/ieefa/062512_ieefa_prb_coal_report_final2.pdf

¹³⁴ <http://www.reuters.com/article/2012/10/18/us-coal-exports-idUSL1E8L5GU020121018>

¹³⁵ http://ieefa.org/end-this-coal-subsidy-now-part-2-one-loophole-closes-and-another-one-opens/?utm_source=Daily+IEEFA+Newsletter&utm_campaign=4a5a5c4b6a-RSS_Feed_Daily_Campaign2_18_2015&utm_medium=email&utm_term=0_e793f87bcc-4a5a5c4b6a-18701005

¹³⁶ <http://ieefa.org/wp-content/uploads/2015/05/IEEFA-royalty-reform-comments-May-2015.pdf>

¹³⁷ http://trib.com/business/energy/rift-emerges-between-peabody-and-cloud-peak-over-coal-royalties/article_c41716a9-0070-57c3-9d9a-6e30030b3806.html

¹³⁸ http://www.doi.gov/news/pressreleases/upload/2014-30033_PI.pdf

One way to calculate this subsidy is to take the average US export price for thermal coal of US\$80-100/t from 2010-2014, and the reforms under consideration would have amounted to a royalty increase from around US\$1/t to upwards of US\$6/t.

In July 2015, US Senators Ron Wyden, of Oregon, and Tom Udall, of New Mexico, introduced a new bill to enable taxpayers in the country to receive royalties for the full value of coal produced on public lands: “Coal Royalty Fairness Act of 2015”.¹³⁹ Their proposal to institute royalties on the final sale of coal is to prevent coal companies gaming the system. The proposal further estimates this would generate additional coal royalties to the US government of US\$140m annually on coal mined from public lands, primarily from the PRB.¹⁴⁰

Multinational coal miners and Singaporean trading hubs

In Australia, royalty rates have been established state by state. Queensland sets the coal royalty at 7% up to A\$100/t.¹⁴¹ New South Wales sets the coal royalty at 8.2% of value of open cut coal and 7.2% of value of underground coal, levied at the free-on-board pricing for exports.¹⁴²

As discussed above, an Australian Senate Inquiry in April 2015 examined issues relating to multinational corporations and tax avoidance. Representatives at Glencore, BHP Billiton, Rio Tinto and Adani Enterprises all appeared before the Inquiry. A key finding was that all four of these coal companies operate “trading hubs” out of Singapore, a country that allows foreign firms to use it as a tax haven. Representatives of these coal companies confirmed under oath that the companies sell their Australian coal to a subsidiary company in Singapore and then on-sell it to end customers. The designated price on which royalties are paid is determined in effect by the coal miners, rather than through open market transactions with independent buyers. Under this arrangement, Australian coal companies are not only avoiding Australian corporate tax, it has been suggested also that they are understating the value of their coal exports and hence the coal royalties due.¹⁴³

Indian-Indonesian coal trader collusion

In January 2015 investigative agencies for the Indian government unearthed a US\$4.7bn scam involving coal importing entities that had over-valued inward shipments and illegally parked funds overseas, all at the cost to Indonesian government coal royalties and to Indian electricity consumers who paid for their electricity on a ‘cost plus’ coal formula.

Ajoy K Das, writing for Mining Weekly, has reported that the Department of Revenue Intelligence (DRI), the Indian government agency mandated to investigate cases involving illegal fund flows overseas, raided 80 offices across the country including those of coal importing companies, shipping agents, trade intermediaries and coal sampling laboratories.¹⁴⁴

The investigation found that coal import contracts had been systematically over-valued, with the difference between the true value and the overstated value passed into overseas accounts. From

¹³⁹ <http://www.wyden.senate.gov/download/?id=18ea2bed-5f0b-4dc4-a917-15553756d989&download=1>

¹⁴⁰ <http://thinkprogress.org/climate/2015/07/31/3686543/coal-program-high-level-review/>

¹⁴¹ <https://www.legislation.qld.gov.au/LEGISLTN/CURRENT/M/MineralReR13.pdf>

¹⁴² <http://www.resourcesandenergy.nsw.gov.au/miners-and-explorers/enforcement/royalties/royalty-rates>

¹⁴³ <http://www.afr.com/opinion/letters-to-the-editor/audit-needed-on-mineral-royalties-20150514-gh1bxq>

¹⁴⁴ <http://www.miningweekly.com/article/indian-agencies-unearth-468bn-illegal-coal-imports-2015-01-06>

2011 to 2014, the DRI reported that these importers had illegally siphoned off an estimated US\$4.7bn.

The bulk of the over-valuations had been applied to imports of coal from Indonesia, which the DRI put at 120Mt from 2012 to 2014, at up to twice the declared value of that reported in the country of origin. Even Indian government-owned companies in the power sector were involved in the alleged scam, importing an estimated 55Mt of coal from 2012 to 2014.

Das reported also that coal-sampling laboratories had been found to have falsely certified the calorific value of the imported coal and that the higher gross calorific value was used to declare a higher payment for imports. As a consequence, the costs of falsely declared value for the imported coal were often passed on to electricity consumers by thermal power companies after factoring in the higher cost of coal into their electricity tariffs, due to the use of a 'cost plus' fuel pricing formula.

The investigations revealed, too, that coal imports were shipped directly from ports in Indonesia to India, although invoices were raised through various intermediaries in places such as Singapore, Hong Kong and Dubai. Inflated payments were remitted to these intermediaries who, in turn, transferred the amount to the original coal suppliers to be subsequently parked in illegal overseas accounts of importers.

It was shown also that although thermal coal imports from Indonesia attracted a nil rate of import duty in India under a bilateral free trade agreement, most importers did not report that this as shipments, since that would have required a certificate on the grade and price of coal from the original supplier of the coal.

Illegal Indonesian coal exports avoid royalties

Indonesia's coal export industry has grown tenfold over the past decade to become the largest exporter of thermal coal globally at over 400Mtpa. However, rampant growth and historically strong profit margins from state owned assets have given rise to an increase in corruption. It is widely reported that Indonesia's coal trafficking is endemic, running at an estimated 50-80Mtpa in 2013-2014, worth US\$3-5bn annually.¹⁴⁵

To clean up the sector, the government has called in the nation's Anti-Corruption Commission, or KPK, which is leading a sweeping review of mining permits.¹⁴⁶ Bambang Tjahjono, the director of coal business supervision at the Ministry of Energy and Mineral Resources' directorate-general of Mineral and Coal, says the intent of the review is: "to increase the government revenue and avoid the leakage of the revenue".

Of the total 3,922 coal-mining permits outstanding across Indonesia, according to the ministry, 1,461 or 40% are listed as non-clean and uncleared because of irregularities that include proposed mines overlapping with other mining or agricultural concessions. The ministry launched its own permit review program five years ago, but results are reported to be mixed, at best.

Working with the KPK and the Supreme Audit Agency, the Ministry of Energy and Mineral Resources is focusing now on the 12 provinces with the highest numbers of mining permits. The aim is to review the legality of the permits, to explore whether mining companies have valid tax identity

¹⁴⁵ <http://ieefa.org/indonesias-coal-trafficking-epidemic-requires-an-impartial-inquiry/>

¹⁴⁶ <http://news.mongabay.com/2014/1016-gfrn-fogarty-indonesia-coal-1.html#hj6h2KQXZhrLwHi2.99>

numbers, are paying their taxes and royalties fully and whether the permits overlap with palm oil or other mining concessions and protected forest areas – all of which are common problems in Indonesia.

In July 2014 the Indonesian government issued a new regulation requiring coal-mining companies to apply for licenses as registered exporters. It is also working to cut the number of ports used for coal exports in hopes of limiting the options for illegal export of the nation's resources.¹⁴⁷

Queensland royalty exemption

A little known loophole in Queensland property laws is that mineral royalties on all land titled before 1910 accrue to the private land owner rather than the state (prevailing Australian rules differ from the US standards, where private land owners generally also accrue the mineral royalties). Few coal companies benefit from this loophole but one does – New Hope Corporation.

New Hope has acquired many properties around its Acland coal mine on the cheap without disclosing this anomaly in the law. It is a perfectly legal maneuver and New Hope as a result will avoid an estimated A\$1bn of royalty payments over the expected life of the mine.¹⁴⁸

Queensland royalty holidays

In 2014 the Queensland Government offered an open-ended royalty holiday to the first mining project to open in the Galilee Basin. Assuming 40Mtpa for five years at US\$50/t, this would have represented a state subsidy of US\$700m (40Mtpa for 5 years at US\$50/t @ 7%) if Adani Mining's Carmichael project had won the race. This subsidy proposal has been withdrawn post the 2015 change of Queensland government.

German coal royalty exemptions

While Germany's Federal Mining Act of 1982 sets a 10% royalty on the market value of production, the country's 175Mtpa of domestic lignite production is exempt from this charge, a savings of about EUR1/t.¹⁴⁹

A2.3 Electricity price subsidies

Studies including those done by the OECD and the IEA have concluded that consumer subsidies of fossil fuels are generally counterproductive in terms of both political objectives of environmental goals and aims to help alleviate energy poverty.¹⁵⁰

Subsidized electricity is generally regressive in nature, with a disproportionate share going to the wealthy. This style of subsidy also dampens the incentive for energy efficiency while serving to

¹⁴⁷ <http://www.bloomberg.com/news/2014-10-03/indonesia-coal-exports-may-drop-through-december-on-permit-rule.html>

¹⁴⁸ <http://www.theguardian.com/australia-news/2015/jul/03/queensland-mine-expansion-state-to-be-a-major-loser-in-acland-royalty-payouts>

¹⁴⁹ <http://www.oecd.org/site/tadffss/DEU.pdf>

¹⁵⁰ <http://www.oecd.org/env/cc/46575783.pdf>

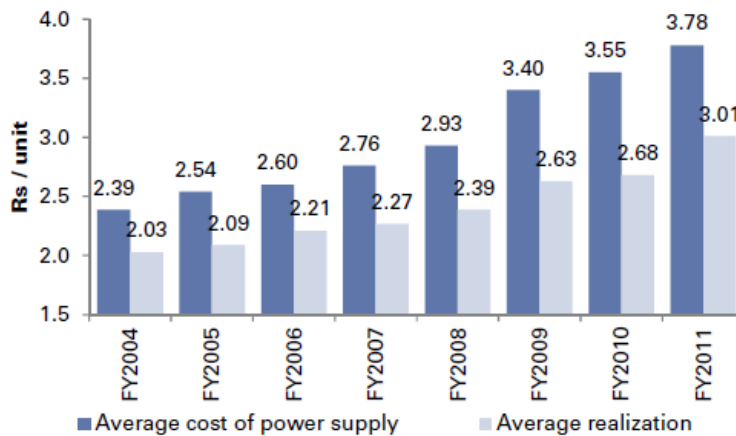
undermine the commercialization of renewable energy and other progressive technologies.¹⁵¹ This is especially evident in India, where the average retail price of electricity is below the wholesale cost, and the subsidy for residential and agricultural users is a discount of 40-80%. Despite this enormous and largely unfunded subsidy, the poorest 25% of Indians have no electricity access to allow them to take advantage of this subsidy, an outcome that is exactly opposite to the stated objective. We also see examples of electricity users and taxpayer subsidies to coal-fired power companies funded by electricity users and taxpayers in Australia and Poland. Indeed this subsidy is so pervasive that the IEA estimated its global value at US\$95bn in 2009.

Electricity price subsidies in India

India permits two clear levels of retail electricity price subsidies. The first is evident in the fact that the retail price of electricity has consistently been sold at 20-25% less than the procurement cost. Secondly, state governments across India provide significant and largely unfunded subsidies to household and agricultural customers.

Compounding the impact of both subsidies is an overall inflation rate of 5-10% annually, meaning the subsidy has grown over the past decade (Figure 16). As a measure of the extent of the problem, Energy Minister Piyush Goyal noted in March 2015 that distribution losses totalled a staggering Rs 69,108 crore (US\$11bn) net after tax loss to power utilities in 2012-13.¹⁵²

Figure 16: The gap between the cost and average realization of electricity is rising



Source: CEA, Goldman Sachs Global Investment Research¹⁵³

These losses have risen steadily from US\$3bn in 2007-08. With a wholesale price of electricity in 2010-11 of Rs3.78/kWh (the latest numbers available from the Central Electricity Authority, April 2015), adding four years of 5% pa inflation to 2014-15 and allowing a 20% positive gross margin for the distribution companies involved, an average retail price of around Rs6/kWh is implied.¹⁵⁴

¹⁵¹ OECD, IEA and World Bank joint report, “The scope of fossil-fuel subsidies in 2009 and a roadmap for phasing out fossil fuel subsidies, 11 November 2010.

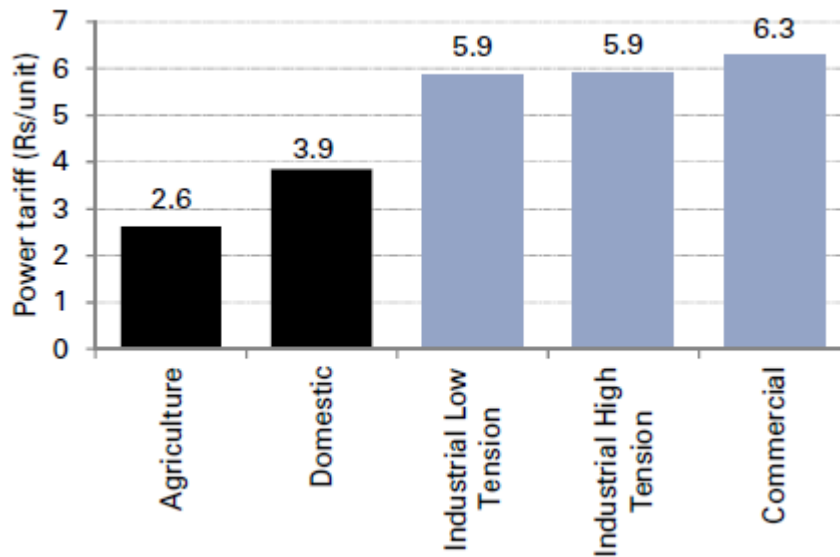
¹⁵² <http://eprahaar.in/power-distribution-losses-of-rs-69108-cr-reported-in-2012-13/>

¹⁵³ Goldman Sachs Global Equity Research, Pulkit Patni & Mohit Soni, “Energizing India: Reforms the bright spark, but regular tariff hikes key”, 19 January 2014.

¹⁵⁴ http://www.cea.nic.in/new_website/reports/monthly/executivesummary/2015/exe_summary-03.pdf

The average Indian retail price of electricity for industrial and commercial electricity users in India in 2010-11 was Rs5-6/kWh, in line with its delivered cost of procurement (Figure 17). However, almost half the electricity in India is consumed the household and the agricultural sectors. Retail consumers in 2010-11 paid Rs3-4/kWh (a 40% subsidy) while the agricultural sector paid Rs1.0-2.6/kWh (amounting to a subsidy of up to 80%, this equates to 2-4c in US\$ terms, less than 20% of the average 14c/kWh retail price of electricity in America and one tenth of the price in Australia).

Figure 17: Commercial/Industrial subsidise agriculture and domestic electricity



Source: CEA, CERC, Goldman Sachs Global Investment Research

India has one of the lowest retail electricity prices in the world. Given that 74% of Indian electricity in 2014-15 was generated from coal (and 4% from recently subsidized gas¹⁵⁵), it is fair to say that Indian coal demand is driven by this huge and largely unfunded subsidy.¹⁵⁶ This subsidy has material adverse implications for the Indian government fiscal deficit. Further, with 23% of India's thermal coal having been imported in 2014-15, the material trade deficit that results from fossil fuel imports has seen the Indian currency continue to depreciate against its trading partners. If electricity prices reflected the true cost, the residential cost of electricity would double and, with a natural price elasticity of demand effect, Indian electricity demand would be substantially lower. If this consumer demand subsidy described here was removed, a doubling of the retail price of Indian electricity would massively stimulate investment in energy efficiency, building efficiency and distributed solar with storage.

Coal industry proponents conveniently ignore this massive subsidy of imported coal fired power generation demand in India in their spurious claims that coal alleviates energy poverty.

¹⁵⁵ <http://www.livemint.com/Money/9tcajBvDxk2qKFPZ9NP3cN/Gas-power-plants-get-temporary-relieve.html>

¹⁵⁶ http://www.cea.nic.in/new_website/reports/monthly/executivesummary/2015/exe_summary-03.pdf

Electricity price subsidies in Queensland

The Queensland Government Concessions Statement for the 2014-15 Budget reports that in just Queensland alone, the government subsidizes remote area electricity consumption to the tune of A\$663m for 2014-15 alone; up almost 20% from A\$560m in the previous year.¹⁵⁷¹⁵⁸

Electricity price subsidies in Western Australia

The West Australian government likewise subsidizes its largely coal-fired electricity system to a similar magnitude.

The Energy Minister of WA Mike Nathan in October 2014 agreed for Synergy (the WA state-owned electricity company) to pay Yanzhou's 80% owned Yancoal Australia (owner of Premier Coal) a significant price rise for coal. *The Australian* estimated this subsidy at tens of millions of dollars annually, suggesting a A\$4-5/t subsidy – or hundreds of millions over the life of the 16 year contract remaining in order to keep the coal mine solvent.¹⁵⁹

Nathan flagged electricity prices would not rise despite this significant cost increase - surely a play on words at best, given this revision to a legally binding contract that was in effect from 2011 for 20 years for the supply of thermal coal by Premier Mines to Synergy. The only clear beneficiary is Yanzhou, the Chinese firm that owns 80% of Yancoal. Yancoal is today financially distressed because it acquired a number of Australian coal mines at the peak of the coal cycle for prices that have proven to be totally uncommercial and value destructive. Excessive leverage combined with the collapse in the coal price have left the ASX-listed company otherwise insolvent if it were not for the finance extended by Yancoal's Chinese parent company.

Electricity price subsidies in America – Prairie State Energy Campus

The Prairie State Energy Campus (Prairie State) was a US\$2bn 1,600MW coal-fired electricity generation project conceived by Peabody Energy in 2006 as a way of utilizing an otherwise stranded coal mine it owned. The mine produces 7Mstpa. Peabody still holds a 5% stake in Prairie State, with a number of utilities owning the balance and underwriting the project with take-or-pay PPAs of up to 30 years duration.

Prairie State was commissioned in 2012, and by then the plant had seen its capital cost blow out to a reported US\$5bn.¹⁶⁰ Further, in the first three years of operation the plant has run at a capacity

¹⁵⁷ Queensland Government State Budget 2014-15, Concessions Statement, page 4.

¹⁵⁸ <https://www.treasury.qld.gov.au/publications-resources/state-budget/2014-15/budget-papers/documents/concessions-statement-2014-15.pdf>

¹⁵⁹ <http://www.theaustralian.com.au/business/mining-energy/synergy-deal-wont-hit-priceof-energy/story-e6frg9df-1227090539789>

¹⁶⁰ http://www.stltoday.com/business/local/delays-cost-overruns-blemish-illinois-coal-project/article_ffaa187e-b729-11e1-b412-001a4bcf6878.html

utilization rate 15-25% below the budgeted rates. The result of these two factors is reported by IEEFA to have driven Prairie State's cost of electricity generation in 2014 run at US\$70/MWh, 40-50% above the prevailing wholesale market rates.¹⁶¹ The subsidy by utility ratepayers for this stranded asset is substantial, and locked in for another 25 plus years (Peabody would argue this was merely a commercial contract gone wrong, whereas the 200 communities paying this subsidy would most likely argue otherwise). In addition the project has received a direct cash subsidy to write down interest costs on the project. The federal Build America Bond program is providing over US\$900m in direct cash payments from the federal treasury to the bond issuers in Prairie State.¹⁶² A myriad of court cases and disputes have resulted from this investment debacle.¹⁶³

Electricity price subsidies in Poland

In June 2015 Polish Prime Minister Ewa Kopacz approved a coal subsidy package worth 25bn zlotys (US\$6.7bn), to be financed from the EU as well as from state and local governments in Poland.¹⁶⁴ The "Silesia 2.0" plan calls for tax exemptions for industries using coal and loans for modernizing Ukraine's coal-based power plants, with the aim of increasing demand for Polish coal. There is also funding for developing technologies to turn coal into gas and for developing road and rail infrastructure. Kopacz stated the following: "*I gave the maximum possible without endangering the budget ... Poland's energy security rests on Polish coal.*"

This massive new coal subsidy moves Europe in the exact opposite direction of its overall decarbonisation goal.

Electricity price subsidies in Europe – Free EU ETS Permits

Fossil fuel electricity production across the entire European Union (EU) over the last decade has been heavily subsidized, and this has predominantly benefited coal. The free allocation of EU emissions trading scheme (EUETS) credits was worth €14bn in 2012, down from €38bn in 2009. All of these free credits amount to additional support for fossil fuel energy, as they allow firms to avoid paying to emit carbon.¹⁶⁵

¹⁶¹ <http://ieefa.org/2014-another-year-of-unmet-promises-for-the-prairie-state-energy-campus/>

¹⁶² https://docs.google.com/file/d/0B_qWeYLAqoq1NFhvNy1teWc3VDQ/edit. See Appendix I.

¹⁶³ <http://www.ieefa.org/wp-content/uploads/2013/08/IEEFA-memo-to-Galion-August-2013.pdf>

¹⁶⁴ http://hosted.ap.org/dynamic/stories/E/EU_POLAND_INDUSTRY?SITE=ILBLO&SECTION=HOME&TEMPLATE=DEFAULT

¹⁶⁵ <http://reneweconomy.com.au/2014/true-cost-of-energy-and-subsidies-in-europe-renewables-win-72398>

A2.4 Free allocations of public assets to private concerns

Coalgate – a US\$32bn subsidy to Indian coal companies

In a scandal appropriately dubbed ‘Coalgate’, the Indian Supreme Court in September 2014 cancelled 204 coal leases granted by the government of India (GoI) to private coal using companies from 1990 to 2010. Having decided the process was totally conflicted and without merit (in effect a wealth transfer from the government to private power companies), the court resumed government ownership on the 204 leases, and demanded a US\$5/t royalty retrospectively on all coal mined from any of these leases (relative to the US\$10/t mining costs, this was an after the event 50% increase in cost of all coal used).

The coal scam first surfaced in March 2012 when the Comptroller and Auditor General of India (CAG), a constitutional entity empowered to audit government financials, submitted a draft report on coal block allocations that occurred from FY2006-07 to FY2010-11. The report argued that although the GoI had the authority and ability to allocate the coal blocks via competitive bidding, it chose not to do so. The Comptroller Auditor General's office estimated that the resulting lower allocation payments made by allocatees saw a monetary loss of Rs1.86trn (US\$31bn) to India's exchequer.¹⁶⁶

From February to April 2015 the government auctioned 29 coal blocks in two tranches to private companies and signed contracts with a life of mine value of over Rs 2 lakh crore.¹⁶⁷ A third tranche is scheduled to be auctioned in September 2015. To ensure transparency and integrity of the tender process, if in any particular auction there were fewer than three bidders the government stopped the auction. Post auction, several tenders were not accepted given the appearance of possible collusion.¹⁶⁸¹⁶⁹ This gives an important endorsement to Indian Prime Minister Narendra Modi's pledge against corruption. Further, the Central Bureau of Investigation has launched legal cases into criminal conspiracy and cheating.¹⁷⁰

The tendering process has proven to be very competitive, and the reverse auction system has extracted commitments to pass on substantial cost savings to Indian electricity consumers as well as ongoing coal royalties to the state governments involved. In fact some of the awards have seen ‘negative bidding’, by which power producers seeking to win captive coal blocks forgo their right to pass on a percentage of coal mining costs to consumers and agree instead to pay the government. This bizarre situation reflects the stranded asset nature of many coal-fired power plants across India, built but unable to operate due to an inability to source a consistent supply of cost-competitive coal.

To give some context to the size of the coal subsidy involved in Coalgate, production from the 204 coal blocks is estimated to reach a peak of 500Mtpa.¹⁷¹ While IEEFA would view this estimate as

¹⁶⁶ <https://salvareport.com/indian-thermal-coal-imports-increase-50mtpa/>;
<http://profit.ndtv.com/news/corporates/article-coal-mine-clearance-status-of-companies-up-for-government-review-776158>

¹⁶⁷ <http://timesofindia.indiatimes.com/business/india-business/We-got-honest-value-of-coal-through-auctions-says-Piyush-Goyal/articleshow/47322786.cms>

¹⁶⁸ <http://in.reuters.com/article/2015/03/02/india-coal-auctions-id!NKBNOLYONI20150302?feedType=nl&feedName=inmoney;>

¹⁶⁹ http://www.business-standard.com/article/pti-stories/no-conclusive-proof-of-collusion-in-jspl-bids-115040101370_1.html

¹⁷⁰ http://india.blogs.nytimes.com/2014/03/10/first-charges-filed-in-30-billion-coal-scandal/?_php=true&_type=blogs&_r=0

¹⁷¹ <http://economictimes.indiatimes.com/industry/energy/power/power-consumers-to-save-rs-69311-crore-due-to-negative-coal-block-bids/articleshow/47029411.cms>

likely to prove optimistic, this state giveaway to coal companies is equivalent to the entire Australian coal industry.¹⁷²

The unwinding of Coalgate represents one of the best examples of the reversal of a government subsidy to coal and of coal industry corruption being dealt with to the benefit of the public over special interest groups seeking to illegally profit from their country's natural resources.

NSW Australia allocations and the Independent Commission Against Corruption

Following a New South Wales Independent Commission Against Corruption (ICAC) inquiry report handed down in July 2013, then Premier Barry O'Farrell in April 2014 cancelled coal licenses at Doyles Creek, Mount Penny and Glendon Brook after corruption findings against former NSW Resources Minister Ian Macdonald, former Labor Minister Eddie Obeid and former union boss John Maitland over the license grants.¹⁷³¹⁷⁴ The Commission also found corrupt conduct on the part of businessmen Travers Duncan, Richard Poole, John McGuigan, John Kinghorn and John Atkinson for their roles in "deliberate misrepresentations".

According to published reports, six weeks after being awarded the coal mine license by Macdonald's department, a A\$1 company, Loyal Coal, sold 90% of the Yarrowa/Ferndale deposit to then-listed miner Coalworks for A\$2.4m. It later sold a further 2.5% for six million share options. The remaining 7.5% could still earn its holders tens of millions of dollars a year over the life of the project.

The Australian listed company Whitehaven Coal subsequently acquired Coalworks in 2012, the then 'owner' of the Yarrowa/Ferndale deposit, which covers a 743Mt inferred coal resource. Whitehaven Coal's deputy chairman is Mark Vaile, a former Deputy Prime Minister of Australia.

The Commission ruled that it was too hard to rescind illegal coal mine allocations at Yarrowa/Ferndale, "by reason of the vast number of innocent investors".

According to the published reports in November 2014, the Commission and the Director of Public Prosecutions served a notice on Eddie Obeid stating that he would be charged with misconduct in public office, with specific charges relating to other interests procured while in Government.¹⁷⁵ Currently, the Australian Tax Office is pursuing more than 30 members of the Obeid family over at least A\$8.6m in unpaid tax and penalties arising from two coal deals.¹⁷⁶

¹⁷² <http://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/req/REQ-June15.pdf>

¹⁷³ http://www.google.com.au/url?sa=t&rct=j&q=&esrc=s&source=web&cd=10&ved=0CEsQFjAJ&url=http%3A%2F%2Fwww.icac.nsw.gov.au%2Fcomponent%2Fdocman%2Fdoc_download%2F4188-investigation-into-the-conduct-of-ian-macdonald-edward-obeid-senior-moses-obeid-and-others-jasp

¹⁷⁴ <http://www.news.com.au/national/icac-inquiry-eddie-obeids-vaile-of-mining-secrecy-is-revealed/story-fncynjr2-1226883077034>

¹⁷⁵ <http://www.afr.com/news/politics/national/eddie-obeid-to-be-charged-with-corruption-20141120-11qxmj>

¹⁷⁶ <http://www.theherald.com.au/story/3012166/obeid-family-fights-tax-case/>

A2.5 German subsidies – coal mining, a loss making industry

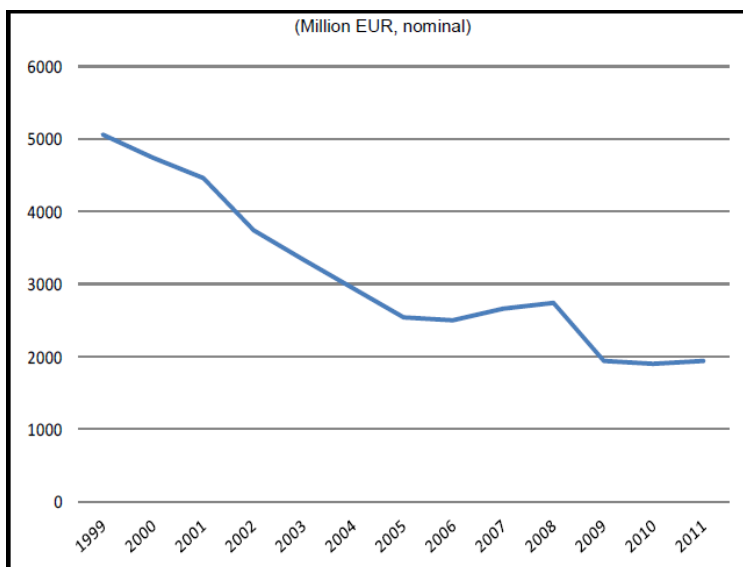
The OECD report on subsidies for fossil fuels provides an interesting case study on Germany¹⁷⁷ where all hard coal mining is undertaken by a single company, RAG Deutsche Steinkohle AG (DSK AG). This company has long been loss making and has been underwritten since 2007 by the federal and state governments. In contrast, opencut lignite mining remains profitable and is undertaken by private firms. In 2007 the shareholders of DSK AG, including E.ON and RWE, transferred their shares for a symbolic €1 to the RAG Foundation. As of 2011, DSK AG operated five deep coal mines at sites in the Ruhr and Saar regions and in North Rhine-Westphalia.

As production costs remain well above revenues, the company gets substantial government subsidies, totaling €1,900m in 2011 alone, thankfully well down on the €5,000m loss back in 1999 – Figure 18. Subsidies have been in place back to 1967. The German government has also been covering the cost of mine closures as part of this program. These subsidies have taken the form of debt relief schemes, mining royalty exemptions and reduced pension contributions for miners.

In 2007 a deal was struck between the government, the unions and DSK AG agreeing to a roadmap that facilitated an orderly community transition, with a gradual scaling back of production and final exit from domestic hard coal mining in Germany by 2018.

For all the complaints about the excessive subsidies involved in Germany’s successful Energiewende program, fossil fuel proponents often overlook the fact that not only are thermal power generation businesses unprofitable in Germany, but also that the domestic hard coal mining sector has been loss-making for decades and exists entirely due to ongoing massive government subsidies.

Figure 18: Total coal mine support by the German government (1999-2011)



Source: [OECD](#), "Germany: Inventory of estimated budgetary support and tax expenditures for fossil fuels – 2013".

At a total subsidy cost of €1.9bn in 2011, compared to hard coal production in Germany in 2011 of 12.1Mt, this equates to a subsidy of a staggering US\$175/t. With domestic production having halved in the last six years, and with the added cost of mine closures and rehabilitation, the subsidy cost per

¹⁷⁷ <http://www.oecd.org/site/tadffss/DEU.pdf>

tonne is ballooning to exceptional levels. Germany is in the top 20 largest hard coal producing nations globally.

In July 2015 Barbara Hendricks, the Federal Minister of the Environment [announced](#) new policies in support of the phase-out of the heavily subsidized German coal industry.

German lignite fired electricity generation subsidy

In July 2015, the German Government announced it would implement a new strategy reserve subsidy to support retention of 2.7GW of lignite electricity generation capacity in a standby mode at a subsidy of €230m per year.¹⁷⁸

RWE is the owner of half of Germany's lignite based electricity generation capacity. RWE's CEO, Peter Terium, has confirmed that 35-45% of their current conventional fleet is unprofitable and that with German wholesale electricity prices at a decade low, RWE's overall thermal generation division is operating at an overall cash breakeven position.¹⁷⁹ Two-thirds of RWE's entire lignite generation fleet totaling 10GW of capacity has been in operation for more than 40 years.

However, this new subsidy to coal fired power generation is being challenged by the announcement in April 2015 that the European Commission will undertake an investigation into proposed capacity markets spanning 11 EU member states.¹⁸⁰ Capacity markets are a form of subsidy that the European Commission has been questioning given that this subsidy in effect undermines the increased emphasis on a pan-European electricity grid.

¹⁷⁸ <http://www.wwf.de/fileadmin/fm-wwf/Publikationen-PDF/WWF-Stellungnahme-Ein-neues-Klimaschutzinstrument-fuer-den-Stromsektor.pdf>

¹⁷⁹ <http://www.wsj.com/articles/rwe-plans-further-cost-cuts-1425968788>

¹⁸⁰ <http://uk.reuters.com/article/2015/04/29/uk-eu-energy-competition-idUKKBN0NK0YV20150429>

A2.6 Poland – US\$9/t Coal Mining Subsidy

The OECD Report into fossil fuel subsidies and support for Poland details how PLN2bn (US\$575m) of annual coal mining producer subsidies were paid as “stranded cost compensations” to cover the excess cost of domestic coal relative to the fuel price the coal-fired power plants could afford to pay whilst still generating an acceptable profit margin on their power purchase agreements (PPA).¹⁸¹ The PPAs started in 2008 and extend to 2027, and cover 40% of Poland’s electricity. With Polish hard coal production of 76Mtpa in the 2009-2011 period, this equates to a subsidy of US\$8/t. The Polish government for the past two decades has shut unprofitable mines and consolidated entities, trying to reduce employment and lift employee productivity as a result, and writing off excessive debts held by various state owned coal companies.

In addition to this US\$8/t annual subsidy, the Polish government incurred US\$70m annually over 2005-2011 or US\$1/t of production on aid for coal mine decommissioning, rehabilitation of coal-mining sites and early retirement benefits for laid off miners, plus US\$11m annually on consumer support for coal.

Poland is the ninth largest coal producer globally.

¹⁸¹ <http://www.oecd.org/site/tadffss/POL.pdf>

A2.7 Government sponsored enabling capital

Government supplied subsidies to the coal industry also extend to providing enabling capital. By subsidizing or outright provision of capital for associated coal rail and port infrastructure, and by offering financial ‘aid’ to promote the continued expansion of coal-fired power plants internationally, governments are using taxpayer support to prop up demand and lower the cost of supply for thermal coal.

A report from March 2015 calculated that the OECD alone provided US\$14bn of preferential loans and state-backed guarantees for export coal over 2003-2013, as part of a wider US\$36.8bn for exporting fossil fuel power generation technology.¹⁸² A further US\$52.6bn was provided in this same period to support the extraction of fossil fuels, including coal. A number of examples are detailed below, including proposed rail and port infrastructure funding guarantees by the Queensland, New South Wales (NSW) and Australian governments, as well as Wyoming State government proposed funding of coal export facilities in the Pacific North West of America. The US government has long provided infrastructure funding for coal-fired power plants.

Australian Rail and Port Infrastructure

In Australia, the Queensland and NSW governments have funded the majority of enabling rail and port infrastructure for the coal export industry over a period of decades, underwriting and socializing part the capital cost of the coal industry development onto taxpayers.

The government owned Queensland Rail put a century of development into the railway infrastructure until it was privatized as the renamed Aurizon and listed on the Australian Securities Exchange in November 2010. More than 80% of Aurizon’s earnings before interest and tax come from coal freight. With an equity market capitalization of A\$11bn as of July 2015, Aurizon’s privatization over 2010-2012 was a timely exit that has freed up an A\$6-7bn of government equity that had previously been underwritten almost entirely for the benefit of the Queensland coal sector.

Likewise the North Queensland Bulk Ports Corporation (NQBP) is owned by the Queensland government, having funded and developed the Abbot Point Port, a dedicated single product coal export facility. In July 2011 NQBP’s effectively privatized the majority of this asset via a 99-year lease Terminal 1 to Adani Ports & SEZ Ltd of India. Going forward, the government is trying to place the capital cost of coal port development and cost of associated dredging onto the private proponents – but this transfer of capital risk is not always effective.

Gladstone Port Corporation has total assets of A\$2.0bn as at June 2014, and has undertaken public-funded investment of A\$450m in the last six years alone.¹⁸³ Its current coal export capacity stands at 77Mtpa (plus the privately owned new 27Mtpa WICET coal facility). Coal is 71% of the Gladstone Port Corporation’s total volumes. This group has averaged a leveraged return on equity after tax of 8% pa over the last five years. While improving, this is below the accepted benchmark return on equity in Australia that IEEFA estimates at 10-12% pa.

The Queensland Government Concessions Statement for the 2014-15 budget reports that the ongoing subsidy for the Gladstone Port Corporation amounted to A\$54m for 2014-15 alone, up from

¹⁸² <http://reneweconomy.com.au/2015/rich-nations-spend-5x-more-on-fossil-fuel-export-subsidies-than-renewables-86564>

¹⁸³ http://www.gpcl.com.au/SiteAssets/Annual%20Reports/GPC_Annual_Report_2013-14.pdf

A\$52m the previous year.¹⁸⁴ With Gladstone exporting 68Mt of coal in 2014/15, and assuming only 71% of this subsidy applies to coal, this equates to A\$0.55/t of coal exported.

Gladstone Port Corporation and NQBP provides much of the co-ordination and government interface for coal port infrastructure for three of the larger coal ports in the world.

Newcastle Port in NSW is one of the two largest coal ports in the world, and prior to its A\$1.7bn privatization in March 2014, was government owned. This 211Mtpa capacity coal port was developed in conjunction with the NSW coal industry, with the actual terminal facilities owned and funded by two private consortia: PWCS¹⁸⁵ and NCIG¹⁸⁶. As evidence that the provision of port infrastructure was subsidized for decades by the NSW government, in January 2015 the now privatized Newcastle Port proposed that the three most common coal-carrying vessels that use the port will pay 60% more to traverse the shipping channel, citing as justification that no price rises have been implemented in the previous decade.¹⁸⁷

Similarly, although private rail freight firms move the export coal from the Hunter Valley to Newcastle, the government owned and funded Australian Rail Track Corporation (ARTC¹⁸⁸) manages the rail network. ARTC has invested over A\$1.3bn of capital in upgrading the Hunter Valley coal rail network in the six years to 2014. Despite A\$3.6bn of shareholders equity, the business has generated a net after tax loss averaging A\$80m annually over the last four years. The government's own Commission of Audit in its 2014 report stated: *"In recent years some of the capital projects undertaken by the Australian Rail Track Corporation have had marginal benefit-cost ratios, were not needed to meet future demand projections or did not effectively address expected capacity constraints."*¹⁸⁹

Australian taxpayers are underwriting the capital risk of enabling rail and port infrastructure for the predominantly foreign owned coal industry in Australia, and then having to fund the ongoing losses thereafter – an open-ended subsidy to a special-interest group.¹⁹⁰

Queensland Government enabling capital to the Galilee

In direct contradiction of the conclusions of the G20 Economic Summit held in Brisbane in November 2014, then Queensland Premier Campbell Newman continued to promote the Adani Carmichael coal, rail and port project proposal in the Galilee Basin through multiple offers of taxpayer subsidies and the provision of enabling capital. Freedom of Information searches¹⁹¹ show that the Newman government made offers of: an open ended coal royalty holiday; free water allocations and purpose built A\$500-A\$1,000m water infrastructure; construction of a new A\$50-A\$100m tug harbour; underwriting for the related single purpose, greenfield coal freight railway; and a proposed

¹⁸⁴ <https://www.treasury.qld.gov.au/publications-resources/state-budget/2014-15/budget-papers/documents/concessions-statement-2014-15.pdf>

¹⁸⁵ <http://www.yancoal.com.au/page/key-assets/infrastructure/port-waratah-coal-services-coal-terminal/>

¹⁸⁶ <http://www.yancoal.com.au/page/key-assets/infrastructure/NCIG/>

¹⁸⁷ <http://www.afr.com/business/mining/coal/glencore-seeks-accp-protection-at-newcastle-port-20150513-gh0vc5>

¹⁸⁸ http://www.artc.com.au/library/annual_report_2014.pdf

¹⁸⁹ <http://www.businessinsider.com.au/report-the-abbott-government-will-sell-off-the-australian-rail-track-corporation-2015-5>

¹⁹⁰ For more details, refer The Australia Institute's report "Mining in the Age of Entitlement: State Government Assistance to the minerals and fossil fuel sector", June 2014, Mick Peel, Rod Campbell and Richard Denniss.

¹⁹¹ Queensland Treasury and Trade, email correspondence, 21 November and 2 December 2014.

“purchase” of dredge spoil at Adani’s Abbot Point Coal Terminal to offset growing investor concerns over the commercial viability of the project.

In November 2014, then Deputy Premier Jeff Seeney offered to take a taxpayer funded 45% equity stake worth A\$455m in the development of the dedicated 388 kilometre rail line for Adani’s Carmichael Coal project proposal.¹⁹² The government’s argument is that this would be an open-access rail facility for all coal mine proposals in the Galilee. At that time, the Queensland Treasury’s Principal Commercial Analyst for this project stated that the *“current financial market feedback indicates that Adani will face significant challenges in demonstrating viability to secure independent debt and equity support”*. The Queensland government also made these commitments without substantive due diligence being undertaken on the proponent.

The election of a new Labour government in February 2015 saw the demise of the Queensland government’s efforts to underwrite the capital costs of opening up the Galilee coal basin.

Australian Government enabling capital to the Galilee

In May 2015 Australian Prime Minister Tony Abbott revealed a new strategy to subsidise the Galilee with his proposed new *‘Northern Australia Infrastructure Fund’*.¹⁹³ The fund’s charter was said to be only open to “uncommercial projects,” Carmichael fits the bill perfectly! The fund targets the provision of power generation, water infrastructure and enabling railway services to North Australia, and specifically includes the Galilee Basin. It seems telling that the Australian Productivity Commission’s “Trade & Assistance Review 2013-14” was released a month later.¹⁹⁴ The warning to the federal government is that with increased corporate assistance, *“resource misallocation is likely. Moreover, governance and due diligence fall short of contemporary, comparable best practice.”*¹⁹⁵

Australia - NSW Government Waivers Development Fees – Newcastle T4

The assignment of the State Significant Project Development tag to the Newcastle coal port’s Terminal 4 (T4) 70Mtpa capacity expansion has allowed this coal port proposal to sidestep the 1% local council development application fee. On the A\$4.8bn investment, the proposal is only required to pay the Newcastle local council A\$0.52m rather than the standard levy of A\$48m. As such, the coal companies will again leave Newcastle ratepayers to subsidise the local council amenities and services that all ratepayers use.

Australia - NSW Government Subsidizing Development Costs – Cobbora Coal

The Cobbora Coal Project is an open cut coal mine proposed in central NSW. The Project was being developed over 2012-2013 to supply up to 9.5Mtpa of lower quality thermal coal, under long-term contracts, to three coal-fired power stations in NSW the government was preparing to privatize.

¹⁹² <http://www.smh.com.au/business/mining-and-resources/adanis-carmichael-mine-is-unbankable-says-queensland-treasury-20150630-gi1i37.html>

¹⁹³ <http://reneweconomy.com.au/2015/abbott-proposes-dirty-energy-finance-corp-for-northern-infrastructure-64673>

¹⁹⁴ <http://www.pc.gov.au/research/recurring/trade-assistance/2013-14/trade-assistance-review-2013-14.pdf>

¹⁹⁵ Australian Productivity Commission’s “Trade & Assistance Review 2013-14” page 2.

In July 2013, the NSW Treasurer Mike Baird [stated](#): “The price agreed by the previous Labor Government for the Cobbora coal supply was not linked to market prices. As a consequence, the development cost of the mine was not covered by the contracts.” The NSW government then [paid](#) A\$300m to Origin Energy to exit a coal supply contract from Cobbora that never delivered any coal.

In August 2014 NSW Treasurer Andrew Constance stated: “The previous Labor Government’s decision to develop the Cobbora Coal Mine exposed taxpayers to the volatile thermal coal market and saddled them with a future liability of more than A\$1.5bn in development costs”.¹⁹⁶

Wyoming Infrastructure Authority to provide financing for Coal Export Terminals

The State of Wyoming’s Legislature is reported to be considering a bill to increase the Infrastructure Authority’s bonding limit from US\$1bn to US\$3bn and also allow that money to be spent outside the state’s borders.¹⁹⁷ The objective is to provide otherwise unavailable financing for companies that are trying to build coal export terminals in the Pacific Northwest.¹⁹⁸ This proposed State subsidy could prove critical to building yet another stranded asset.

In February 2015, the State of Utah approved a US\$53m investment via Utah's Community Impact Fund Board into Oakland's Terminal Logistics Solutions. Of the 16m short tons (Mst) of coal produced in Utah each year, only about 1Mst is currently exported.¹⁹⁹

US Tax Exempt Bond Subsidies and Coal Fired Power Generation

The US government supports a wide variety of public infrastructure development through the issuance of tax-exempt bonds. State, municipal and specially designated public corporations issue bonds to support the construction of highways, schools, hospitals, water and sewer lines, solid waste treatment plants and power generation plants. The bonds are typically backed by tax revenues from the issuing governmental jurisdictions.

In the case of power generation plants, bonds are typically issued by municipal electric systems and public power authorities and backed by revenues from the sale of electricity from the plant. The price for the electricity is decided by municipal and state boards with independent rate setting authority.

Interest payments made to bondholders are received as income that is free from federal income tax. This allows the issuers to offer the bonds at a lower interest rate producing subsidised borrowing costs for the power generators. These ‘below market’ interest payment, plus tax advantage to the investor, keep the bond competitive against other comparable corporate and Treasury instruments. In addition, since most tax-exempt bonds have either direct or indirect backing of the taxing power of state and local governments, they are seen as relatively secure investments.

In 2013 the outstanding balance of tax-exempt bonds in the US was US\$3.7trn.²⁰⁰

¹⁹⁶ <http://www.cobbora.com/Resources/Documents/Publications/2014-12-22-Media-Release---Govt-considers-options-for-Cobbora-Coal-Mine.pdf?iframe=true&innerWidth=590&innerHeight=650>

¹⁹⁷ <http://insideenergy.org/2014/12/18/wyoming-looks-to-finance-coal-export-terminals/>

¹⁹⁸ <http://www.washingtontimes.com/news/2015/may/19/wyoming-governor-coal-exports-critical-to-states-i/?page=all>

¹⁹⁹ http://www.mercurynews.com/my-town/ci_27981682/unlikely-partners-utah-investing-53-million-export-coal

The annual foregone revenue to the federal budget from these bonds is estimated at US\$37bn annually. According to the GAO, 3.3% of all issuances were for power generation projects and 1.6% were for pollution control equipment.²⁰¹ By IEEFA's estimates approximately US\$1.85bn annually is foregone revenue to the federal government for power generation and pollution control projects, and that almost all of this relates to fossil fuel power plants. This equates to a subsidy of some US\$1/tpa for all US coal used in the power sector over the last decade (adjusting for coal's share of thermal electricity capacity).

United States Department of Agriculture – Rural Utility Service (RUS)

In the 1930's, as part of the New Deal, President Roosevelt passed the Rural Electrification Act. The new law had as its cornerstone the provision of low interest, long-term capital for the development of power generation to unserved rural areas in the United States. The law and subsequent development would unleash a series of investment in hydroelectric, nuclear and coal electric generation investments. By 2013, the nation's network of electric cooperatives that serve 12% of residential consumers relies on coal for 58% of its capacity, whereas the nation relied upon coal for only 45% of its capacity.²⁰²

The subsidy from RUS has fluctuated with the rise and fall of Treasury and general interest rates over time. And, RUS has a number of different interest rate programs. At times the subsidy has risen to six and seven percentage points. Historically we would conservatively estimate that the spread between the government loan rate and the market rate has been three to four percentage points. Assuming that 40% of the US\$38bn lent during the 1970's and 1980's went for coal projects (a significant amount went for nuclear power), then the subsidy over the course of thirty years is US\$11bn.

As noted by the GAO, despite these subsidies, at least a half dozen of these plants fell into default in the 1990's, necessitating write-offs in the hundreds of millions of dollars.²⁰³

In 2008, then President Bush terminated the use of USDA rural electrification loans for new coal plant construction.²⁰⁴ The program nevertheless continues to make loans to rural electric coops for retrofits of the legacy coal fleet. Electric cooperatives remain one of the most coal dependent sectors of the US power market.

China underwrites coal fired power in Pakistan

In June 2015, it was reported that Engro Powergen of Pakistan was likely to proceed with the 660MW Thar domestic coal-fired power project at a total cost of US\$2.05bn.²⁰⁵ Of this, US\$825m

²⁰⁰ <http://www.publicpower.org/files/PDFs/MunicipalBondsAndPublicPowerFeb2013IB.pdf>

²⁰¹ <http://www.gao.gov/assets/280/272369.pdf>

²⁰² <https://www.nreca.coop/wp-content/uploads/2013/07/Distributioncoopfuelmix.pdf>

²⁰³ <http://www.gao.gov/assets/110/107348.pdf>

²⁰⁴ <http://www.washingtonpost.com/wp-dyn/content/article/2008/03/12/AR2008031203784.html>

²⁰⁵ <http://www.rtcc.org/2015/06/02/china-billions-drive-pakistan-coal-power-expansion/>

would be financed by Power Construction Corp. of China Ltd and its associated Chinese banks. The project involves a US\$950m mine mouth coal mine and a US\$1.1bn coal-fired power plant, to be built by the Chinese. The balance of funding is expected to be raised from Pakistani banks with the help of the Sindh provincial government.

Putting aside the unquestionable need by Pakistan for additional electricity capacity, the suggestion that coal is competitive and bankable, without the support of local government and funding from foreign state-owned enterprises, is clearly not evident in this proposal. A second US\$2bn, 1.32GW imported coal fired power plant proposal for Pakistan is likewise being funded by China Power Construction Corp and Chinese state owned banks.

A2.8 Unfunded Pension Liabilities

US coal companies that have committed to paying retirement benefits and pension obligations have not funded their obligations. As such, the retired workers of these companies are financially exposed should the companies go into Chapter 11. Peabody Energy's 2014 annual report details that as of Dec. 31, 2014, it had US\$839m of accumulated retirement benefit obligations, and a further US\$163m of pension liabilities. Alpha Natural Resources 2014 Annual Report shows a similar picture: a US\$1,237m unfunded liability for Post Retirement Benefits plus another US\$145m liability for Black Lung Obligations. However, public filings seem to state that a proposed plan to cover these liabilities was zero-funded. In effect, then, coal workers are funding the capital of Peabody Energy and Alpha Resources by sharing company risk.

By comparison, public filings suggest that Peabody has a pension and savings plan on for "certain US-salaried employees and eligible hourly employees ... senior management," with a liability of US\$1,002m funded to the tune of 84% or US\$840m. Further, Peabody Energy continued to fund quarterly dividend payments to shareholders in lieu of funding retired worker pension plans up until November 2014.

In September 2014, the president of the United Mine Workers of America, gave an interview arguing that US coal companies had to be allowed to survive so that retired workers could receive their unfunded pension benefits.²⁰⁶ In effect, current workers make contributions to fund a portion of the benefits promised to retired workers who have little chance of ever collecting on the retirement promises made to them.

A2.9 Overturning Legitimate Contracts

Adani Power and Tata Power, Indian electricity-industry conglomerates and owners of the Mundra Ultra Megawatt Power Plant, have managed to argue successfully in court that "unforeseen circumstances," that is, the fall in India's currency-exchange rate and movements in international coal prices and coal-export tax rates, should allow legally binding 25-year PPAs to be overturned due to "force majeure."

When the higher court overturned the controversial decision in favor of Adani and Tata, the two power companies with a combined 8GW of capacity at Mundra ceased electricity supply without notice, causing widespread blackouts in an effort to hold the state hostage in exchange for subsidies.

²⁰⁶ <http://www.snl.com/InteractiveX/article.aspx?ID=29048500&KPLT=4>

A2.10 Externalizing Health and Environmental Costs

Coal Dust

Coal shippers typically transport coal in uncovered open-top rail cars. This allows significant amounts of coal dust to blow over residential and agricultural areas, and to pollute waterways, crops, and the air.²⁰⁷ Each car on a coal train releases 500 to 2,000 pounds of coal dust over the course of its journey, according to a study by the Berkshire Hathaway owned Burlington Northern Santa Fe Railway (BNSF).²⁰⁸ Thus, a typical 125-car coal train could release up to 30-110 tonnes per train trip, around 3% of all coal moved by rail in the US.

Coal dust externalizes a huge cost onto the environment, damaging waterways, adjacent agricultural land and causing severe health costs to communities.

The world's largest coal port sits in the middle of Newcastle, Australia a city of 300,000 people. Coal dust and the associated respiratory problems have been an ongoing issue in Newcastle for decades, with various government reports heavily conflicted and compromised.²⁰⁹

Coal Ash and Slurry Pond “Leakages”

The US Environmental Protection Agency (EPA) recently published research titled: “Damage Cases: Fugitive Dust Impacts” noting the public health impacts of coal ash. Ruth Santiago [reported](#) in July 2015 the issues at AES Corp’s Puerto Rico plant, which is generating 400,000 tons annually of coal ash and using it virtually without treatment as a landfill in construction sites.

In December 2014, the US EPA created a number of new reporting by utilities, ground water monitoring and containment requirements for coal ash waste sites. In 2013 alone, 115m tonnes of waste product was generated by coal-fired power plants. While 45% was recycled, the majority was either contained in coal slurry ponds or put into landfill.²¹⁰ As a single estimate of the potential multi-billion dollar clean-up cost, Duke Energy estimated that 14 coal ash sites in North Carolina could cost US\$2-10bn for rehabilitation.²¹¹

In July 2015, it was reported that flooded Vietnam coal mines slurry ponds have leaked toxic slurry into World Heritage-listed Ha Long Bay, a UNESCO World Heritage site visited by millions of tourists each year.²¹²

Railway, Mining Disasters and Black Lung Deaths from Coal

A 2011 US Harvard study that detailed an estimate of the full external societal impacts of the US coal industry²¹³ should be compulsory reading on the externality costs of coal. Funding of black lung

²⁰⁷ http://action.sierraclub.org/site/DocServer/100_158_CoalDust_FactSht_04_X1A_2_.pdf?docID=12643

²⁰⁸ <http://www.coaltrainfacts.org/docs/BNSF-Coal-Dust-FAQs1.pdf>

²⁰⁹ <http://www.abc.net.au/news/2015-02-13/calls-for-chief-scientist-to-have-final-say-on-coal-dust-impacts/6092208>

²¹⁰ <https://www.snl.com/InteractiveX/article.aspx?ID=30271623&KPLT=4>

²¹¹ Duke Energy, Form 10Q 2014 First Quarter, page 45.

²¹² <http://mobile.abc.net.au/news/2015-08-01/heavy-rain-floods-vietnam-coal-mines-threatening-ha-long-bay/6665570>

²¹³ ANNALS OF THE NEW YORK ACADEMY OF SCIENCES, Paul R. Epstein, Jonathan J. Buonocore, Kevin Eckerle, Michael Hendryx, Benjamin M. Stout III, Richard Heinberg, Richard W. Clapp, Beverly May, Nancy L. Reinhart,

victims in the US is also subsidised. The government-funded payments to victims are exempt from taxation even though they act as income; and the majority of the funding to cover the health care costs of affected workers has come from taxpayers rather than from the coal industry or its insurers.

One example from the study shows that in 2007 alone, a total of 246 people were killed in US rail accidents involving coal rail transportation. The report used actuary values on the value of life to estimate this societal cost at US\$1.8bn pa, or US9c/kWh of electricity produced.

Coal mining deaths in Turkey attracted global focus with the loss of 311 lives in a single coal mining disaster at Soma in 2014. It is reported that an average of 100 coal mine workers were killed on average each year over the last decade in Turkey.²¹⁴ This is of course a global issue, as the 2010 Pike River disaster in New Zealand (29 deaths) illustrated.²¹⁵

Black lung disease (or pneumoconiosis) that leads to chronic obstructive pulmonary disease is the primary illness affecting underground coal miners. In the 1990s, over 10,000 former US miners died from coal workers' pneumoconiosis and the prevalence has more than doubled since 1995. Since 1900 coal workers' pneumoconiosis has killed over 200,000 in the US.²¹⁶

A suite of studies of US county-level mortality rates from 1979–2004 by Hendryx found that all-cause mortality rates, lung cancer mortality rates and mortality from heart, respiratory, and kidney disease were highest in heavy coal mining areas, less so in light coal mining areas, lesser still in non-coal mining areas in Appalachia, and lowest in non-coal mining areas outside of Appalachia.²¹⁷

Ocean Shipping of Coal – Who Covers the Environmental Cost?

The Queensland Government's Great Barrier Reef Marine Park Authority in May 2015 stated it cannot afford the estimated A\$50m cost to clean up all the toxic mess left over from the grounding of a bulk coal carrier on the reef in 2010. A Chinese coal ship owned by Shenzhen Energy Company called '*Shen Neng One*' ran aground on Douglas Shoal off the central Queensland coast on April 3, 2010, veering 10 kilometres outside the shipping lane. The grounding damaged one of the ship's fuel tanks, resulting in a four-kilometre-long slick of heavy fuel oil and leaving toxic antifouling paint embedded in the sea floor. It also carved a three-kilometre-long scar in the Douglas Shoal, the largest known damage to the Great Barrier Reef caused by a ship. The Federal Government is pursuing legal action against the owner, but five years on, the progress has been pathetic and cleanup effort absent.²¹⁸

Melissa M. Ahern, Samir K. Doshi, and Leslie Glustrom. 2011, "Full cost accounting for the life cycle of coal", Ecological Economics Reviews, N.Y. Acad. Sci. 1219: 73–98.

http://www.chgeharvard.org/sites/default/files/epstein_full%20cost%20of%20coal.pdf

²¹⁴ <http://www.bbc.com/news/world-europe-27414972>

²¹⁵ https://en.wikipedia.org/wiki/Pike_River_Mine_disaster

²¹⁶ Goodell, J. 2006. "Big Coal: The Dirty Secret Behind America's Energy Future", Houghton Mifflin. NY.

²¹⁷ Hendryx, M. 2008, "Mortality rates in Appalachian coal mining counties: 24 years behind the nation." Environ. Justice 1: 5–11.

²¹⁸ <http://www.abc.net.au/news/2015-05-25/barrier-reef-authority-cannot-afford-to-clean-up-after-spill/6495998>

A2.11 Carbon Capture and Storage

One of the myths promulgated over the last decade or two is that the global damage of carbon emissions from coal mining and its downstream use should be tolerated because the industry is rapidly working towards a solution: carbon, capture and storage (CCS).

CCS is in fact a red herring that allows both coal mining companies and owners of coal-fired power stations to suggest that the financial risks associated with their projects will be mitigated through technological innovation, but always at some future point. Such promises usually are presented as solutions that will materialize sometime in the future.

Australian Government Funding of Carbon Capture and Sequestration (CCS)

In 2008 the Australian Coal Association announced that it had formed a Carbon Capture and Storage Taskforce to deliver a suite of legislative and policy measures to ensure that 10,000 gigawatt hours of CCS power would be delivered in Australia by 2020.²¹⁹ Billions of dollars of taxpayer funding have been offered over successive years by successive Australian governments. In 2009 the Australian government has launched two main sources of funding for CCS projects in Australia. These are the CCS Flagships Program and the Global CCS Initiative (GCCSI).²²⁰

The CCS Flagships Program of 2009 builds on the National Low Emissions Coal Initiative, which includes research, demonstration, mapping and infrastructure elements, and the Global CCS Institute's support for accelerated deployment of industrial-scale CCS projects world-wide. The program promotes the wider dissemination of CCS technologies by supporting a small number of demonstration projects that capture and store CO₂ emissions from industrial processes. The CCS Flagship program had earmarked A\$1.9bn over nine years for the support of construction of two to four commercial scale CCS projects with combined capacity of 1,000MW for other industrial processes. These funds are to include regional development projects, for example pipeline systems and storage hubs. The Australian government aimed to fund up to one third of the non-commercial costs of CCS Flagship projects that are ultimately selected.

The Global CCS Initiative (GCCSI) was announced by the Australian government in September 2008 and began operating independently in July 2009. The Institute is a not-for-profit entity and owned by its worldwide members, with the government initially committing A\$100m annual funding to the organization for a four-year period. The GCCSI announced in October 2010 that six projects around the world were to receive financial support at a total of A\$18m.

In May 2011, the Australian government announced steep funding cuts for CCS programs, reducing funding by A\$421m through June 2015. Given the limited progress to-date and regular funding cutbacks, we have not included this as a per tonne subsidy.

In the budget announced in May 2014, the Abbott government quietly cut A\$459m taxpayer funding from the Carbon Capture and Storage Flagships Programme.²²¹ Yet for proponents who still hold out the hope CCS might work commercially²²², the Australian Coal Association's 2020 milestone is looking unreachable given the questionable progress that has been delivered, particularly with the Association silently disbanded in 2014.²²³

²¹⁹ <http://reneweconomy.com.au/2014/stand-back-big-coal-formed-ccs-roundtable-18935>

²²⁰ https://sequestration.mit.edu/tools/projects/australia_ccs_background.html

²²¹ http://www.budget.gov.au/2014-15/content/bp2/html/bp2_expense-17.htm

²²² http://www.afr.com/brand/special_reports/energy_security/coals-last-best-shot-20150501-1mxfi9

²²³ <http://reneweconomy.com.au/2014/the-death-throes-of-the-australian-coal-industrys-ccs-dream-28019>

The fact that CCS R&D has been funded predominantly by government subsidies across the EU, America and Australia goes unmentioned when the coal industry talks of subsidies for renewable energy and energy efficiency R&D.

The IEA has acknowledged that CCS development has occurred at a materially slower rate than they had anticipated. From the IEA: *“This increase in PV compensates for slower progress in the intervening years in CCS”*.²²⁴ The IEA’s *“Energy Technology Perspectives 2015”* highlights how a price on carbon and/or strong emissions reduction goals globally are key to providing a framework that could facilitate the deployment of CCS.

SaskPower CCS – Boundary Dam 110MW for US\$1.2bn

In May 2014, Canadian utility SaskPower commissioned its aging 110MW coal-fired unit retrofitted with CCS.²²⁵ This project is one the largest operational projects on a coal-fired power plant in the world, showcasing commercial scale deployment. The plant will burn coal but cuts carbon dioxide emissions by 90% or 1Mtpa by trapping the carbon before it enters the atmosphere. The captured CO₂ is transported by pipeline to nearby oil fields in southern Saskatchewan where it is used for enhanced oil recovery by injection underground.

The economics of this C\$1.35bn (US\$1.2bn) Boundary Dam power plant retrofit, like any other CCS project, are entirely unjustifiable. The cost of this CCS technology would need to be reduced to a fifth of its current deployment cost to have any commercial prospect. Alternatively, the world would need to introduce a price on carbon emissions at such a level that would be far more cost effective to move straight to renewable energy and energy efficiency instead. Therein lies the point: coal-fired power is only competitive to the extent that it can externalize its environmental and health costs onto the community and maintain its multitude of subsidies.

It is material to the SaskPower project that the decision to undertake the CCS retrofit was entirely dependent on a C\$240m payment from the Canadian government, another taxpayer subsidy to coal. Another material issue is that the CCS process is very energy intensive, reducing the net thermal efficiency of coal-fired power plants by 7-12% according to the IEA.²²⁶

CCS also entails significant long tail carbon storage risks that require expensive insurance protection that further erodes the viability of this technology. Royal Dutch Shell Plc cited this fact as another key challenge in May 2015: *“As the risk can currently neither be defined nor quantified, no insurance solutions are available.”*²²⁷

²²⁴ IEA, “Technology Roadmap Solar PV Energy 2014”, Page 7.

<http://www.iea.org/publications/freepublications/publication/EnergyTechnologyPerspectives2015ExecutiveSummaryEnglishversion.pdf>

²²⁵ <http://www.saskpower.com/our-power-future/innovating-today-to-power-tomorrow/capturing-carbon-and-the-worlds-attention/>

²²⁶ Source: IEA page 59, VGB PowerTech e.V., Germany, “Electricity Generation: Facts and Figures 2009/2010”. https://www.iea.org/ciab/papers/power_generation_from_coal.pdf

²²⁷ <http://www.bloomberg.com/news/articles/2015-06-11/shell-says-carbon-capture-projects-face-large-risk-premiums>

FutureGen 2.0 – Cancelling CCS R&D program

In February 2015, the US Department of Energy cancelled its US\$1bn subsidy for the FutureGen 2.0 project, citing failure to achieve project timelines and lack of commercial support from private partners.²²⁸ The FutureGen concept was initiated as part of the Clinton Administration's Vision 21 program some two decades back, but has stalled ever since.

Kemper County – CCS cost projects blowout

In May 2015, South Mississippi Electric announced it was pulling out of the Kemper County Mississippi CCS project, citing schedule delays and increased costs.²²⁹ The project involves a 582MW lignite fired integrated gasification combined cycle plant fitted with CCS by using the carbon for enhanced oil recovery. The original budget in 2004 was US\$2.2bn, and since tripled to US\$6.1bn on the latest best estimates.²³⁰

Vattenfall CCS – Cancelling CCS R&D program

In May 2014, European power utility Vattenfall announced that it would axe its CCS R&D program because it needed to set priorities to match “whatever is most needed.”²³¹ The company’s decision meant the end of the 30MW CCS pilot plant at Schwarze Pumpe lignite-fired power plant in Germany and another at the Ferrybridge power station in the U.K. This pattern of announcements followed by project cancellations has been repeated worldwide on CCS for the last decade.

²²⁸ <http://peabodyenergy.investorroom.com/index.php?s=43&item=871>

²²⁹ <http://reneweconomy.com.au/2015/clean-coal-suffers-another-setback-as-yet-more-ccs-projects-fold-34566>

²³⁰ <http://www.afr.com/opinion/letters-to-the-editor/get-ahead-get-an-arts-degree-20150505-ggu7dz>

²³¹ <http://corporate.vattenfall.com/press-and-media/press-releases/2014/vattenfall-opts-for-efficient-research-projects-to-boost-its-business/>

Appendix 3: Elasticity estimates studies

This paper has sought estimates of PED's for coal from the PRB and for export into the Indian seaborne market. The following tables list papers and estimates therein of PED's that are related to or may apply to coal from either market. Tables are separated into a PRB table and Indian seaborne market table.

Table of estimated PED's for coal subsidies/prices of PRB coal in the northeastern and southeastern US electricity system.

Relative Price/Supply Relationship	Elasticity, distinguished by time period	Observation	Trend	Source
1. US gas supply changes relative to US domestic coal prices – cross price elasticity of gas demand.	We have inferred -0.5 short run PED from text. Gas market highly efficient, volatility declined since 2008 due to shale supply.	US gas & coal market is regional – weak correlation between gas & coal prices. Intense competition between coal & gas.	Moving upwards due to highly efficient, liberalized gas market & flexible gas supply. Market still has short run inelasticities due to technology, bottlenecks etc.	IE, IMF, IEF & OPEC report to G20 Finance Ministers October 2011.
2. EIA, 2012, Table 2, US gas supply changes relative to the US coal price – cross price elasticity of gas demand – See Table 2 copied below.	Calculated by the paper at the <i>national level</i> as 10% rise in the coal price ²³² leads to a 1.4% ²³³ rise in the use of gas, in the short run. In PRB supplied regions the estimated cross-price elasticity of substitution varies from -0.01 to -0.49.	Data is disaggregated by North American Reliability Council (NERC) regions. Regions show wide variations but central & eastern regions have higher results between -0.3 & -0.49.	Inferred trend is up with the central and eastern region leading the increase in elasticity – though it is a slow process , more efficient markets (e.g. central and eastern regions) are identified as having higher elasticities.	Table 2, Fuel Competition in Power Generation and Elasticities of Substitution, June 2012, US Energy Information Administration.

²³². Where the coal price goes up 10% but gas is unchanged

²³³. EIA, 2012, pg 10, The authors are quite clear in their meaning that an approximately 100% rise in the coal/gas price ratio led to a 14% increase in gas usage. A 100% increase in the coal/gas price ratio can be interpreted as holding the gas price constant, whilst increasing the coal price 100%.

Relative Price/Supply Relationship	Elasticity, distinguished by time period	Observation	Trend	Source
3. EIA, 2012, Table 3, US generation fuel – own price elasticity of demand – see Table 2 copied below.	Calculated by the paper at the <i>national level</i> as 10% rise in the coal price leads to a 1.1% fall in the use of coal, in the short run. In PRB supplied regions the estimated own price elasticity of demand varies from -0.18 to -0.53.	Data is disaggregated by North American Reliability Council (NERC) regions. Regions show wide variations but central & eastern regions have higher results between -0.53 & -0.18.	Inferred trend is up with the central and eastern region leading the increase in elasticity – though it is a slow process whereby this paper shows more efficient markets (e.g. central and eastern regions) are identified as having higher elasticities.	Table 3, Fuel Competition in Power Generation and Elasticities of Substitution, June 2012, US Energy Information Administration.
4. PRB coal price varies causing changes in the demand for PRB coal - Own price elasticity of demand for PRB coal.	Data from 1990 to 1999, showed a long run -1.75 price elasticity demand for PRB coal.	The implementation of sulphur dioxide controls on power plants caused a switch towards PRB coal.	The new trend towards finally implementing appropriate air pollution controls creates the reverse trend away from PRB coal towards substitutes.	Meghan R. Busse and Nathaniel O. Keohane, “Market Effects of Environmental Regulation: Coal, Railroads, and the 1990 Clean Air Act”, CSEM WP 137, September 2004.
5. Own price elasticity of demand for PRB coal from 1988 to 1999.	PRB coal burn rose from the mid 1980’s potentially based on falling railroad charges revealing a long run own price elasticity of demand of -3.79.	The paper compared high sulphur to low sulphur PRB coal. Other options were excluded.	The paper reviews data over ten years ensuring it is a long run elasticity.	Shelby Gerking and Stephen F. Hamilton, “What explains the increased utilisation of Powder River Basin Coal in Electric Power Generation?”, Am. J. Agr. Econ. (2008) 90 (4): 933-950.
6. US underground and Appalachian coal & US gas	Short run (1 year) underground coal is 0.61; long run	Single point quotes – unable to extrapolate but the variation is of	Trend not discussed in detail but it was noted that elasticity	ENERGY POLICY – Energy Demand and Supply Elasticities, Carol Dahl, Colorado School of Mines,

Relative Price/Supply Relationship	Elasticity, distinguished by time period	Observation	Trend	Source
own price elasticities.	underground coal 1.31; Appalachian coal from 0.41 to 7.90; natural gas 0.41.	note.	was considerably more flexible with time.	Golden, Colorado, USA. Publisher: UNESCO, ©Encyclopedia of Life Support Systems (EOLSS), 2002, http://www.eolss.net/
7. Calculated own price elasticities for coal and gas in the supply of electricity.	Coal had a long run, own price elasticity of -0.822, and gas had a long run, own price elasticity of -0.903.	Using US EIA data they studies the substitutability of different energy sources for the use of coal, gas, petroleum, electricity, wood and waste for supply of electricity.	The data here can be considered the long run elasticities of a developed, relatively efficient market, given the time period 1970 to 2012.	Yeboah et al. (2014), Osei Yeboah, Saleem Shalik, Afia Fosua Agyekum, Julie Melikpor-Lee, Energy Substitution in US Electricity Generation, North Carolina Agricultural & Technical State University, USA; 2. North Dakota State University, USA, Journal of Business and Economics, ISSN 2155-7950, USA October 2014, Volume 5, No. 10, pp. 1845-1853.

The table below is taken from the US Energy Information Administration report for 2012. It illustrates the disparity in elasticities by NERC region in the gas-coal column.

Table 2. Estimated Cross Price Elasticities of Substitution and Dynamic Rate of Adjustment

NERC REGION	Coal - Gas	Coal - Oil	Gas - Coal	Gas - Oil	Oil - Coal	Oil - Gas	Adjustment Parameter
FRCC	0.43**	0.09**	0.10**	0.36**	0.13**	2.03**	0.95
MRO	0.08	0.03	0.31	0.00	0.70	0.00	0.46**
NPCC	0.14**	0.09*	0.03**	0.19**	0.10*	1.16**	0.65**
RFC	0.16**	0.02	0.49**	0.11**	0.38	0.75**	0.79**
SERC	0.20**	0.03**	0.38**	0.03**	0.89**	0.64**	0.95
SPP	-0.01	-0.01	-0.01	0.02*	-0.51	1.79*	0.73**
TRE	-0.08	0.00	-0.02	0.00	-0.30	0.85	0.86
WECC	0.14**	0.00	0.05**	0.00	0.16	0.49	0.72**
US	0.17**	-0.06**	0.14**	0.14**	-0.63**	1.89**	0.82**

Note: ** indicates coefficient is statistically significant with 95 percent level of confidence. * indicates 90 percent statistical significance. Statistical significance of elasticities determined using Chi-square statistic from Wald test. Significance of adjustment parameters is determined from standard t-test on estimated λ coefficients.

Source EIA, 2012.

Table 3. Own Price Elasticity Estimates

REGION	Coal	Natural Gas	Petroleum
FRCC	-0.53**	-0.46**	-2.16**
MRO	-0.11	-0.31	-0.70**
NPCC	-0.23**	-0.21**	-1.26**
RFC	-0.18**	-0.60**	-1.13**
SERC	-0.22**	-0.41**	-1.53**
SPP	0.02	-0.02	-1.28**
TRE	0.08	0.02	-0.55*
WECC	-0.14**	-0.05**	-0.64**
US	-0.11**	-0.29**	-1.26**

Note: ** indicates coefficient is statistically significant with 95 percent level of confidence, based on Chi-square statistic from a Wald test. * indicates 90 percent statistical significance.

Source EIA, 2012.

Table of estimated PED's or related elasticities for coal subsidies/prices of seaborne coal (Australian) with relation to the Indian electricity system.

Relative Price/Supply Relationship	Elasticity, Distinguished by Time Period	Observation	Trend	Source
1. Indian gas prices effects on the Indian coal supply.	Gas prices unlikely to affect the supply of Indian coal as the relationship is inelastic due to 'regulated' market, infrastructure supply constraints – 0.	Short-term power market inelastic with respect to gas prices, as gas supply not available – recent efforts have been made to supply gas, which may or may not be sustainable.	No change – inferred four years later.	IE, IMF, IEF & OPEC report to G20 Finance Ministers October 2011.
2. South African	-4	Elasticity of	No trend – as	De Wet (2003),

Relative Price/Supply Relationship	Elasticity, Distinguished by Time Period	Observation	Trend	Source
coal export elasticity – can apply to Indian supply of imported coal by inference.		South African coal (export) based on Armington elasticity and working with the ORANI CGE model. Elasticities are derived from the combined effect of all the other variables in the model. Estimates are agreed to by the modeller.	Indian coal price is ‘regulated’.	Section 8.3, subsection vi, The Effect of a Tax on Coal in South Africa: A CGE Analysis, T.J. De Wet, PhD (Economics) in the Faculty of Economics and Management Sciences, Pretoria, October 2003 at the University of Pretoria.
3. Australian non-metallic mining estimated elasticity of substitution in intra-industry trade.	0.5	Based on intra-industry trade-where trade between industries is much more elastic than trade between consumers and imports. Regarded as in intuitively correct & in line with other studies.	Not known.	IMF, Working Paper, Armington Elasticities, in Intermediate Inputs Trade: A problem in using multilateral trade data, Mika Saito, Table 5, pg 29.
4. Elasticity of substitution between different fuels for electricity generation	The full paper is not yet published – a small paper referencing the results stated “The expected result is a low interfuel elasticity of substitution.”	Not known	Not known	Per. Comm. – to be published, “Fuel Competition in Power Generation in India and its Implications for Fuel Price Reforms and Decarbonization,” Anupama Sen, Senior Research Fellow, Oxford Institute for Energy Studies. A

Relative Price/Supply Relationship	Elasticity, Distinguished by Time Period	Observation	Trend	Source
				short version can be found here in the footnotes. ²³⁴

²³⁴ <http://www.iaee.org/iaee2015/submissions/ExtendedAbs/SEN.pdf>

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