SANEDI

Carbon Capture and Storage and the Carbon Tax in South Africa

FINAL REPORT
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GLOSSARY

“Combustion emissions”: Greenhouse gas emissions occurring as a result of combustion (see below)

“Combustion”: The exothermic reaction of a fuel with oxygen (as described in the Draft Carbon Tax Bill, 2015)

“EOR”: Enhanced Oil Recovery is the process whereby captured CO2 is used to extract otherwise unattainable quantities of fuel from oil reservoirs

“Fugitive emissions”: Means emissions that occur from the release of greenhouse gases during the extraction, processing and delivery of fossil fuels (as described in the Draft Carbon Tax Bill, 2015). Note that this definition of ‘fugitive emissions’ is different from the colloquial understanding of the term, and includes emissions from coal-to-liquid processes (which are more commonly regarded as process emissions). However, this definition is consistent with the classification of coal-to-liquid emissions by the IPCC, a fact confirmed by a representative of Sasol.

“Offset allowance”: A taxpayer may reduce the amount in respect of the carbon tax for which the taxpayer is liable in respect of a tax period by utilising carbon offsets as prescribed by the Minister. The reduction of the liability for the carbon tax may not exceed so much of the percentage of the total greenhouse gas emissions of a taxpayer in respect of a tax period as is determined by matching the line in the column “Sector” with the percentage in the corresponding line of the column “Offsets allowance %” in Schedule 2. (as described in the Draft Carbon Tax Bill, 2015)

“Performance allowance”: A taxpayer’s who’s measured and verified greenhouse gas emissions intensity is less than the relevant sector or sub-sector’s greenhouse gas emissions intensity benchmark (as prescribed by the Minister of Finance) may receive a tax-free allowance in respect of that tax period not exceeding five per cent of the total greenhouse gas emissions of that taxpayer (as described in the Draft Carbon Tax Bill, 2015)

“Process emissions”: Means greenhouse gas emissions other than combustion emissions occurring as a result of intentional or unintentional reactions between substances or their transformation, including the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock (as described in the Draft Carbon Tax Bill, 2015)

“Product use”: Means greenhouse gases used in products and product applications (as described in the Draft Carbon Tax Bill, 2015)

“Sequestered emissions”: Represents the number in respect of greenhouse gas emissions, expressed in terms of carbon dioxide equivalent, that were sequestrated in respect of that tax period as verified and certified by the Department of Environmental Affairs (as described in the Draft Carbon Tax Bill, 2015)
### “Stationary emissions source”:

Energy combustion emissions are classified according to whether they emanate from a stationary or mobile source category and their emission factors also differ across these categories (as described in the Explanatory Memorandum for the Draft Carbon Tax Bill, 2015)

### “Trade-exposure allowance”:

A tax-free allowance for trade-exposed sectors (maximum 10%). This allowance is calculated based on the ratio of the revenue received from goods that are exported to the total revenue received from all similar goods that are sold by the taxpayer, and will be deemed 0% if a company’s export revenue to total revenue ratio is less than 5% (as described in the Draft Carbon Tax Bill, 2015)
1 INTRODUCTION

This report presents the outcomes of a study conducted on behalf of SANEDI that aimed to explore the interaction between the proposed carbon tax and Carbon Capture and Storage (CCS) as a mitigation technology. The study consisted of two key components, being a background review to identify international experience on the interplay between CCS and the carbon tax, and a financial modelling exercise to explore the implications of South Africa’s carbon tax design for the financial viability of CCS in South Africa.

While the focus of this study was on carbon taxes only, given South Africa’s intention to introduce a carbon tax, the review also includes consideration of the impact of an alternative carbon pricing mechanism known as emissions trading on CCS. Both of these options put a price on carbon in an attempt to reverse the status quo, under which emitters benefit from the activities that produce greenhouse gas (GHG) emissions, with society as a whole having to bear the impacts of climate change. When emitters have to pay a price for every tonne of carbon they emit an incentive is created to undertake mitigation action to reduce their carbon emissions, to avoid having to pay the carbon price associated with emissions that are not emitted.

Carbon taxes work by setting the price of carbon emissions and letting the market control the quantity of emissions that are emitted (Cloete et al., 2010). Because a carbon tax creates a cost to releasing a tonne of CO$_2$e into the atmosphere (equal to the carbon tax), it makes sense for firms to undertake mitigation actions that cost less than the carbon tax per tonne of CO$_2$e to implement. However, even if firms don’t have mitigation options available to them that are cheaper than the carbon tax, the tax may further reduce emissions through one of two mechanisms. The first of these is that by increasing the cost of production, it becomes less profitable for the firms to sell their output and therefore the amount of output they produce is reduced. The second is because firms will ultimately pass on the cost of a carbon tax to their customers, the cost of their products increases which may reduce demand for the products (see Cloete et al (2010) for a more detailed discussion of the way carbon taxes lead to GHG mitigation).

The other mechanism used internationally to create an explicit carbon price is that of emissions trading schemes (ETSs). Under an ETS firms are required to hold emissions certificates for the GHG emissions that they emit (Carmona et al., 2010; Cloete et al., 2010; Robb et al., 2010; Andrew & Kaidonis, 2011). Firms can receive all or some of the certificates they require to emit GHGs for free, and/or they can be required to purchase certificates from a central issuing authority. The supply of certificates is restricted over time to ensure that there are insufficient certificates available to allow firms to emit as much GHGs as they did before the ETS was put in place. This creates a cap on emissions that ensures emissions are reduced over time. Because there is shortage of certificates within the ETS as a whole, firms that do not have enough certificates to cover their emissions, either because they received less certificates initially or because they don’t have attractive mitigation options, are forced to buy certificates from other firms that have surplus emissions. Firms may have surplus emissions because, for example, they have access to more attractive mitigation options and therefore are able to reduce their emissions by more than is required. A firm that holds an emissions certificate thus always faces two options, it can use the certificate to cover the emissions it emits, or it can sell it to another firm to allow that firm to emit the same amount of emissions. The price per tonne of GHG emissions at which certificates are traded between firms is the price of carbon within an ETS.

When the price of carbon is set by a carbon tax, a firm has the choice to not emit a tonne of CO$_2$e and save the carbon tax, or it can emit the tonne of CO$_2$e and pay the carbon tax. Under an ETS a firm has the option to use an emissions certificate to allow it to emit a tonne of CO$_2$e, or it could sell the certificate to another firm (thus earning...
the carbon price) and not emit the tonne of CO₂e (by implementing a mitigation option that costs less per tonne of CO₂e than the carbon price). If profit is defined as income minus expenditure, then from an economic perspective avoiding an expenditure of R 1 (by, for example, being able to avoid a tax payment of R 1) or gaining income of R 1 (by, for example, selling an emissions trading scheme) both increases a firm’s profit by R 1. For this reason, an equivalent carbon price created by a carbon tax or an ETS creates a similar incentive to implement mitigation actions since firms’ bottom lines are impacted in the same way (see Appendix A) (Andrew & Kaidonis, 2011; Goulder & Schein, 2013; Robb et al., 2010).

For these reasons, the experience with carbon prices internationally is instructive when considering the impact that a carbon tax can have on CCS deployment in South Africa, even in cases where the carbon price has been set by an ETS. Therefore while the focus of this study is on carbon taxes, the experience of carbon prices set by both carbon taxes and ETSs on CCS deployment is considered. From an analytical perspective, any mention of a carbon price (which in theory could have been set by either a carbon tax or an ETS) should thus be interpreted as providing information that is directly applicable to considering the extent to, and mechanism through, which carbon taxes can support CCS deployment.

2 BACKGROUND LITERATURE REVIEW ON CARBON PRICING AND CCS

CCS technology has been proposed to represent a significant climate change mitigation option due to its applicability in a number of industries, with some sources suggesting that CCS could reduce energy emissions by 10 percent internationally by 2050 (International Energy Agency, 2012). Internationally there are 45 large-scale CCS projects in operation or under development (Global CCS Institute, 2015; ZERO, n.d.).

CCS technology is, however, costly to implement, especially when applied as a retrofit. Part of the high costs of CCS are attributed to the fact that capture and storage sites are often located in different locations due to geological constraints, thus requiring expensive transportation infrastructure to be built (International Energy Agency, 2008; Finkenrath et al., 2012). Energy loss can also occur when CCS is implemented, thereby further increasing the cost of the technology (Feron & Paterson, 2011; Global CCS Institute, 2015). There are thus currently weak incentives to invest in CCS projects in the absence of strong commercial incentives (such as Enhanced Hydrocarbon Recovery (EHR) and/or stringent mitigation policies (Bassi et al., 2015).

This section provides a review of existing literature on potential types of financial support mechanisms that are available to drive CCS, and then discusses in greater detail the potential carbon taxes and CCS might interact.

2.1 Overview of potential CCS support mechanisms

Due to the high financial barriers to CCS implementation, a number of incentive mechanisms have been proposed to increase its attractiveness. Price (2014) describes three broad categories of CCS incentives: transitional incentives, contingent value incentives and carbon price incentives. Transitional incentives, which are

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1 This effect is known as the invariance axiom of rational choice theory. It posits that an economic agent is ambivalent between receiving R 1 when he/she was not expecting it, or avoiding losing R 1 where he/she was expecting to lose the R 1, since in both cases the economic agent is R 1 better off than he/she was expecting to be (see, for instance, Tversky and Kahneman (1984) for a discussion).

2 Enhanced Hydrocarbon Recovery (EHR) is the process whereby captured CO₂ is used to extract otherwise unattainable quantities of fuel from reservoirs. This can take the form of Enhanced Oil Recovery (EOR); Enhanced Gas Recovery (EGR) or Enhanced Coalbed Methane Recovery (ECBM). The most common form is EOR which extends the life of oil wells once traditional extraction methods are no longer cost effective. It involves injecting CO₂ into a well which forces any remaining oil to drift up to where it can be collected (International Energy Agency, 2008). For the remainder of this report we will be using the terms EHR and EOR interchangeably.
mechanisms to mitigate the low value of CO₂ emissions reductions while national climate change mitigation policies are relatively weak, include interventions like investment assistance, traditional (non-carbon) tax incentives, and subsidies to help reduce the effective cost of CCS projects. This is akin to transitional assistance within the broader climate change mitigation context to help firms transition to low carbon pathways (Cloete et al., 2010). Transitional assistance in the form of subsidies for green technologies, such as CCS, could support a carbon price by helping alleviate high upfront costs and sending a message about the direction of future policy direction that increases policy certainty and thus the attractiveness of CCS investments (Winkler & Marquard, 2007; Cloete et al., 2010).

Contingent value incentives, designed to increase the expected future economic value of CCS projects, can take the form of liability reductions (limiting risks to developers of long-term storage being compromised) and asset creation mechanisms (ownership rights for underground geological features that have potential CCS storage capacity are created in a similar fashion to mineral rights in extractive industries) (Price, 2014).

Both carbon taxes and ETSs, the focus of this study, provide carbon price incentives that enable investors to earn returns on CCS expenditure (UNIDO, 2010; Andrew & Kaidonis, 2011; Price, 2014).

2.2 The interaction between carbon pricing and CCS

The most obvious interaction between carbon prices and CCS is that as the carbon price increases, CCS (as a way of reducing CO₂ emissions and therefore carbon tax costs) will become more attractive and will be adopted quicker and more widely – provided that cheaper mitigation options are not available within similar time frames and with similar or lower risk profiles (Herzog & Golomb, 2004; Aldy et al., 2012; House of Commons, 2014). Additionally, existing CCS projects may be incentivised to expand their sequestration activities (Moreno-Cruz & Kim, 2014). In the absence of external support to CCS projects, the carbon price would need to be higher than the cost of sequestering a tonne of CO₂ to make CCS commercially viable (S2V Consulting, 2013; Herzog & Golomb, 2004). In the EU electricity generation market, for CCS to be cost-effectively installed at power plants, it is estimated that a carbon price would need to be in the range of EUR 35-69/tCO₂ for coal plants and EUR 90-105/tCO₂ for gas plants (Bassi et al., 2015).

Large, capital-intensive investments like CCS, however, typically require predictable returns to justify high up-front investment (Purvis & Vaghi, 2015). If future carbon prices are uncertain, so are future payoffs from investing in mitigation technology – which might delay or prevent investment (Parry & Pizer, 2007; Insight Economics, 2011; Energy Institute, 2011). In addition to creating a carbon price that is sufficiently high to justify CCS, a carbon pricing instrument thus also needs to create a carbon price with a relatively high degree of certainty if it is to effectively incentivise CCS deployment. In this context price certainty really means specifying a minimum carbon price, since increasing the carbon tax will increase the benefits from CCS. The simplest way to provide carbon tax price certainty is to explicitly state an expected future price path for the tax. Demonstrating a commitment to GHG emissions reductions over time also provides an indication that carbon tax rates are unlikely to fall in the medium term. Even if the stated carbon tax level is significant and the tax well defined, investment into CCS technologies can still be discouraged if public sector commitment to mitigation policy is questionable (UK Department for Business Innovation and Skills, 2009; Cloete et al., 2010). It is therefore not enough to merely have a well-defined policy in place, the political will to keep the carbon tax in place over time must also be demonstrated (Insight Economics, 2011; International Energy Agency, 2012).

A carbon price thus needs to be clear, consistent and expected to continue for a significant period of time to incentivise CCS (ZERO, 2013). Carbon tax levels that are not seemingly high enough to incentivise CCS
deployment can influence the decision to invest in CCS projects if the tax is believed to be permanent and is expected to increase over time. This will create an expectation that at some (preferably predictable) point in future the tax will become more burdensome than implementing CCS, thus incentivising an investment now that is expected to have long-term future financial benefits (Bassi et al., 2015; Price, 2014). The importance of this signalling effect is illustrated by the fact that momentum for the deployment of CCS in coal combustion has recently slowed down as a result of uncertainty about future carbon prices internationally (World Nuclear Association, 2015; Purvis & Vaghi, 2015).

Different industries face different exposure to carbon price risk; different financial capacity to adopt CCS; varying costs to implement CCS; and have different competing mitigation technologies (Global CCS Institute, 2015; Bassi et al., 2015). The influence of a carbon price on the attractiveness of CCS as a mitigation option is thus likely to be highly country and sector-specific. Given the scale required for CCS projects to be cost-effective, and the high upfront cost that this implies, however, a carbon tax, for example, will only be effective in driving uptake if the cost of implementing a CCS project is less than the expected amount of tax an entity would pay otherwise; and the entity undertaking the project is still financially viable after the cost of undertaking CCS (Price, 2014).

Climate change policies such as setting carbon prices incentivise a range of potential mitigation options, and it is thus important to consider how competition between mitigation options impacts the attractiveness of CCS. Vital to note is the fact that cost is just one of the criteria influencing the attractiveness of mitigation options. Additional factors can change a mitigation option’s attractiveness from a policy perspective, such as its impact on employment, wealth distribution and economic growth; its ease of implementation; and its inherent risks both from the perspective of society and implementers (Department of Environmental Affairs, 2014). A carbon price will thus only effectively incentivise CCS deployment if there are no other mitigation options available that can deliver similar mitigation benefits at a similar scale for a lower price. And the price of mitigation options is often influenced by public sector support. It is thus important to take these issues into consideration when reflecting on the impact that a carbon price is expected to have on incentives to deploy CCS within a specific context.

Finally, carbon taxes and ETSs can target GHG emissions at a number of different levels. A carbon tax, for example, can be levied on inputs to processes that generate GHG emissions, on GHG emissions released by processes directly, or on final products or services based on the amount of carbon produced during their production (embedded carbon) (Cloete et al., 2010). Depending on the carbon tax design, different rules and guidelines may be necessary to ensure that the sequestering of emissions translate into actual carbon tax savings. This can be done directly by allowing sequestered carbon to be offset against the direct emissions from a process (or reduce total emissions deemed to be embedded in a product) for tax purposes. In the case of input taxes, where the carbon tax rate is often a flat rate on a unit of input rather than calculated based on the amount of emission that will be released by using the input, some form of rebate may be required to account for sequestered emissions. The tax benefit linked to CCS can be applied to the entity liable for the carbon tax, or tradable tax credits based on verified carbon sequestration volumes can be created to account for the possibility that firms that are not directly paying the carbon tax (or at least not the full carbon tax) may be best placed to undertake CCS activities (Metcalf & Weisbach, 2009). Tradable tax credits also remove the need for capture and storage infrastructure to be physically accessible by a firm to benefit from the tax benefits of CCS projects, and allows for the pooling of funds and/or diversification of risk when undertaking CCS projects.
2.3 Factors influencing interaction between carbon prices and CCS

The International Energy Agency (2012) believes that carbon prices are generally still too low to incentivise CCS, and that only by 2050 will the unit costs of maturing CCS technology fall below global carbon prices, which are assumed to continue to rise (International Energy Agency, 2012; Global CCS Institute, 2015a).

As mentioned in section 2.1, however, there are two main categories of incentive measures that can be used to support CCS, other than carbon pricing, namely transitional incentives and contingent incentives. CCS can become a viable mitigation option when these measures are deployed together with carbon prices (International Energy Agency, 2012). The CCS project experience considered in the following section supports this assertion, and echoes the view of the Global CCS Institute (2012, p.87) that “[c]arbon prices are … [an] essential but not sufficient drivers of CCS projects”. There will be stronger incentives to deploy CCS when carbon prices are implemented in conjunction with a number of other factors. Some of the options to achieve these synergies are described here.

2.3.1 The presence of carbon injection revenue streams

The primary alternative carbon injection revenue stream, which can help support CCS, is achieved by combining CCS with enhanced oil recovery (EOR). The revenues from enhanced oil recovery effectively bring down the cost of CCS and can result in earlier investment than would be the case if the only drivers were climate taxes or other pricing mechanisms. EOR can support the development of CCS as an industry, given that the revenues from EOR effectively bring down the cost of CCS and results in earlier investment than would be the case if the only driver was climate pricing. However, EOR storage capacities are generally smaller than purely storage-based geological locations (Global CCS Institute, 2012). The combination of a credible carbon price and CO₂ EOR can lead to a higher level of geologic storage of CO₂ than what would be justified if only the commercial value (in terms of increased hydrocarbon production) of CO₂ EOR was considered. This illustrates the importance of EOR as an early driver of CCS deployment, but also points to the need for EOR to be gradually replaced by stricter climate policy as a driver for CCS so that its deployment is not limited by the availability of hydrocarbon extraction processes. The issue of long-term liability in the case of CO₂ leakage, however, must be addressed when transitioning from EOR to CCS (Global CCS Institute, 2012).

To be considered as a CCS project, EOR projects must include comprehensive monitoring and accounting protocols to ensure that the storage of anthropogenic CO₂ is indeed permanent. The requirement for storage to be permanent explains why industrial processes that sequester CO₂ into products are usually not considered as CCS since the CO₂ may be released when products are disposed of or decompose over time. Should industrial uses of captured carbon become available where it is possible to prove that the carbon can be permanently sequestered in products, these industrial uses could also be considered CCS and would be able to play a similar role to EOR by enhancing the impact of carbon taxes to support CCS deployment.

The presence of revenue streams originating from the use of CO₂ removes the need for transitional incentives, since there is an additional incentive to invest in CCS even when carbon prices are still relatively low. The value of these revenue streams can, however, be increased by utilising contingent value incentives to reduce possible future liabilities from EOR activities.
2.3.2 The presence of general government support

Governments can help kick-start the adoption of CCS technology by providing initial R&D support and context-specific policies for different stages of CCS development (Bassi et al., 2015). The U.S, for example, offers Federal tax credits to CCS activities (credits on normal tax – no carbon tax in place), with some independent states also offering extra tax incentives for CCS (Clean Air Task Force, 2015).

The International Energy Agency (2012) mentions that additional policy support such as concessionary finance and operational subsidies are required to help advance CCS technology during the early stages of deployment even in the presence of carbon prices. This is borne out by international experience, as demonstrated in Section 3. Government support lowers the cost of implementing CCS, either by directly contributing to the funding of projects, or by assuming some of the possible future risks linked to CCS (for which project developers then do not have to budget for). A lower cost of implementation means that the point where it is cheaper to sequester emissions rather than to pay a carbon tax on the emissions is reached at lower monetary values. This means that a lower carbon tax is necessary to make CCS financially viable as a result of carbon tax savings.

General government support can take the form of either transitional support or contingent value incentives (where the government support isn’t focussed on influencing current costs, but rather on reducing expected future costs or liabilities).

2.3.3 The presence of dedicated funding mechanisms

Dedicated funding mechanisms, like general government support, increases the impact of a given level of carbon price on CCS deployment by reducing the cost of CCS. In practice, however, dedicated funding mechanisms can have a larger leveraging effect by increasing the probability that projects will receive support, since support is focussed on a small number of eligible projects. Carbon pricing instruments can also be used to fund dedicated funding mechanisms.

A number of dedicated funds have been created to support the development and deployment of low emissions technologies, including CCS. Australia’s Low Emission Technology Demonstration (LETD) Fund is a capital and operating costs subsidy programme that³ has supported two CCS projects through contributions from both the public and private sector (IEA, 2014). Australia’s Carbon Capture and Storage Flagships programme, whose sole mandate is the support of large-scale CCS projects, has provided funding to the South West hub and CarbonNet projects (Australian Government, 2015).

Bonus emission trading allowances such as the NER 300 programme have been designed to support renewable energy and CCS with the EU ETS. The programme sets aside 300 million allowances from the New Entrants’ Reserve to co-finance low carbon technologies (European Commision, 2016). The allowances can be sold at market value and the proceeds used to offset project costs. This mechanism has been less effective for CCS due to lower than anticipated EU carbon prices (Global CCS Institute, 2015a). Only one CCS project, White Rose has received funding through NER 300. The EU Council has agreed to a successor programme called NER 400, which will continue to support CCS. The details of NER 400 are yet to be finalised.

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³ The LETD funding programme ended in 2008, but one of the beneficiary CCS projects- Gorgon Project- is in the advanced stages of development.
The UK government created a GBP 1 billion CCS commercialisation fund to support CCS deployment\(^4\) in addition to the support from the EU ETS and the UK EU-ETS carbon price floor (Carbon Capture and Storage Association, n.d.; Sandbag, 2012; UK Department of Energy and Climate Change, 2013).

Dedicated funding mechanisms are best suited to providing transitional incentives to CCS projects.

### 2.3.4 The design of carbon pricing mechanisms

The design of a carbon price mechanism can have significant impact on the extent to which it incentivises CCS deployment. At the most basic level, the design of a carbon pricing mechanism must not be prejudiced against CCS (as is currently the case under the California Cap-and-Trade Scheme, see Table 2, and the proposed South African carbon tax, see Section 4.3.2). At the other end of the spectrum, carbon pricing mechanism can be designed to explicitly provide support to CCS. Box 1 discusses the case of Shell’s Quest project in Alberta, Canada. Here general government support was used to reduce the upfront investment cost of the CCS project, whereas an adjustment of the standard rules of the local carbon pricing instrument (the Special Gas Emitters Regulation (SGER)) was used to create an artificial carbon price that is sufficiently high to cover the operating cost of the CCS project.

This example shows that the presence of carbon pricing instruments increases the universe of possible support mechanisms that can underpin CCS deployment in the right set of circumstances. In Alberta the expected future value of an emissions-intensive natural resource (oil sands) would be significantly reduced in a carbon-constrained world. This created the incentives for the owners of the resource (Shell) to work with the public sector to prove the feasibility of CCS that could potentially ensure the value of this resource is increased in the medium to long term. While the support in the Quest example was provided within the context of an ETS, it is also possible to provide this kind of support through a carbon tax.

The benefit of providing support through the design of a carbon tax rather than through general public sector support is that it reduces the amount of upfront funding that needs to come from the fiscus. There is still a real opportunity cost attached to this type of support as it leads to tax revenue being forgone. Existing budget allocations before the imposition of the carbon tax, however, are not influenced and this could make support for CCS deployment through the design of a carbon tax more politically palatable than increased general public sector support.

The design of carbon price mechanisms is well suited to providing transitional incentives to CCS deployment, as is demonstrated in the Quest example. The additional support provided to the project was capped both in terms of the period for which it would be valid and the maximum amount of support provided. In this example the transitional incentives provided through the carbon pricing instrument was combined with transitional incentives provided through general government support and contingent value incentives (the Alberta government assumed all future liability related to sequestered CO\(_2\)).

\(^4\) The CCS commercialization fund was however recently shut down, and this caused a number of UK CCS projects that were under development to be stalled or cancelled – illustrating the importance of public sector support in addition to carbon pricing to ensure the commercial viability of CCS projects (see Section 3.1).
The oil sands in Alberta represent a valuable natural resource, with 350 billion Canadian Dollars (CAD) in royalties; CAD 122 billion in tax revenue; and 500,000 jobs expected to be generated from oil sands processing over the next 25 years (Government of Alberta, 2014). However, producing of crude oil from oil sands is significantly more emission-intensive than conventional oil production, and increasingly stringent international commitment to climate change mitigation is expected to become a significant barrier to the exploitation of this resource (Huot & Grant, 2012). In order to maximise the benefits from this resource it is thus critical that the carbon intensity of oil sands processing is reduced; and CCS provides an opportunity to do this. Consequently Canada has invested heavily into CCS development, committing more than CAD 2 billion into CCS projects (Government of Canada, 2013).

Alberta has a baseline-and-credit trading scheme in place (the Specified Gas Emitters Regulation (SGER)) whereby firms are required to reduce their emissions intensity by 12% a year. Firms can meet this target by reducing their emissions, purchasing carbon offsets from Alberta-based projects, purchasing emissions performance credits from firms that have reduced their emission intensity by more than 12% in a year, or paying a levy of CAD 15 per tonne of CO\textsubscript{2}e into the Climate Change and Emissions Management Fund (Partington, 2013; Sears, 2015a). Since most firms typically pay the levy due to a shortage of credits, the effective carbon price (and credit price) is CAD 15 per tonne of CO\textsubscript{2}e (Kebede, 2015).

The Quest CCS project, which is operating commercially and is set to capture and store over one million tonnes of CO\textsubscript{2} emissions from Shell’s Scotford Upgrader (which produces crude oil from Alberta’s oil sands), was seen as an important milestone to prove the viability of CCS in oil sands processing (Shell Global, 2015).

The local carbon price of CAD 15 per tonne of CO\textsubscript{2}e, however, was significantly less than the USD 100 per tonne of CO\textsubscript{2}e required to make the project commercially viable. So in order to incentivise investment in the project (and thus proving CCS could be deployed at scale at oil sands operations) the Canadian and Albertan governments jointly provided CAD 865 million of the project’s CAD 1.35 billion investment cost on the condition that Shell share information on Quest’s design and processes to support the worldwide deployment of CCS (Hone, 2014; Shell Global, 2015; Dawson, 2015). Furthermore, the Alberta government assumed the liability for all sequestered CO\textsubscript{2} to reduce the risk of future liability to Shell and its partners (The Legislative Assembly of Alberta, 2010).

In addition to this general public sector support, to reduce the operating cost of the project, it was agreed that Quest would receive double the normal carbon price benefit under the SGER for every tonne of CO\textsubscript{2} sequestered. The project receives one performance credit for each tonne of GHG ‘reduced’ at the Scotford Upgrader, and an additional offset credit for each tonne of GHG sequestered by the Quest Project, for a maximum of 10 years or 10.8 million credits (Province of Alberta, 2007; Hone, 2014). This multi-credit agreement has reduced the project’s operating costs from CAD 44 million to CAD 14 million per year (based on the current carbon price of CAD 15 per tonne of CO\textsubscript{2}e) (Alberta Department of Energy, 2014).

The successful implementation of Shell’s Quest CCS project illustrates how general government support can be combined with support through carbon pricing design to ensure the commercial viability of CCS projects.
2.4 Country experiences on using carbon pricing and other mechanisms to support CCS

A number of countries have experimented with carbon pricing policies. In particular, European countries and Canada lead the way in this regard (Price, 2014; Global CCS Institute, 2015). Globally, however, carbon prices have mostly been too low to incentivise implementation of CCS technology directly (ZERO, 2013). In 2015 99 percent of countries had a carbon price below USD 30/tCO₂ and 85 percent of countries had a carbon price of less than USD 10/tCO₂. Globally carbon price mechanisms also covered only 12% of all emissions in that year (7 GtCO₂) (World Bank & Ecofys, 2015). This section provides an overview of publicly available information on international experiences relating to carbon prices and other support mechanisms, and their impact on supporting CCS roll-out.

Carbon prices are provided in a number of different currencies in this section. Carbon prices refer to different periods, and source documents include varying assumptions. For this reason the carbon prices have not been standardised and presented in one currency. Refer to Section 3.4 for a US dollar comparison of carbon prices in the countries discussed in this section.

2.4.1 Norway

Norway has the first commercially operating CCS project that has been incentivised, at least in part, by a carbon tax, with the tax having been introduced in 1991 (Price, 2014). The project is located at Statoil’s Sleipner Project, which involves the removal of CO₂ from a natural gas extraction process to allow the remaining natural gas stream to adhere to the 2.5% CO₂ limit at which it is suitable for commercial sale (MIT, 2015). The CCS investment at Sleipner cost Statoil and its private partners USD 80 million and was paid back within 18 months based on carbon tax savings at USD 50/tCO₂ (World Nuclear Association, 2015; Herzog & Golomb, 2004). Without a carbon tax in place, Sleipner would have most likely vented the excess CO₂ to meet commercial quality standards. If Statoil had decided to run operations without CCS it would have been liable for carbon taxes which would have cost them in the order of NOK 1 million/day (MIT, 2015).

It is noted that in addition to the carbon tax drivers, the Norwegian government has invested billions of kroner into CCS research and development (R&D) (Volla, 2012).

2.4.2 European Union

The EU ETS creates an explicit carbon price through emissions allowance trading. However, the EU-ETS price has historically been low, remaining below USD 25/tCO₂ in 2013 and remaining at around USD 9/t CO₂ in 2015 (SBC Energy Institute, 2013; World Bank & Ecofys, 2015). It is considered unlikely that the carbon prices in the EU will achieve a level to make CCS cost competitive within the next decade (generally believed to be around USD100/tCO₂ – although this varies based on local conditions) and uncertainty linked to future prices remains an issue (Bassi et al., 2015; House of Commons, 2014).

2.4.3 United Kingdom

The UK introduced a carbon price floor in 2013 that started at GBP 15.70/tCO₂ (2009 prices) and will rise each year by GBP 2 until it reaches GBP 30 in 2020 (Sandbag, 2012). This carbon price floor underpins the EU ETS and appears to be an attempt to guard against the EU ETS price falling too low to incentivise mitigation in the UK (Bassi et al., 2015). The main aim of the carbon price floor was to place a fair price on carbon and reduce...
uncertainty in order to increase the impetus for early technology investment. The carbon price floor was also one of the interventions proposed as part of the UK’s Electricity Market Reform (EMR) proposed in a 2011 White Paper designed to increase investment in new low-carbon technologies like CCS (Carbon Capture & Storage Association, 2016). The UK government began a CCS Commercialisation Programme to bolster the deployment of CCS with GBP 1 billion in capital and operational support. The programme was, however, cancelled late in 2015 due to budgetary constraints (BBC News, 2015). The cancellation occurred only six months before the programme’s expected disbursement of funding (see Section 3.1) (House of Commons, 2014; Carrington, 2015).

2.4.4 Australia

In 2014 Australia repealed its carbon pricing law which was originally envisaged, in part, to incentivise CCS. The law was repealed through a parliamentary vote by the ruling Liberal-National coalition that campaigned on abolishing the tax (Baird, 2014). The Liberal-National party is opposed to any form of carbon pricing being applied to Australia given the local context, and proposed to replace the carbon pricing instrument with a subsidy scheme (as it duly did when it came to power). Of the three large-scale CCS projects in Australia, one (Gorgon Carbon Dioxide Injection Project) is nearing completion while the other two (CarbonNet Project and South West Hub) have not progressed beyond the planning and analysis stages (Energy and Earth Resources, 2014; Chevron Australia, 2015; Department of Mines and Petroleum, 2015).

It is unclear to what extent the repealing of the carbon pricing instrument has influenced CCS deployment in Australia, since it has been replaced by a voluntary subsidy scheme. While the Australian Carbon Pricing Mechanism (CPM) was in place, however, its future was believed to be too uncertain, and its level too low (A$24.15 compared to the roughly A$80/tCO₂e required), to incentivise CCS projects in the absence of public sector support (Dawson, 2011; Aldous, 2012; IGCC, 2012; Clean Energy Regulator, 2015). So while some sources indicated that the introduction of the CPM in Australia was one of the drivers of the most advanced of the Australian CCS projects, Gorgon Carbon Dioxide Injection Project, it is instructive to note that the announcement that the CPM would be repealed did not influence the decision to proceed with the project (MIT, 2016; Kemp, 2013).

The Emissions Reduction Fund, the voluntary subsidy scheme that replaced the CPM, enables the Australian government to fund emissions reductions from firms and individuals to incentivise low carbon development (with CCS projects being eligible to participate) (House of Representatives, 2014). Firms that undertake verified abatement activities receive one Australian carbon credit unit (ACCU) for each tonne of CO₂e abated or sequestered. ACCUs can be sold to the Australian government by entering into a carbon abatement contract (the price of which is set via a reverse auction to incentivise the most cost-effective abatement) or to other firms (who, for example, have undertaken insufficient abatement to meet their carbon abatement contract requirements5, or who want to voluntarily offset their carbon emissions) (Clean Energy Regulator, 2016; Department of the Environment, 2015; Clean Energy Regulator, 2015a). Projects that are previous recipients of government funds such as the CCS projects identified above are not eligible for ACCU. Only new projects in the project planning phase qualify (Clean Energy Regulator, 2016).

5 While participation in the Emissions Reduction Fund is voluntary, entering into a carbon abatement contract with the Australian government creates a contractual obligation to provide ACCUs. So irrespective of the subsequent performance of mitigation projects or other commercial/market factors, a firm is legally bound to deliver ACCUs once it has contracted to do so.

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2.4.5 Canada

There is no national carbon price in Canada, but carbon prices are set in two provinces. The 2015 carbon prices in the provinces of Alberta and British Columbia were USD 2/tCO₂ and USD 23/tCO₂ respectively (see section 3.4). This is below the USD 100/tCO₂ carbon price level that is considered necessary internationally to make CCS financially viable without additional support (House of Commons, 2014). It is thus unlikely that CCS projects in Canada have been undertaken solely in response to carbon pricing, and there is evidence to suggest that both the two Canadian CCS projects have been implemented without EOR in Alberta and British Columbia benefitted from significant government support (see Box 1 for a discussion of the support provided to Shell’s Quest project).

3 ANALYSIS OF CARBON PRICE REGIMES AND CCS

The previous section provides a background review of the international understanding on the relationship between carbon pricing and other financial support mechanisms and CCS. In this section, a deeper analysis is presented of the existing large scale projects drawn from the Global CCS Institute’s project database in November 2015 to consider the extent to which carbon pricing regimes have supported CCS deployment (Global CCS Institute, n.d.). The table in the Appendix provides a list of the projects and the references used to compile the data, unless otherwise stated.

3.1 Carbon prices and CCS deployment

As indicated previously, the Global CCS Institute lists 45 large-scale CCS projects being developed or in operation globally. Large scale projects are defined as integrated commercial-scale projects involved in the capture, transport, and storage of carbon dioxide (CO₂) at a scale of “at least 800,000 tonnes of CO₂ annually for a coal–based power plant, or at least 400,000 tonnes of CO₂ annually for other emissions–intensive industrial facilities (including natural gas–based power generation)” (Global CCS Institute, 2015). The institute recognises two types of storage for CO₂: the gas can be injected into dedicated geological storage (DGS) sites and/or used in EOR.

Projects are considered at both a national and a regional level. In countries like Canada, China and the United States no national carbon pricing regimes are in place, but there is evidence of carbon taxes or trading schemes at the state, provincial or district level. Depending on where they are located, some CCS projects in these countries can thus be in jurisdictions with a carbon price while others are in jurisdictions without a carbon price.

Figure 1 shows the distribution of CCS projects according to whether or not a there is a carbon price in the jurisdiction where the projects are located. Just over half the large-scale carbon projects are in jurisdictions without a carbon price.
When comparing Figure 1 and Figure 2 it becomes clear that the majority, but not all, CCS projects that are not linked to EOR (and thus use dedicated geological storage) are in jurisdictions with carbon prices in place. Of the 21 projects utilising dedicated geological storage, only four\(^6\) are in jurisdictions without carbon pricing. This indicates that in some jurisdictions CCS is implemented for strategic mitigation purposes even without carbon pricing. The lack of EOR opportunities in South Africa means that the development of CCS in South Africa will be linked to dedicated geological storage.

\(^6\) While not currently in place, a carbon price was previously in place in Australia and therefore could have influenced the decision to develop the three local CCS projects.
Table 1 shows that all CCS projects with dedicated geological storage depend heavily on public sector support. All projects in jurisdictions without a carbon price has received some form of public sector support, and in the majority of cases carbon pricing regimes are used in conjunction with some other form of government support. The Illinois Industrial Carbon Capture and Storage project which does not benefit from carbon pricing, and which is currently being constructed, for example, received more than 60% of its funding by the US government (Office of Fossil Energy, US Government, n.d). And while there is a carbon price in the UK, the future of a number of UK projects is uncertain due to challenges in obtaining UK or EU funding. The Peterhead Project will not proceed due to being unsuccessful in securing such funding (Carrington, 2015). The cancellation of the UK’s GBP 1 billion competition CCS technology fund has cast a shadow over the future of most CCS projects in the UK. This provides a strong illustration of the importance of public sector support for CCS (see Section 3 for further examples).
### TABLE 1: LARGE SCALE DEDICATED GEOLOGICAL STORAGE PROJECTS GLOBALLY AND THEIR SUPPORT MECHANISMS*

<table>
<thead>
<tr>
<th>Dedicated Geological Storage Projects</th>
<th>Capture Capacity (Mtpa)</th>
<th>Region</th>
<th>Carbon Pricing</th>
<th>Dedicated Clean Energy/CCS Funding Mechanism*</th>
<th>Foreign/Local Government Partnership</th>
<th>Federal government funds</th>
<th>Carbon Credits</th>
<th>Project status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Caledonia Clean Energy Project</td>
<td>3.8</td>
<td>UK</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CarbonNet Project</td>
<td>1.0 - 5.0</td>
<td>Australia</td>
<td>No (Yes previously)</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>China Resources Power (Haifeng) Integrated CCS Demonstration</td>
<td>1.0</td>
<td>China-Guangdong</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Don Valley Power Project</td>
<td>1.5</td>
<td>UK</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gorgon Carbon Dioxide Injection Project</td>
<td>3.4 - 4.0</td>
<td>Australia</td>
<td>No (Yes previously)</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Korea-CCS 1 &amp; CCS 2</td>
<td>1 &amp; 1</td>
<td>South Korea</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peterhead CCS Project</td>
<td>1.0</td>
<td>UK</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td>X (cancelled)</td>
</tr>
<tr>
<td>Rotterdam Opslag en Afvang Demonstratieproject (ROAD)</td>
<td>1.1</td>
<td>Netherlands</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td>X (cancelled)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shell Quest</td>
<td>1.0</td>
<td>Canada-Alberta</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sleipner CO₂ Storage Project</td>
<td>0.9</td>
<td>Norway</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Snøhvit CO₂ Storage Project</td>
<td>0.7</td>
<td>Norway</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>South West Hub</td>
<td>2.5</td>
<td>Australia</td>
<td>No (Yes previously)</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Spectra Energy’s Fort Nelson CCS Project</td>
<td>2.2</td>
<td>Canada-BC</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Teesside Collective Project</td>
<td>2.8</td>
<td>UK</td>
<td>Yes</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>White Rose CCS Project</td>
<td>2.0</td>
<td>UK</td>
<td>Yes</td>
<td>(EU funds)</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>In Salah CO₂ Storage</td>
<td>Suspended</td>
<td>Algeria</td>
<td>No</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Illinois Industrial CCS Project</td>
<td>1.0</td>
<td>US-Illinois</td>
<td>No</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shenhua Ningxia CTL Project</td>
<td>2.0</td>
<td>China-Inner Mongolia</td>
<td>No</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shenhua Ordos CTL Project (Phase 2)</td>
<td>1.0</td>
<td>China-Inner Mongolia</td>
<td>No</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Government funds ring-fenced for Clean Energy or CCS development. Funding is obtained through targeted government programmes.
3.2 Carbon pricing regimes

Carbon taxes, or trading schemes that lead to stable prices (and thus function much like carbon taxes) are prevalent in countries with large-scale CCS projects. Norway has a CO₂ discharge tax; the United Kingdom has a price floor (see Section 3.5 - the total carbon price stays constant even though the cost of EU ETS certificates and the floor price component varies); and the Canadian province of British Columbia has a carbon tax. The Canadian province of Alberta has a baseline-and-credit scheme in place that allows trade in credits and offsets, but a shortage of these instruments means that their price is largely set at the level of the levy charged on emissions above the target intensity baseline (CAD 15 per tonne of CO₂e at present) (Bankes, 2015). Norway’s carbon tax predates the EU ETS, which it is also a part of, and the UK’s price floor was implemented after the EU ETS in 2013. Norway has two carbon pricing schemes that incentivise CCS development. The Norwegian carbon tax applies to emission from oil and gas production operations (Global CCS Institute, 2014), and the Norwegian Trading Scheme (now part of the EU ETS) was designed for emissions from power production (Norwegian Ministry of the Environment, 2008).

Policy and regulatory frameworks relating to carbon pricing are also are currently being reviewed by Norway, Australia and the province of Alberta. Alberta is expected to repeal the SGER in favour of an explicit carbon tax (Sears, 2015). Canada’s new Climate Change Policy was announced in November 2015 and is currently undergoing stakeholder consultations (Canadian Energy Law, 2015).

3.3 Matching CCS development status with carbon pricing regimes

The type of CCS activities within carbon tax/trading jurisdictions can be analysed using the project lifecycle as defined by the Global CCS Institute. As demonstrated in Figure 3 below the majority of projects are currently in in the planning phase.

![FIGURE 3: LARGE-SCALE CCS PROJECTS REPRESENTED BY COUNTRY AND CO₂ STORAGE TYPE](source: Adapted from Global CCS Institute Large Scale Projects Definitions)

The three large-scale projects that are currently operating are located in countries where carbon pricing has been in place for a number of years. Norway’s carbon tax was implemented in 1991, while Canada’s Alberta Province’s
Special Gas Emitters Regulation (SGER - which functions similarly to a carbon tax in practice – see Section 2.3.4) came into effect in 2007.

In addition to the three operating plants, another three large-scale projects are currently being constructed. The Australian Gorgon CO₂ Injection project is almost complete despite the repeal of Australian carbon pricing (Chevron Australia, 2015). This project’s inception, however, predates carbon pricing in Australia and public sector support is therefore likely to have been a stronger driver of the project than carbon pricing. Engineering work on capture facilities has commenced at the two Alberta Trunk Line (ACTL) projects which are subject to carbon pricing in the form of the SGER (Alberta’s Industrial Heartland, 2015).

3.4 The price of carbon

Current carbon prices ranged between USD 2 and USD 52 per tonne of CO₂e in jurisdictions where CCS is being undertaken. It is difficult to find reliable carbon price projections for most jurisdictions, but future prices are typically expected to be higher than current prices as is shown in the figure below. All carbon prices are expected to increase over time as international commitments to contain climate change intensify, and where no future price projections are provided in Figure 4 this is simply an indication that no consistent estimates of future prices could be found. There is still a large amount of uncertainty about future carbon prices, not helped by the repealing of Australian’s Carbon Pricing Mechanism (CPM). Despite price uncertainty, a number of large CCS projects have advanced to the final stages of the project cycle. This could be an indication that project proponents are confident that carbon prices will increase in future, or at the very least that government commitment to climate change mitigation in these countries is sufficient to ensure that if this is not the case CCS operation will receive ongoing public sector support.

FIGURE 4: CURRENT AND PROJECTED CARBON PRICES (US$/TCO2E) IN JURISDICTIONS WITH CCS

Source: (World Bank & Ecofys, 2015). Price projections obtained from sources referenced in Appendix A.
Note: Australian carbon price path as projected by Australian Treasury when carbon regime was in place.
3.5 Treatment of CCS in carbon pricing regimes

The treatment of CCS by the policy and regulatory frameworks of jurisdictions with carbon tax or trading schemes vary according to the design of the policy instruments. Table 2 illustrates the treatment applied to CCS in various jurisdictions. As an example, the UK EU-ETS carbon price floor was designed to use a combination of the EU ETS price and a floor price set in the UK. The UK price floor covers additional tonnes of CO$_2$e emitted in the power sector that are not covered by the free allocation of the EU-ETS certificates (Ares, 2014). Firms thus have to pay a top-up fee on emissions for which EU-ETS certificates need to be purchased so that the top-up fee and the certificate costs jointly equal the floor price. The United Kingdom reduces the liability of power generation stations fitted with CCS technology in proportion to the estimated level of CO$_2$ abatement. The tax liability reduction is determined on a case-by-case basis. EU ETS prices are currently substantially lower than when UK’s price floor was introduced, resulting in significant additional carbon costs (The Scottish Government, n.d). Guangdong province in China has a trading scheme allowing emissions sequestered by CCS to generate emissions reduction certificates that can be traded with other firms.

TABLE 2: TREATMENT OF CCS UNDER CARBON PRICING REGIMES

<table>
<thead>
<tr>
<th>Instruments Applied:</th>
<th>No. of projects</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tradable Carbon credits</td>
</tr>
<tr>
<td>Australia$^1$</td>
<td>3</td>
</tr>
<tr>
<td>Canada- Alberta</td>
<td>1</td>
</tr>
<tr>
<td>Canada- British Columbia</td>
<td>1</td>
</tr>
<tr>
<td>China-Guangdong</td>
<td>1</td>
</tr>
<tr>
<td>Netherlands</td>
<td>1</td>
</tr>
<tr>
<td>Norway</td>
<td>2</td>
</tr>
<tr>
<td>South Korea</td>
<td>2</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>5</td>
</tr>
<tr>
<td>United States- California$^2$</td>
<td>1</td>
</tr>
</tbody>
</table>

$^1$Australia’s Carbon Pricing Mechanism was repealed, with effect from 1 July 2014.
$^2$CCS is not currently allowed under the California Cap-and-Trade Scheme, but work is underway to formally include CCS in the scheme (Air Resources Board, 2016; Dixon, 2014)

4 THE PROPOSED SA CARBON TAX AND CCS

4.1 Background$^7$

The design of the proposed South African carbon tax is provided in the Draft Carbon Tax Bill published in November 2015 (Republic of South Africa, 2015a). It is envisaged that the carbon tax will be implemented in a

$^7$Section 4 benefitted from work undertaken by the authors on the design of the proposed South Africa carbon tax for Business Leadership South Africa.
number of phases, with the first phase extending from January 2017 to December 2020. The carbon tax design will be reviewed during the first phase and could change significantly for the second and later phases.

The proposed South African carbon tax is set at a rate of R 120 per tonne CO$_2$e, but due to a number of tax-free allowances the effective tax rate will be lower. The allowances determine what fraction of a firm’s emissions is subject to the carbon tax, with more allowances effectively translating into a lower overall carbon tax rate. The carbon tax applies directly only to stationary emission sources. While the intention is to eventually make all significant stationary emissions subject to the carbon tax, during the first phase of the carbon tax the Agriculture, Forestry and Other Land Use (AFOLU) and waste sectors have been excluded from the carbon tax. The residential sector is also not subject to the carbon tax.

### 4.2 Carbon tax calculation formula

In order to understand the implications for the current carbon tax design on CCS deployment, it is useful to consider the way in which carbon tax costs will be calculated. The amount of carbon tax payable is calculated based on the equation shown in the figure below (Republic of South Africa, 2015a):

$$\text{Amount of carbon tax payable} = (E - D - S) \times (1 - C) \times R + (P \times (1 - J) \times R) + (F \times (1 - K) \times R)$$

---

*FIGURE 5: CARBON TAX CALCULATION EQUATION*

The equation has three terms, which relate to different GHG emission types, namely: fossil fuel combustion GHG emissions, industrial process or product use GHG emissions and fugitive GHG emissions. In the equation, $E$, $P$ and $F$ are respectively the total tonnes of GHG emissions of each type: combustion, process and fugitive. Each term in the equation also contains an adjustment for the tax-free allowance: $(1 - C)$, $(1 - J)$ and $(1 - K)$, where $C$, $J$ and $K$ represent the extent of tax relief (cumulative fraction of relevant tax-free allowances) applicable to fossil fuel combustion emissions, process emissions and fugitive emissions respectively. All terms in the equation are also multiplied by the same carbon tax rate, $R$, which is currently set at R 120 per tonne of CO$_2$e.

In the equation, the total combustion GHG emissions, $E$, are adjusted to account for GHG emissions from petrol and diesel combustion (indicated by $D$) as well as for any emissions sequestered by a firm as verified and certified by the Department of Environmental Affairs (indicated by $S$). It is noted that $(E - D - S)$ in the equation cannot be a negative value.

---

*While the implementation date of the carbon tax was not officially confirmed in the 2016 National Budget Speech, the Budget Review provided an “update on the implementation of the carbon tax”, and no delay in the implementation was announced (National Treasury, 2016, p. 52). Officially, the first of January 2017 thus still seems to be the expected start date of the carbon tax.

*The carbon tax will be applied indirectly to the emissions from petrol and diesel through an adjustment to the existing fuel tax regime. While diesel and petrol emissions are excluded from taxable emissions in the Draft Bill, the fact that a carbon tax will be levied on transport fuels via the fuel regime is only mentioned in the Draft Explanatory Memorandum for the Carbon Tax Bill and not the Draft Carbon Tax Bill itself (Republic of South Africa, 2015b; Republic of South Africa, 2015a). The legal status of this approach is thus not clear. What is clear from the Draft Carbon Tax Bill, though, is that there will be no carbon tax payable directly on emissions generated from the use of petrol or diesel, whether in stationary or non-stationary applications.*
The implications of this formula and the carbon tax design more generally are described in the section that follows.

### 4.2.1 Carbon tax allowances

The terms $C$, $J$ and $K$ in the carbon tax calculation equation are made up of a number of different carbon tax allowances or discounts. These allowances have the effect of reducing the effective carbon tax rate applied to combustion, process and fugitive emissions. The effective tax rate is equal to $(1 - C) \times R$ for combustion emissions, $(1 - J) \times R$ for process emissions and $(1 - K) \times R$ for fugitive emissions.

The carbon tax allowances are:

- A basic tax free allowance of 60%;
- An allowance for process or fugitive emissions of either 0% or 10% depending on the sector;
- A carbon budget allowance of 5% if companies participate in the carbon budget system;
- A trade exposure allowance of up to 10%;
- A performance allowance of up to 5%; and
- An offsets allowance of up to 5% or up to 10% depending on the sector.

While a standard set of allowances are applicable to all activities that are taxed, the values of the allowances (effectively the tax relief) differs according to the activity that releases GHG emissions and the type of emissions released. A basic 60% allowance applies to all types of emissions, but additional allowances are used to ensure fugitive emissions and industrial process or product use emissions are taxed at a lower rate than emissions generated from the combustion of fossil fuels. In other words, $J$ and $K$ include a 10% allowance for process or fugitive emissions, which is not applicable $C$.

A number of allowances are also variable based on the characteristics of the entities that are subject to the tax. A variable trade-exposure allowance is calculated based on the extent to which firms export their products or services, an offset allowance depends on the number of locally-generated offsets firms can procure, and a performance allowance is calculated based on the extent to which firms are more carbon efficient (have a lower emissions intensity) than their peers. All three the variable allowances are capped to ensure that the maximum total level of allowance afforded to a firm is capped at levels specified in the Draft Bill.

The value of the different carbon tax allowances (discounts) are shown in Figure 6 in relation to the headline carbon tax rate and the minimum possible carbon tax rate (applicable to process and fugitive emissions) after taking all allowances into account.
FIGURE 6: VALUE OF CARBON TAX ALLOWANCES FOR PROCESS AND FUGITIVE EMISSIONS (R/TCO₂E)

Source: Adapted from (Republic of South Africa, 2015a)

Notes: * All firms within a sector receive the same carbon tax discount. For the carbon budget allowance, firms need to have participated in the carbon budget system.

^The level of the carbon tax discount depends on the characteristics of individual firms. Not all firms within a sector will receive the same carbon tax discount.

The minimum and maximum tax-free allowance applicable to each of combustion, process and fugitive emissions is shown in Table 3 together with the resulting maximum and minimum effective tax rates. It is important to point out that some allowances vary only between sectors (e.g. all firms within a qualifying sector get the same discount) and some allowances vary both between sectors and within sectors (the actual value of the carbon tax allowance is determined by an individual firm’s characteristics). Therefore, not only will different sectors face different effective carbon tax rates (based on the types of emission they produce and whether they qualify for certain allowances), but carbon tax rates will also differ between firms within sectors.

The basic tax-free allowance of 60% applies to all emissions and to all firms subject to the carbon tax. R 48/TCO₂e is thus the highest effective carbon tax rate than a firm can pay under the first phase of the carbon tax for combustion emissions. And a firm would only pay this rate if exports were less than 5% of its total sales, it was more carbon intensive than the average firm that undertakes an GHG emitting activity, it did not participate in the DEA’s carbon budgets system, and it did not own any qualifying emissions offsets (i.e. it didn’t benefit from any of the variable allowances). From the Draft Bill, firms giving rise to process and fugitive emissions always are given the allowance for process and fugitive emissions and thus the maximum effective carbon tax rate for these emissions is R 36/TCO₂e.
## TABLE 3: CARBON TAX ALLOWANCES APPLICABLE TO COMBUSTION, PROCESS AND FUGITIVE EMISSIONS, AND RESULTING MAXIMUM AND MINIMUM C, J AND K AND ASSOCIATED EFFECTIVE CARBON TAX RATES

<table>
<thead>
<tr>
<th>Carbon tax allowance</th>
<th>Combustion emissions</th>
<th>Process emissions</th>
<th>Fugitive emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic carbon tax allowance</td>
<td>60%</td>
<td>60%</td>
<td>60%</td>
</tr>
<tr>
<td>Allowance for process or fugitive emissions</td>
<td>n/a</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>Carbon budget allowance</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Trade exposure allowance</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>Performance allowance</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Offsets allowance</td>
<td>10%</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Maximum cumulative fraction of relevant tax-free allowances</td>
<td>C = 0.9</td>
<td>J = 0.95</td>
<td>K = 0.95</td>
</tr>
<tr>
<td>Resulting minimum effective tax rate</td>
<td>((1 – C) \times R) ((1 – 0.9) \times R \times 120) R 12/tCO₂e</td>
<td>((1 – J) \times R) ((1 – 0.95) \times R \times 120) R 6/tCO₂e</td>
<td>((1 – K) \times R) ((1 – 0.95) \times R \times 120) R 6/tCO₂e</td>
</tr>
<tr>
<td>Minimum cumulative fraction of relevant tax-free allowances</td>
<td>C = 0.6</td>
<td>J = 0.7</td>
<td>K = 0.7</td>
</tr>
<tr>
<td>Resulting maximum effective tax rate</td>
<td>((1 – C) \times R) ((1 – 0.6) \times R \times 120) R 48/tCO₂e</td>
<td>((1 – J) \times R) ((1 – 0.7) \times R \times 120) R 36/tCO₂e</td>
<td>((1 – K) \times R) ((1 – 0.7) \times R \times 120) R 36/tCO₂e</td>
</tr>
</tbody>
</table>

Source: Adapted from (Republic of South Africa, 2015a)

Figure 7 demonstrates the variability in effective tax rates between firms in different sectors (and emission types within sectors). As noted above, allowances differ by type of emissions and also by the activity that generates the emissions. So for example, combustion emissions from electricity and heat production (the first column in the figure) are only eligible for the basic tax-free allowance (60%), a carbon budget allowance (5%) and a carbon offsets allowance of up to 10%. Resulting in an effective carbon tax rate on combustion emissions of R 30/tCO₂e.

Combustion emissions from a firm in the iron and steel industry are eligible for different allowances to combustion emissions from firms involved in electricity and heat production. These firms could claim a further 10% allowance for trade exposure and up to 5% performance allowance, resulting in a minimum effective tax rate on combustion emissions of R 12/tCO₂e.

Furthermore, the process emissions from a firm in the iron and steel industry (as shown by the third column in the figure) are eligible for different allowances to combustion emissions generated by the same firm (the second column). Here, process emissions from iron and steel are eligible for the 10% allowance for process emissions, but the carbon offsets allowance is limited to 5%. The final column in the figure shows the allowances and effective carbon tax rate for fugitive emissions from coal to liquid processes, which are similar to process emissions from iron and steel as the same allowances apply.

Having said that, however, Figure 7 also shows that whereas some allowances are fixed (meaning that every firm that qualifies for the allowance will receive the same amount of tax relief), other allowances vary based on the characteristics of individual firms. The trade exposure allowance, performance allowance and offset allowances can thus vary from firm to firm. This means that two firms in the same sector may not receive the same level of tax relief, and consequently may thus not pay the same carbon tax rate. The offset allowance, for example, is dependent on the amount of carbon offsets that a firm purchases.
4.3 Implications of the carbon tax for CCS deployment

4.3.1 Price certainty

There is very little price certainty regarding the proposed South African carbon tax. The headline carbon tax rate (before allowances) is specified as R 120 per tonne CO₂e in the Draft Carbon Tax Bill, but the Draft Explanatory Memorandum to the Bill mentions that the actual carbon tax rate will be confirmed by the Minister of Finance through the annual budgetary process. Furthermore, while critical elements of the carbon tax design may change post 2020, very little detail has been provided as to what these changes may look like (Republic of South Africa, 2015a; Republic of South Africa, 2015b). The possibility of reducing all the tax-fee allowances at the start of the second phase is mentioned, as is the possibility of adjusting the allowances from relative (percentage) to absolute (fixed thresholds set in tonnes of CO₂e) to align with the Department of Environmental Affairs’ company-level carbon budgets. This signals that some of the tax relief included in the current tax design will remain, and could be interpreted that the carbon tax rate is unlikely to be higher than R 120 per tonne CO₂e in 2021.

There is thus very little clarity on either carbon tax levels in specific years or even the trajectory of carbon tax levels going forward. This is in contrast to the National Treasury’s previous policy position on the evolution of the carbon tax. The degree of price certainty provided in terms of the 2013 and 2015 carbon tax design proposals is show in Table 4.

Source: Calculations based on Republic of South Africa (2015a)

Notes: 1) Fugitive emissions from coal-to-liquids (CTL) processes are classified as ‘Other Fugitive Emissions From Energy Production’ in terms of both the Draft Carbon Tax Bill and IPCC guidelines. This was confirmed by Sasol representatives.
2) ‘Fixed’ allowances indicate that every firm in a sector will receive the same carbon tax discount, while allowances that are ‘Not Fixed’ indicate that the level of carbon tax discount will differ based on the characteristics of individual firms (all firms within a sector will thus not receive the same carbon tax discount).
### TABLE 4: CARBON TAX PRICE CERTAINTY BASED ON 2013 AND 2015 CARBON TAX DESIGNS

<table>
<thead>
<tr>
<th>Component</th>
<th>2013 NT Policy Paper</th>
<th>2015 Carbon Tax Design</th>
</tr>
</thead>
<tbody>
<tr>
<td>Headline carbon tax rate off which fixed carbon tax discounts will apply (carbon tax trajectory 2015 – 2020)</td>
<td>R 120/tCO$_2$e in 2015 increasing at 10% per year up to 2019</td>
<td>Introduced at R 120/tCO$_2$e, but actual rate will be confirmed by Minister of Finance in annual budget</td>
</tr>
<tr>
<td>Headline carbon tax rate off which discounts will apply (carbon tax rate in 2021)</td>
<td>R 176/tCO$_2$e (based on known 2019 value) Or R 213/tCO$_2$e (assume 10% annual increase continues)</td>
<td>R 120/tCO$_2$e (no guidance on future headline carbon tax rate provided)</td>
</tr>
<tr>
<td>Carbon tax discounts in 2021</td>
<td>Tax-free thresholds will be lower (post 2019)</td>
<td>Tax-free allowances could be phased down and/or could be replaced with single absolute tax-free threshold aligned with proposed carbon budgets (post 2020)</td>
</tr>
</tbody>
</table>

Source: (National Treasury, 2013; Republic of South Africa, 2015b)

When the National Treasury initially released a detailed carbon tax design in 2013, it indicated that the base rate of R 120 per tonne CO$_2$e would increase by 10% a year in nominal terms from 2015. It also mentioned that a revised tax regime would be implemented from 2020 with lower tax-free thresholds and a revised headline carbon tax rate (so higher than the carbon tax rate of R 176 per tonne CO$_2$e that was expected for 2019) (National Treasury, 2013). Extrapolating this information forward, the expected headline carbon tax rate in 2021 for which carbon tax discounts would have applied was expected to be higher than R 176 per tonne CO$_2$e (and probably around R 213 per tonne CO$_2$e if it was assumed the signalled 10% nominal increases would continue into the next phase of the carbon tax).

The impact of different carbon tax prices post 2020 on CCS is explored as part of the modelling exercise reported in Section 1.

#### 4.3.2 Treatment of sequestered emissions

The carbon tax calculation formula shown in Section 4.2 is repeated below:

\[
\text{Amount of carbon tax payable} = \{E - D - S \times (1 - C) \times R\} + \{P \times (1 - J) \times R\} + \{F \times (1 - K) \times R\}
\]

**FIGURE 8: CARBON TAX CALCULATION EQUATION**

It is clear from the formula that sequestered emissions (term $S$) reduces a firm’s taxable GHG emissions directly, and is thus unrelated to the carbon tax allowances discussed previously (which are jointly considered in terms $C$, $J$ and $K$ of the formula). The treatment of sequestered emissions under the current carbon tax design has two important implications for CCS deployment.
Firstly, according to the carbon tax calculation equation, sequestered emissions can only be used to reduce taxable emissions by an amount equal to or smaller than a firm’s fossil fuel combustion emissions (Republic of South Africa, 2015a). So all firms can reduce their taxable emissions through sequestration, but they are only allowed to claim a benefit that is equal to, or smaller than, the amount of GHG emissions they emit from the combustion of fossil fuels (irrespective of how the sequestered emissions were generated). So while this allows CCS to be deployed in the electricity generation sector (where firms generate mostly fuel combustion emissions – allowing them to reduce their carbon tax liability to close to zero through the use of CCS), it means that firms that undertake activities like coal-to-liquid processes that generate significant amounts of fugitive emissions¹⁰ (according to the classification in Schedule 2 of the Draft Bill) will be limited to receiving a carbon tax reduction for sequestered emissions that is equal to their equivalent tonnage of combustion emissions. Economies of scale in the deployment of CCS linked to processes like coal-to-liquid is thus reduced (and project costs increased) since a carbon tax benefit can only be received for the sequestration of a portion of total emissions.

To illustrate this point, compare Figure 9 and Figure 10. Figure 9 shows a hypothetical “Company A” that generates only combustion emissions. This company can theoretically sequester 100% of their combustion and will see the carbon tax benefit of sequestering all these emissions. After sequestering all 100 tonnes of emissions their carbon tax will be R 0 and the carbon tax benefit of sequestration equal to R 4,200 (assuming the firm participates in the Department of Environmental Affairs’ first phase of carbon budgets in South Africa and thus receives the 5% tax-free carbon budget allowance in addition to the 60% basic allowance for combustion emissions). Company B, as shown in Figure 10, generates both combustion and fugitive emissions. Even if 100% of these emissions are sequestered, Company B will only see a carbon tax benefit up to the limit imposed by the constraint \((E - D - S) > 0\). Assuming the same allowances as company A under combustion emissions and a further 10% fugitive emissions allowance, the carbon tax benefit from sequestering 100 tonnes of emissions will be limited to R 2,100.

¹⁰ The definition of ‘fugitive emissions’ provided in the Draft Carbon Tax Bill is different from the colloquial understanding of the term, and includes emissions from coal-to-liquid processes. It is, however, consistent with the classification of coal-to-liquid emissions by the IPCC, a fact confirmed by a representative of Sasol.
**FIGURE 9: RAND BENEFIT OF SEQUESTERING 100% OF A COMPANY’S COMBUSTION EMISSIONS TO REDUCE TAXABLE EMISSIONS**

Source: Authors’ calculations based on (Republic of South Africa, 2015a)

Carbon tax benefit of sequestering 100 tonnes CO₂e combustion emissions = R 4,200 – R 0 = R 4,200

**FIGURE 10: RAND BENEFIT OF SEQUESTERING A COMPANY’S FUGITIVE EMISSIONS TO REDUCE TAXABLE EMISSIONS SHOWING THE LIMIT IMPOSED BY THE (E – D – S) TERM**

Source: Authors’ calculations based on (Republic of South Africa, 2015a)
Secondly, since sequestered emissions (from whatever source) reduce a firm’s taxable fuel combustion emissions, the tax benefit a firm will receive per unit of CO₂ stored via CCS is equal to the effective carbon tax rate applied to combustion emissions (including tax relief) (see Table 3). So irrespective of how the emissions that are sequestered were generated, in the current carbon tax formula sequestration can only reduce the amount of carbon tax paid on combustion emissions (term (E - D - S)). The carbon price from the perspective of incentivising CCS deployment is thus much lower than the stated R 120 per tonne CO₂e. An electricity generator, for example, which doesn’t utilise any offsets, will receive a R 42 tax benefit for every tonne of CO₂e sequestered through CCS as is illustrated in Figure 9 (R 42,000 divided by 100 tonnes sequestered). Given that process and fugitive emissions receive more tax-free allowances than combustion emissions (and thus face a lower effective carbon tax rate)¹¹, there would still be a weaker carbon tax incentive to deploy CCS in sectors with significant process and fugitive emissions even if the restriction inherent in the term (E – D – S) on the amount of these emissions that can receive a carbon tax benefit through sequestration is changed. This is illustrated in Figure 11. Comparing Figure 11 and Figure 10 shows that under the same assumptions for company B, if sequestered fugitive emissions reduce the amount of fugitive emissions taxed rather than combustion emissions taxed, a lower carbon tax saving is observed (a R 30/tCO₂e saving compared to a R 42/tCO₂e saving).

\[
\text{Amount of carbon tax payable} = (E - D - S) \times (1 - C) \times R + (P \times (1 - J) \times R + (F - SF) \times (1 - K) \times R)
\]

**COMPANY B: BEFORE**

\[
\begin{align*}
E &= 50 \text{ tonnes CO}_2e \\
D &= 0 \text{ tonnes CO}_2e \\
S &= 0 \text{ tonnes CO}_2e \\
C &= 0.65 (60\% + 5\%) \\
R &= R 120/tCO_2e
\end{align*}
\]

\[
\begin{align*}
P &= 0 \text{ tonnes CO}_2e \\
J &= 0.75 (60\% + 10\% + 5\%) \\
R &= R 120/tCO_2e \\
SF &= 0 \text{ tonnes CO}_2e \\
K &= 0.75 (60\% + 10\% + 5\%) \\
R &= R 120/tCO_2e
\end{align*}
\]

\[
\begin{align*}
\text{Amount of carbon tax payable} &= ((50 - 0) \times (1 - 0.65) \times 120) + \{0 \times (1 - 0.75) \times 120\} + \{50 \times (1-0.75) \times 120\} \\
&= R 2,100 + R 1,500 = R 3,600
\end{align*}
\]

**COMPANY B: AFTER SEQUESTERING 50 tonnes CO₂e fugitive emissions**

\[
\begin{align*}
E &= 50 \text{ tonnes CO}_2e \\
D &= 0 \text{ tonnes CO}_2e \\
S &= 0 \text{ tonnes CO}_2e \\
C &= 0.65 (60\% + 5\%) \\
R &= R 120/tCO_2e
\end{align*}
\]

\[
\begin{align*}
P &= 0 \text{ tonnes CO}_2e \\
J &= 0.75 (60\% + 10\% + 5\%) \\
R &= R 120/tCO_2e \\
SF &= 50 \text{ tonnes CO}_2e \\
K &= 0.75 (60\% + 10\% + 5\%) \\
R &= R 120/tCO_2e
\end{align*}
\]

\[
\begin{align*}
\text{Amount of carbon tax payable} &= ((50 - 0) \times (1 - 0.65) \times 120) + \{0 \times (1 - 0.75) \times 120\} + \{(50 - 50) \times (1-0.75) \times 120\} \\
&= R 2,100 + R 0 = R 2,100
\end{align*}
\]

Carbon tax benefit of sequestering 50 tonnes CO₂e fugitive emissions = R 3,600 – R 2,100 = R 1,500

**FIGURE 11: HYPOTHETICAL CASE OF THE RAND BENEFIT OF SEQUESTERING A COMPANY’S FUGITIVE EMISSIONS TO REDUCE TAXABLE EMISSIONS WHERE SEQUESTERED FUGITIVE EMISSIONS REDUCE TERM F AS OPPOSED TO TERM E**

Source: Authors’ calculations based on (Republic of South Africa, 2015a)

¹¹ Using the examples of combustion emissions from Iron and Steel production, process emissions from Iron and Steel production and fugitive emissions from a coal-to-liquid process, Figure 7 shows that the lowest carbon tax rate that can be paid on combustion emissions will be R12/tCO₂, while the lowest carbon tax rate than can be paid on process and fugitive emissions is R6/tCO₂. Combustion emissions originating from electricity or heat production as a firm’s primary activity is a special case, and the lowest tax rate that can be paid on this type of combustion emissions is R30/tCO₂e.
4.3.3 Treatment of offsets

The Draft Carbon Tax Bill indicates that firms can reduce their carbon tax by using approved carbon offsets (Republic of South Africa, 2015a). Firms that obtain carbon offsets (carbon credits which have been approved for use under the carbon tax regime) are thus able to claim a reduction in their carbon tax liability through the use of the carbon offset allowance. Which carbon offsets will be approved for use within the carbon tax regime is not elaborated on in the Draft Bill, but the Draft Explanatory Memorandum mentions that only carbon offsets based on emissions reductions within South Africa, and in sectors not covered by the carbon tax, would be allowed (Republic of South Africa, 2015b).

In the carbon tax calculation formula shown in Section 4.2, carbon offsets are included in the C, J and K terms as an allowance. The current carbon tax design thus means that a firm is able to reduce its carbon tax liability by R 120 for every tonne of CO₂e for which it can produce a carbon offset. This is shown in Figure 12, where Company C has access to 1 tonne of GHG offsets (equal to 1% of its total emissions of 100). The value of the offsets remains constant irrespective of which emissions it is offset against. In the example in Figure 12 the offsets are utilised to reduce combustion emissions by 0.5 tonnes and fugitive emissions by 0.5 tonnes.

![Figure 12: RAND Benefit of Off-setting 1% of Emissions to Reduce Carbon Tax Liability](image)

Source: Authors’ calculations based on (Republic of South Africa, 2015a)

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12 The Draft Explanatory Memorandum to the carbon tax bill defines carbon offsets as “measurable avoidance, reduction or sequestration of carbon dioxide (CO₂) or other greenhouse gas emissions” (Republic of South Africa, 2015b, p. 7). The difference between a carbon offset and carbon sequestration is that in the case of offsets the firm that reduces its GHG emissions is not the firm that receives the carbon tax benefit. The emissions reduction is transferred to a third party via an authorized emissions reduction contract (a carbon credit). In the case of sequestration, the firm that sequesters the emissions gains the carbon tax benefit.

13 See clarification in Footnote 16.

14 Amount of carbon tax payable = \(((E - D - S) \times (1 - C) \times R) + (P \times (1 - J) \times R) + (F \times (1 - K) \times R)\). \(C\) represents the extent of tax relief (cumulative percentage value of relevant tax-free allowances) applicable to fossil fuel combustion emissions, \(J\) the tax relief applicable to industrial process and product use emissions, and \(K\) the tax relief applicable to fugitive emissions.
The treatment of offsets has two key implications for CCS deployment:

- Firstly, as shown in Table 3, effective carbon tax rates differ between sectors and firms. To elaborate on the example of the electricity generator mentioned in Section 4.3.2, should an electricity generator that implements a CCS project be allowed to generate and sell carbon offsets to other firms (which is not allowed under the current carbon tax design), this generator could theoretically be able to generate an income of close to R 120 for every tonne of CO₂e sequestered. This would clearly be a stronger incentive to invest in CCS than the R 42/CO₂e benefit it would receive by reducing its own combustion emissions at its indicative effective carbon tax rate.

- Secondly, the inability of firms subject to the carbon tax to generate carbon offsets recognised under the carbon tax regime means that only firms that have physical access to CCS infrastructure (and can thus sequester emissions directly) can benefit from CCS projects. This limits the amount of funds that could be pooled to invest in CCS projects, and also reduces the ability to diversify risk by increasing the number of firms that participate in a CCS project (either through investing directly in a project or by purchasing the rights to a portion of the future offsets generated by a CCS project).

### 4.3.4 Calculation of performance allowance

One of the tax-free allowances included in the current carbon tax design is a performance allowance (capped at 5% of emissions) calculated based on the extent to which firms are more carbon efficient, or have a lower emissions intensity, than their peers. It is not clear from the Draft Carbon Tax Bill or the Draft Explanatory Memorandum whether sequestered emissions are included in the calculation of the performance allowance (Republic of South Africa, 2015a; Republic of South Africa, 2015b). Figure 13 shows the impact of whether or not sequestered emissions are included in the calculation of the performance allowance on the incentive to deploy CCS.

Consider a firm where half its emissions are fugitive emissions and half its emissions are combustion emissions (as a result of employing a coal-to-liquids (CTL) process, for example). As mentioned earlier, the firm will receive a tax benefit equal to its effective tax rate on combustion emissions, and this benefit will only apply to half its emissions. So even if the sequestered emissions are able to account for all the firm’s combustion emissions, this is still only half of the firm’s overall emissions and the benefit received will be much lower rate than R 120 per tonne CO₂e (if, in addition to its CTL process, the firm also generates heat or electricity, this benefit will be at most R 42 per tonne CO₂e akin to the earlier electricity generator example).

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15 Since a firm purchasing the offset will receive a carbon tax saving, it should thus be willing to pay close to R120 for a tonne of CO₂e offsets. When paying R120/CO₂e for an offset, a firm is ambivalent between purchasing an offset or paying the tax, but every cent the firms pays less than R120/CO₂e provides it with a net carbon tax saving. The actual price paid for the offsets will depend on the relative supply and demand for qualifying offsets.

16 This point was recently clarified by the National Treasury during a public workshop. Firms that have to pay carbon tax will only be allowed to generate offsets from activities in sectors that are not covered by the carbon tax. A firm that emits GHG emissions from a gas-to-liquids process in the petrochemical industry, for example, cannot generate offsets by reducing its GTL emissions. But the same firm can generate offsets if it invests in projects to reduce emissions in the waste or agriculture sectors as emissions in these sectors are not currently subject to the carbon tax.
FIGURE 13: IMPACT OF PERFORMANCE ALLOWANCE ON VALUE OF SEQUESTERED EMISSIONS

Source: Authors’ calculations based on (Republic of South Africa, 2015a)
Notes: Petrol and diesel emissions (D) is assumed to be zero, so E-D-S = E-S.
Tax liability = \[\frac{(E-S)(1-C)R}{120/tCO_2e} + \frac{(F)(1-K)R}{120/tCO_2e}\]
Z is capped at 5% in the Draft Carbon Tax Bill | The emissions intensity calculation shown above is a simplification, since the Draft Carbon Tax Bill promotes benchmarking on an activity and not a product basis.

Should these sequestered emissions however be included in the firm’s emissions intensity calculation for the purposes of determining whether the firm receives a performance allowance, the sequestered emissions could lead to the firm also paying a lower carbon tax rate on its remaining, non-sequestered emissions (resulting from a
higher performance allowance). This is clearly shown in Figure 13. If the firm is able to sequester 5% of its fugitive emissions, for example, it benefits from a R 42 reduction in carbon tax for every tonne of CO₂e sequestered if the sequestered emissions are not taken into consideration when the performance allowance is calculated (Scenario 2). When sequestered emissions are taken into account in the calculation of the performance allowance, however, the benefit per tonne of CO₂e sequestered increases to R 156. The larger the total amount of emissions remaining after sequestration, the larger the increase in benefit per tonne of CO₂e sequestered. So the benefit of being able to include sequestered emissions in the performance allowance calculation decreases as the amount of emissions sequestered increases. If the firm in our example was able to sequester all its fugitive emissions, it would be able to claim the sequestration benefit against all its combustion emissions. In this case, however, being able to count the sequestered emissions during the performance allowance would only increase the benefit per tonne of CO₂e sequestered to R 48.

Whether or not sequestered emissions will be included in the calculation of the performance allowance will clearly have an important impact on the incentives created by the carbon tax to implement CCS. It is thus important that this issue is clarified.

5 ASSESSMENT OF THE IMPACT OF THE TAX ON THE FINANCIAL PERFORMANCE OF CCS

To complement the findings of the background review presented thus far in this report, a financial model was developed to explore the impacts of a carbon tax on the cost implications of CCS, and in particular the relationship between rising carbon tax levels and decreasing costs of CCS. The financial model used in this study takes as its departure point an existing financial model commissioned by SANEDI, and developed by Parsons Brinckerhoff, that supported a techno-economic review of CCS implementation in South Africa (Parsons Brinckerhoff, 2013). However the purposes of this current study required a somewhat different analysis to that conducted by Parson Brinckerhoff. The following section describes the various methodological considerations to be taken into account when analysing the financial performance of CCS that are then drawn upon to develop the model for use in this current project. As part of this discussion, the authors of this work also interrogate some of the assumptions underpinning the previous study (and other studies) in more detail.

What became very clear during the modelling process was how sensitive the findings are to model inputs. Different studies can come up with significantly different CCS costs, depending on the approach taken and input assumptions. The model’s base year is also an important consideration – given how substantially exchange rates of the rand against the dollar and euro, on which capital costs are typically based, fluctuate. As such the numbers presented here are not intended to be absolutely accurate, but rather to provide trends and comparative measures.

5.1 Methodological considerations

A review was conducted to gather information on how other studies analysed the costs of CCS used in different industries and under different infrastructure configurations. This review included both international studies and other South African financial modelling studies, notably those of Parsons Brinckerhoff (2013), Telesnig et al. (2013) and SLR (2013). The review identified the variability in scope and methodologies followed in the different studies, highlighting how differences in assumptions can lead to significant differences in the estimated costs of otherwise similar systems (Rubin et al., 2013).
Data from a literature review by Rubin, et al. (2015), which illustrates the impact of specific assumptions on results, is presented in Figure 14. The study compared levelised costs\textsuperscript{17} from the most recent available data for CCS applied to supercritical pulverised coal (SCPC) coal power, integrated gasification combined cycle (IGCC) coal power and natural gas combined cycle (NGCC) power. All costs are presented in 2013 US dollars and only the capital costs were adjusted to a common basis of Total Capital Requirements (TCR) (see Section 5.1.2 where different capital costs are explained).

\textbf{FIGURE 14: RANGE OF TOTAL COSTS FOR CO}_2 \textbf{CAPTURE IN NEW POWER PLANTS, TRANSPORT AND GEOLOGICAL STORAGE (RUBIN ET AL., 2015).}

Certain CCS cost methodological choices are dictated by the purpose of the assessment. In general, CCS cost estimate studies are undertaken to inform either policy or technology assessments (Rubin et al., 2013). Policy assessments aim to support governmental activities relating to regulation, taxes or support programmes for specific technologies. Technology assessments on the other hand support technology selection for future capital investments, marketing strategies or R&D priorities and are more likely to be done on a more detailed project specific basis.

In technology assessments which are focused on screening alternatives, analyses may be done on a technology-levelling basis, where only the differences due to the CCS capture technology are highlighted. This requires the cost differences between different technologies to be captured as accurately as possible, with less focus on capturing the absolute project costs. Technology-levelling assumptions are thus made to ensure a comparable basis for the different CCS technologies, including those related to plant size, fuel type, capacity factors, etc. Studies that follow this approach should not be used to inform actual capital investment required or impacts of policy for a specific country, as these typically do not account for owner specific costs or location specific factors that may impact on these costs. For such purposes a detailed costing exercise is required. Having said this, for the purposes of this study, a technology levelling approach is used in order to understand the relative impact of the carbon tax on CCS, rather than to conduct a full assessment of the costs of a CCS project which may be required as part of an extensive policy analysis.

\textsuperscript{17} Levelised cost of energy is the constant price at which a unit of energy generated should be sold for the investment to break even (a net present value of zero).
The purpose of the assessment will therefore inform the system configuration to be explored in the analysis, cost inclusions and exclusions, and the model structure and economic assumptions to be used for calculating costs. These aspects of the methodology are explored in this section.

5.1.1 System configuration

It is clear that the system configuration that is modelled has a significant impact on study findings. System elements that need to be defined include:

- types of emitting facilities;
- capture technologies;
- pipeline configurations; and
- storage sites.

Some of the considerations that need to be taken into account in this regard are presented here. It is noted that this discussion is not intended to serve as an exhaustive technology review, but rather to highlight the major factors that can impact on CCS cost estimations.

Emitting facilities and capture technologies

The capture cost of CCS differs for different industries, and will be determined by factors including the concentration of CO₂ in the stream considered, the total volume of sequestered CO₂ and the stage of development of the selected capture technology. Installations normally considered as being suited to carbon capture include electricity generation, synthetic fuel production (CTL and GTL) and energy-intensive industrial processes. The latter can include oil refineries, cement production, iron and steel production, fertiliser production and paper mills. Synthetic fuel production and coal fired power stations are, however, preferred options for CCS with the former generating relatively high concentration CO₂ streams and the latter generating large volumes of CO₂ (Parsons Brinckerhoff, 2013; WorleyParsons, 2011).

Pre-combustion capture is the technology with the lowest risk and is closest to commercial scale rollout (Parsons Brinckerhoff, 2013). Pre-combustion capture is well suited for use in CTL and GTL facilities to capture the CO₂ from synthetic fuel production, as these facilities have high concentration CO₂ streams available from the Rectisol process, as well as from Benfield towers. It is, however, less suited for application in the coal fired power generation sector, as it can only be paired with IGCC coal power stations (rather than supercritical power stations which Eskom currently operates, or future ultra-supercritical stations). Although IGCC coal power is a proven technology, it has not been rolled out at a commercial scale yet (Parsons Brinckerhoff, 2013).

Post-combustion capture utilising solvents is the technology furthest along in development for capture at supercritical and ultra-supercritical coal fired power stations. Post-combustion capture is also the recommended option for retrofitting existing power stations. The alternative capture technology for these types of power stations is oxy-combustion CCS, a technology still in early stages of development with high uncertainties associated with efficiencies and costs of capture (Parsons Brinckerhoff, 2013). Retrofitting an existing facility with CCS generally results in a higher levelised cost of electricity when compared to new build options, because of increased capital costs for installation of CCS, lower power generation efficiencies, higher energy consumption per tonne CO₂ captured and shorter remaining plant lifetimes (Rubin et al., 2015).

Development of CCS for energy intensive industries is lagging behind that of power generation and synthetic fuel production technologies due to a lack of international large-scale demonstration projects. It is expected that CCS
for industrial facilities will only be rolled-out on a commercial scale post-2030 (ZEP, 2013). The capture technology of choice for an energy-intensive industrial facility depends on the process, the plant configuration and the remaining lifetime of the facility. Post-combustion capture and oxy-combustion are the technologies most widely considered, with post-combustion capture recommended for retrofits to existing facilities (Parsons Brinckerhoff, 2013). Although pilot projects in various industries have validated the potential for CCS, large-scale demonstration projects are required for more accurate estimations on technical and economic factors (ZEP, 2013).

CCS at any facility will require additional energy for the capture process and might also result in reduced production efficiency for industrial processes (ZEP, 2013). For a greenfield power generation plant the net power output can be designed to be the same before and after CCS, with the facility consuming additional fuel to supply the energy required for CCS. For a retrofit to an existing power station the cost of the energy penalty is typically simulated with the cost of new-build power or as a loss of revenue, based on the electricity price. Industrial facilities will be required to purchase additional electricity for CCS (e.g. grid electricity) or generate electricity on-site. These facilities might also experience a loss in production output as a result of CCS, which should be quantified and included in the cost of CCS.

**Pipeline configuration and storage**

Costs of transport and storage can contribute a significant portion to the overall cost of CCS, with local studies suggesting that this contribution may lie between 10% and 30% (Parsons Brinckerhoff, 2013; Telsnig et al., 2013). There is however a large variation in these costs between different studies, as some simply apply a generalised average cost per tonne of CO\textsubscript{2} (transport and storage combined), whereas others do more detailed analyses based on the specific project.

The most significant assumptions that impact on transport and storage cost are:

- Pipeline configuration; and
- Type and location (onshore or offshore) of storage.

For the pipeline configuration, either a point-to-point pipeline from capture to storage site can be used or a network of centralised trunk lines with branch lines. Optimising the pipeline configuration can be a complicated exercise for multiple capturing sites, and in designing the pipeline configuration consideration should be given to the timing of when the largest CCS facilities will come on-line to avoid underutilisation of pipelines for extended periods, which will negatively impact on the cost of CCS. Terrain and population density will also impact on the cost of pipelines.

The decision on type and location of storage is country specific and determined by the storage capacities of the available reservoirs. Offshore pipelines are more expensive than onshore due to the requirement of thicker pipes to prevent collapse of the pipeline due to the external pressure of the water (Knoope et al., 2014), with offshore storage being on average about three times as expensive as that of onshore due to the higher overall capital cost requirements (Rubin et al., 2015).

**5.1.2 Cost inclusions and exclusions**

Literature studies differ with regards to the costs included in the cost estimations and the naming conventions used for these costs. It is for this reason that the study by Rubin, et al., (2013) proposed a nomenclature and methodology for CCS cost items. See Table 5 and Table 6 below for the recommended cost nomenclature.
### TABLE 5: NOMENCLATURE FOR CAPITAL COSTS (RUBIN ET AL., 2013)

<table>
<thead>
<tr>
<th>Nomenclature for sum of preceding elements</th>
<th>Capital cost elements</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bare Erected Cost (BEC)</strong></td>
<td>Process equipment (Includes all materials and sales tax (if applicable))</td>
</tr>
<tr>
<td></td>
<td>Supporting facilities (Onsite facilities needed for the project)</td>
</tr>
<tr>
<td></td>
<td>Labor (direct and indirect)</td>
</tr>
<tr>
<td><strong>Engineering, Procurement &amp; Construction (EPC) Cost</strong></td>
<td>Engineering services (Typically estimated as a percentage of the BEC)</td>
</tr>
<tr>
<td><strong>Total Plant Cost (TPC)</strong></td>
<td>Process Contingency (Accounts for process or specific component maturity (e.g. CO$_2$ capture equipment))</td>
</tr>
<tr>
<td></td>
<td>Project Contingency (Subject to level of overall project cost estimate and design stage)</td>
</tr>
<tr>
<td><strong>Total Overnight Cost (TOC)</strong></td>
<td>Owner’s costs: Feasibility studies, Surveys, Land, Insurance, Permitting, Finance transaction costs, Pre-paid royalties, Initial catalyst and chemicals, Inventory capital, Pre-production (start-up)</td>
</tr>
<tr>
<td></td>
<td>Other site-specific items unique to the project (such as unusual site improvements, transmission interconnects beyond site boundary, economic development incentives, etc.)</td>
</tr>
<tr>
<td><strong>Total Capital Requirement (TCR)</strong></td>
<td>Interest during construction (IDC)</td>
</tr>
<tr>
<td></td>
<td>Cost escalations during construction</td>
</tr>
</tbody>
</table>

### TABLE 6: NOMENCLATURE FOR OPERATING AND MAINTENANCE COSTS (RUBIN ET AL., 2013)

<table>
<thead>
<tr>
<th>Naming convention for sum of all items</th>
<th>Operating and maintenance cost element</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fixed O&amp;M Costs</strong></td>
<td>Operating labour</td>
</tr>
<tr>
<td></td>
<td>Maintenance labour</td>
</tr>
<tr>
<td></td>
<td>Administrative and support labour</td>
</tr>
<tr>
<td></td>
<td>Maintenance materials</td>
</tr>
<tr>
<td></td>
<td>Property taxes</td>
</tr>
<tr>
<td></td>
<td>Insurance</td>
</tr>
<tr>
<td><strong>Variable O&amp;M Costs</strong></td>
<td>Includes all materials used in proportion to product generated (itemized for each project):</td>
</tr>
<tr>
<td></td>
<td>Fuel</td>
</tr>
<tr>
<td></td>
<td>Other consumables, e.g.: Catalysts, Chemicals, Auxiliary fuels,</td>
</tr>
<tr>
<td></td>
<td>Water</td>
</tr>
<tr>
<td></td>
<td>Waste disposal (excl. CO$_2$)</td>
</tr>
<tr>
<td></td>
<td>CO$_2$ transport and CO$_2$ storage (Transport &amp; storage may also be capital cost items, depending on project scope)</td>
</tr>
<tr>
<td></td>
<td>By-product sales (credit)</td>
</tr>
<tr>
<td></td>
<td>Emissions tax (or credit) (Fee paid (or credit received) per unit of emissions, with or without CCS (if applicable))</td>
</tr>
</tbody>
</table>

Costs provided in the literature are usually based on specific locations and fuel heating values. These costs can be adjusted to obtain project specific cost estimates using location and fuel adjustment factors such as those provided in the study by WorleyParsons (2011). Location factors adjust the reference costs for country specific productivity and cost of labour, sourcing of equipment and importation requirements of materials. Fuel factors adjust the capital cost and plant efficiency provided in the literature to account for the fuel heating value used in the specific project case.

Cost decreases in CCS technologies over time can be achieved through additional rollout of the same technology or with the introduction of improved or new technologies. With additional rollouts of the same technology, experience will lead to a reduced process contingency for the CCS technology. Costs are typically presented in
literature for first-of-a-kind (FOAK) or nth-of-a-kind (NOAK) facilities. The latter is for facilities where there is no more risk or uncertainty in the installation of the technology, and therefore the process contingency is zero (note that this is not the project contingency, which is subject to the detail of the site cost estimate; see Table 5). For power station CCS installations of a specific technology, it is believed that NOAK costs will only be achieved once the technology has been rolled-out onto 100 GW of total combined power station capacity (WorleyParsons, 2009). This cost reduction between FOAK and NOAK only represents a decrease in risk of implementing an existing technology, and does not account for the implementation of improvements or new technologies. Rubin, et al. (2015) found that the actual costs obtained from front-end engineering and design studies for FOAK plants are significantly higher than those of NOAK plants, although most studies typically only quote costs for mature NOAK plants.

The application of learning rates is another method used in some studies to account for cost reductions through increased installed capacity over time. A study by WorleyParsons (2009) however found that studies applying this approach report significantly larger reductions in cost over time than those using specific process contingency costs based on FOAK and NOAK. This can be ascribed to different learning rate approaches followed, as some learning rates are based on elapsed time from the introduction of the technology (annual decreasing cost), whereas others depend on the actual cumulative installed capacity. Also, care should be taken when applying learning rates to CCS-technologies for established power generation or industrial processes, as steep reductions in cost with experience gained should only apply to the capture technology and not to the entire facility.18

In order to achieve significant cost reductions in CCS over time, advancements must be made in new technologies (WorleyParsons, 2009). A recent report by IEAGHG (2014) details new CCS technologies under development, the current phases of development and estimated potential for cost reduction. These cost reduction potentials are however only initial estimates with large uncertainty and no details are provided on the time to commercial rollout of these technologies.

5.1.3 Financial model structure and inputs

The considerations presented in the previous sections are then coded into a financial model to calculate the various cost parameters used for policy or technology evaluation. A number of decisions need to be made by the modeller which will impact on the model outputs.

Firstly, the owner and operating structures of the different aspects of CCS (capture, transport and storage) need to be defined, as this will impact on the payback periods required of investments, as well as on potential tariffs charged for usage of transport and storage equipment if these were to be owned and operated by independent parties. Most studies apply the assumption of a single owner-operator for the entire CCS value chain, which does not account for higher costs associated with the commercial interfaces between multiple owners (Rubin et al., 2015).

The choice of whether to use real (constant) or nominal (current) monetary values in the model can also have an impact on the cost outputs. Real values do not include the effects of inflation and are used in most CCS cost studies where a levelised cost is calculated as an output. Nominal values include the effects of inflation and are preferred in cost estimates for specific projects in that they provide a more realistic indication of actual current cost (Rubin et al., 2015). The approach selected will impact on the inflation and discount rates used. Care should

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18 Learning rates in renewable energy technologies are applied to entire projects, but for CCS in established industries learning should only be applied to CCS related equipment.
be taken to consistently apply nominal rates (inflation and discount) to nominal financial models, and real rates to real models. The approach of using real values is recommended for CCS studies to eliminate the effects of study specific inflation rate assumptions and thereby avoiding misinterpretation between different studies (Rubin et al., 2013).

The discount rate used for calculating present values is a predefined rate of return required to cover capital costs, which in financial models is typically a combination of equity and debt. The ownership structure of each part of the CCS system will determine this rate, as private investors demand higher rates of return on equity, whereas governments normally use a lower social discount rate. This social discount rate is a topic of great debate, especially where it pertains to climate change related technology investments. Sometimes rates as low as 0% are used internationally for investments with social benefits, with a real discount rate of 8% recommended as a default for South African government projects (DEAT, 2004).

5.1.4 Cost output metrics

Models can be constructed to provide a variety of financial indicators as outputs. A common output metric used for comparing CCS in power generation is the levelised cost of electricity, expressed as a cost per unit of electricity generated (e.g. R/MWh). This is the present value of all costs normalised over the net electricity generated during the plant lifetime. It represents the tariff that the power plant must charge for electricity to generate the desired rate of return on the capital investment.

In assessments where the purpose of the cost estimation is for GHG mitigation, the output metric of cost of avoided CO$_2$ is typically used, expressed as a cost per tonne of CO$_2$ avoided (e.g. R/tonne CO$_2$). This measure allows for cost comparisons of CCS applications across different industries, as well as to that of other GHG mitigating technologies. Calculating this output metric requires the facility with CCS to be compared to a reference plant without CCS, and it is important that the emissions and costs from the entire CCS chain (capture, transport and storage) be included. If a carbon price or carbon tax are not simulated as part of the financial model, the resultant avoidance cost can be interpreted as the price of carbon or carbon tax that will be required to make the facility with CCS economically viable.

5.2 Description of the model used in this study

The model used in this study is now described in terms of four scenarios selected to determine the impact of CCS costs and configurations on financial performance; the emitting facilities and capture technologies included in the assessment; the pipeline and storage options; the approach taken to financial modelling; and data inputs. The section ends with a comparison between the models used in this work and those used in other existing studies.

5.2.1 Description of the scenarios

Four scenarios were chosen to illustrate the relationship between CCS costs and the impact of the carbon tax:

- **Scenario 1: An initial CCS test scenario that will assist in local CCS learning.** Under this scenario, the capture site will be located at Sasol’s Secunda CTL facility that produces a high quality (high volume with high concentration) CO$_2$ stream, which will allow for lower capture costs than other potential capture facilities. Pre-combustion capture will be applied to the high quality CO$_2$ stream from the Rectisol process and that from the Benfield towers. Start date of CCS is 2025. **First-of-a-kind (FOAK) costs** are used for cost estimations. Total CO$_2$ captured under this scenario is 22.4 Mtonne.
Scenario 2: This scenario represents larger scale roll-out of CCS in South Africa, only considering the sites and technologies proven to be the most technically and economically viable from previous studies. It includes CTL as in Scenario 1, post-combustion capture at Medupi and Kusile power stations and one 1,300 MW new-build IGCC coal fired power station with pre-combustion capture. The start date for CCS is once again 2025. FOAK costs will be used for cost estimations. Total CO₂ captured under this scenario is 85.3 Mtonne.

Scenario 3: This scenario is identical to Scenario 2, except that the new-build power station will be a 600 MW ultra-supercritical pulverised coal (USCPC) power station rather than an IGCC power plant. Total CO₂ captured under this scenario is 81.3 Mtonne.

Scenario 4: This scenario is the same as Scenario 2, but with a CCS start date of 2030. This scenario assumes that by 2030 South Africa will benefit from international CCS learning and experience, and therefore no-of-a-kind (NOAK) costs are used for cost estimations in this scenario. Total CO₂ captured under this scenario is 85.3 Mtonne.

The design of the scenarios used the conclusions of the PB study and the scenarios are thus based on the most promising capture sites and technologies for South Africa. Hence, only offshore storage is considered feasible as a long-term solution. As indicated previously, however, the purpose of building this model differs from that which informed the models developed for the PB study, which was focused on the techno-economics and therefore explored CCS fully deployed in all sectors.

5.2.2 Emitting facilities and capture technologies

South African facilities with the greatest potential for carbon capture are Sasol’s Coal-to-Liquids (CTL) facility in Secunda, emitting more than 40 Mtonne CO₂ per annum, and the two supercritical pulsed coal (SCPC) fired power stations that are currently under construction (Medupi and Kusile), which are each expected to emit more than 20 Mtonne CO₂ per annum. Although some of the existing coal fired power stations in South Africa are also large emitters, the remaining lifetimes of these facilities are too short to make it feasible to retrofit CCS.

Of all the other current energy intensive South African industries assessed in the Parsons Brinkerhoff (2013) study, none emit more than 5 Mtonne per annum, with most facilities emitting less than 2 Mtonne per annum. While these relatively smaller volumes do not preclude them from considering CCS, given the uncertainty surrounding cost estimations and time to commercialisation for CCS in these industries, as well as the typically lower economic viability when compared to CCS in power generation and synfuels production (ZEP, 2013), it is considered unlikely that CCS will be applied in these industries in South Africa in the next 15 to 20 years or longer. CCS in industrial applications other than CTL is thus not considered further in this study.

Sasol’s Secunda CTL facility produces 150,000 barrels of synfuels per day and consumes about 110 ktonne of coal per day (Hook & Aleklett, 2009). It generates to the order of 19.8 Mtonne CO₂ per annum at a high concentration from the Rectisol process, and a further 2.6 Mtonne CO₂ from the Benfield tower which is also suited to capture19. This stream allows for relatively low capture costs with the pre-combustion technology (Parsons Brinckerhoff, 2013). Other emissions from this facility will require capture from more diluted and dispersed streams through post-combustion capture techniques. Due to the lower technical and economic viability of capturing these streams, only pre-combustion capture from the high concentration stream is considered for this study.

19 Hietkamp, S., Personal communication, March 2016.
The lifetime of the CTL facility in Secunda is uncertain, as some studies assumed a lifetime up to 2050 (Parsons Brinckerhoff, 2013), whereas the Wuppertal Institute (2012) reported that, based on stakeholder feedback from the Fossil Fuel Foundation of South Africa, this facility may be decommissioned around 2030. Due to a lack of more recent information, it was assumed in this study that the Secunda CTL facility would still be operational for 30 years from the time of installation of the carbon capture equipment.

Medupi and Kusile are the most recent coal fired power stations to be constructed in South Africa, and the first in 20 years. Both the power stations will use SCPC technology when fully operational. Medupi will be rated at 4,764 MW (6 units generating 794 MW each) with units expected to be online in 2019\(^20\), and Kusile rated at 4,800 MW (6 units generating 800 MW each) with all units expected to be online by 2021\(^21\). The Department of Environmental Affairs requested Eskom to design Kusile to be CCS ready (CCSR). The future impacts of this classification on capture technology construction time and costs remain uncertain, as the South African interpretation of how the CCSR requirements are to be met is confidential (BBB Energy, 2012). Being CCSR does however indicate a high likelihood that this facility will use CCS in future and that the construction of CCS at this site will probably be less cost and time intensive than that of a CCS retrofit at Medupi, which is not a CCSR facility. This potential difference in cost and construction time between these two facilities is not investigated in this study. The capture technology simulated for both Medupi and Kusile is post-combustion capture, as this is an established technology recommended for retrofitting SCPC fired power stations (Parsons Brinckerhoff, 2013). The lifetime of all power stations is assumed as 30 years (DoE, 2013).

In addition to potential existing capture sites, CCS in new coal fired power generation facilities of emerging generation technologies will also be considered. Both the Integrated Resource Plan (IRP) and the Coal Baseload Independent Power Producer Procurement Programme (CBIPPPP)\(^22\) currently only make provision for SCPC and fluidised bed coal technologies, as these are well established (DoE, 2013). Although the IGCC technology has not yet been rolled-out yet on a commercial scale, it has the potential for higher power generating efficiency than SCPC and fluidised bed technologies. Eskom is also in the process of testing this technology with a pilot plant that has been operational since 2007, and is considering constructing a new 1.3 GW facility at the Majuba coalfield in Mpumalanga (Telsnig et al., 2013). The impact of the cost of pre-combustion carbon capture in such a new build IGCC power plant on CCS will therefore be assessed in this study. Another emerging coal power technology, ultra-supercritical pulverised coal (USCPC), will also be simulated as a separate new-build option to the size of 600 MW, which is the maximum allowed sized for individual bids under the CBIPPPP. It is assumed that this site will also be constructed at the Majuba coalfield in Mpumalanga, and that it will use post-combustion carbon capture technology.

In summary, the following existing and potential future capture sites and technologies are simulated in this study:

- Sasol Secunda CTL with pre-combustion capture;
- Kusile and Medupi with post-combustion capture;
- New-build IGCC coal power with pre-combustion capture (at the current Majuba power station site); and
- New-build USCPC power with post-combustion capture (at the current Majuba power station site).

\(^20\) http://mg.co.za/article/2015-01-22-the-long-long-wait-for-medupi
\(^22\) https://www.ipp-coal.co.za
To account for the energy requirements of the carbon capture equipment, it is assumed that the cost and emissions intensity of electricity consumed by Sasol Secunda CTL is the same as grid electricity. For capture in coal-fired power stations, new-build and retrofits are treated similarly, assuming that energy will come from the existing facility and that the power output to the grid will be the same before and after capture, i.e. new-build sites are sized to have the same net power output with and without carbon capture, and the energy penalties of retrofitting existing facilities are quantified with the levelised electricity generation cost of that power station with CCS. The latter assumption for retrofits inherently assumes that either the total capacity of the existing facility will be increased to ensure that the same power is provided to the grid when CCS is implemented, or that a new identical facility will be constructed to compensate for the energy required by CCS.

All existing and future coal fired power stations are assumed to consume sub-bituminous coal with an average gross calorific value (GCV) of 19.77 GJ per tonne and emission factor of 0.0946 tonne CO₂e per GJ. Coal consumed for CTL has an assumed average GCV of 19 GJ per tonne.

Emissions associated with the consumption of grid electricity are based on forecasted emissions data from the IRP’s Revised Baseline Scenario (DoE, 2011). This data is only forecasted up to 2030; data from 2021-2030 was conservatively extrapolated in a straight line to project emissions up to 2050. Although the forecasted grid emission factor is fixed as per the IRP (DoE, 2011), the rollout of CCS on coal fired power stations should theoretically result in a reduced grid emissions factor, which will increase the calculated total emissions avoided for all scenarios where grid electricity is used to power CCS equipment (e.g. carbon capture equipment in CTL and pumping stations for CO₂ pipeline). Such a changing grid emission factor is deemed to have insignificant impacts on the calculation of CCS costs and is therefore not simulated in this model.

5.2.3 Pipeline configuration and storage

Potential storage sites for the sequestered greenhouse gases were selected based on the analysis of South African carbon storage sites from the Parsons Brinckerhoff (2013) study. Based on the location of the selected capture sites and the required storage capacity over the 30-year lifetime of the projects, the offshore Durban & Zululand basin was nominally selected for modelling under this study.

Based on the sites included in the scenarios, only direct pipeline configurations needed to be modelled, rather than having to consider a trunkline configuration. The route considered for the onshore pipeline from the capture sites to the shoreline near Duku in KwaZulu-Natal is shown for the different scenarios in Figure 15 and Figure 16. It was assumed that the pipeline will not follow a straight line from point to point, but rather be constructed alongside existing roads for ease of construction and maintenance. Scenario 1 is simulated with a fixed diameter onshore pipeline with length of 480 km. The diameter of the pipeline for Scenarios 2, 3 and 4 will increase with each additional capture site along the route, with a total onshore pipeline length of 940 km made up of the following segments:

- 350 km from Medupi to Kusile;
- 90 km from Kusile to Sasol Secunda CTL;
- 115 km from Sasol Secunda CTL to Majuba; and

---

23 It is noted that Sasol generates much of its own electricity requirements and the cost and emissions intensity varies from grid electricity, however, information was not available to support more realistic assumptions. The impact on final results is not significant.
25 IPCC 2006 default emission factors for bituminous coal
26 Based on dynamic storage capacity calculations in Parsons Brinckerhoff (2013), no onshore sites were found to be viable for storage.
27 Duku was used in the Parsons Brinckerhoff (2013) study as the point where the offshore pipeline would start for storage in the Zululand basin.
385 km from Majuba to Duku.

For all the scenarios, an offshore pipeline length of 100 km is assumed from Duku to the storage site (Parsons Brinckerhoff, 2013).

**FIGURE 15: PROPOSED PIPELINE ROUTE FOR SCENARIO 1**

**FIGURE 16: PROPOSED PIPELINE ROUTE FOR SCENARIOS 2, 3 AND 4**

28 [Link to map](https://goo.gl/maps/Lo1SANAYz4T2)
29 [Link to map](https://goo.gl/maps/DEdb7V1Ctat)
As for most other South African studies, this study assumes that CO$_2$ will be transported in its “dense phase”, more specifically in the supercritical fluid phase (above 80 bar). Transport of CO$_2$ in its supercritical phase is desired for transport of large volumes over long distances (more than 100 km) and for storage in reservoirs with high reservoir pressures (as is the case for offshore saline aquifers) (Knoope et al., 2014).

Pipeline inlet pressures at capture sites was set at 110 bar, which is the average of the optimal inlet pressure range as recommended by Knoope, et al., (2014), and the same as the value used in South African study by Telsnig, et al., (2013). The latter study also reported an average pressure drop of 20 bar per 100 km of pipeline and therefore, to allow for a 10 bar safety margin above the evaporation pressure, a pumping station is assumed to be required for every 100 km of pipeline, which is also the maximum recommended distance between pumping stations of onshore pipelines (Knoope et al., 2014). Pumping stations for offshore pipelines are highly discouraged as these can be very expensive. As a result of the assumed 100 km offshore pipeline distance in this study, offshore pumping stations will not be required if a pumping station is located near the shoreline close to Duku. The storage site will have its own additional pumping requirements to store the CO$_2$, but the specifications and costs of this is included in the storage site design and does not form part of the pipeline.

It was assumed that as a default, all onshore pipelines would pass through rural, low population density areas. See Table 7 for the design factors used for pipe thickness estimations, which make provision for thicker pipes to increase safety in more densely populated areas.

**TABLE 7: PIPELINE DESIGN FACTORS (KNOOPE ET AL., 2014)**

<table>
<thead>
<tr>
<th>Population density</th>
<th>Design Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low, rural areas</td>
<td>1</td>
</tr>
<tr>
<td>Medium (also factor recommended for offshore pipelines)</td>
<td>0.72</td>
</tr>
<tr>
<td>High</td>
<td>0.5</td>
</tr>
</tbody>
</table>

5.2.4 Cost inputs and technical plant parameters

The WorleyParsons (2011) study provides the latest and most comprehensive cost data for the selected power generation facilities and carbon capture technologies evaluated in this study. The following information is used from the WorleyParsons (2011) study:

- Operating parameters for power output, efficiency, and capacity factor;
- Detailed capital cost data for BEC of equipment, materials and labour;
- EPC costs;
- Contingency costs for CCS specific process equipment allowing the user to distinguish between FOAK and NOAK costs;
- Contingency costs for each project as a whole;
- Owner’s cost rate of 15%;
- Construction duration of 4 years and IDC cost rate of 9%;
- Fixed and variable O&M costs for equipment, materials and labour;

---

30 The dense phase refers to CO$_2$ above the critical pressure (7.4 MPa) independent of temperature and thus refers to CO$_2$ in all liquid forms including the supercritical state, which refers to CO$_2$ above the critical pressure and critical temperature (31.1°C) (Knoope et al., 2014).
Location adjustment factors to adjust cost of equipment, materials, and labour from the United States to South Africa; and

Adjustment factors for impact of coal calorific value on capital cost and efficiency of SCPC power stations.

Increased costs as a result of retrofitting were not available and are therefore not simulated in this study.

For CTL, South African specific costs were obtained from the study by Telsnig et al. (2013). This study reported one capital investment cost, which was assumed to be the TPC that already includes EPC and contingency costs. Rates for owner’s cost and interest during construction were applied as per the WorleyParsons (2011) study to obtain the TCR. Other information used from the Telsnig, et al. (2013) study includes the Fixed O&M costs, plant availability (hours per year) and plant energy efficiency. Additional information specific to Sasol Secunda CTL was taken from the Parsons Brinkerhoff (2013) study for the plant’s synfuel production capacity, percentage of total site emissions that is as a result of the Rectisol process (CO₂ available in one high concentration stream), and the carbon capture efficiency. Electricity requirements for CCS in CTL facilities were obtained from a recent study by Kong, et al., (2015).

The costs for onshore and offshore pipelines were estimated using a rigorous CCS pipeline costing methodology developed by Knoope, et al., (2014). Storage cost was taken from the Parsons Brinkerhoff (2013) study, as the same storage site is used in this study. For both the transport and storage, capital costs values obtained from the abovementioned sources was assumed to be TPC. Rates for owners cost and interest during construction was applied as per the WorleyParsons (2011) study.

Engineering cost indices that account for growth rates in industrial equipment, commodity prices and inflation, are used to adjust costs from literature reported vintages to 2015 values. As the indices used in this study are based on the US market, all reported costs were converted to US dollars using the appropriate exchange rate for the year in question, adjusted with the appropriate index to a 2015 US dollar value, and then converted to a 2015 Rand value using an early 2015 US dollar to Rand exchange rate. The cost indices used and areas of application in the model are (IHS, 2015):

- Power Capital Cost Index (PCCI) excluding nuclear power – applied to coal power station costs; and
- Downstream Capital Costs Index (DCCI) for refining and petrochemical projects – applied to CTL and pipeline costs.

5.2.5 Financial modelling of CCS

The financial modelling of CCS is similar to the financial modelling approach to that of the WorleyParsons (2009) study. Under this approach, real\(^2\)\(^2\) (constant) 2015 rand values are used to calculate the levelised cost output metric of cost of avoided CO₂ (COAC), expressed as a cost per tonne of CO₂ avoided (e.g. R/tonne CO₂) (illustrated in Figure 17). This metric is typically used in assessments where the purpose of the cost estimation is for GHG mitigation and allows for cost comparisons of CCS applications across different industries, as well as to those of other GHG mitigating technologies. If a carbon price or carbon tax are not simulated as part of the financial model, the resultant avoidance cost can be interpreted as the price of carbon or carbon tax that will be required to make the facility with CCS economically viable.

---

\(^2\)\(^2\) www.x-rates.com used for all exchange rates

\(^2\)\(^2\) Real values do not include the effects of inflation and are used in most CCS cost studies where a levelised cost is calculated as an output (Rubin et al., 2015). In order, however, to bring figures to 2015 values, an average annual inflation of 5.12% was assumed for time value of money adjustments in this study, based on the average historic inflation from 2009-2015, http://www.tradingeconomics.com/south-africa/core-inflation-rate.
Calculating this cost metric requires the facility with CCS to be compared to a reference plant without CCS, and it is important that the emissions and costs from the entire CCS chain (capture, transport and storage) be included:

\[
COAC = \frac{(LCOE)_{CCS} - (LCOE)_{ref}}{(\text{tonne CO}_2/\text{GJ})_{ref} - (\text{tonne CO}_2/\text{GJ})_{CCS}}
\]

The subscript “CCS” refers to the scenario with CCS, and “ref” to the reference scenario without CCS.

Levelised costs of energy (LCOE) is calculated for power plants and the CTL facility, expressed as a cost per unit of energy generated (e.g. R/GJ). For this calculation, the total capital cost is levelised with a capital recovery factor, which considers the discount rate and the levelisation period (typically the lifetime of the site). All other annual costs are levelised by applying "levelisation factors" to the cost values, as determined for the first year of the site. Application of annual levelisation factors to annual costs can be disregarded in the special case where all costs are expressed in constant (real) values and there are no increases in the costs over that of inflation (i.e. these costs remain constant over the lifetime of the site).

Levelised cost are calculated as (WorleyParsons, 2009):

\[
LCOE = \frac{F_{\text{CRF}_y}C_{\text{Capital}} + F_{\text{FOM}}C_{\text{FOM}}}{F_{\text{cap}}E_{\text{Annual}}} + F_{x,\text{VOM}}C_{x,\text{VOM}}
\]

Where:

- \(F_{\text{CRF}_y}\) = Capital recovery factor for levelisation period of \(y\) years (unitless)
- \(F_{\text{FOM}}\) = Levelisation factor for fixed O&M (unitless)
- \(F_{x,\text{VOM}}\) = Levelisation factor for variable O&M of type \(i\), (unitless)
- \(F_{\text{cap}}\) = Capacity factor, (unitless)
- \(E_{\text{Annual}}\) = Annual energy generation of the facility, (GJ)
- \(C_{\text{Capital}}\) = Total capital cost, (R)
- \(C_{\text{FOM}}\) = Annual fixed operating and maintenance costs, (R)
- \(C_{x,\text{VOM}}\) = Annual variable operating and maintenance costs of type \(x\), with typical types including general variable O&M cost, fuel cost and carbon tax, (R/GJ)

The capital recovery factor is calculated using the discount rate (WACC) over the levelisation period, \(y\), which is the lifetime of the project (WorleyParsons, 2009):
The levelisation factor for each type of cost, $F_j$ (e.g. $F_{FOM}$, $F_{x,VOM}$), is determined based on the discount rate and the specific escalation rate, $i_j$, above that of inflation (WorleyParsons, 2009):

$$F_j = \frac{E_j(1-E_j^r)}{P(1-E_j^r)}$$

Where:

- $P = \frac{(1+WACC)^{Y-1}}{WACC(1+WACC)^Y}$ Present value factor
- $E_j = \frac{1+i_j}{1+WACC}$ Escalation factor for cost $j$

A simple approach assuming one owner with a social interest (e.g. government) will own and operate the entire CCS value chain. The discount rate in this study is calculated as the weighted average cost of capital (WACC), which considers the source of capital (debt or equity) and the interest rate on each source. This calculation also includes the potential for a tax rate deduction from the interest rate on debt. The WACC, based on real rates, is calculated as:

$$WACC = f_{\text{debt}}R_{\text{debt}}(1-R_{\text{tax}}) + f_{\text{equity}}R_{\text{equity}}$$

Where:

- $f_{\text{debt}} = $ Debt fraction of capital costs, assumed as 90%
- $f_{\text{equity}} = $ Equity fraction of capital costs, assumed as 10%
- $R_{\text{debt}} = $ Real debt interest rate, 4.13% \(^{33}\)
- $R_{\text{equity}} = $ Equity interest rate, 6.68% \(^{34}\)
- $R_{\text{tax}} = $ Rate of deductible taxes, 28% \(^{35}\)

The resulting calculated discount rate used in this study is 3.36%, which is in-between the 8% discount rate used in the Telsnig et al. (2013) study and the 3% rate used in the SLR (2013) study. The impact of this discount rate is tested as part of the sensitivity analysis.

Once the levelised costs of applying CCS were calculated for each of the individual scenarios, the year on year carbon tax payable with and without the implementation of CCS is assessed and presented graphically for each emitting facility for each scenario (whilst recognising that carbon tax is payable at a facility and not a company level – and hence the amounts shown here exclude taxes payable on emissions from facilities other than those considered here). An example of this is presented in Figure 18.

The carbon tax payable without CCS in 2015 billion Rand per year (left) is determined by multiplying the effective tax in a particular year (in 2015 Rand per tonne CO\(_2\)) by the annual CO\(_2\) emissions from a facility (in tonnes) for that year assuming that CCS is not implemented. The cost of CCS\(^{36}\) plus the carbon tax payable with the implementation of CCS is indicated by the stacked graph on the right, where the green shaded area represents the proportion of the total cost associated with the carbon tax payable that is payable after CCS has been implemented and the yellow shaded area represents the proportion of the total cost associated with the cost of installing and operating the CCS technology (with CAPEX having been distributed over the lifetime of the technology). The difference in the carbon tax payable (green shaded area) between the left and right graphs

---

\(^{33}\) Average historic inflation from 2009-2015, [http://www.tradingeconomics.com/south-africa/core-inflation-rate](http://www.tradingeconomics.com/south-africa/core-inflation-rate), and deducting assumed annual average inflation to approximate the real debt interest rate.

\(^{34}\) Assumption based on a desired nominal rate of return on equity of 12%, with a real rate value calculated by deducting assumed annual average inflation.

\(^{35}\) SARS Corporate Income Tax Rate: [http://www.sars.gov.za/TaxTypes/CIT/Pages/default.aspx](http://www.sars.gov.za/TaxTypes/CIT/Pages/default.aspx)

\(^{36}\) Calculated as levelised cost of sequestration in Rand per tonne of CO\(_2\) multiplied by tonnes sequestered in that year.
represents the carbon tax savings achieved through the implementation of CCS. This amounts to approximately 2 billion Rand (2015) per year in the example used here.

FIGURE 18: SAMPLE GRAPH FOR THE YEAR ON YEAR CARBON TAX PAYABLE WITHOUT CCS (LEFT), AND COST OF CCS AND CARBON TAX PAYABLE WITH CCS (RIGHT) (2015 BILLION RAND PER YEAR)

5.2.6 Modelling the impact of the carbon tax

The approach described in the previous section is that used to model the costs of CCS under four specific implementation scenarios. The key focus of this study, however, is to explore how these scenarios are impacted upon by the proposed carbon tax.

In this study, the tax is simulated as a variable cost to a facility and is calculated based on the facility’s direct emissions. The carbon tax liability for a company will therefore reduce with the implementation of CCS at the facility. As detailed in Section 4, the carbon tax is structured according to the latest Draft Carbon Tax Bill, which proposes a tax regime for the period 2017-2020, with an initial rate set at R 120/tCO₂e (National Treasury, 2015). The effective tax rate will vary depending on the extent of tax relief, which differs according to the activity that releases GHG emissions and the type of emissions released. Table 8 presents the maximum tax-free allowances applicable to the two sectors considered for CCS deployment, electricity generation from fossil fuel combustion and liquid fuel production from coal-to-liquid production, as well as highlighting those allowances are standard for all activities and those that are variable.

TABLE 8: BREAKDOWN OF MAXIMUM TOTAL ALLOWANCES FOR ELECTRICITY GENERATION AND COAL-TO-LIQUIDS PRODUCTION INDUSTRY SECTORS (NATIONAL TREASURY, 2015)

<table>
<thead>
<tr>
<th>Tax-free allowances</th>
<th>Electricity</th>
<th>Coal-to-liquids</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic tax-free allowance for fossil fuel combustion emissions</td>
<td>60%</td>
<td>60%</td>
<td>Fixed</td>
</tr>
<tr>
<td>Basic tax-free allowance for process emissions</td>
<td>0%</td>
<td>0%</td>
<td>Fixed</td>
</tr>
<tr>
<td>Additional tax-free allowance for fugitive emissions</td>
<td>0%</td>
<td>10%</td>
<td>Fixed</td>
</tr>
</tbody>
</table>
In testing the impact of the carbon tax on CCS, initially the following assumptions are made:

- **Trade-exposure allowance impact on tax-free threshold:** This allowance is calculated based on the extent to which products or services exported by firms contribute to their revenue (capped at 10% for CTL). For this study, a notional trade-exposure allowance of 5% is allocated to CTL facilities.

- **Offset allowance impact on tax-free threshold:** Firms are able to reduce their carbon tax by using approved carbon offsets, being those based on emissions reductions within South Africa, and in sectors or activities not covered by the carbon tax (Republic of South Africa, 2015a; Republic of South Africa, 2015b). For this study, a default offset allowance of zero is assigned to electricity and CTL facilities.

- **Performance (Z-factor) allowance impact on tax-free threshold:** As an incentive for firms to reduce the carbon intensity of their products, an adjustment will be made to the tax-free threshold by a factor (Z) (currently capped at 5% for CTL) (Republic of South Africa, 2015a). Essentially, firms below the agreed upon benchmark emissions intensity for the sector (including both Scope 1 and Scope 2 emissions) will be rewarded and firms above it will be penalised. For this study, a z-factor of zero is assigned to both electricity and CTL facilities.

- **Tax increase per annum:** It is assumed that there will be no increases in the carbon price after 2020, apart from inflation.

- **Tax-free threshold:** It is assumed that the tax-free threshold will decrease annually by 5% after 2020, for both electricity and CTL facilities.

Figure 19 presents the indicative projections for the effective carbon tax for electricity and CTL facilities based on the assumptions made above.
As part of the sensitivity analysis, the impacts of changes in the carbon tax price and the tax-free thresholds regime post 2020 is considered. Furthermore the impact of changing the carbon tax formula structure is explored.

5.2.7 *Summary of study approach and comparison with existing studies*

The resulting volumes of emissions that are generated, captured and released for each of the facilities considered in this study is shown in Table 9.

**TABLE 9: SUMMARY OF EMISSIONS GENERATED, CAPTURED AND RELEASED BY FACILITY (MTONNE CO$_2$/ANNUM)**

<table>
<thead>
<tr>
<th>Facility</th>
<th>Generated</th>
<th>Captured</th>
<th>Released</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTL Facility</td>
<td>54.5</td>
<td>22.4</td>
<td>31.1</td>
</tr>
<tr>
<td>Medupi</td>
<td>30.9</td>
<td>27.8</td>
<td>3.1</td>
</tr>
<tr>
<td>Kusile</td>
<td>31.1</td>
<td>28.0</td>
<td>3.1</td>
</tr>
<tr>
<td>New build IGCC (Majuba)</td>
<td>7.9</td>
<td>7.1</td>
<td>0.8</td>
</tr>
<tr>
<td>New build PC ultra-supercritical (Majuba)</td>
<td>3.4</td>
<td>3.1</td>
<td>0.3</td>
</tr>
</tbody>
</table>

Highlights of the approach and assumptions used in this current study are compared to the three most recent South African CCS studies in Table 10 and Table 11. It is noted that none of the other studies considered the impacts of the carbon tax, and hence this component of the analysis is not included in the tables below.
### TABLE 10: COMPARISON OF SCENARIOS, SCOPE AND DESIGN OF SOUTH AFRICAN CCS FINANCIAL MODELS

<table>
<thead>
<tr>
<th>Study</th>
<th>Scenarios</th>
<th>Capture sites and technologies</th>
<th>Pipeline configuration</th>
<th>Storage sites</th>
<th>Results</th>
</tr>
</thead>
</table>
| Techno-Economic Review of CCS Implementation in South Africa         | Six scenarios simulated.                                                   | All current and potential future power plants (based on IRP) and refineries considered. Only existing industrial facilities for steel, cement and paper and pulp considered. Technologies for industrial CCS are the same for all scenarios. For power generation: | Branchlines from capture sites connect to 5 large onshore trunklines leading to capture sites. All trunklines constructed in 2025. Only for alternative scenarios 1 and 2 is only one trunkline constructed. Scenarios only impact on branchlines and offshore transport cost. Pipelines set to operate between 103-150 bar. | Basins for storage vary with scenario simulated. All potential onshore and offshore storage sites were considered, but due to the large-scale roll out of CCS simulated, only offshore storage is utilised. | For implementation in 2025 under the base injectivity P50 scenario (2010 Rand/tonne CO$_2$ avoided):  
  - Pulverised post-combustion coal power: 571  
  - Refinery (incl. CTL): 254  
  - Steel: 288  
  - Cement: 553  
  - Paper: 292 |
| (Parsons Brinckerhoff, 2013)                                          | All potential capture sites in South Africa considered (power generation, refineries and industry), but only implemented for sites with a minimum remaining lifetime of 10 years and minimum annual emissions of 0.4 Mtonne CO$_2$. For industrial CCS, only one site per company was selected (it was assumed that one company will not roll-out CCS at multiple sites). Scenarios:  
  - Low Injectivity Scenario (P30);  
  - Base Injectivity Scenario (P50);  
  - High Injectivity Scenario (P70);  
  - Alternative Scenario 1: Durban & Zululand Basin storage only; P30 (low) injectivity phased implementation;  
  - Alternative Scenario 2: Durban & Zululand Basin Storage only; P50 (med) injectivity phased implementation; and  
| Assessment of selected CCS technologies in electricity and synthetic fuel production for CO$_2$ mitigation in South Africa (Telsnig et al., 2013) | One scenario simulated considering only the most promising new-build capture sites, technologies and storage sites for South Africa. Two potential start dates for CCS simulated: 2025 and 2040. | Only new build sites considered:  
  - Integrated gasification combined cycle (IGCC) coal fired power plant (1258 MW) at the Majuba coal field in Mpumalanga;  
  - Ultra-supercritical (USC) coal fired power plant (800 MW) at the Majuba coal field in Mpumalanga;  
  - CTL plant (80,000 bbl/day) in Limpopo; and  
  - GTL plant (45,000 bbl/day) in Secunda. | Separate pipelines for each capture site to storage location. Pipelines set to operate between 80-110 bar. | Only onshore storage in the Zululand Basin considered (limited to 4,600 Mtonne CO$_2$ storage capacity). Onshore storage provides the most stable formation for storage, but the available capacity is only sufficient for 30 year storage of one of the evaluated projects. Offshore | For implementation in 2025 (2007 Rand/tonne CO$_2$ avoided):  
  - IGCC coal power: 170  
  - USC coal power: 220  
  - CTL: 800  
  - GTL: 810 |
<table>
<thead>
<tr>
<th>Study</th>
<th>Scenarios</th>
<th>Capture sites and technologies</th>
<th>Pipeline configuration</th>
<th>Storage sites</th>
<th>Results</th>
</tr>
</thead>
</table>
| Impacts of Carbon Capture and Storage (CCS) on South African National Priorities other than Climate Change (SLR, 2013) | Two CCS scenarios were simulated for a 20 year operational period between 2025 and 2045:  
• Low Scenario: 20 Mtonne CO₂/annum by 2045 (as presented in the LTMS); and  
• High Scenario: 80 Mtonne CO₂/annum by 2050.  
All CCS projects set to start in 2025. | According to this study, Eskom has already investigated building a new IGCC power plant at the Majuba coal field in Mpumalanga, which could also be used for CCS. The pilot plant has already been constructed. | Low scenario: one pipeline. High scenario: initially one pipeline, with a second pipeline after 2035 to accommodate the increased volume. Pipeline pressure not disclosed. Fixed pipeline distance of 500 km for both scenarios. | Only onshore storage in the Mesozoic Basin in Zululand was simulated. | Only onshore storage in 2025 (2012 Rand/tonne CO₂ avoided):  
Low scenario: 146 High Scenario: 327 (219 excluding cost of energy penalty) |
| This study | Three scenarios simulated considering only the most promising capture sites, technologies and storage sites for South Africa:  
• Scenario 1: Only Secunda CTL. Start date in 2025.  
• Scenario 2: Secunda CTL, Medupi, Kusile, and one 1.3 GW new-build coal fired power stations. Start date in 2025.  
• Scenario 3: Same as Scenario 2, but with a 600 MW new-build USCPC power station.  
• Scenario 4: Same as Scenario 2, but with start date of CCS in 2030. | Only most promising existing and potential future capture sites considered:  
• Sasol Secunda CTL with pre-combustion capture.  
• Kusile and Medupi with post-combustion capture.  
• New-build IGCC with pre-combustion capture.  
• New-build USCPC with post-combustion capture. | A single pipeline connecting all facilities. | Only offshore storage in the Zululand basin simulated. |  
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**TABLE 11: COMPARISON OF COST AND ECONOMIC ASSUMPTIONS FROM SOUTH AFRICAN CCS STUDIES**

<table>
<thead>
<tr>
<th>Study</th>
<th>Lifetime of equipment and discount rate</th>
<th>Cost adjusted for location and fuel calorific value</th>
<th>Learning rates or decreasing cost over time applied</th>
<th>EPC, owner’s costs and contingency costs included</th>
<th>Energy penalty and production efficiency losses as a result of CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Techno-Economic Review of CCS Implementation in South Africa (Parsons Brinckerhoff, 2013)</td>
<td>No discounting was done for costs of CCS technologies and no capital recovery or levelisation factors applied for calculating levelised costs. (1% inflation rate indicated in model, but not used). A discount rate of 10% over 30 years was used for calculating levelised capital cost of Nuclear power.</td>
<td>No cost adjustments made.</td>
<td>No learning or cost reductions.</td>
<td>No additional costs explicitly stated or disclosed.</td>
<td>Reduced electricity output in power stations displaced with new nuclear build power. Energy requirements and production efficiency losses in industrial facilities not quantified or simulated.</td>
</tr>
<tr>
<td>Assessment of selected CCS technologies in electricity and synthetic fuel production for CO₂ mitigation in South Africa (Telsnig et al., 2013)</td>
<td>Lifetime of 30 years assumed for all technologies. Discount rate of 8% used.</td>
<td>No cost adjustments made.</td>
<td>Costs for 2025 and 2040 presented with improved efficiencies and reduced cost from 2025 to 2040.</td>
<td>No additional costs explicitly stated or disclosed.</td>
<td>Electricity outputs of the coal fired power stations are the same for plants with and without CCS. Grid electricity is used for CCS energy requirements in CTL and GTL plants.</td>
</tr>
<tr>
<td>Impacts of Carbon Capture and Storage (CCS) on South African National Priorities other than Climate Change (SLR, 2013)</td>
<td>Lifetime of 20 years assumed for all technologies. Discount rate of 3% used.</td>
<td>No cost adjustments made.</td>
<td>Technology learning rate of 0.3% per annum after 2022 was simulated.</td>
<td>EPC and owner’s cost Included in capital cost estimations.</td>
<td>Reduced electricity output in power stations as a result of CCS was quantified based on lost revenue using the price of electricity. For CTL it was assumed that waste process heat could be used to compress the concentrated CO₂ stream, therefore no additional energy is required.</td>
</tr>
<tr>
<td>This study</td>
<td>Lifetime of 30 years assumed for all technologies. Discount rate of 3.36% used.</td>
<td>Adjustments made for location and fuel calorific value impacts on cost.</td>
<td>No learning rates applied. FOAK costs used for roll-out in 2025 and NOAK costs for 2030.</td>
<td>EPC, owner’s costs and contingency costs included.</td>
<td>Grid electricity is used for CCS energy requirements in Sasol CTL. Electricity outputs of coal fired power stations are the same for plants with and without CCS.</td>
</tr>
</tbody>
</table>
5.3 Results

In this section the results of the economic modelling are presented. Section 5.3.1 presents the results from the analysis of levelised costs of CCS for the different scenarios using the reference case assumptions, in the absence of CCS. Section 5.3.2 provides a sensitivity analysis of these levelised costs of CCS in the absence of the carbon taxes to various input parameters in the models. Section 5.3.3 then begins the carbon tax and CCS interaction analysis, by looking at the carbon tax payable by different companies with and without CCS and how this compares to the cost of CCS. Finally, in Section 5.3.4, the sensitivity of the results from the previous section to the design of the tax post 2020 (which is still not known) is explored.

5.3.1 Levelised costs of CO₂ emissions reductions

Figure 20 presents the levels cost of emissions reductions, using the default values for the cost parameters.

![Figure 20: Levelised cost of avoided CO₂ for all scenarios by emitting facility (2015 Rand/tonne CO₂ avoided)](image)

The Medupi and Kusile retrofits, and the USCPC new build facilities have the largest levelised costs of emissions reductions, followed by the IGCC new build and finally CTL. The differences in the costs of emissions reductions between facilities is predominantly due to the differences in the cost of CO₂ capture (as seen in Figure 21). Although Medupi, Kusile and the CTL facilities generate similar volumes of CO₂, the highly concentrated stream from the CTL’s Rectisol process allows for a relatively low cost capture in comparison to that of the retrofitted facilities. Similarly, the USCPC new build facility is modelled to be fitted with the same post-combustion CO₂ capture technology as the retrofits and therefore, on the basis of one tonne CO₂ avoided, is considerably more costly than the CTL facility. The IGCC new build facility is fitted with pre-combustion CO₂ capture technology (i.e. CO shift, Selexol scrubbing and CO₂ compression), similar to that which is used at the CTL facility. However, the costs associated with capture at IGCC are much higher than at CTL facilities, due predominantly to the higher total capital requirements (Telsnig et al., 2013).
Figure 21: Contribution of capture, transport and storage phases to the levelised cost of avoided CO₂ for scenario 2 (Medupi, Kusile, CTL and IGCC) and scenario 3 (USCPC) [2015 Rand/tonne CO₂ avoided]

Figure 22 illustrates total levelised cost of avoided CO₂ for each scenario, showing the contribution of the individual facilities. The total levelised cost of each scenario was adjusted by the weighted average of the levelised costs of each facility according to the tonnes of CO₂ avoided by that facility in relation to the total tonnes of CO₂ avoided for the particular scenario. As expected, the bulk of the cost for Scenarios 2, 3 and 4 are associated with the Medupi and Kusile retrofits. The contribution of the CTL facility in Scenario 1 is much higher than that of the other scenarios as it absorbs all the transport and storage costs, while these costs are allocated amongst the various facilities in the other scenarios.

Figure 22: Contribution of emitting facilities to total levelised cost of avoided CO₂ of CCS scenarios [2015 Rand/tonne CO₂ avoided]

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5.3.2 Sensitivity analysis for the levelised cost calculations

The key parameters in the model relating to CCS costs were identified and the impact of varying these on the overall costs of CCS has been explored via a sensitivity analysis. Table 12 highlights the main assumptions addressed in the sensitivity analyses, along with the different value options, default values and a brief comment on the impact of the parameter on the costs of avoided CO₂ (COAC) in units of R/tonne CO₂. The key parameters identified in the Table are as follows:

- **Discounting**: The discount rate used for calculating present values is a predefined rate of return required to cover capital costs, which is typically a combination of equity and debt. The ownership structure of each part of the CCS system will determine this rate, as private investors demand higher rates of return on equity, whereas governments normally use a lower social discount rate. This social discount rate is a topic of great debate, especially where it pertains to climate change related technology investments. Sometimes rates as low as 0% are used internationally for investments with social benefits, with a real discount rate of 8% recommended as a default for South African government projects (DEAT, 2004). For this reason, a range of 0% to 8% for the discount rate has been assessed in a sensitivity analysis.

- **Levelisation period**: The levelised cost of energy (LCOE) is the constant price at which a unit of energy generated should be sold for the investment to break even (a net present value of zero). The LCOE, expressed as a cost per unit of energy generated (e.g. R/GJ) for the power plants and the CTL facility, is calculated by levelising the total capital cost with a capital recovery factor, which considers the discount rate and the levelisation period (typically the lifetime of the site). As a default, the lifetime of all power stations are assumed as 30 years (DoE, 2013). The levelisation period of Medupi and Kusile equate to the remaining lifetime at the time of installation of the carbon capture equipment. On the other hand, it was assumed that the Secunda CTL facility would still be operational for 30 years from the time of installation of the carbon capture equipment.

- **Coal price**: The price of Eskom power station coal in 2015 was R 170 per tonne for long-term standing contracts and R 460 per tonne for new BEE contracts. The former price is simulated as a default in the model and compared to the latter in the sensitivity analysis. Future coal price increases are assumed to follow the new policies fuel price projection as provided in the World Energy Outlook (IEA, 2014).

- **Electricity price**: The electricity price in the model is based on the anticipated electricity price path from the Integrated Resource Plan (IRP), which proposes a “high” price path (maximum price of 1.12 2010-ZAR/kWh) and a “low” price path (maximum price of 0.98 2010-ZAR/kWh) (DoE, 2011). The “high” price path is simulated as a default in the model, and compared to the “low” price path in a sensitivity analysis. With the trend in this projection after 2025 being flat (or almost decreasing), it is assumed that there will be no real increases in the electricity price post-2025. The 2010 Rand values were inflated to 2015 Rand values for this study using historical inflation rates.

The key technical aspects considered in the sensitivity analysis are:

- **Capture technologies**: In order to achieve significant cost reductions in CCS over time, advancements must be made in new technologies (WorleyParsons, 2009). A recent report by IEAGHG (2014) details new CCS technologies under development, the current phases of development and

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estimated potential for cost reduction. These cost reduction potentials were tested in the model through the two emerging technologies, polymeric membranes used in post-combustion applications and warm gas clean-up used in pre-combustion applications (IEAGHG, 2014). These were selected based on their stage of development, the former is in its developmental phase as a fully integrated pilot tested in a relevant environment with potential reduction of LCOE of 30% if implemented; while the latter is currently being demonstrated at commercial scale with potential reductions of LCOE of 3% if implemented (IEAGHG, 2014).

- **Pipeline cost:** The most significant methodological assumptions that impact on transport and storage cost are pipeline configuration, and type and location (onshore or offshore) of storage. Terrain and population density will also impact on the cost of pipelines, as high-density regions require thicker pipelines than those located in low-density, rural regions, for safety reasons (Knoope et al., 2014). As a default, all onshore pipelines were assumed to pass through rural, low population density areas. The impacts of pipelines passing through medium- to high-density populations are included in the sensitivity analysis.

- **Storage cost:** Costs of transport and storage can contribute a significant portion to the overall cost of CCS, ranging between 10%-30% of the total cost, based on local studies (Parsons Brinckerhoff, 2013; Telsnig et al., 2013). Storage cost (CAPEX and OPEX) was taken from the PB study (2013), as the same storage site is used in this study, i.e. the offshore Durban & Zululand basin. There is however large variation in these costs for different studies. For this reason the sensitivity analysis includes variations on the cost of storage, considering the impact if the storage cost were half or double that recommended in the PB study (2013).
### TABLE 12: MAIN ASSUMPTIONS ADDRESSED IN SENSITIVITY ANALYSES

<table>
<thead>
<tr>
<th>Assumptions (default value)</th>
<th>Unit</th>
<th>Description</th>
<th>Values</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Levelisation and Discounting</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Default CTL and new-build levelisation period</td>
<td>years</td>
<td>2025</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>Default levelisation period for retrofits</td>
<td>years</td>
<td>2025</td>
<td>25</td>
<td>20</td>
</tr>
<tr>
<td>Debt / equity ratio</td>
<td>%</td>
<td>2025</td>
<td>90% / 10%</td>
<td></td>
</tr>
<tr>
<td>Effective discount rate (default based on WACC with</td>
<td>%</td>
<td>2025</td>
<td>0% to 20%</td>
<td>The lower the discount rate, the lower the COAC.</td>
</tr>
<tr>
<td>debt/equity ratio of 90%/10%)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Coal and Electricity price</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal price in 2015 based on &quot;long-term&quot; or &quot;new&quot; supply contract</td>
<td>R/tonne</td>
<td>Long-term</td>
<td>170</td>
<td>An increase of the coal price (i.e. new BEE supply contract) results in an increased COAC for all technologies.</td>
</tr>
<tr>
<td>(default = &quot;Long-term&quot;)</td>
<td></td>
<td>New</td>
<td>460</td>
<td></td>
</tr>
<tr>
<td>Electricity price in 2025 based on &quot;high&quot; or &quot;low&quot; price forecast</td>
<td>R/MWh</td>
<td>High</td>
<td>1,422.96</td>
<td>A decrease of the electricity price results in significant increase of COAC of CTL, and less so for other tech.</td>
</tr>
<tr>
<td>(default = &quot;Low&quot;)</td>
<td></td>
<td>Low</td>
<td>1,245.09</td>
<td></td>
</tr>
<tr>
<td><strong>Capture technologies (IEAGHG, 2014)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Post-combustion: Polymeric membranes (default = &quot;No&quot;)</td>
<td>% change in LCOE</td>
<td>No</td>
<td>0%</td>
<td>Implementation of new post combustion tech. at Medupi and Kusile results in decreased COAC.</td>
</tr>
<tr>
<td>(default = &quot;No&quot;)</td>
<td></td>
<td>Yes</td>
<td>- 30%</td>
<td></td>
</tr>
<tr>
<td>Pre-combustion: Warm gas clean-up (can be used in</td>
<td>% change in LCOE</td>
<td>No</td>
<td>0%</td>
<td>Implementation of new pre-combustion tech. at IGCC results in decreased COAC.</td>
</tr>
<tr>
<td>combination with capture) (default = &quot;No&quot;)</td>
<td></td>
<td>Yes</td>
<td>- 3%</td>
<td></td>
</tr>
<tr>
<td><strong>Pipeline cost (Knoope et al., 2014)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Onshore design factor as a function of population density</td>
<td>Dimensionless</td>
<td>Low density</td>
<td>1.00</td>
<td>Increased population density decreases the onshore design factor, which in turn increases COAC.</td>
</tr>
<tr>
<td>(default = &quot;Low&quot;)</td>
<td></td>
<td>Med. density</td>
<td>0.72</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>High density</td>
<td>0.5</td>
<td></td>
</tr>
<tr>
<td><strong>Storage cost (default = “0%”)</strong></td>
<td>% change in Levelised Annual Fixed Cost</td>
<td>-</td>
<td>-50% to 50%</td>
<td>Positive change increases COAC.</td>
</tr>
</tbody>
</table>
Figure 23 illustrates the range of potential costs of CCS for each facility in 2025 and 2030, achieved when varying the parameters within the ranges defined above. Although the costs associated with the Medupi and Kusile retrofits correlate quite closely with that reported in previous studies (see Table 13), it is the most uncertain, as is the costs associated with the new USCPC facility, and, to a lesser extent, the new IGCC facility. The CTL cost estimates are less uncertain and fall within the range of costs from previous studies (Table 13).

![Figure 23: Variability in the costs of CCS for each facility with implementation of CCS in 2025 and 2030](image)

<table>
<thead>
<tr>
<th>Emitting facility</th>
<th>CTL 2025</th>
<th>CTL 2030</th>
<th>Retrofit Medupi 2025</th>
<th>Retrofit Medupi 2030</th>
<th>Retrofit Kusile 2025</th>
<th>Retrofit Kusile 2030</th>
<th>IGCC new build 2025</th>
<th>IGCC new build 2030</th>
<th>USCPC new build 2025</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upper bound</td>
<td>458</td>
<td>458</td>
<td>1,321</td>
<td>1,402</td>
<td>1,266</td>
<td>1,346</td>
<td>848</td>
<td>830</td>
<td>1,170</td>
</tr>
<tr>
<td>Default</td>
<td>267</td>
<td>267</td>
<td>752</td>
<td>799</td>
<td>724</td>
<td>771</td>
<td>451</td>
<td>439</td>
<td>663</td>
</tr>
<tr>
<td>Lower bound</td>
<td>157</td>
<td>157</td>
<td>187</td>
<td>194</td>
<td>170</td>
<td>177</td>
<td>251</td>
<td>245</td>
<td>131</td>
</tr>
</tbody>
</table>

**TABLE 13: LEVELISED COST OF CCS FOR VARIOUS EMITTING FACILITIES, BASED ON PREVIOUS STUDIES [CONVERTED TO 2015 RAND/TONNE CO₂ AVOIDED]**

<table>
<thead>
<tr>
<th>Emitting facility</th>
<th>Value</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Retrofit</td>
<td>725</td>
<td>(Parsons Brinckerhoff, 2013)</td>
</tr>
<tr>
<td>Refinery (incl. CTL)</td>
<td>320 - 1,190</td>
<td>(Parsons Brinckerhoff, 2013; Telsnig et al., 2013)</td>
</tr>
<tr>
<td>IGCC</td>
<td>250</td>
<td>(Telsnig et al., 2013)</td>
</tr>
<tr>
<td>USC</td>
<td>325</td>
<td>(Telsnig et al., 2013)</td>
</tr>
</tbody>
</table>

Finally, looking at the model results in greater detail suggests that the cost data is most sensitive to assumptions regarding:

- **Technology choice**: Significant cost reductions are achieved through the implementation of polymeric membranes, an emerging technology in post-combustion applications (IEAGHG, 2014). The potential reduction was estimated as a percentage change of LCOE of 30%, which significantly reduces the CCS cost estimates for the retrofits (Medupi and Kusile) and the new build USCPC, between 55-65%.
**Discount rate:** As expected, the CCS costs for all facilities are sensitive to the choice of the discount rate. A discount rate is directly proportional to the CCS cost, i.e. a decrease in the discount rate results in a decrease in the costs (0% equates to a reduction of 15-25%), and an increase in the discount rate results in an increase in the cost (8% equates to an increase of 30-45%).

**Storage costs:** The CCS costs are also sensitive to the storage cost, particularly for CTL where halving the storage cost results in a reduction in CCS costs by 18%. Reductions for the other facilities range from 7% to 11%.

It is these parameters that are most critical to have closely defined in making the business case for CCS.

### 5.3.3 The relationship between carbon tax and CCS

The previous section presents the levelised cost of CCS applied under the different scenarios, to provide an indication of the relative contribution of the different cost components to CCS, and of the costs of CCS for different installations. Consideration is now given to how CCS costs are impacted upon by the introduction of the carbon tax. Given that the carbon tax changes on a year-by-year basis, rather than present a single levelised costs, the CCS costs (calculated as levelised cost of CCS for a facility multiplied by CO$_2$ emissions sequestered) and carbon taxes are considered on a year-by-year basis. This section presents a sample of the model outputs on this subject to demonstrate the trends and key observations, with the full set of results presented in Appendix C.

For the results presented in this section, it is assumed that the carbon tax headline rate remains unchanged at R 120 per tonne (in 2017 Rands). After 2020, the overall allowances are assumed to reduce by 5% per annum until they reach zero. The impact of the assumptions about the structure of the tax after 2020 are explored in Section 5.3.4.

The left hand plot of Figure 24 shows the carbon tax payable by the CTL facility in the absence of CCS under Scenario 1 in billion 2015 Rands. The carbon tax payable remains flat to 2020 as per the 2015 draft bill, and thereafter rises, under the assumption that the allowances will reduce between 2020 and 2033, where after the total quantum is flat again. This results indicate that by 2033 the savings will cover to the order of 40% of the cost of implementing CCS under this scenario. What is also interesting to note on this plot is the substantial tax burden to CTL even after implementation of CCS. As mentioned previously, this is due to the current structure of the tax calculation formula, which only allows for tax credit for sequestration on volumes of emission up to the level the equivalent of the company’s fossil fuel combustion emissions. For the volumes of emissions sequestered and captured, please refer to Table 9.
The picture changes when looking at the relationship between the carbon tax and CCS for the power stations, as seen for Medupi in Scenario 2 (Figure 25). In the absence of CCS the carbon tax increases by a factor of three between the start year and the year once all of the allowances have fallen away. The right hand graph indicates that the introduction of CCS reduces the tax burden substantially. However this tax savings comes at the significant cost for CCS. A similar observation may be made for Kusile, as shown in Figure 27 in Appendix C. The relationship between CCS and tax for CTL and new build IGCC in Scenario 2 is also shown in Appendix C.
Appendix C also shows the carbon tax/CCS plots for Scenario 3 and 4. While the magnitude of the impacts changes somewhat as a result of the changes in the technologies considered (Scenario 3) and year of introduction, the observations remain similar: that CTL still has a high tax burden even after introduction of CTL although the tax savings does go some way to covering the costs of implementing CCS, while power stations register a proportionally higher tax savings, although the cost of introducing CCS far outweighs the carbon tax benefit.

5.3.4 Sensitivity of results to the design of the carbon tax

As indicated previously, the design of the carbon tax has not yet been finalised, and as such a selection of sensitivities was run to determine how the results change in response to changes in the design of the tax. The key parameters explored here are the increase in the carbon headline rate per year and the decrease in the tax-free threshold per year. Table 14 presents the baseline assumptions (explored in the previous section), and the three additional sensitivities that were run on the carbon tax regime post 2020.

<table>
<thead>
<tr>
<th>Assumptions</th>
<th>Baseline</th>
<th>Sensitivity A</th>
<th>Sensitivity B</th>
<th>Sensitivity C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increase in carbon tax headline rate per year</td>
<td>0%</td>
<td>10%</td>
<td>0%</td>
<td>10%</td>
</tr>
<tr>
<td>Decrease in overall tax-free threshold per year</td>
<td>5%</td>
<td>0%</td>
<td>0%</td>
<td>5%</td>
</tr>
</tbody>
</table>

In addition to the above, a further sensitivity was run to determine the impact of changing the carbon tax structure to one where rather than subtracting sequestrated emissions from the combustion terms in the carbon tax formula for CCS, they are subtracted from the fugitive emissions.

Figure 26 shows the carbon tax applied to CTL before and after installation of CCS, under Sensitivity A, where the headline rate continues to increase by 10% per annum post 2020. The growing tax burden under this scenario is clear. What is seen here, however, is that the cost of CCS is small relative to the carbon tax burden, and has significant potential to ease the tax burden.
For the other sensitivities explored on the carbon tax structure, the impact on the trends is insignificant, although the magnitude of tax payable and relative cost of CCS changes. See Appendix C.2 for the resulting plots.

### 5.3.5 Level of carbon tax required to make CCS viable

As indicated previously in this study, a combination of measures, rather than a single financial mechanism like a carbon price, has been required in other countries to support the implementation of CCS elsewhere in the world. For illustrative purposes, however, the model was run to determine the theoretical value of the tax that would be required to support the uptake of CCS in South Africa. This was calculated as the headline tax rate required to make the difference between the carbon tax savings achieved by CCS and the cost of CCS zero, over the period between implementation of CCS and 2050. In reading these numbers, however, it is important to remember that investors would likely require the actual carbon tax rate to be higher than the minimum headline tax rate provided by the models, in order to account for a risk element in implementing CCS. Furthermore, setting the tax rate at these levels will have significant impacts for the remainder of the economy and the implementation of other mitigation options which are not accounted for here.

Bearing these comments in mind, the following observations are presented:

- Under Scenario 1, which only considers CCS for CTL, and where the allowances on the tax rate decline by 5% per year post-2020, the headline tax rate required is R 340 per tonne CO$_2$ sequestered in 2015 Rands.
- In Scenario 2, the baseline tax required is R 520. However this is an average rate that takes into account all of the facilities included in the scenario. What is interesting here is that the power stations will effectively “cross subsidise” the cost of CCS for the CTL facility. The headline tax required is slightly higher for Scenario 3, at R 530 per tonne, and slightly lower for Scenario 4 at R 514 per tonne.
A further interesting observation is the minimum headline carbon tax required when the allowances are not removed post 2020. The result thereof is that the carbon tax savings is much lower, and hence the headline tax needs to be substantially higher to make CCS more financially viable. In the case where allowances are not removed:

- For Scenario 1, which includes CCS on CTL only, the headline tax required is R 1,035 per tonne CO₂ to allow the tax to support CCS.
- For Scenario 2, the average headline tax rate required is R 1,425 per tonne CO₂ to allow the tax to support CCS, taking into account the “cross-subsidisation” across facilities.

In conclusion, while these observations are relatively broad, two key observations can be made:

- The headline carbon tax needs to be substantially higher if it were to be used as the sole mechanism to drive the update of CCS.
- Knowledge of the carbon tax structure post 2020 is critical to understanding the impact of the carbon tax on the uptake of CCS. If the allowances are not removed, or removed very slowly, the price of carbon to drive CCS would need to be higher than in the case where the allowance are removed at 5% per annum.

Finally, once again these results must be interpreted in the context of being relevant to a particular set of scenarios being modelled, which are underpinned by a particular set of assumptions.

6 CONCLUSIONS

This objective of this study was to explore the interaction between the proposed South African carbon tax and Carbon Capture and Storage (CCS) as a mitigation technology. The study consisted of two key components: a background review and a financial modelling exercise. The literature review firstly identified international experience on the interplay between CCS and the carbon tax and secondly unpacked the South African carbon tax (and the implications of the design itself on CCS). The financial model explores the implications of South Africa’s carbon tax design for the financial viability of CCS in South Africa into the future.

6.1 Findings from the review of international experience

While the literature review presented in Section 2 has shown that while there are sound economic reasons why a carbon tax can support CCS deployment if the carbon tax is high enough, in the analysis of the experience on the ground it has been demonstrated that carbon prices (whether set by a carbon tax or an ETS) have not been sufficiently high to drive CCS deployment on their own. When combined with other factors like enhanced oil recovery (EOR) or public sector support, however, carbon taxes seem to create strong incentives to consider CCS.

When considering large-scale CCS projects that do not involve EOR, it is rare to find CCS being implemented in jurisdictions where carbon prices aren’t in place, or have been put into place recently. Interestingly, public sector support still seems to be the main driver for implementing CCS projects in jurisdictions even when carbon pricing is present. Given the relatively low level of carbon prices internationally, it would thus seem that having a carbon price in place is more likely to act as a signal of the commitment of authorities to climate change mitigation (and therefore more stringent future climate change policies) than as a punitive measure to incentivise CCS. Having a carbon price in place seems to make public sector support for CCS more palatable, possibly because it
introduces an element of burden sharing between the private and public sectors (and in some cases there is a direct link in that carbon pricing mechanisms generate funds that are then utilised to support low carbon technologies like CCS).

Public sector support can be provided for CCS directly via the design of a carbon tax (as is the case in Alberta where a baseline and credit scheme functions like a carbon tax in practice). The benefit of providing support through the design of a carbon tax rather than through general public sector support or dedicated CCS funding is that it reduces the amount of funding that needs to be committed upfront by the fiscus to support CCS deployment.

CCS as a mitigation option needs to be attractive relative to the other mitigation options available within a jurisdiction for it to be supported by the public sector. In order to prevent catastrophic climate change, the best current indications indicate that all mitigation options (including CCS) will have to be deployed. But given the relatively slow pace at which countries’ mitigation commitments under the UNFCCC are being ratcheted up, countries will most likely be prioritising mitigation interventions over the coming decades due to funding and capacity constraints. For this reason it is necessary to consider the cost of completing mitigation options. The cost of these mitigation options will however be country-specific and will change over time. From a firm perspective, a carbon tax at the correct level will incentivise CCS (since it is unlikely that competing mitigation options at a similar scale required will be less costly than CCS), but the cost of CCS will be influenced by government support. So the ‘required’ level of the tax will be determined by government support, and government support will be determined by the order in which it wants to support mitigation options.

But once it is decided that CCS make sense, the combination of a carbon tax (particularly one with a design that is conducive to supporting CCS) and government support is likely to be an attractive option to incentivise CCS deployment.

6.2 The implications of the design of the South African carbon tax for CCS

The proposed South African carbon tax is very complicated and this makes it hard to fully understand the mitigation incentives it will create. From a CCS deployment perspective, however, a number of design features included in the current carbon tax design may reduce the incentives it creates for CCS deployment.

At a high level, the lack of certainty regarding both the trajectory and future level of the carbon tax rate is not conducive to large, capital-intensive mitigation projects like CCS. At a technical level, the current carbon tax design only allows firms to use sequestration to reduce their GHG emissions up to the level of their energy combustion emissions. Other types of emissions can be sequestered (i.e. process or fugitive emissions), but the carbon tax benefit is limited to the size of its combustion emissions. Offsets can only be generated by firms

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39 In a perfect world carbon pricing would be used as the central measure to drive mitigation action as it leads to mitigation where it is cheapest within an economy, creates incentives to undertake mitigation action throughout value chains as carbon costs are passed on, and allows firms the flexibility to decide how much mitigation to undertake and when to undertake it (Hood, 2011). As a result of market imperfections and barriers, however, in practice carbon pricing needs to be supported by policies to unlock cost effective mitigation options that are available but not being implemented due to information asymmetries, risk aversion or other market failures (like energy efficiency or CCS where future liabilities are unknown), and policies to fund research, development and demonstration to allow new mitigation options to be rolled-out as fast as possible (again, with CCS being a good example) (Hood, 2011). To illustrate this point, Acemoglu et al (2012) shows that using a carbon tax alone to support the roll-out of new mitigation technologies, as opposed to combining the carbon tax with a subsidy for mitigation technology research, requires a carbon tax that is 40 times higher than when combined with a research subsidy and leads to significant welfare loss. Particularly in cases where the firms deploying CCS compete in international markets (through exports or imports), a carbon tax that is increased incrementally to the level where it incentivises CCS may lead to an increase in production costs that causes firms to close down before this level of carbon tax is reached (IEA, 2014b)
through activities that are not subject to the carbon tax, which removes the ability of firms to gain the maximum possible financial benefit from CCS activities (by generating offsets through CCS linked to their main taxable activities which are likely to be their emissions most suitable to CCS) and selling them to other carbon taxpayers. This also restricts the benefits from CCS projects to firms that have physical access to CCS infrastructure (and can thus sequester emissions directly), which in turn limits the amount of funds that can be pooled to invest in CCS projects. The ability to diversify the risk of investing in CCS projects by increasing the number of firms that participate in the project (either through investing directly in a project or by purchasing the rights to a portion of the future offsets generated by a CCS project) is reduced. Finally, the current carbon tax design rewards firms that are more carbon-efficient than their peers with a carbon tax discount through the so-called “z-factor” on all their taxable emissions. Sequestered emissions, however, are not currently taken into consideration when the carbon efficiency of a firm is calculated. If sequestered emissions were included in the calculation of this performance allowance, this could significantly increase the incentive to deploy CCS created by the carbon tax.

6.3 Findings from the financial modelling exercise

The financial model was developed with the purposes of testing the relationship between CCS and the carbon tax, including under scenarios where CCS is applied to different technologies, and where it is introduced later rather than earlier (which impacts on the cost of implementation which is assumed to come down when CCS is introduced later). The impact of different alternatives for the structure of the carbon tax post 2020, as well as a change in the way sequestration of emissions from CCS are handled in the carbon tax is also explored.

Prior to exploring the relationship between the tax on CCS, the models were used to interrogate the findings of other studies with respect to the costs of CCS, using the levelised cost of sequestered carbon prior to application of the tax as a financial indicator. The results showed that while the model developed under this study provided comparative estimates of levelised costs to other studies, it did demonstrate the significant sensitivity of results to assumptions made in the models. This is particularly the case for the power generation options. While for Sasol the levelised cost of CO₂ ranged from approximately 50% above to about 40% below the default case at the highest and lowest values, in the case of Medupi the figures were approximately 220% above and 40% below the default case at their highest and lowest values. This demonstrates the extreme uncertainty surrounding the costs of CCS in the future.

In terms of the observations regarding the relationship between CCS and the carbon tax, while the magnitude of the impacts changes somewhat as a result of the changes in the technologies considered (e.g. Scenario 3 considers ultra-supercritical pulverised coal (USCPC) rather than an IGCC power plant) and year of introduction of CCS (2030 vs. 2025), the overriding message under the baseline carbon tax scenario is clear: CTL still has a high tax burden even after introduction of CCS although the tax savings do go some way to covering the costs of implementing CCS. In contrast, while power stations achieve a proportionally higher tax savings from introducing CCS than CTL does, the cost of introducing CCS far outweighs the carbon tax benefit.

The structure of the carbon tax post 2020 does have an impact on the relationship between carbon tax and CCS: when the tax's headline rate continues to rise, the ability of CCS to offset the tax is increased, and the relative cost of CCS to the tax burden becomes smaller.

Two final observations are made based on the modelling results. The first is that given the relative cost of CCS to the tax savings, additional support mechanisms beyond the carbon tax will be required to make CCS viable in South Africa. This is in line with the findings of the international experience as presented in this report. The
second, but linked, observation is that certainty in the tax structure post-2020 is critical to support decision-making around CCS in South Africa. These observations were supported by the illustrative calculations of the level of tax that would be required if the tax were to be used as the sole instrument to drive CCS. A headline tax rate of R 340 to R 530 per tonne would be required (depending on the scenario) if allowances were slowly removed after 2020, while a headline rate in excess of R 1,000 would be required if the allowances were to be retained.
7 REFERENCES


Cloete, B., Robb, G. & Tyler, E., 2010. Study to provide an overview of the use of economic instruments and develop sectoral plans to mitigate the effects of climate change. Johannesburg: NEDLAC.


ZERO, 2013. Policy instruments for large-scale CCS. Oslo.

A MITIGATION INCENTIVES OF CARBON TAXES AND EMISSIONS TRADING SCHEMES

Under a carbon tax, firms will abate CO$_2$ emissions up to the point where the cost of abating an extra tonne of CO$_2$ is just below cost of the tax (Cloete et al., 2010). Similarly, under an ETS, firms will abate CO$_2$ emissions up until the point where the cost of abating an extra tonne of CO$_2$ is just below market price of emissions certificates (Goldblatt, 2010). After the point where abating an extra tonne of CO$_2$ is greater than the cost of the tax or the market price of the emissions certificates, then firms will rather pay the tax or purchase certificates, respectively. Both of these methods result in economically efficient outcomes, whereby companies abate until the point where abating one more tonne of CO$_2$ costs more to the firm than it would save (in the case of a carbon tax) or earn (in the case of an ETS) as a result of the carbon price (Cloete et al., 2010).

Consider the example of two firms with mitigation costs of R 50/tCO$_2$e and R 150/tCO$_2$e and a carbon price set through a carbon tax and through an ETS. For each firm two ETS scenarios are considered, one where the firm starts out owning no ETS certificates, and one where the firm owns sufficient ETS certificates to cover all its emissions. In Table 15 it is assumed firms only have options to abate half their emissions, while in Table 16 it is assumed firms can abate all their emissions.

**TABLE 15: FIRM BEHAVIOUR UNDER CARBON TAX AND ETS WITH LESS THAN 100% MITIGATION POTENTIAL**

<table>
<thead>
<tr>
<th>Mitigation cost of firm with 200 tonnes of mitigation potential and 400 tonnes of total GHG emissions</th>
<th>Behaviour under R100/tCO$_2$e carbon tax</th>
<th>Behaviour under R100/tCO$_2$e ETS certificate price (firm does not own certificates)</th>
<th>Impact on firm profit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Firm 1: R50/tCO$_2$e mitigation cost</td>
<td>Firm abates 200 tonnes @ R 50/tonne and pays tax on 200 tonnes @ R 100/tonne</td>
<td>Firm abates 200 tonnes @ R 50/tonne and purchases 200 tonnes’ worth of ETS certificates</td>
<td>Firm profits reduced by R 30,000</td>
</tr>
<tr>
<td>Firm owns no ETS certificates</td>
<td></td>
<td></td>
<td>Firm profits reduced by R 30,000</td>
</tr>
<tr>
<td>Firm has ETS certificates covering all emissions</td>
<td>Firm abates 200 tonnes @ R 50/tonne and purchases 200 tonnes’ worth of ETS certificates</td>
<td>Firm abates 200 tonnes @ R 50/tonne (-R 10,000 cost) and sells 200 tonnes worth of ETS certificates (+R 20,000 income). Firm uses ETS certificates for 200 tonnes to cover remaining emissions (-R 20 000$^{(a)}$)</td>
<td>Firm profits reduced by R 10,000</td>
</tr>
<tr>
<td>Firm 2: R 150/CO$_2$e mitigation cost</td>
<td>Firm pays tax on 400 tonnes @ R100/tonne</td>
<td></td>
<td>Firm profits reduced by R4 0,000</td>
</tr>
</tbody>
</table>

$^{(a)}$ The certificates are not sold, and thus the firm is forfeiting R 20,000 in income.
Firm owns no ETS certificates | Firm purchases 400 tonnes' worth of ETS certificates to cover emissions (-R 40,000) | Firm profits reduced by R 40,000
---|---|---
Firm has ETS certificates covering all emissions | Firm uses 400 tonnes' worth of ETS certificates to cover emissions (-R 40,000) | Firm profits reduced by R 40,000

**TABLE 16: FIRM BEHAVIOUR UNDER CARBON TAX AND ETS WITH 100% MITIGATION POTENTIAL**

<table>
<thead>
<tr>
<th>Mitigation cost of firm with 400 tonnes of mitigation potential and 400 tonnes of total GHG emissions</th>
<th>Behaviour under R 100/tCO₂e carbon tax</th>
<th>Behaviour under R 100/tCO₂e ETS certificate price</th>
<th>Impact on firm profit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Firm 1: R 50/tCO₂e mitigation cost</td>
<td>Firm abates 400 tonnes @ R 50/tonne</td>
<td>Firm abates 400 tonnes @ R 50/tonne</td>
<td>Firm profits reduced by R 20,000</td>
</tr>
<tr>
<td>Firm owns no ETS certificates</td>
<td>Firm abates 400 tonnes @ R 50/tonne</td>
<td>Firm abates 400 tonnes @ R 50/tonne</td>
<td>Firm profits reduced by R 20,000</td>
</tr>
<tr>
<td>Firm has ETS certificates covering all emissions</td>
<td>Firm abates 400 tonnes @ R 50/tonne (-R 20,000 cost) and sells 400 tonnes worth of ETS certificates (+R 40,000 income).</td>
<td>Firm abates 400 tonnes @ R 50/tonne</td>
<td>Firm profits increase by R 20,000</td>
</tr>
<tr>
<td>Firm 2: R150/CO₂e mitigation cost</td>
<td>Firm pays tax on 400 tonnes @ R 100/tonne</td>
<td>Firm purchases 400 tonnes' worth of ETS certificates to cover emissions (-R 40,000)</td>
<td>Firm profits reduced by R 40,000</td>
</tr>
<tr>
<td>Firm owns no ETS certificates</td>
<td>Firm purchases 400 tonnes' worth of ETS certificates to cover emissions (-R 40,000)</td>
<td>Firm purchases 400 tonnes' worth of ETS certificates to cover emissions (-R 40,000)</td>
<td>Firm profits reduced by R 40,000</td>
</tr>
<tr>
<td>Firm has ETS certificates covering all emissions</td>
<td>Firm uses 400 tonnes' worth of ETS certificates to cover emissions (-R 40,000)</td>
<td>Firm uses 400 tonnes' worth of ETS certificates to cover emissions (-R 40,000)</td>
<td>Firm profits reduced by R 40,000</td>
</tr>
</tbody>
</table>

In both tables the impact of firm behaviour (how much mitigation is undertaken) and the impact of firm profits are equal under a carbon tax and an ETS when firms don’t start out owning ETS certificates, or when the carbon price is higher than cost of mitigation. And in both tables, while the impact on firm profits differ between a carbon tax and an ETS when firms start out owning ETS certificates, firm behaviour does not. These two tables illustrate that the incentives to undertake mitigation action (like implementing CCS, for example) are similar under a carbon tax and an ETS when the carbon prices set by the two instruments are the same.

The examples in the tables illustrate that in the case where firms aren’t given any ETS certificates for free (which is the end state that all ETS strive for), and the carbon price is higher than the cost of mitigation – thus creating an incentive to undertake mitigation action – the reduction in tax liability that a firm receives by undertaking mitigation action rather than paying a carbon tax will be equivalent to the revenue it can earn by undertaking mitigation action and selling ETS certificates rather than using them to cover its GHG emissions (Goldblatt, 2010; Robb et al., 2010).
A firm will thus face the same incentives to implement CCS as a result of a carbon price being in place irrespective of whether the carbon price is set by a carbon tax or an ETS.
## B LARGE-SCALE GLOBAL CCS PROJECTS

### B.1 Large-scale global CCS projects and carbon price regimes

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Project Lifecycle Stage</th>
<th>Primary Storage Type **</th>
<th>Operation Date</th>
<th>Industry</th>
<th>Capture Capacity (Mtpa)</th>
<th>Location: State/ Country</th>
<th>Carbon Price Regime</th>
<th>Regime Start Date</th>
<th>Carbon Price (US$/tCO\textsubscript{2}e)</th>
<th>Price Path</th>
<th>Support Mechanism</th>
<th>General Treatment of CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Abu Dhabi CCS Project (Phase 1 being Emirates Steel Industries (ESI) CCS Project)</td>
<td>Execute</td>
<td>Enhanced oil recovery</td>
<td>2016</td>
<td>Iron and Steel Production</td>
<td>0.8</td>
<td>Abu Dhabi</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Air Products Steam Methane Reformer EOR Project</td>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>2013</td>
<td>Hydrogen Production</td>
<td>1.0</td>
<td>Texas</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>DOE funding through the American Recovery and Reinvestment Act (ARRA)'s Industrial Capture and Sequestration (IICS) Program</td>
<td>N/A</td>
</tr>
<tr>
<td>Alberta Carbon Trunk Line (&quot;ACTL&quot;) with Agrium CO2 Stream</td>
<td>Execute</td>
<td>Enhanced oil recovery</td>
<td>2016-17</td>
<td>Fertiliser Production</td>
<td>0.3 - 0.6</td>
<td>South-Central Alberta</td>
<td>Alberta SGER</td>
<td>2007</td>
<td>12 (Nominal price on 1 August 2015)</td>
<td>N/A</td>
<td>Payments to CCEM increased from $15/tCO\textsubscript{2}e to $20 for 2016 and $30 for 2017. Alberta government CCS Fund (no link to Carbon tax). Canadian’s ecoEnergy Technology Initiative, and the Clean Carbon tax compliance requires actual reductions to on-site CO2 emissions. CCS enables</td>
<td>N/A</td>
</tr>
<tr>
<td>Project Name</td>
<td>Lifecycle Stage</td>
<td>Primary Storage Type **</td>
<td>Operation Date</td>
<td>Industry</td>
<td>Capture Capacity (Mtpa)</td>
<td>Location: State/ Country</td>
<td>Carbon Price Regime</td>
<td>Regime Start Date</td>
<td>Carbon Price (US$/tCO₂e)</td>
<td>Price Path</td>
<td>Support Mechanism</td>
<td>General Treatment of CCS</td>
</tr>
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<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Alberta Carbon Trunk Line (&quot;ACTL&quot;) with North West Sturgeon Refinery CO2 Stream</td>
<td>Execute</td>
<td>Enhanced oil recovery</td>
<td>2017</td>
<td>Oil Refining</td>
<td>1.2 - 1.4</td>
<td>South-Central Alberta</td>
<td>Alberta SGER</td>
<td>2007</td>
<td>12 (Nominal price on 1 August 2015)</td>
<td>Payments to CCEM increased from $15/tCO₂e to $20 for 2016 and $30 for 2017. Alberta government CCS Fund (no link to Carbon tax), Canadian's ecoEnergy Technology Initiative, and the Clean Energy Fund</td>
<td>Energy Fund</td>
<td>large emitters to meet this requirement through credits</td>
</tr>
<tr>
<td>Boundary Dam Carbon Capture and Storage Project</td>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>2014</td>
<td>Power Generation</td>
<td>1.0</td>
<td>Saskatchewan</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Saskatchewan's law on CO₂ emissions reductions. Funded by Montana, Saskatchewan and Canadian government, as well as SaskPower</td>
<td>Project status is uncertain, project was placed on the reserve list for the UK CCS Commercialisa</td>
</tr>
<tr>
<td>Caledonia Clean Energy Project</td>
<td>Evaluate</td>
<td>Dedicated Geological Storage</td>
<td>2022</td>
<td>Power Generation</td>
<td>3.8</td>
<td>United Kingdom</td>
<td>EU ETS price floor / EU ETS</td>
<td>2013</td>
<td>28 (Nominal price on 1 August 2015)</td>
<td>Price changes annually, projections informed by EU estimates</td>
<td>Tax abatements in proportion to the level of CO₂ abated for generating</td>
<td></td>
</tr>
<tr>
<td>Project Name</td>
<td>Lifecycle Stage</td>
<td>Primary Storage Type</td>
<td>Operation Date</td>
<td>Industry</td>
<td>Capture Capacity (Mtpa)</td>
<td>Location: State/ Country</td>
<td>Carbon Price Regime</td>
<td>Regime Start Date</td>
<td>Carbon Price (US$/tCO₂e)</td>
<td>Price Path</td>
<td>Support Mechanism</td>
<td>General Treatment of CCS</td>
</tr>
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</tr>
<tr>
<td>CarbonNet Project</td>
<td>Evaluate</td>
<td>Dedicated Geological Storage</td>
<td>2020's</td>
<td>Power Generation</td>
<td>1.0 - 5.0</td>
<td>Victoria</td>
<td>Australia CPM</td>
<td>2012/2014</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>In February 2012, the Australian government’s CCS Flagships Program awarded Victorian CarbonNet $70 million, and the Victorian state government pledged $30m, towards feasibility studies. Could receive Australian Carbon Credit Units (ACCUs) for sequestration projects.</td>
</tr>
<tr>
<td>Century Plant</td>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>2010</td>
<td>Natural Gas Processing</td>
<td>8.4</td>
<td>Texas</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Could receive Australian Carbon Credit Units (ACCUs) for sequestration projects.</td>
</tr>
<tr>
<td>China Resources Power (Haifeng)</td>
<td>Identify</td>
<td>Dedicated Geological Storage</td>
<td>2019</td>
<td>Power Generation</td>
<td>1.0</td>
<td>Guangdong Province</td>
<td>Guangdong Pilot ETS</td>
<td>2013</td>
<td>2 (Nominal price on 1 August 2015)</td>
<td>National ETS set to be implemented in 2017 N/A hence price projections for regional ETS’s lacking. Doubtful that ETS supported this CCS project as both began in 2013. And this is a demonstration project which seems to be supported by UK government. Indeed, CCS in China is allowed compliance companies to use Chinese Certified Emissions Reduction (CCER).</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Name</td>
<td>Project Lifecycle Stage</td>
<td>Primary Storage Type **</td>
<td>Operation Date</td>
<td>Industry</td>
<td>Capture Capacity (Mtpa)</td>
<td>Location: State/ Country</td>
<td>Carbon Price Regime</td>
<td>Regime Start Date</td>
<td>Carbon Price (US$/tCO₂e)</td>
<td>Price Path</td>
<td>Support Mechanism</td>
<td>General Treatment of CCS</td>
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</tr>
<tr>
<td>Coffeyville Gasification Plant</td>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>2013</td>
<td>Fertiliser Production</td>
<td>1.0</td>
<td>Kansas</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>State Legislation offers normal tax credits for CCS</td>
</tr>
<tr>
<td>Don Valley Power Project</td>
<td>Define</td>
<td>Dedicated Geological Storage</td>
<td>2020</td>
<td>Power Generation</td>
<td>1.5</td>
<td>United Kingdom</td>
<td>EU ETS price floor / EU ETS</td>
<td>2013</td>
<td>28 (Nominal price on 1 August 2015)</td>
<td>Price changes annually, projections informed by EU estimates</td>
<td>None project did not receive EU NER300 funding and the UK CCS Commercialisation Competition funds, start date is uncertain</td>
<td></td>
</tr>
<tr>
<td>Enid Fertilizer CO2-EOR Project</td>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>1982</td>
<td>Fertiliser Production</td>
<td>0.7</td>
<td>Oklahoma</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Started operating prior to any support mechanisms</td>
<td></td>
</tr>
<tr>
<td>Gorgon Carbon Dioxide Injection Project</td>
<td>Execute</td>
<td>Dedicated Geological Storage</td>
<td>2017 (Institute estimate)</td>
<td>Natural Gas Processing</td>
<td>3.4 - 4.0</td>
<td>Western Australia</td>
<td>Australia CPM (repealed)</td>
<td>2012N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Gorgon Carbon Dioxide Injection Project represents an investment of about AUD 2 billion. In November 2006, the Australian government announced Could receive Australian Carbon Credit Units (ACCUs) for sequestration projects.</td>
<td></td>
</tr>
<tr>
<td>Project Name</td>
<td>Lifecycle Stage</td>
<td>Primary Storage Type **</td>
<td>Operation Date</td>
<td>Industry</td>
<td>Capture Capacity (Mtpa)</td>
<td>Location: State/ Country</td>
<td>Carbon Price Regime</td>
<td>Regime Start Date</td>
<td>Carbon Price (US$/tCO2e)</td>
<td>Price Path</td>
<td>Support Mechanism</td>
<td>General Treatment of CCS</td>
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</tr>
<tr>
<td>Great Plains Synfuel Plant and Weyburn-Midale Project</td>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>2000</td>
<td>Synthetic Natural Gas</td>
<td>3.0</td>
<td>Saskatchewan</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>funding support of AUD 60 million from its Low Emissions Technology Demonstration Fund (LETDF) for the CCS part of the project</td>
</tr>
<tr>
<td>Huaneng GreenGen IGCC Project (Phase 3)</td>
<td>Evaluate</td>
<td>Enhanced oil recovery</td>
<td>2020</td>
<td>Power Generation</td>
<td>2.0</td>
<td>Beijing/Hebei Province</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>There are no specific legal frameworks or policies on CCS.</td>
</tr>
<tr>
<td>Hydrogen Energy California Project (HECA)</td>
<td>Define</td>
<td>Enhanced oil recovery</td>
<td>2020</td>
<td>Power Generation</td>
<td>2.7</td>
<td>California</td>
<td>California CaT</td>
<td>2012</td>
<td>13 (Nominal price on 1 August 2015)</td>
<td>Futures Price for the 2020 contract at $16.06 as at December 2015</td>
<td>Project uncertain. Funds withheld from Federal Tax Credits &amp; Clean Coal Power Initiative</td>
<td>Sector Specific Offset Credits for verified CCS projects</td>
</tr>
<tr>
<td>Illinois Industrial Carbon Capture and Storage Project</td>
<td>Execute</td>
<td>Dedicated Geological Storage</td>
<td>2016</td>
<td>Chemical Production</td>
<td>1.0</td>
<td>Illinois</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>US Recovery Act. DOE funding from the American Recovery and Reinvestment Act of 2009</td>
<td>N/A</td>
</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th>Project Name</th>
<th>Lifecycle Stage</th>
<th>Primary Storage Type **</th>
<th>Operation Date</th>
<th>Industry</th>
<th>Capture Capacity (Mtpa)</th>
<th>Location: State/ Country</th>
<th>Carbon Price Regime</th>
<th>Regime Start Date</th>
<th>Carbon Price (US$/ tCO₂e)</th>
<th>Price Path</th>
<th>Support Mechanism</th>
<th>General Treatment of CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>In Salah CO₂ Storage</td>
<td>Operate (Suspende d)</td>
<td>Dedicated Geological Storage</td>
<td>2004</td>
<td>Natural Gas Processing</td>
<td>0.0 (injection suspended)</td>
<td>Algeria</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Carbon Capture and Sequestration (ICCS) Program</td>
<td></td>
</tr>
<tr>
<td>Kemper County Energy Facility (formerly Kemper County IGCC Project)</td>
<td>Execute</td>
<td>Enhanced oil recovery</td>
<td>2016</td>
<td>Power Generation</td>
<td>3.0</td>
<td>Mississippi</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>No ETC/Carbon tax incentive, there are three CCS project support mechanisms at federal level: 1. Federal Tax/investments incentives for clean coal 2. Clean Coal Power initiative funding 3. American Recovery and Reinvestment Act of 2009</td>
<td></td>
</tr>
<tr>
<td>Korea-CCS 1</td>
<td>Evaluate</td>
<td>Dedicated Geological Storage</td>
<td>2020</td>
<td>Power Generation</td>
<td>1.0</td>
<td>South Korea</td>
<td>South Korea ETS</td>
<td>2015</td>
<td>9 (Nominal price on 1 August 2015)</td>
<td>Could reach $30 by 2017. Korea's ETS pilot began around a similar time as the governments' national framework to develop CCS. Has also</td>
<td>CCS included in carbon offsetting as part of the ETS trading scheme</td>
<td></td>
</tr>
<tr>
<td>Project Name</td>
<td>Lifecycle Stage</td>
<td>Primary Storage Type **</td>
<td>Operation Date</td>
<td>Industry</td>
<td>Capture Capacity (Mtpa)</td>
<td>Location: State/ Country</td>
<td>Carbon Price Regime</td>
<td>Regime Start Date</td>
<td>Carbon Price (US$/tCO₂e)</td>
<td>Price Path</td>
<td>Support Mechanism</td>
<td>General Treatment of CCS</td>
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</tr>
<tr>
<td>Korea-CCS 2</td>
<td>Evaluate</td>
<td>Dedicated Geological Storage</td>
<td>2023</td>
<td>Power Generation</td>
<td>1.0</td>
<td>South Korea</td>
<td>South Korea ETS</td>
<td>2015</td>
<td>9</td>
<td>(Nominal price on 1 August 2015)</td>
<td>Could reach $30 by 2017.</td>
<td>Korea’s ETS pilot began around a similar time as the governments’ national framework to develop CCS. Has also received government funding</td>
</tr>
<tr>
<td>Lost Cabin Gas Plant</td>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>2013</td>
<td>Natural Gas Processing</td>
<td>0.9</td>
<td>Montana</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>State Legislation offers normal tax credits for CCS</td>
<td></td>
</tr>
<tr>
<td>Peterhead CCS Project</td>
<td>Define</td>
<td>Dedicated Geological Storage</td>
<td>2019-20</td>
<td>Power Generation</td>
<td>1.0</td>
<td>United Kingdom</td>
<td>EU ETS price floor / EU ETS</td>
<td>2013</td>
<td>28</td>
<td>(Nominal price on 1 August 2015)</td>
<td>Price changes annually, projections informed by EU estimates</td>
<td>None - project did not receive EU NER300 funding and the UK CCS Commercialisation Competition funds, it will therefore not proceed</td>
</tr>
<tr>
<td>Petra Nova Carbon Capture Project (formerly NRG Energy Parish)</td>
<td>Execute</td>
<td>Enhanced oil recovery</td>
<td>2016</td>
<td>Power Generation</td>
<td>1.4</td>
<td>Texas</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>No ETC/Carbon tax incentive, there are three CCS project support mechanisms</td>
<td>N/A</td>
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</table>

**Note:** CCS = Carbon Capture and Storage, ETS = Emissions Trading System, EU ETS = European Union Emissions Trading System.
<table>
<thead>
<tr>
<th>Project Name</th>
<th>Project Lifecycle Stage</th>
<th>Primary Storage Type **</th>
<th>Operation Date</th>
<th>Industry</th>
<th>Capture Capacity (Mtpa)</th>
<th>Location: State/ Country</th>
<th>Carbon Price Regime</th>
<th>Regime Start Date</th>
<th>Carbon Price (US$/tCO₂e)</th>
<th>Price Path</th>
<th>Support Mechanism</th>
<th>General Treatment of CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Petrobras Lula Oil Field CCS Project</td>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>2013</td>
<td>Natural Gas Processing</td>
<td>0.7</td>
<td>Brazil</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>There are no specific legal frameworks or policies on CCS.</td>
</tr>
<tr>
<td>PetroChina Jilin Oil Field EOR Project (Phase 2)</td>
<td>Define</td>
<td>Enhanced oil recovery</td>
<td>2017</td>
<td>Natural Gas Processing</td>
<td>0.5</td>
<td>Jilin Province</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>There are no specific legal frameworks or policies on CCS.</td>
</tr>
<tr>
<td>Riley Ridge Gas Plant</td>
<td>Evaluate</td>
<td>Enhanced oil recovery</td>
<td>2020</td>
<td>Natural Gas Processing</td>
<td>2.5</td>
<td>Wyoming</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>There are no specific legal frameworks or policies on CCS.</td>
</tr>
<tr>
<td>Rotterdam Opslag en Afvang Demonstratie project (ROAD)</td>
<td>Define</td>
<td>Dedicated Geological Storage</td>
<td>2019-20</td>
<td>Power Generation</td>
<td>1.1</td>
<td>Netherlands</td>
<td>EU ETS</td>
<td>2005</td>
<td>9</td>
<td>2013N/A2020: $15 price projections 2021N/A2028: $35 price projections</td>
<td>Project uncertain. Very low EU price has created a financing gap delaying the financial investment decision</td>
<td>CCS included in EU ETS Directive of 2009; emissions captured by CCS are not emitted. NER 300 funding</td>
</tr>
<tr>
<td>Project Name</td>
<td>Project Lifecycle Stage</td>
<td>Primary Storage Type **</td>
<td>Operation Date</td>
<td>Industry</td>
<td>Capture Capacity (Mtpa)</td>
<td>Location: State/ Country</td>
<td>Carbon Price Regime</td>
<td>Regime Start Date</td>
<td>Carbon Price (US$/tCO₂e)</td>
<td>Price Path</td>
<td>Support Mechanism</td>
<td>General Treatment of CCS</td>
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</tr>
<tr>
<td>Shanxi International Energy Group CCUS Project</td>
<td>Identify</td>
<td>Not specified</td>
<td>2020</td>
<td>Power Generation</td>
<td>2.0</td>
<td>Shanxi Province</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The US Department of Energy and China National Energy Administration have included this project in the US-China Fossil Energy Protocol</td>
<td>There are no specific legal frameworks or policies on CCS.</td>
</tr>
<tr>
<td>Shell Quest</td>
<td>Operate</td>
<td>Dedicated Geological Storage</td>
<td>2015</td>
<td>Hydrogen Production</td>
<td>1.0</td>
<td>Alberta</td>
<td>Alberta SGER</td>
<td>2007</td>
<td>12 (Nominal price on 1 August 2015)</td>
<td>Payments to CCEM increased from $15/tCO₂e to $20 for 2016 and $30 for 2017.</td>
<td>Shell negotiated a two-for-one carbon credit deal with the province. Funds obtained from Alberta government CCS Fund</td>
<td>Carbon tax compliance requires actual reductions to on-site CO₂ emissions. CCS enables large emitters to meet this requirement through credits</td>
</tr>
<tr>
<td>Shenhua Ningxia CTL Project</td>
<td>Identify</td>
<td>Dedicated Geological Storage</td>
<td>2020</td>
<td>Coal-to-liquids (CTL)</td>
<td>2.0</td>
<td>Inner Mongolia</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Ningxia provincial government support</td>
<td>There are no specific legal frameworks or policies on CCS.</td>
</tr>
<tr>
<td>Shenhua Ordos CTL Project (Phase 2)</td>
<td>Evaluate</td>
<td>Dedicated Geological Storage</td>
<td>2020</td>
<td>Coal-to-liquids (CTL)</td>
<td>1.0</td>
<td>Inner Mongolia</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Chinese government funding</td>
<td>There are no specific legal frameworks or policies on CCS.</td>
</tr>
<tr>
<td>Project Name</td>
<td>Project Lifecycle Stage</td>
<td>Primary Storage Type</td>
<td>Operation Date</td>
<td>Industry</td>
<td>Capture Capacity (Mtpa)</td>
<td>Location: State/ Country</td>
<td>Carbon Price Regime</td>
<td>Regime Start Date</td>
<td>Carbon Price (US$/tCO₂e)</td>
<td>Price Path</td>
<td>Support Mechanism</td>
<td>General Treatment of CCS</td>
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</tr>
<tr>
<td>Shute Creek Gas Processing Facility</td>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>1986</td>
<td>Natural Gas Processing</td>
<td>7.0</td>
<td>Wyoming</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Started operating prior to any support mechanisms</td>
<td>N/A</td>
</tr>
<tr>
<td>Sinopec Qilu Petrochemical CCS Project</td>
<td>Define</td>
<td>Enhanced oil recovery</td>
<td>2017</td>
<td>Chemical Production</td>
<td>0.5</td>
<td>None</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>There are no specific legal frameworks or policies on CCS.</td>
</tr>
<tr>
<td>Sinopec Shengli Power Plant CCS Project</td>
<td>Define</td>
<td>Enhanced oil recovery</td>
<td>2018</td>
<td>Power Generation</td>
<td>1.0</td>
<td>Shangdong Province</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>There are no specific legal frameworks or policies on CCS.</td>
</tr>
<tr>
<td>Sleipner CO2 Storage Project</td>
<td>Operate</td>
<td>Dedicated Geological Storage</td>
<td>1996</td>
<td>Natural Gas Processing</td>
<td>0.9</td>
<td>Norway</td>
<td>Norway carbon tax/EU ETS</td>
<td>1991</td>
<td>52(upper limit) 3 (lower limit)</td>
<td>Currently under review?</td>
<td>CCS projects became feasible due to the tax involving 'gas sweetening' (removing CO₂).</td>
<td>Tax incentives in place through the SkatteFUNN Scheme</td>
</tr>
<tr>
<td>Snøhvit CO2 Storage Project</td>
<td>Operate</td>
<td>Dedicated Geological Storage</td>
<td>2008</td>
<td>Natural Gas Processing</td>
<td>0.7</td>
<td>Norway</td>
<td>Norway carbon tax/EU ETS</td>
<td>1991</td>
<td>52(upper limit) 3 (lower limit)</td>
<td>Currently under review?</td>
<td>CCS project became feasible due to the tax involving 'gas sweetening' (removing CO₂).</td>
<td>Tax incentives in place through the SkatteFUNN Scheme</td>
</tr>
<tr>
<td>South West Hub (formerly South West CO2)</td>
<td>Evaluate</td>
<td>Dedicated Geological Storage</td>
<td>2025</td>
<td>Fertiliser Production</td>
<td>2.5</td>
<td>Australia</td>
<td>Australia CPM (repealed)</td>
<td>2012N/A 2014</td>
<td>N/A</td>
<td>N/A</td>
<td>Federal and State governments have</td>
<td>Could receive Australian Carbon</td>
</tr>
<tr>
<td>Project Name</td>
<td>Project Lifecycle Stage</td>
<td>Primary Storage Type **</td>
<td>Operation Date</td>
<td>Industry</td>
<td>Capture Capacity (Mtpa)</td>
<td>Location: State/ Country</td>
<td>Carbon Price Regime</td>
<td>Regime Start Date</td>
<td>Carbon Price (US$/ tCO\textsubscript{2}e)</td>
<td>Price Path</td>
<td>Support Mechanism</td>
<td>General Treatment of CCS</td>
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<tr>
<td>Geosequestration Hub</td>
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</tr>
<tr>
<td>Spectra Energy’s Fort Nelson CCS Project</td>
<td>Define</td>
<td>Dedicated Geological Storage</td>
<td>2019 (Institute estimate)</td>
<td>Natural Gas Processing</td>
<td>2.2</td>
<td>Northeast British Columbia</td>
<td>British Columbia carbon tax</td>
<td>2008</td>
<td>23 (Nominal price on 1 August 2015)</td>
<td></td>
<td></td>
<td>committed $350 million of funding, with the bulk of this funding coming from the Australian Government through the CCS Flagships Program.</td>
</tr>
<tr>
<td>Teesside Collective Project</td>
<td>Evaluate</td>
<td>Dedicated Geological Storage</td>
<td>2020's</td>
<td>Various</td>
<td>2.8</td>
<td>United Kingdom</td>
<td>UK carbon tax / EU ETS</td>
<td>2013</td>
<td>28 (Nominal price on 1 August 2015)</td>
<td></td>
<td></td>
<td>Tax rate maintained at current levels for the foreseeable future. Tax influence not clear. Funds obtained from British Columbia government and Canada’s ecoEnergy Technology Initiative. CCS activities have tax exemptions or refunds.</td>
</tr>
<tr>
<td>Texas Clean Energy Project</td>
<td>Define</td>
<td>Enhanced oil recovery</td>
<td>2019</td>
<td>Power Generation</td>
<td>2.4</td>
<td>Texas</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Funding from the Clean Coal Power Initiative and the American</td>
<td></td>
</tr>
</tbody>
</table>

* CCS activities have tax exemptions or refunds.
<table>
<thead>
<tr>
<th>Project Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uthmaniyah CO2 EOR Demonstration Project</td>
</tr>
<tr>
<td>Val Verde Natural Gas Plants</td>
</tr>
<tr>
<td>White Rose CCS Project</td>
</tr>
<tr>
<td>Yanchang Integrated Carbon Capture and Storage Demonstration</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Project Lifecycle Stage</th>
<th>Primary Storage Type **</th>
<th>Operation Date</th>
<th>Industry</th>
<th>Capture Capacity (Mtpa)</th>
<th>Location: State/ Country</th>
<th>Carbon Price Regime</th>
<th>Regime Start Date</th>
<th>Carbon Price (US$/tCO₂e)</th>
<th>Price Path</th>
<th>Support Mechanism</th>
<th>General Treatment of CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>2015</td>
<td>Natural Gas Processing</td>
<td>0.8</td>
<td>Saudi Arabia</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>Recovery and Reinvestment Act. The Export-Import Bank of China is expected to provide a loan of over $1 billion.</td>
<td>Saudi Arabia, Norway, Netherlands and UK in 4-Kingdom initiative to help boost CCS and make it commercially viable</td>
<td>N/A</td>
</tr>
<tr>
<td>Operate</td>
<td>Enhanced oil recovery</td>
<td>1972</td>
<td>Natural Gas Processing</td>
<td>1.3</td>
<td>Texas</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Define</td>
<td>Dedicated Geological Storage</td>
<td>2020-21</td>
<td>Power Generation</td>
<td>2.0</td>
<td>United Kingdom</td>
<td>UK carbon tax / EU ETS</td>
<td>2013</td>
<td>28 (Nominal price on 1 August 2015)</td>
<td>Price changes annually, projections informed by EU estimates</td>
<td>Awarded funds through the NR300 funding mechanism of the EU ETS</td>
<td>Tax abatements in proportion to the level of CO2 abated for generating stations fitted with CCS tech.</td>
</tr>
<tr>
<td>Define</td>
<td>Enhanced oil recovery</td>
<td>2017</td>
<td>Chemical Production</td>
<td>0.4</td>
<td>Shanxi Province</td>
<td>None</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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</table>

** Note: **Primary Storage Type is marked as "**" to denote column title.
<table>
<thead>
<tr>
<th>Project Name</th>
<th>Project Lifecycle Stage</th>
<th>Primary Storage Type **</th>
<th>Operation Date</th>
<th>Industry</th>
<th>Capture Capacity (Mtpa)</th>
<th>Location: State/ Country</th>
<th>Carbon Price Regime</th>
<th>Regime Start Date</th>
<th>Carbon Price (US$/ tCO₂e)</th>
<th>Price Path</th>
<th>Support Mechanism</th>
<th>General Treatment of CCS</th>
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<td>Project</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>on CCS.</td>
</tr>
</tbody>
</table>

* N/A represents situations where either there is no carbon price regime in the jurisdiction or emissions that the CCS project would capture are not covered by the carbon price regime

** Note: Primary Storage Type of Dedicated Geological Storage relates to CCS projects that only store gasses underground, whereas Enhanced Oil Recovery relates to projects that pump gasses underground to store and to increase the economic benefit of already occurring oil/gas drilling.
B.2 Appendix Table References

**General references: Project List & Carbon Prices**


**China Project References**

**China Resources Power (Haifeng) Integrated Carbon Capture and Sequestration Demonstration Project**


Huaneng GreenGen IGCC Project (Phase 3); PetroChina Jilin Oil Field EOR Project (Phase 2); Shanxi International Energy Group CCUS Project; Shenhua Ningxia CTL Project; Shenhua Ordos CTL Project (Phase 2); Sinopec Qilu Petrochemical CCS Project; Sinopec Shengli Power Plant CCS Project & Yanchang Integrated Carbon Capture and Storage Demonstration Project


**Other Project References**

**Air Products Steam Methane Reformer EOR Project**


**Alberta Carbon Trunk Line (“ACTL”) with Agrim CO2 Stream &**

**Alberta Carbon Trunk Line (“ACTL”) with North West Sturgeon Refinery CO2 Stream**


Boundary Dam Carbon Capture and Storage Project


Caledonia Clean Energy Project


Carbon Capture and Sequestration Technologies @ MIT, 2015. Captain Clean Energy Project Sheet: Carbon Dioxide Capture and Storage Project. [ONLINE] Available at: https://sequestration.mit.edu/tools/projects/captain.html

CarbonNet Project


Coffeyville Gasification Plant

Don Valley Power Project


Enid Fertilizer CO2-EOR Project


Gorgon Carbon Dioxide Injection Project


Carbon Pulse. 2016. Climate Change Authority urges Australia to keep emissions trading option on table. [ONLINE] Available at: http://carbon-pulse.com/12637/


Hydrogen Energy California Project (HECA)


Illinois Industrial Carbon Capture and Storage Project

Kemper County Energy Facility (formerly Kemper County IGCC Project) & Petra Nova Carbon Capture Project (formerly NRG Energy Parish CCS Project)


Korea-CCS 1 & Korea-CCS 2


Carbon Capture and Sequestration Technologies @ MIT, 2015. Korea CCS 1&2 Project Fact Sheet: Carbon Dioxide Capture and Storage Project. [ONLINE] Available at: https://sequestration.mit.edu/tools/projects/korea_ccs.html


Lost Cabin Gas Plant


Peterhead CCS Project


Rotterdam Opslag en Afvang Demonstratieproject (ROAD)


**Shell Quest**


**Shute Creek Gas Processing Facility**


**Sleipner CO2 Storage Project & Snøhvit CO2 Storage Project**


**South West Hub (formerly South West CO2 Geo-sequestration Hub)**


Spectra Energy’s Fort Nelson CCS Project


Teesside Collective Project


Texas Clean Energy Project


Uthmaniyah CO2 EOR Demonstration Project


White Rose CCS Project


C ADDITIONAL PLOTS OF THE RELATIONSHIP BETWEEN CARBON TAX AND CCS FOR THE DIFFERENT SCENARIOS

C.1 Baseline scenarios

FIGURE 27: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR KUSILE RETROFIT FACILITY AS MODELLED IN SCENARIO 2 (2015 BILLION RAND PER YEAR)

FIGURE 28: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR SECUNDA CTL FACILITY AS MODELLED IN SCENARIO 2 (2015 BILLION RAND PER YEAR)
FIGURE 29: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR IGCC NEW BUILD FACILITY AS MODELLED IN SCENARIO 2 (2015 BILLION RAND PER YEAR)

FIGURE 30: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR MEDUPI RETROFIT FACILITY AS MODELLED IN SCENARIO 3 (2015 BILLION RAND PER YEAR)
FIGURE 31: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR KUSILE RETROFIT FACILITY AS MODELLED IN SCENARIO 3 (2015 BILLION RAND PER YEAR)

FIGURE 32: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR SECUNDA CTL FACILITY AS MODELLED IN SCENARIO 3 (2015 BILLION RAND PER YEAR)
FIGURE 33: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR USCPC NEW BUILD FACILITY AS MODELLED IN SCENARIO 3 (2015 BILLION RAND PER YEAR)

FIGURE 34: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR MEDUPI RETROFIT FACILITY AS MODELLED IN SCENARIO 4 (2015 BILLION RAND PER YEAR)
FIGURE 35: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR KUSILE RETROFIT FACILITY AS MODELLED IN SCENARIO 4 (2015 BILLION RAND PER YEAR)

FIGURE 36: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR SECUNDA CTL FACILITY AS MODELLED IN SCENARIO 4 (2015 BILLION RAND PER YEAR)
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FIGURE 37: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR IGCC NEW BUILD FACILITY AS MODELLED IN SCENARIO 4 (2015 BILLION RAND PER YEAR)

FIGURE 38: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR MEDUPI RETROFIT AS MODELLED IN SCENARIO 2 UNDER CARBON TAX SENSITIVITY A (2015 BILLION RAND PER YEAR)
FIGURE 39: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR CTL AS MODELLED IN SCENARIO 2 UNDER CARBON TAX SENSITIVITY B (2015 BILLION RAND PER YEAR)

FIGURE 40: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR MEDUPI RETROFIT AS MODELLED IN SCENARIO 2 UNDER CARBON TAX SENSITIVITY B (2015 BILLION RAND PER YEAR)
Figure 41 shows the impact of the reformulation of the carbon tax on the tax liability for CTL. As indicated previously, in this case a company can offset up emissions up to the total volume of its fugitive emissions (rather than combustion emissions). Given that the captured fugitive emissions are significantly lower than the combustion emissions, this restructure of the tax has little impact on the results.
FIGURE 43: CARBON TAX PAYABLE WITHOUT CCS (LEFT) AND COST OF CCS PLUS CARBON TAX PAYABLE WITH CCS (RIGHT) FOR CTL AS MODELLED IN SCENARIO 2 WITH A REFORMULATION OF THE CARBON TAX (2015 BILLION RAND PER YEAR)