2Co Targeted Report

Making the business case for CCS

November 2012

SUPPORTED BY

GLOBAL CCS INSTITUTE

Co-financed by the European Union

European Energy Programme for Recovery

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1. Introduction

A considerable number of companies and investors around the world have ambitions to create large-scale power plants with Carbon Capture and Storage (CCS). To do so on a sustainable model requires them to obtain a suitable return on their investment in order to accommodate the risks inherent in the technology. But CCS faces a key hurdle that, without sufficient intervention, is preventing development of CCS facilities and the emergence of a new industry. The cost of CCS facilities is not sufficiently covered by electricity sales revenue at current wholesale power prices anywhere in the world, nor is it covered by the ability to earn income from avoiding or reducing CO_2 emissions.

CCS investors, therefore, need to carefully build a suitable business case sufficient to meet the fundamental challenge of the mismatch between costs and revenues.

2Co Energy Limited (2Co) has written this knowledge product to share its real-life CCS business case for its CCS project in the UK, the Don Valley Power Project (DVPP), with the members of the Global CCS Institute. By sharing its business case in this way, 2Co hopes to provide practical information that can be of use to members of the Institute as they develop their own business cases for CCS around the world.

The report covers the following:

- A brief overview of 2Co and its CCS project in the UK, DVPP.
- A summary of existing business case-related knowledge products previously published for the Institute by other CCS projects, summarising the factors of most importance to their business cases.
- A description of the market and regulatory context for CCS faced by DVPP and other projects in the UK.
- A discussion of the financing challenge that 2Co faces and the resulting financing strategy.
- The resulting business plan, including revenue and cost profiles, sensitivities and prospects for future cost reduction.
- A description of the key risks to the project and mitigation plans.

2. Executive Summary

2Co Energy is a dedicated CCS company, aiming to utilise CO_2 captured in CCS facilities to produce more oil using Enhanced Oil Recovery (EOR) techniques. In the UK 2Co is developing the Don Valley Power Project (DVPP), a 920MW gross, 650MW net, pre-combustion CCS power plant at Stainforth in South Yorkshire. The CO_2 is then envisaged to be pumped to mature oil fields in the Central North Sea where it would be used to produce up to 150 million barrels of extra oil while being permanently stored at the same time.

Successful development of a business case for large-scale CCS projects is difficult and complex. A review of business cases published by other projects for the Global CCS Institute suggests several items that are important to success:

- Support in the form of capital grants from government
- Access to the revenue potential of EOR
- A CO_2 emissions price that incentivises CO_2 capture
- Government backed lending to reduce the finance burden for the project
- A premium power price to provide sufficient revenue to meet the additional costs of CCS

The market and regulatory environment in the UK provides additional context. A legislative requirement to drastically reduce climate change causing emissions has resulted in a government drive to enable CCS, and mechanisms put in place will provide capital grants, a CO_2 emissions price, and a premium power price. The UK is blessed with a number of large offshore oil fields suitable for EOR.

The financing required for DVPP is very significant, and this poses a significant challenge to the project despite the advantages of being in the UK market. It was concluded a mix of equity, debt and grant funding would be necessary to meet the challenge. As UK government backed lending is not available, the project aims to maximise the use of official sources of debt from other sources, for example the European Investment Bank. Various grants available to CCS from the UK government and EU can also be used (although 2Co was not successful in its application for a grant under the UK's recent CCS Commercialisation Programme). This leaves an acceptably sized equity requirement, potentially attractive to a range of investors, that would both deliver a suitable return and a competitive low-carbon power price.

The financing plan can be combined with the envisaged construction and operating parameters of the project to generate a cost and revenue profile for the project. This establishes that the three major sources of revenue; the UK wholesale power price, the power price premium that will be available to CCS in the UK market, and the revenue from oil production will together be sufficient to meet the costs of CCS and provide sufficient return to the investors.

However the risks to successful implementation of the project loom large and need to be addressed before investors will be confident enough to take a final investment decision. UK regulatory risk aside, the most important risks include changes to capital costs, delays in commissioning, changes in oil price, and challenges with decommissioning. Where investors are not willing to take these risks 2Co is working to mitigate them, for example by passing construction risk through to the EPC contractor.

If the financing and risk strategies are implemented effectively, and the UK government implements its planned regulations supporting CCS, 2Co is confident that DVPP can be one of the first successful large-scale CCS projects to be built in Europe.

3. Overview of 2Co Energy

3.1. History of the business

2Co Energy is a UK-based energy company formed by two senior energy industry executives, Gareth Roberts and Lewis Gillies.

Gareth Roberts is the founder and the former CEO of Denbury Resources International. Denbury takes naturally occurring CO_2 found in the Southern states of the USA and injects it into old oil fields. This CO_2 pushes extra oil out of the fields, in a process called Enhanced Oil Recovery (EOR).

Lewis Gillies is the founder and former CEO of Hydrogen Energy, a joint venture between BP and Rio Tinto. Hydrogen Energy, focused on CCS power projects in the UK, Abu Dhabi and California, planned to build facilities to convert coal or gas into hydrogen and CO_2.

TPG, one of the world's largest private equity companies, has invested in 2Co Energy to test the business model and is the major shareholder.

Many former employees of Hydrogen Energy and also from Denbury Resources have subsequently joined 2Co. The combination of the two company backgrounds brings a unique business model and unparalleled experience to the deployment of CCS.

3.2. Commercial strategy

2Co aims to use man-made $CO_{2,}$ initially envisaged to come from CCS projects at power plants, to profitably produce oil using EOR techniques while also storing the CO_2 permanently.

The 2Co team has considerable experience in building the business case for integrated CCS value chains. The core commercial team has built value chains for CCS projects in many different countries around the world and, through the successes and failures experienced, has built a valuable understanding of project features that can maximise the chances of success for CCS projects.

Having reviewed the prospects for CO_2 EOR around the world, 2Co considered that the UK North Sea would be an attractive opportunity for development.

Since the 1970s the UK has produced more than 25 billion barrels of oil from North Sea oil fields, but production is now declining as the fields age. Some eight billion barrels of oil remain, but if CO_2 were injected into the old fields it is estimated that up to another eight billion barrels of extra oil could be produced. Using CO_2 to produce extra oil in this way is routine in North America, and has been studied in the North Sea since the late 1970s. All that has held back its development has been the lack of a supply of CO_2.

2Co's core carbon capture project is the Don Valley Power Project (DVPP), a planned 920MW gross, 650MW net low carbon power plant in the village of Stainforth, near Doncaster in Yorkshire, England. Described in more detail in Section 4 below, DVPP will convert two million tonnes per year of coal into hydrogen, which will be burned to create low-carbon electricity. It will also create nearly five million tonnes of CO_2 a year, which will be transported more than 300km along a pipeline to the Central North Sea offshore Scotland, where it will be stored safely and permanently in mature oil fields. Here, EOR techniques will be used to push out up to 150 million barrels of extra oil, with the facilities potentially able to accept CO_2 from other sources for storage even after DVPP reaches the end of its life. National Grid, which will be transporting the CO_2, is also developing a potential secondary storage option in deep offshore saline formations that could be used by either DVPP or other CCS projects under development in the region.

DVPP is the recipient of European Union funding under the European Energy Programme for Recovery (EEPR) scheme. This scheme provides €180m of funding for development of the power plant, the CO_2 pipeline, the EOR project and storage options. This funding will meet the majority of the project's development costs until the end of 2013.

3.3. Ownership structure

2Co Energy has a number of subsidiary companies, the principal ones relating to development of its UK project being 2Co Power (Yorkshire) Limited (2Co Power) and 2Co Oil Limited (2Co Oil). 2Co Power focusses on developing the power plant and carbon capture facility. 2Co Oil concentrates on developing 2Co's CO_2 storage with EOR project in the UK Central North Sea. Having two separate companies allows each to focus on the unique commercial challenges faced by the different parts of CCS. It also allows each to adopt its own funding strategy, as the funding strategy (and equity partners) most suitable for a power plant are different to those for an offshore oil development.

The ownership structure is discussed in more detail in Section 7.6 of this report.

The transportation of the CO_2 from carbon capture facility to storage site is to be provided by National Grid, the operator of the UK's gas transmission network, as discussed further in Section 6.4.1 of this report.

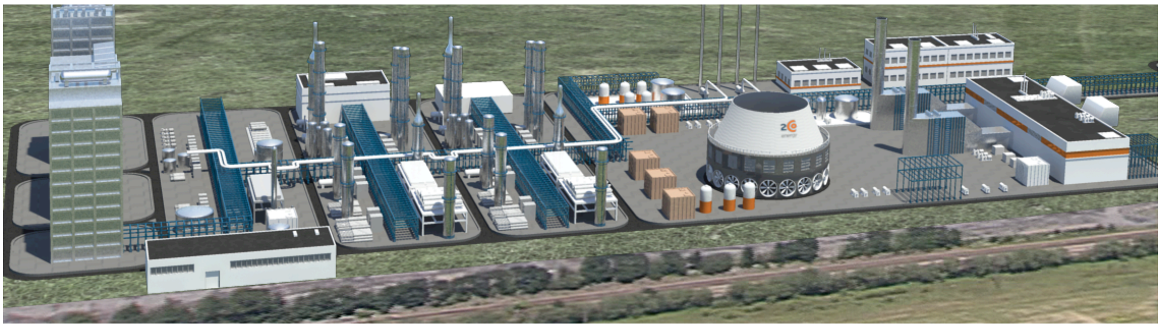
Figure 1: Ownership Structure

4. Overview of Don Valley Power Project

4.1. Description of the project

The Don Valley Power Project (DVPP) is a new-build industrial-scale Integrated Gasification Combined Cycle (IGCC) plant with CO_2 capture facilities. It will include twin train coal gasification and capture process units, together with a Combined Cycle Gas Turbine (CCGT) plant with a total capacity of around 920MW gross, 650MW net. A rendering of DVPP is shown in Figure 2, while a Block Diagram of the process is shown in Figure 3. This size of plant was selected to take advantage of economies of scale, integration efficiency, and technology development to deliver an asset that can operate as competitively as possible in the electricity market. Its size also means it can provide sufficient volumes of CO_2 to enable a viable Enhanced Oil Recovery (EOR) project alongside CO_2 storage in the North Sea. Although realising efficiencies of scale on a per unit of production basis, this large size does pose challenges in terms of the absolute level of funding required, both in terms of providing sufficient debt and equity, and in terms of accessing grant funding from government. This tension between grant funding available and optimum plant size is a recurring issue with the largest CCS projects, and how DVPP's business case was developed to minimise grant funding is described in more detail later in this report.

Figure 2: Don Valley Power Plant rendering



The Project will capture 90% or more of the carbon in the coal as CO_2, or up to 5 million tonnes of CO_2 per annum once in the mature stage of operations, capturing about 95 million tonnes in total over its expected 20 year life.

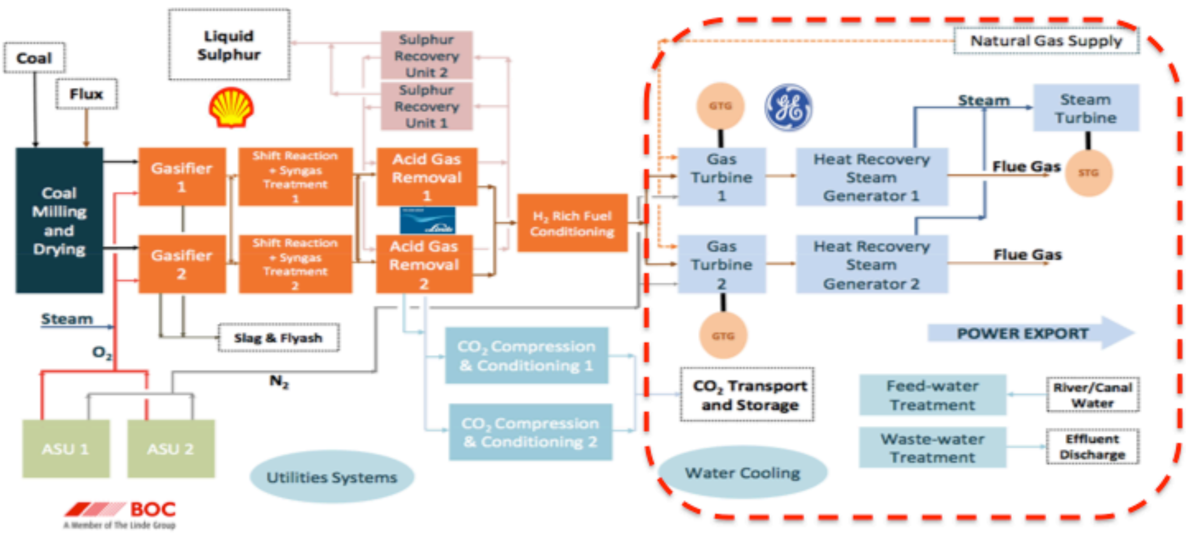
The Front End Engineering Design (FEED) for DVPP was completed in 2009 and the planning permission (Section 36 consent) has been awarded by the Government. DVPP has also obtained primary utility connection agreements for electricity, gas and water.

2Co holds Technology Licenses (with performance guarantees) and Engineering Service Agreements for all key component technologies:

- Shell for the Gasifiers,
- Linde for Acid Gas Removal (AGR),
- Worley Parsons for the Sulphur Recovery Unit (SRU).

A Value Assurance FEED (VAF) contract has been placed with Samsung C&T Corporation to complete a refresh on the FEED package to further refine costs and schedule. The VAF will provide more accurate capital cost numbers for the project, and will be followed by an EPC contract with Samsung Construction and Trading. Similarly, a VAF contract is being placed with Linde to complete an update of the Air Separation Unit (ASU) scope, schedule and cost.

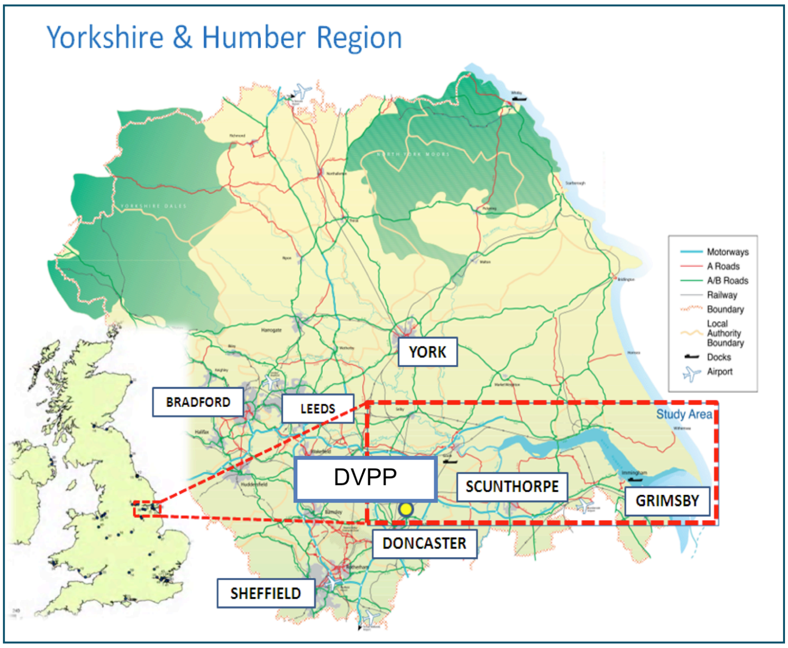
Figure 3: DVPP Block Diagram



About 18% of the UK's CO_2 emissions are within a 60 kilometre radius of the site in the Yorkshire and Humber area; the largest concentration of power and industrial emitters in the UK. As such, DVPP potentially enables the prospect of accelerated, lower-cost CCS deployment at nearby facilities, which could make use of the transportation and storage infrastructure established to serve DVPP.

The location of DVPP within the Yorkshire and Humber cluster of emitters is shown in Figure 4.

Figure 4: DVPP in Yorkshire and Humber Region



4.2. Progress to date

The project was launched by its original owners, Powerfuel plc, in 2006. FEED was undertaken and completed in 2009 and planning permission was granted for construction of the facility in the same year.

Also in 2009, DVPP won a competition to become the recipient of European Union funding under the European Energy Programme for Recovery (EEPR) scheme. This scheme provides €180m of funding for development of the power plant, the CO_2 pipeline, the storage with EOR project and the saline storage project. This funding will meet the majority of the project's development costs until the end of 2013.

In 2011, 2Co acquired the project, and began undertaking value assurance on the FEED package. DVPP was also entered into the European Union's New Entrant Reserve 300 (NER300) competition for financial support for CCS projects. It was the top listed project in this process when the shortlist was announced in mid-2012.

In mid-2012 DVPP applied for funding under the UK Government's CCS Commercialisation Programme. In October 2012 it was announced that DVPP would not be awarded funding under this programme, and that as a result the UK was also notifying the European Commission it would not be co-funding DVPP under the NER300 programme.

Development work on the CO_2 pipeline was begun by National Grid Carbon following award of EEPR funding. A route corridor was chosen in 2011 and permitting work is underway on the selected route for the onshore part of the pipeline.

4.3. Activities to completion

Once the value assurance FEED work is complete and funding is in place, a Final Investment Decision will be undertaken. It is anticipated that this could occur as early as the end of 2013. At the same time this will be followed by a period of site preparation. Site preparation works are scheduled to start during 2013 and construction of the DVPP plant itself will take approximately 36 months. Once construction is complete, initial commissioning and testing will take 6 to 9 months. The power plant will initially be commissioned and tested on natural gas. Syngas from the gasifiers will then be introduced in a controlled manner until steady-state operation is achieved.

On the basis of the current project timeline the expectation is that operations will start in early 2017. A degree of phasing of both commissioning, testing and operations will be required to ensure safe and effective start-up and operation of the full chain of capture, transportation and storage.

5. Business Cases in existing Global CCS Institute Publications

5.1. Global CCS Institute Publications

Before setting out the business case for 2Co's Don Valley Power Project, it was considered worthwhile to review the business cases of other well-advanced CCS projects around the world. Some of these cases are summarised here, in order to enable 2Co's business case to be compared against them, to highlight the similarities and to identify any differences.

Numerous members of the Global CCS Institute have published useful reports ('Knowledge Products') covering aspects of building a business case for CCS. The reports have often been published as a result of funding agreements agreed between the Institute and the projects, and they are all freely available online at the Institute's website, http://www.globalccsinstitute.com/publications.

2Co reviewed the published reports and identified several that contained information relevant to this report. Listed in Table 1, these reports are from projects in North America and Europe, and are all from CCS projects that are, or were, at an advanced stage of development.

Table 1: Global CCS Institute Business Case Knowledge Products

Report title	Published
AEP Mountaineer CCS business case report	22 Feb 2012
Project Pioneer: An overview of federal and provincial regulatory frameworks and gaps that guide and affect implementation of CCS	18 Apr 2012
ROAD project: Handling and allocation of project risks	17 May 2012
Rotterdam CCS Network Project: Case study on Lessons Learnt	18 Apr 2012

2Co also reviewed the 2012 'Global Status of CCS' report, published by the Global CCS Institute in October 2012. The 'project views' section of this report contains information from the Institute's regular surveys of projects, and provides input into which policy instruments are considered by projects to contribute best to the CCS business case.

5.2. Content of reports

5.2.1. AEP Mountaineer CCS business case report

The report describes how the AEP Mountaineer CCS project, which was to be a 235MW post-combustion capture facility on the 1300MW Mountaineer power plant in West Virginia, USA, went about constructing its CCS business case. Economic modelling identified the key challenge to the business case was a substantial gap between costs and the revenues available to the project as a regulated utility. (As a regulated utility AEP faced additional requirements, for example that the underlying power plant's output could not be lost, even temporarily, as a result of installation of the CCS equipment.) The report lists the potential solutions AEP identified. Unfortunately, the identified solutions were not available to the project, so it was shelved in early 2011.

The solutions AEP considered were as follows:

- Identify potential revenue generating uses for the captured CO_2. EOR was considered the most promising option, but even if the CO_2 were to be sold for $40/tonne, it would not be sufficient to raise revenue enough to provide an adequate rate of return.
- Reduce capital costs via capital grant. AEP won a grant under the US Department of Energy's Clean Coal Power Initiative, which covered 50% of costs. This greatly reduced the requirement for additional funding from other sources. However, in order to generate sufficient return to AEP the grant would need to cover 80% or more of costs if it was to be the sole source of additional funding.
- Reduce the project's required rate of return via borrowing. Given the riskiness of the technology and the challenging financing environment, it was considered that government-backed loan guarantees would be the only way to enable this borrowing.
- Increase revenue via rate recovery in the regulated power markets in which AEP operates (Virginia and West Virginia). With a federal mandate to reduce CO_2 emissions, AEP believed this would be possible. Without a mandate, however, their request for rate recovery was refused.

So while AEP was unfortunately unable to obtain the support necessary to build the Mountaineer CCS project, it did identify four important aspects to building a CCS business case: EOR revenue, capital grants, government-backed lending, and a premium power price.

5.2.2. Project Pioneer: 'An overview of federal and provincial regulatory frameworks and gaps that guide and affect implementation of CCS'

Project Pioneer was a CCS project planned to be built at the Keephills power plant near Edmonton, Alberta, Canada. It was to be a post-combustion facility capturing 1 million tonnes of CO_2 per year and utilising it for EOR. The project was cancelled in early 2012 when it was judged that the revenues available from CO_2 mitigation and sales were not sufficient to cover the cost of construction.

One of the reports Project Pioneer prepared for the Global CCS Institute was a report on the regulatory framework being developed for the project, and the gaps remaining to be addressed. While the bulk of the report does not directly address the topic of building the CCS business case, it did point out important pieces of the regulatory framework that, if filled, can at least partly bridge the gap between costs and revenues for CCS:

- The implementation of a climate change strategy by the province of Alberta in 2008 resulted in a clear vision for the deployment of CCS through to 2050 and resulted in the implementation of a number of helpful initiatives. In particular, a C$2 billion CCS funding program, and the associated Carbon Capture and Storage Funding Act 2009, provided Project Pioneer with a capital grant sufficient to cover the majority of the projected capital costs for their facility.
- In late 2011 the federal government announced national greenhouse gas emissions reduction initiatives. It is possible that, once fully in place, these initiatives would mean the sequestration of CO_2 would have direct value, whether via a carbon credit scheme or avoidance of tax, which would either increase the revenue or decrease the cost of CCS facilities like Project Pioneer. However, there was too much doubt over the ultimate nature of this regime for it to provide a sufficiently strong signal for Project Pioneer's backers to proceed.

The report therefore identified two aspects of a CCS business case: the helpfulness of a capital grant, and the potentially beneficial effect of attaching value to CO_2 emission reductions.

5.2.3. ROAD Project – 'Handling and allocation of business risks'

ROAD (Rotterdam Opslag en Afvang Demonstratie project, or Rotterdam Storage and Capture Demonstration Project) is a project to fit 250MW of carbon capture to a 1100MW power plant in the port of Rotterdam in the Netherlands. As part of the project's funding agreement with the Global CCS Institute it published a report addressing its business risks and how these are being mitigated. The report consequently addresses a number of issues of importance to the topic of building a CCS business case.

As the project is a retrofit of an existing coal-fired power plant, there is no incremental power revenue to meet the costs of CCS. As the project is storing CO_2 in a depleted gas field, there is no revenue from CO_2 use. Consequently the project is depending on development and capital funding support from the European Commission and the Netherlands Government. The project also relies on the value of preventing CO_2 emissions under the rules of the EU Emissions Trading Scheme (EU ETS), in which a requirement to purchase allowances for emitting CO_2 is avoided when CO_2 is stored.

The risks ROAD identifies in the report are risks to these lines of support for the project:

- A likely requirement for the host power plant to co-fire significant amounts of biomass reduces the proportion of stored CO_2 considered 'avoided', as the proportion of CO_2 from biomass is not included as CO_2 emitted for the purposes of the EU ETS.
- EU rules require the project to provide a financial security in the event of a leak of CO_2 from the storage site, with the size of the security increasing as the value of allowances under the EU ETS rises. The obligation only ends 20 years after CO_2 injection stops. This requirement also reduces the value the project gains from reducing CO_2 emissions under the EU ETS.
- The Netherlands government, struggling to meet its goal for renewable energy generation, could penalise thermal power generation and divert support to renewables, both reducing the direct financial support provided to ROAD and rendering its host power plant less competitive.

In summary, therefore, the report identified two key tools to enabling a CCS project to succeed, government capital support and a CO_2 price incentivising the reduction of CO_2 emissions, while at the same time highlighting risks to the effective use of these tools.

5.2.4. 'Rotterdam CCS Network Project: Case study on Lessons Learnt'

The Rotterdam Climate Initiative (RCI) was founded in 2006 and comprises 18 major companies working with local and national government and regulators to create a CCS infrastructure network throughout the Rotterdam area, the Rotterdam CCS Network Project. As this Project is considered to be a successful example of co-operation, the Global CCS Institute and RCI agreed to prepare a report on lessons learnt, for the benefit of other regions around the world considering working to develop CCS in the same collaborative way. The lessons learnt report contains some interesting insight into the CCS business case.

When summarising the reasons why the RCI was created, the document lists the several business case advantages of developing a cluster of CCS projects:

- Economies of scale from shared infrastructure;
- Multiple participants can help each other through development challenges and ultimately drive specialisation;
- Accelerates deployment for smaller or niche capture projects that might not be able to bear the costs of transport and storage on their own;

- Ultimately enables a larger amount of CO_2 to be stored, increasing the strategic attractiveness of CCS in the region to government, and increasing the likelihood that government support will be forthcoming.

The report also briefly describes how the RCI identified that a CCS 'market space' needed to be created for the new technology to develop, in order to avoid being out-competed by existing power generation technologies. This resulted in the RCI advocating a policy plan to obtain funds for CCS from the EU and the Netherlands government in 2008-2009.

This RCI Case Study report, therefore, identifies two aspects of a CCS business case; the benefits of a cluster of projects, and the importance of support from government funding.

5.2.5. Tenaska Trailblazer: 'Bridging the commercial gap for Carbon Capture and Storage', and 'Financing a new pulverized coal plant with post combustion carbon capture'

Tenaska Trailblazer is a planned new 600MW net coal power plant with post-combustion carbon capture on the full plant capacity, in Nolan County, Texas. As part of a project funding agreement with the Global CCS Institute, Tenaska produced two reports covering the topic of its CCS business case.

The first, 'Bridging the Commercial Gap for Carbon Capture and Storage', was published in mid-2011. It summarises the key financial challenge facing the project; higher costs and lower output compared with a typical new build thermal power plant in the Texas power market. The report considered three key routes to bridging the commercial gap in order to secure the business case for construction:

- Electricity revenues. In the market into which Tenaska would sell its electricity (the ERCOT market) there are no incentives to generate low-carbon electricity, so there was no opportunity to bridge the commercial gap here.
- Enhanced Oil Recovery. The plant's site is ideal for CO_2 export to the Permian Basin, the most mature EOR province globally. CO_2 sales would bridge a large portion of the commercial gap.
- Government Support. The project benefits from local government tax exemptions, and some significant credits from the state of Texas. The only federal benefit the project would have access to is a tax credit for CO_2 storage, which is problematic as it only applies to the first 75 million tonnes of CO_2 stored at any project nationwide, and is therefore not a certain source of value.

Had the federal government introduced further support, for example a cap and trade scheme for CO_2 emissions, then the commercial gap would likely be bridged entirely. Tenaska has also sought direct government grant funding to bridge the gap, including via trying to achieve re-allocation of grants from cancelled projects, but has not yet been successful. Tenaska consider that such government support is vital; in the absence of action, the project requires an increase in either power prices or CO_2 prices before it can proceed.

The second report, 'Financing a new Pulverized Coal Plant with Post Combustion Carbon Capture', took the output of the first report and added the further question of financing. Tenaska, like many Independent Power Producers, plans to debt finance the project in order to meet its required rate of return. This adds numerous additional commercial requirements to the project:

- The first-of-a-kind nature of the facility means operating as a merchant plant would not be financeable, therefore the project requires long-term offtake agreements for power and CO_2, and long term agreements for water, waste water, fuel supply and operations.
- Importantly, the project needs the participation of a highly qualified, creditworthy technology provider and EPC contractor (in Trailblazer's case, Fluor fills this role).

- The CO_2 storage site must be considered to be safe. In Trailblazer's case, storage in the Permian Basin would fulfil this requirement given the history of CO_2 EOR there.
- While the first report concluded that additional federal support would bridge the commercial gap, the second report concludes that the exact type of federal support is also important for financing. The federal tax credit for CO_2 storage is too uncertain, for example, to be counted on as a revenue stream by lenders. Some other incentives that were considered by the administration during 2011 might have been more effective, but perhaps most useful would be access to federal loan guarantees.

The two reports by Tenaska, therefore, identify several important aspects required for their business case: government support (ideally via loan guarantees), EOR, long term supply and offtake agreements, and large and credible suppliers.

5.2.6. Global CCS Institute: 'The Global Status of CCS 2012'

The Global CCS Institute publishes a comprehensive annual review of the status of CCS globally. One of the aspects covered by this report are the views of the different large projects around the world on the CCS policy environment, collected from the Institute's regular survey of projects, and presented in the 'project views' section. Included in this section is a table listing the policy instruments that projects would most prefer to be in place. This list suggests carbon pricing is considered most preferable, and is followed by 'power purchase agreements, feed-in tariffs, up-front capital subsidies (such as grants or low-interest loans), access to viable storage solutions, and regulated returns (especially in the US where some projects will be operating in regulated electricity markets).' As this question in the survey only covered policy frameworks the list did not include some aspects considered important in the reports from the projects listed above, such as EOR revenue.

Included in the Global Status of CCS 2012 report is a chapter on the CCS business case, drawing from the global experience of the Institute's members .It is a valuable additional reference document to this one for those interested in the CCS business case.

5.3. Conclusions from Global CCS Institute reports

Together, the reports identified a number of common features to successful CCS business cases across the different projects. Table 2 below shows the frequency with which business case features occurred:

Table 2: Business Case Features in Reports

Business case feature	AEP Mountaineer	Project Pioneer	ROAD	Rotterdam Climate Initiative	Tenaska Trailblazer	Global CCS Institute survey
Capital Grant	✓	✓	✓	✓	✓	✓
EOR Revenue	✓	✓			✓	
CO_2 Emission Price		✓	✓			✓
Government backed lending	✓				✓	
Premium Power Price	✓					✓
Project Clustering				✓		
Tax incentives					✓	
Long term supply, offtake agreements					✓	
Large, credible suppliers					✓	
Viable storage solutions						✓
Regulated returns						✓

The most frequently identified element for CCS's business case is the importance of a capital grant from government, followed by the revenue benefits of utilising captured CO_2 for EOR. The value of government-backed lending, and the potential to benefit from a regime where CO_2 emissions are priced, were also mentioned more than once. But all features would ease the path to a successful business case for CCS.

2Co's Don Valley Power Plant faces many of the same challenges as the above projects. In order to create a successful business case, it is making use of a number of the same tools. This report will now turn to the Don Valley Power Plant and discuss the context and the business case in more detail.

6. Market structure and regulation

6.1. CCS developments to date in the UK

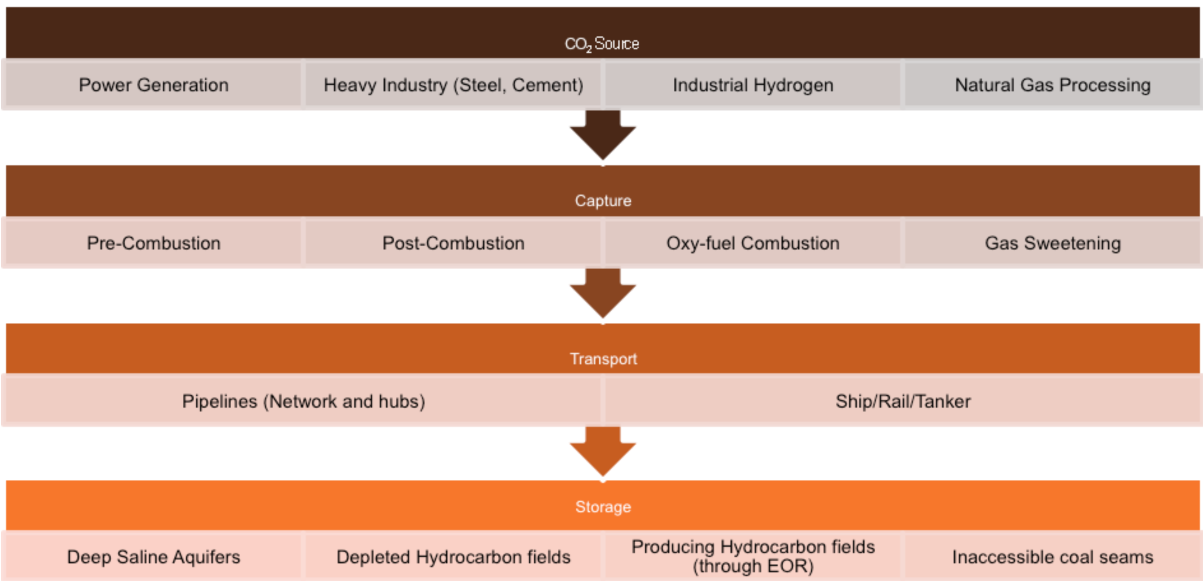
6.1.1. Brief history of CCS

CCS has become increasingly important to governments and regulators across the globe as a necessary option for reducing carbon emissions. There are currently seven operational fully integrated CCS projects worldwide, which are predominantly in the gas processing sector. The oldest of these, the Val Verde gas plant in the USA, has been operational since 1972, and a further two were commissioned in the 1980s. The majority of the projects are based in North America, with two projects (both in Norway) operational in Europe. As yet, there are no operational CCS projects in the power generation sector, although the Global CCS Institute has identified two such projects to be currently in construction (Boundary Dam and Kemper County) and within a couple of years of commencing operations.

Whilst further research and innovation will be necessary to reduce costs and improve the efficiency of future projects, the individual technologies required for commercial-scale CCS power projects have largely been proven (albeit in some cases within small-scale demonstration projects) and are ready to be built on an industrial scale. The IEA estimates 50% of the long-term potential for CO_2 mitigation worldwide lies in power generation[1], and so it is essential that there is commercial demonstration of the viability of CCS in power generation in the near future.

Figure 5 presents the industries and processes involved along the CCS value chain. Depending on the CO_2 source, the capture method may vary, but generally transport and storage methods can apply to any source type.

Figure 5: Components of CCS value chain



The application of CCS to power generation in the UK remains limited to small-scale demonstrations of individual components of the value chain (for example, Doosan Babcock Energy currently operates

1 BNEF: 'Leading the Energy Transition' 2012

the world's largest oxy-fuel combustion demonstration project at 40 MW_{th})[2]. However, as we set out below, there is the potential for at least one large[3] CCS power plant to be built in the UK to demonstrate the full process and its commercial potential.

6.1.2. CCS in the UK

The UK possesses a number of advantages that make it well suited for the integration and deployment of CCS:

- Proximity to the North Sea and its extensive potential storage capacity, as well as the prevalence of oil and gas fields available to make use of the CO_2 for EOR
- Pre-existing clusters of power and industrial plants which may be able to share CCS infrastructure, especially pipeline transportation networks and hubs
- Globally recognised expertise in the oil and gas industry, which will be useful for offshore CO_2 transport and storage
- A strong level of academic research and expertise to further develop the technology
- Political support both at a national and an EU level

However, there is no full-scale demonstration of a CCS chain currently in operation in the UK nor have any large projects reached FID (Final Investment Decision) to date. Small-scale demonstration of the technology exists across various industries, and commercial-scale CCS exists abroad, predominantly in North America, but with some dissimilarities from the form the industry is expected to take in the UK. We expand on these differences in Section 6.5.3.

6.1.3. Projects in the UK

There are currently six large CCS power stations being planned in the UK at various stages of development, as shown in Figure 6. The total capacity of these plants, if fully built, would be 2.7GW net. There may be the potential for developing clusters of CCS plants sharing certain facilities and a transportation network around certain geographical locations. Clusters may emerge first in the Yorkshire region populated by White Rose and DVPP, but potentially also further north around Teesside and in Scotland.

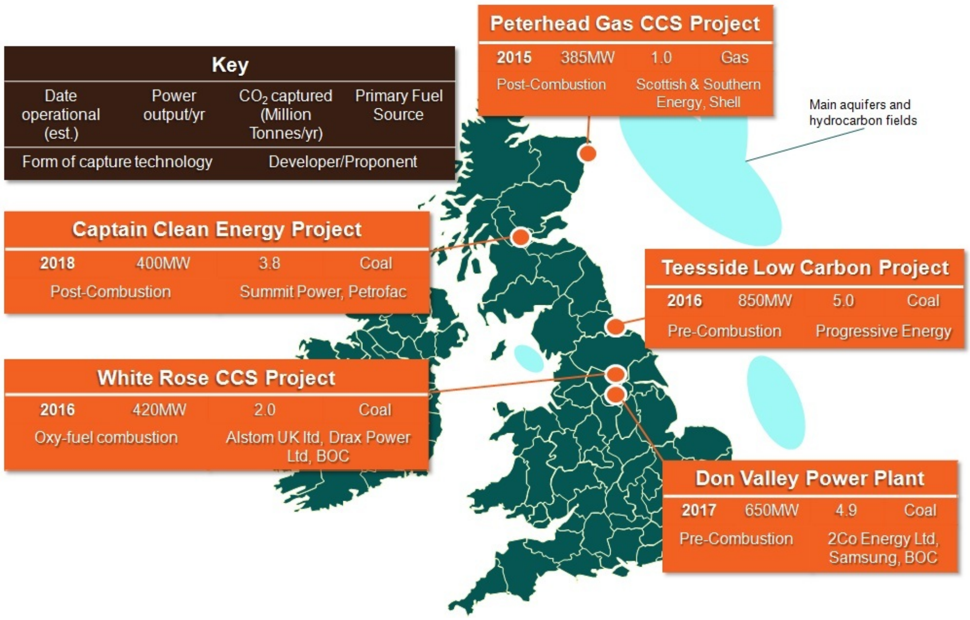
Global CCS Institute classification of development level		
1	**Identify**	Captain Clean Energy Project
2	**Evaluate**	Peterhead, Teesside, White Rose
3	**Define**	DVPP
4	**Execute**	No current developments
5	**Operate**	No current developments

Source: www.GlobalCCSInstitute.com December 2012

2 The Oxyfuel (Oxycoal 2) pilot project at Doosan Power System's Clean Combustion Test Facility in Renfrew, Scotland

3 BNEF define a large project as an integrated 'Source to Sink' project, with at least 0.6Mt CO2 stored a year

Figure 6: Proposed CCS projects in the UK



6.1.4. Problems encountered by projects that have not come to fruition

In recent years, as in all nascent industries, many CCS projects across the globe have been cancelled or suspended; the same is true in the UK. Two of the more notable projects are Longannet and Hunterston. Scottish Power's Longannet project was cancelled due to excessive costs[4] (despite a £1bn grant being on offer), while Peel's Hunterston development has been suspended following local opposition to the construction of what would have been a new coal power plant most of which would not have had carbon capture applied[5]. There are three key lessons to be learned from these cancelled and delayed developments:

- **Retrofitting old plants is costly and difficult** – which partly explains why all of the planned projects previously discussed are new-build or re-built power plants. The retrofitting of Longannet, for example, was eventually decided to be too costly. However, the Canadian Boundary Dam CCS project looks likely to complete the retrofitting of a coal fired power station in the near future in spite of these high costs, helped in no small part by a CA$240million payment from the Canadian government.

- **Adequate public funding is essential to the success of a project** – regardless of the technology solution, CCS power projects produce at a higher levelised cost of energy compared to existing unabated fossil fuel plants. Hence, all current projects rely on present or future grants or loans from government, the EU, and/or premium priced electricity sales contracts. No CCS projects in the power sector are expected to proceed in Europe at the present time without grant funding.

- **Public opposition can halt a project** – it is essential that the case for a new project is made effectively to the public in order for planning permission to be granted and for construction to proceed. This requirement was a substantial challenge faced by Peel's Hunterston development, a now-postponed CCS project in West Scotland.

4 http://www.bbc.co.uk/news/uk-scotland-scotland-business-15511590

5 BNEF: 'Leading the Energy Transition' 2012

These key lessons are mirrored across several other cancelled projects in Europe and across the globe.

6.2. UK Government energy policy

6.2.1. EU and UK targets

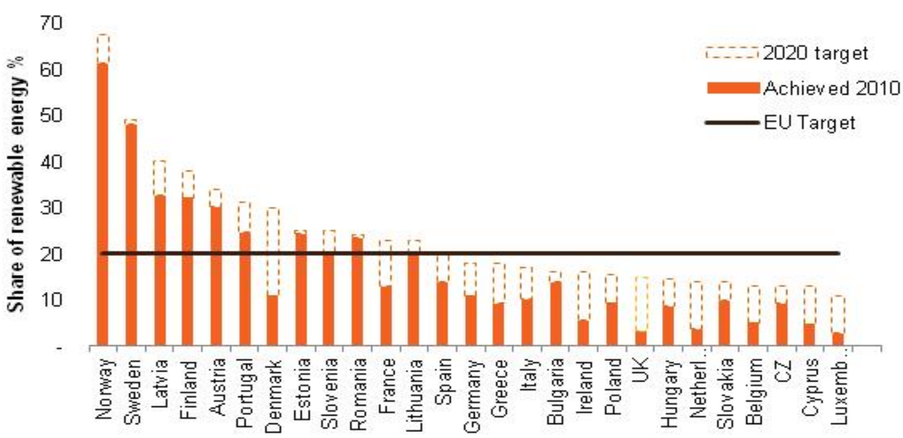
Energy policy since privatisation of the UK power generation and distribution sector in the early 1990s has seen the focus range across different policy instruments depending on the priorities of the incumbent government. Through this period two variables have remained a constant priority: security of supply and affordability.

1. The current wholesale markets have delivered security of supply, in the form of healthy capacity margins, predominantly through investment in gas fired plants.

2. The introduction of competition following privatisation and the liberalisation of energy supply markets has given the UK some of the lowest power prices in the EU.

Decarbonisation is now a key focus of energy policy in addition to security of supply and affordability, as shown in the 2011 Energy White Paper[6]. At an EU level, the target is 20-20-20: a 20% cut in emissions of greenhouse gases by 2020, compared with 1990 levels; a 20% increase in the share of renewables in the energy mix; and a 20% cut in energy consumption. The UK has been set its own target of 15% renewable energy by 2020, up from a baseline level of 1.5% in 2006. To achieve the 15% target, separate renewable energy targets have been set for renewable electricity (with 30% of total electricity generation to be sourced from renewable sources by 2020), renewable heat (c. 12% of total heating) and renewable transport (c.10% of total transport). Combined these are expected to deliver the 15% UK target. The UK lags behind the majority of Europe in terms of meeting its targets for renewable electricity shares, and to date the focus has been on renewables such as wind rather than CCS decarbonisation.

Figure 7: EU Member State performance against 2020 as a means of achieving renewables targets



While there are as yet no specific targets for Member States post 2020, it is likely that the drive to reduce emissions will continue as the European Commission (EC) has produced an Energy Roadmap (2011)[7] to reducing emissions over the coming decades. This mentions both the need to switch to unconventional energy sources and the role of traditional fuels in the transition to low carbon energy, but also includes some new initiatives. For example, following agreements at the Kyoto Protocol

6 Electricity Market Reform (EMR) White Paper 2011, DECC

7 EC Energy Roadmap (2011)

Durban meeting in 2011, CCS technology will be included in the Clean Development Mechanism (CDM[8]), and the technology can be incorporated in future market mechanisms to tackle emissions. The UK has also introduced specific carbon budgets[9], which specify a cap on the total quantity of greenhouse gas emitted over a specified time. It is the only country to do so, and the budgets will run to 2050.

6.2.2. The role of the Department of Energy and Climate Change in delivering energy policy

The principal role of government departments and their agencies is to implement government policy and to advise ministers. As such, the Department of Energy and Climate Change (DECC) will be responsible for implementing policies proposed in the Energy Bill to be introduced in late 2012. DECC has four key priorities, the first three of which relate to the decarbonisation and management of energy:

1. Deliver secure energy on the way to a low carbon energy future
2. Drive ambitious action on climate change at home and abroad
3. Manage the UK's energy legacy responsibly and cost effectively
4. To ensure that every home is adequately and affordably heated

The Office of Carbon Capture and Storage (OCCS), within the UK Department of Energy and Climate Change, was created to set the strategic path for the development and wide-scale deployment of CCS in the UK.

6.2.3. CCS and decarbonisation

Diversifying the generation mix can help ensure security of supply while reducing carbon intensity, however intermittent generation sources, such as wind, create a challenge to maintaining security of supply. CCS and biomass currently offer the best potential for baseload low carbon generation which will help grid operators offset some of the challenges of intermittent generation.

As the UK moves to decarbonise the economy an increasing amount of transport, heating and industrial energy must be met by electricity. According to DECC, in 2011 the UK consumed 1608 TWh of energy (1636 TWh in 2010), and the UK's demand for energy is expected to be 1566 TWh in 2020 according to the central government projections[10].

Despite progress towards reducing the carbon intensity of the electricity sector, the Committee on Climate Change (CCC), a statutory body created to monitor government progress towards meeting its statutory emissions reduction targets, has suggested that further reductions in the carbon intensity of energy sources compared to current baseline projections[11] are required. DECC has forecast that, due to a combination of increasing volumes of intermittent generation and the retirement of up to 20 GW of fossil fuel and nuclear power plants in the period to 2020, de-rated capacity margins will fall significantly from 2013, which supports the need for non-intermittent yet low carbon energy production in the UK.

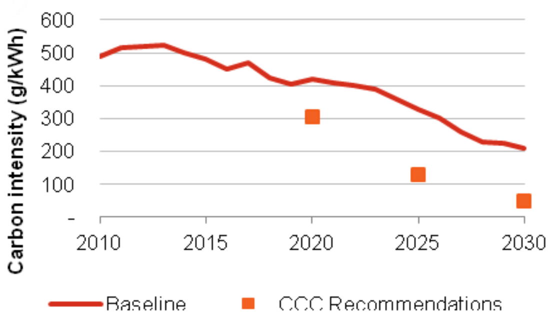
8 The CDM allows industrialised countries to invest in emission reductions wherever it is cheapest globally

9 The Climate Change Act 2008, more detailed planning in The Carbon Plan (2011), DECC

10 DECC UK Energy Roadmap http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/renewable-energy/2167-uk-renewable-energy-roadmap.pdf

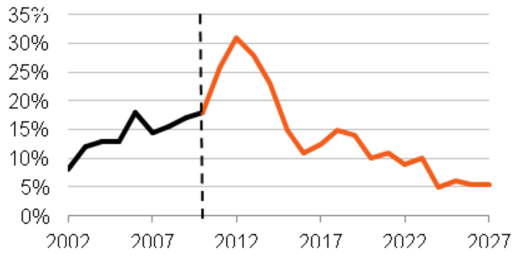
11 The CCC set out in its 2012 report that the carbon intensity of electricity supplied in the UK fell by 2% from 496 gCO2/kWh in 2010 to 486 gCO2/kWh in 2011, with a final carbon intensity goal of 50 gCO2/kWh by 2030

Figure 8: Electricity carbon intensity reduction path



Source: CCC with University College London

Figure 9: De-rated capacity margin forecast



Source: DECC

6.2.4. The role of UK Government in providing incentives for CCS

The UK Government considers that the current electricity market is unable to deliver the investment in low carbon technology necessary to meet targets whilst ensuring security of supply. The Technology Innovation Needs Assessment (TINA)[12], a study that aims to identify and value the innovation needs of low carbon technologies, estimates that electricity generation with CCS could deliver c.10-35% UK energy needs by 2050, saving the country hundreds of billions of pounds in system costs up to 2050 and establishing a UK industry which adds between £3-16 billion to GDP (narrowing this view, a North American sustainability consultancy AEA estimate this to be around £5bn)[13]. Consequently, Ed Davey, Secretary of Energy and Climate Change, has repeatedly indicated Government support for CCS, saying "CCS is a key part of our aim to reduce carbon emissions from gas and coal in our future energy mix[14]. As part of Government's commitment to achieving their aim of enabling industry to take investment decisions to build CCS equipped fossil fuel power stations in the early 2020s, April 2012's CCS Roadmap confirmed that the Government will:

- Create an electricity market that will enable CCS to compete with other low carbon sources;
- Launch a CCS commercialisation programme with £1bn of capital support, targeted specifically to learn by doing and to share resulting knowledge to reduce the costs of CCS such that it can be commercially deployed, without capital support, in the 2020s;
- Work closely with industry to reduce costs, including through the establishment of a CCS Cost Reduction Task Force;
- Remove barriers and obstacles to deployment;
- Develop the regulatory environment, including for the long-term storage of CO_2;
- Promote the capture and sharing of knowledge to accelerate deployment; and
- Help build a stable foundation by supporting private sector access to skills and developing the supply chain.

European efforts are also focused on CCS technology as a means to decarbonise energy. The New Entrant Reserve 300 (mentioned in Section 3.2 above) is a financing instrument managed jointly by the European Commission, European Investment Bank and Member States. The Emissions Trading Directive (Directive 2003/87/EC and amending Council Directive 96/61/EC) allows for 300 million allowances (rights to emit one tonne of CO_2) in the New Entrants' Reserve of the European Emissions Trading Scheme to be set aside for subsidising installations of innovative renewable energy technologies and CCS. The allowances are being sold on the carbon market and the money raised

12 Report: CCS in the Power Sector, 2012. AEA: Future Value of Carbon Abatement Technologies in Coal and Gas Power Generation to UK Industry

13 AEA: Future Value of Carbon Abatement Technologies in Coal and Gas Power Generation to UK Industry

14 Ed Davey, October 2011, speech in announcement of new £20million ETI project to develop and demonstrate CCS

will be made available to projects as they operate although, in the case of CCS, funding can be converted into a capital grant if the Member State agrees.

In addition to the CCS commitments set out above, the UK Government is reforming the electricity market. The reforms are designed to provide drivers for investment in low carbon and renewable technologies, while maintaining security of supply. In May 2012 a draft Energy Bill was published by the Secretary of State for Climate Change. This Bill was introduced to Parliament in late 2012 and is expected to complete its passage into legislation by the end of 2013. Electricity Market Reform (EMR), first published as a White Paper in 2011, is a key facet of the draft energy bill, putting in place measures to attract the £110 billion investment that is needed to replace current generating capacity and upgrade the grid by 2020..

6.3. EMR in the context of Don Valley Power Project

6.3.1. Key features of EMR

The Government's Energy Bill identifies four mechanisms that it believes will meet the three policy objectives of reducing emissions, security of supply and affordability.

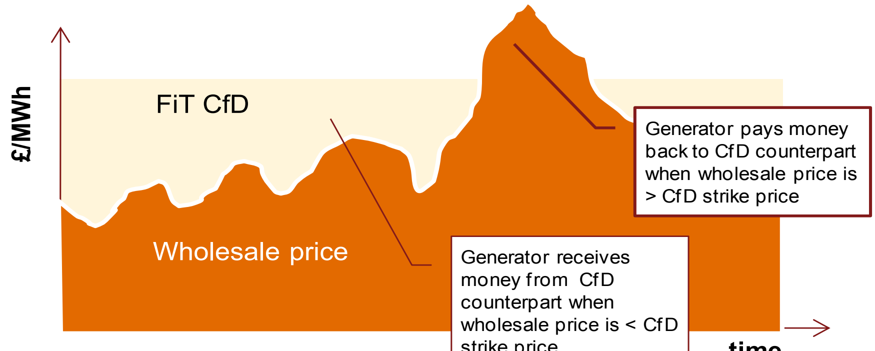
1. Replacing the Renewables Obligation (RO) scheme with Feed In Tariffs with Contracts for Difference (FIT CfDs);
2. A Carbon Price Support (CPS) Mechanism will create a higher carbon price than EU ETS;
3. The introduction of a capacity market to incentivise flexible plants; and
4. An Emission Performance Standard (EPS) to limit the emissions of new fossil fired generators.

6.3.2. CfD Mechanism

The means by which future low carbon and renewable plants will be remunerated is expected to change significantly if the 'preferred' set of proposed reforms is implemented. The Feed-in-Tariff (FIT) Contract for Difference (CfD) mechanism is the most important change in the context of CCS. The aim of this mechanism is to remove the power plant's exposure to volatile power prices and provide a stable revenue stream, at a level sufficient to allow CCS investors to achieve a reasonable risk adjusted rate of return. UK power prices look set to become even more volatile as the deployment of intermittent energy sources such as wind increase and cause large variations in seasonal energy supply over the coming decades. CfDs are thus likely to become a greater feature in the energy market reducing risk and uncertainty for CCS power generators such as the DVPP project. Key aspects of the FIT CfD include:

- Stabilisation of revenues for low carbon generators, changing the risk profile of investment and lowering the cost of capital (thus removing the exposure to volatile power prices);
- Under current proposals, from 2017 each low carbon or renewable technology will receive a fixed level of remuneration for each MWh of generation, payable via the FIT CfD mechanism. The FIT will vary depending on the generation source. Nuclear and CCS are included in the 'low carbon' definition;
- Under the CfD, generators sell their electricity into the market then receive a top-up payment or make a repayment (if electricity prices are higher than the agreed tariff); and
- The top-up payment or repayment is calculated as the difference between the reference market wholesale price and the agreed tariff level, as set out in Figure 10 below.

Figure 10: Revenue composition for low carbon generators under the proposed FIT regime



Source: EMR Consultation Document

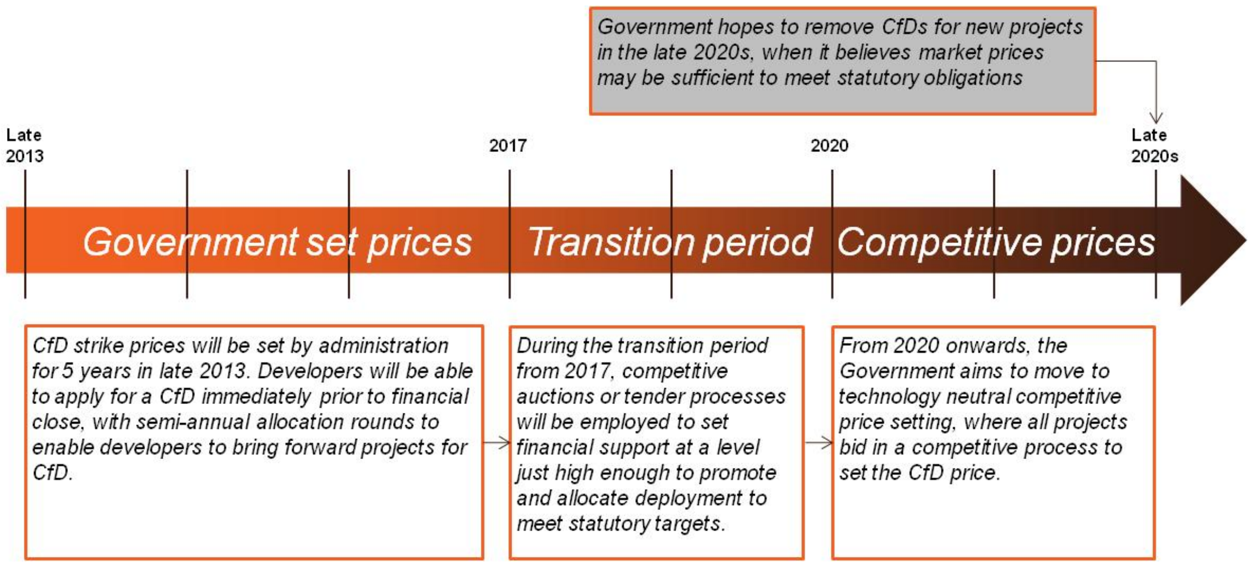
Future projects under the CfD will receive settlement payments from suppliers (under one of the proposed payment models) similar to the arrangements under the UK's existing Balancing and Settlement Code (BSC). However, in response to concerns from certain industry stakeholders, government has since introduced proposals for an alternative payment model for further consultation. In either model the CfD Strike Price is fixed for a set period of time.

Table 3: FIT CfD model options

Model 1: Statutory payment model	Model 2: Alternative payment model
• Contracts for Difference (CfDs) as a statutory instrument with obligations on numerous parties • Settling payments will be facilitated by an agent	• The alternative payment model seeks to address industry concerns relating to the multiparty contract approach under the preferred payment model • Key issues include: ownership structure, clarity on roles/functions and CfD funding

The Government intends to use a phased approach to the introduction of CfDs:

Figure 11: CfD introduction



However, under the CCS commercialisation programme, early projects such as DVPP will require the level of financial support under a CfD to be set ahead of the above timetable in order to facilitate the necessary revenue projections before the project reaches its final investment decision. 2Co will therefore require a process of early bilateral negotiations with DECC to negotiate the CfD level to be applied when the project commences operations in 2017.

6.3.3. EMR impact on DVPP

The aim of the EMR process is to deliver the investment in low carbon technology that is required to decarbonise the UK economy whilst ensuring a secure and affordable energy mix. As the UK transitions towards a low carbon power sector there will be an impact on the wholesale power price, driven by the generation mix.

In terms of specific CCS developments, EMR will provide each form of low carbon electricity with a FIT CfD set at a level that will enable developers to determine whether they wish to invest. In their CCS Roadmap, DECC consider that the greater revenue certainty provided by the FIT CfD should lead to developers being able to reduce the costs of financing their investments. Further, EMR will exempt power stations with CCS from the Carbon Price Floor, (which is a mechanism that will set a minimum price for CO_2 emissions allowances within the UK) in proportion to the CO_2 captured and stored. EMR will also exempt CCS projects from the Emissions Performance Standard proposed in the Energy Bill where they are supported under the commercialisation programme[15].

6.3.4. CfD uncertainties

Whilst the exact form of the eventual CfD is yet to be finalized, the Government has highlighted a number of emerging proposals set to ensure that the CfD functions effectively for CCS. These are outlined in Table 4.

Table 4: CfD terms as outlined in EMR[16] and identified uncertainties

Term	Description	Emerging Proposal	Uncertainty
Reference Price	The market price for electricity that is referenced in the CfD for the purpose of calculating CfD payments.	Baseload: Year Ahead, price source to be determined.	It is not clear that a baseload index will be optimal for a project in the earlier years when commissioning and operating risk is higher.
CfD Volume	The volume of electricity for the purpose of calculating CfD payments	Pay the CfD on the basis of metered output unless the price in the reference market is negative, in which case to pay on a measure of availability.	Again, in the early years of operation, a measure using deemed generation may be better for the project developer, when output is uncertain.
Fuel price indexation	Arrangements for adjusting the CfD in order that payments reflect a generator’s input fuel costs.	The CfD should provide indexation appropriate to hedge against long-term fuel price variability.	It will be important to have consistency between the duration of the reference price index (e.g. 1 year ahead) and the duration of the coal price index, to avoid basis risk for the project.
Allocation of supplier payments	How suppliers’ payment obligations / entitlements are calculated.	Base suppliers’ payment obligations on market Share.	This is likely to be superseded with a revised payment model.
Settlement	Process and timing for invoicing and administering CfD payments.	Settlement periods will be at most one month.	While monthly settlement is consistent with current UK market arrangements, a shorter settlement cycle will reduce collateral requirements.

15 UK CCS Commercialisation Plan, DECC – launched April 2012

16 EMR, DECC – Annex B: Feed in Tariff with contracts for differences

CfD Length	The length of the CfD from the payment start date	For any CCS project under the Commercialisation Program, the length looks likely to be 10 years (subject to negotiations). Nuclear and long-term CCS equipped plant CfD lengths are yet to be determined.	The shorter the CfD duration, the greater the required headline price. The preference would be to have the contract length better match the asset life, e.g. 20 years.
Inflation Indexation	Arrangements for adjusting the CfD strike price in line with inflation.	Choose CPI as a standardised and established inflation measure.	The risk for the projects is that actual costs move relative to another reference point e.g. RPI.
Credit and Collateral	The requirements on generators and suppliers to provide credit / collateral.	Place a collateral requirement based on an estimate of likely settlement amounts due in a given trading (settlement) period.	See comment on 'Settlement'.
Amendment of the reference price and other CfD parameters	The arrangements for amending CfD parameters in response to changes in trading arrangements which change or render variable definitions invalid.	Include an 'independent expert' role in the CfD framework to manage any review of CfD parameters and determine any amendments required.	The market has managed these types of risk historically in previous long-term power contracts.
Change in Law	Arrangements for adjusting the CfD in response to relevant changes (e.g. regulatory) that materially affect the value of the CfD to either party.	In principle the CfD should contain change in law provisions, the form and scope of which remain to be determined. Further detail will be known when the bill is published.	If the CfD cannot adjust to law changes, it risks adversely affecting parties by changing the terms of the agreement
Dispute Resolution	Procedures for resolving any disputes arising under the CfD.	The Government will seek further legal advice in this area before engaging with stakeholders.	Without proper resolution procedures, there is a risk of wider market disturbance during disputes

6.4. Transportation and storage environment

The London-based industry group, the CCS Association (CCSA), has argued[17] that the benefits of over-sizing initial CCS transport and storage infrastructure are clear, in the form of lowering unit costs for subsequent projects. Private companies are however reluctant to invest in over-sizing due to uncertainty around the risk-reward balance in the absence of a clear and robust long-term CCS policy in the UK and a commitment from Government to share the financial risks involved.

6.4.1. Transportation

The development of the infrastructure necessary to transport and permanently store CO_2 is one of the key challenges for a CCS project. However, the UK's history of a monopoly-provided gas transmission network infrastructure provides an opportunity for National Grid, the owner of this infrastructure, to use its scale and experience to expand its areas of service provision to the CO_2 market.

National Grid's role in the gas network is to manage and maintain the existing and future infrastructure, and optimise the system for its end users. As a business licensed by the UK's electricity market regulator Ofgem, National Grid also has statutory powers, such as the right to bury their pipes under public highways and the ability to use compulsory powers to purchase land to enable the conduct of their businesses.

17 CCSA: Carbon Capture & Storage in the UK Our Key Messages in Brief (ccsassociation.org)

For DVPP, National Grid Carbon (NGC) will provide the transport infrastructure necessary to deliver captured CO_2 to the offshore storage facility. Specifically, they are responsible for the design, construction and operation of the CO_2 transportation system from the DVPP site boundary to the riser inlet of the injection platform offshore.

There are benefits to NGC arising from the DVPP project being in the centre of a potential cluster of projects, such as the White Rose CCS Project that can be served by one large pipeline rather than multiple smaller ones. NGC expects that clustering could reduce costs, as a single storage site and backbone pipeline could then serve multiple emitters. According to NGC, a clustered transport system could save over 25 per cent of expenditure on a unit basis compared to a point-to-point system, depending on the scale of the cluster. This reduces barriers to future investment and increases the speed of deployment. It also opens up the opportunity to connect small emitters for whom point-to-point solutions may be too expensive.

The regulation and policy of CCS transportation is considered further in Section 9.3.1.

6.4.2. Forms of storage

There are several possible ways to store captured CO_2, the most notable of which are shown in Table 5. Due to its geographical location, the UK boasts an enviable capacity for CO_2 storage over the next half century. The UK and Norwegian Government commissioned 'One North Sea' study[18] estimates that 80% of Europe's CO_2 storage capacity lies under the North Sea, and the UK is likely to have sufficient capacity for at least the next century.

Table 5: Different forms of storage for CO_2

Type	Description	Est. UK Capacity	Est. UK requirements	Cost
Deep Saline Aquifers	Injection of supercritical liquid CO_2 into brine-filled sedimentary rocks, overlain by an impermeable rock cap or seal.	60,971Mt[2]	2,500Mt (by 2050)	High[4]
Depleted Hydrocarbon fields	CO_2 injected into depleted hydrocarbon reservoirs via retired rigs.	7,300Mt[1]	c. 15,000Mt (2100)[3]	Low
Producing Hydrocarbon fields	CO_2 used for Enhanced Oil/Gas Recovery in producing hydrocarbon reservoirs.			Low
Unmineable Coal Seams	CO_2 can be injected into coal below economic mining depth, where it may react and be absorbed.	Not currently economically viable	-	-

Sources: 1. GeoCapacity Survey, 2. Geocapacity survey + SCCS estimation of Scottish aquifers (assuming 2% efficiency), 3. DECC CCS Road Map 4. Costs associated with storage in aquifers are relatively higher due to exploration/appraisal costs not necessary for hydrocarbon fields.

6.4.3. Key considerations and challenges for storage

There are several key considerations as to what represents the most viable form of storage for captured CO_2 in the UK:

- **Availability**: the most abundant form of storage both in the UK and worldwide, lies in deep saline aquifers, though in the short term there is also more than adequate space in depleted hydrocarbon fields;
- **Safety**: the most well understood form of storage is hydrocarbon fields, given the extensive knowledge of the characteristics of each reservoir built up by the field's operator over its operating life; and

18 One North Sea, report by Element Energy for The Norwegian Ministry of Petorleum and Energy and The UK foreign and Commonwealth Office, on behalf of The North Sea Basin Task Force, 2010.

- **Cost**: hydrocarbon fields offer the most cost advantageous option due to the reduced exploration and appraisal costs. Within the hydrocarbon fields subset, oil fields are preferable if EOR is technically and commercially feasible, as the revenues from oil production offset costs further. By comparison, the complete geological appraisal of an aquifer takes several years, and costs at least tens of millions of pounds.

6.4.4. The regulatory and legislative environment for storage

The risks associated with storing CO_2 underground in geological formations have periodically elicited concern from governments, private investors and members of the public in different parts of the world. The UK's legislation that regulates the offshore underground storage of CO_2 has been introduced to combat this concern, and includes:

- The EU CCS Directive[19], a 2009 Directive from the European Parliament provides guidance and sets out responsibilities for CO_2 storage. The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010 implement much of the EU CCS Directive and establish licensing for CO_2 storage permits. The follow on Storage of Carbon Dioxide (Licensing etc.) (Scotland) 2011 Regulations extend similar rules to Scotland. These regulations outline the appropriate permitting processes for CO_2 storage, including the necessity of contracts to detail the sharing of liability between operator and government. Although the exact forms of such contracts are yet to be finalised, current legislation indicates that it would be likely for an operator to be liable for any leakage until 20 years after injection stops, upon which point the Government would assume liability (so long as the operator could prove the security of the stored CO_2). Any potential operator would have to be able to prove financial and operational capability before a permit could be granted, as well as possibly having a mechanism to cover the costs of possible leakages above 0.5% CO_2 stored per year.
- Amendments to the London Protocol and the OSPAR Convention affect the legality of transboundary CO_2 transportation and CO_2 storage in the North Sea respectively. These should not impact DVPP as the CO_2 is not intended to cross any national boundaries, but they do set out some legal guidelines for liability in the event of CO_2 leakage or transportation issues, which could affect more than just the UK's interests.

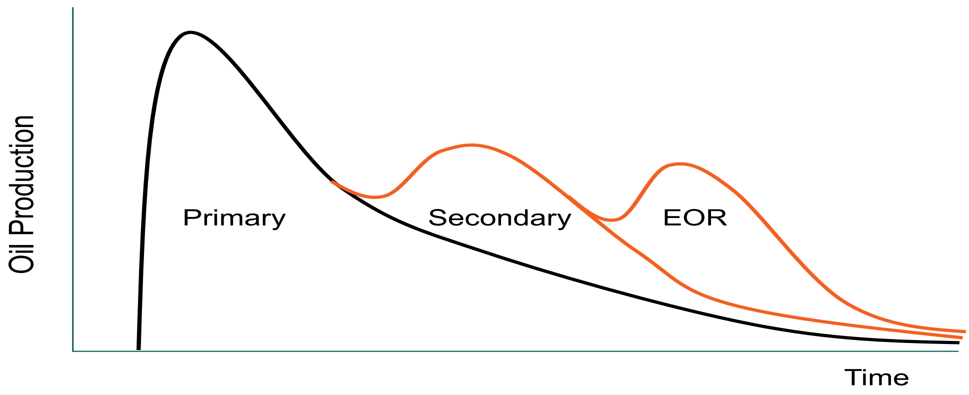
6.5. Enhanced Oil Recovery (EOR)

6.5.1. What is EOR?

Enhanced Oil Recovery (EOR) is a process which enables the extraction of a greater percentage of Original Oil in Place (OOIP) in a reservoir than would otherwise be possible in the first two stages of extraction, as shown in Figure 12.

19 Directive 2009/31/EC

Figure 12: Additional oil production from EOR



1. The primary phase of extraction relies on the natural pressure in the reservoir, and typically extracts 5-20% OOIP;

2. The secondary phase of extraction involves injection of water or other substances into the reservoir to increase pressure and extract a further 10-20% OOIP;

3. By injecting substances which change the viscosity of the oil, EOR techniques can extract additional oil. CO_2 injection is one of the most effective forms, enabling the production of up to an additional 20% OOIP[20], and offers the greatest potential of North Sea oil recovery, for example a recent study estimated additional recovery could total 5.7 billion barrels of oil[21], other studies up to 8 billion barrels.

Globally, there are already 170 CO_2 EOR projects underway[22], of which the vast majority are in North America. Many use CO_2[23], although most projects use naturally occurring CO_2 rather than anthropogenic CO_2. There are currently no CO_2 EOR projects in operation on the UK Continental Shelf, despite the technology's great potential. A major inhibitor has been the lack of a regular and reliable supply of CO_2. As such, CCS equipped power plants could provide a regular, reliable source of CO_2 to the North Sea and enable an EOR industry with all the employment, skills, energy security and tax revenue generating benefits that brings.

6.5.2. DVPP and EOR in the North Sea

By utilising EOR techniques, companies operating in the North Sea could gain access to oil currently beyond their reach. So long as a relatively high oil price persists, this represents a clear economic advantage for companies with access to CO_2. However, estimates for the impact of additional operating costs, in particular the cost of separating and re-injecting CO_2 from the newly produced oil are substantial, and the extra capex required to fit the necessary technology could limit EOR only to larger oil fields.

The exact implications of CO_2 EOR for the North Sea as a whole depend on the speed of the uptake of the technology within the area, given the potential benefits of shared transport and other equipment for hubs of producers. As will be discussed in greater detail in Section 8.6, DVPP will help increase the speed of uptake in the region and possibly reduce costs for future CCS projects engaged in offshore storage. Scottish Enterprise and Element Energy Ltd analysed the changes in both CO_2 use

20 US Department of Energy 2008

21 Scottish Enterprise/Element Energy 'Economic Impacts of CO2 – enhanced oil recovery for Scotland 2012'

22 BNEF 'Leading the Energy Transition' 2012

23 Of the six largest North American projects in operation, only 23% of the CO2 used in EOR came from anthropogenic sources in 2011, with the majority coming from natural reserves. From the Advanced Resources International 2011, source BNEF 2012

and oil production in the North Sea based on three possible rates of project construction as set out in Table 6 below.

2Co's envisaged EOR storage option would be of a sufficient size to store all of the CO_2 from DVPP, plus potentially additional CO_2 from other projects utilising the same infrastructure.

Table 6: The possible impact of EOR on North Sea oil production

Scenario	EOR "Go Slow"	Medium EOR	"Very High" EOR
Number of projects operating by 2035	2	5	>12
Peak CO_2 supply for EOR projects Mt/yr	<12	<38	<120
Cumulative incremental EOR oil produced (million barrels)	300	1,356	2,807
Cost of CO_2 monitoring, liabilities etc.	£3/t	£2/t	£1/t

Source: Scottish Enterprise/ Element Energy 2012

6.5.3. The opportunity of EOR for CCS

Making use of EOR primarily as a tool for CO_2 storage, as is the case for 2Co, represents a rather different approach to EOR than has been seen in places such as the USA thus far. Rather than following the US example of maximising the oil production efficiency of each tonne of CO_2, which leads to storage of the lowest possible amount of CO_2, the primary objective of the project is to store a given volume of CO_2. This leads to a less efficient EOR operation. For example, whilst on average in current US projects one tonne of injected CO_2 would provide two to six additional barrels of oil, when carbon storage is the primary goal this is likely to be closer to one barrel of oil per tonne of CO_2 injected.

The key reason for this difference in efficiency is due to a different re-injection philosophy. Some of the CO_2 injected during EOR will resurface with the oil and needs to be captured and re-injected. Over time this resurfacing CO_2 will become the bulk of CO_2 available at the EOR site; 2Co estimates that after eight years of production, four fifths of the CO_2 injected will be recycled rather than fresh[24]. If efficient oil extraction were the primary goal of the project this resurfacing CO_2 would reduce the demand for fresh CO_2 over the life of the project. For an integrated CCS project like 2Co and DVPP, however, their primary focus is on storing the fresh CO_2 over the life of the project, so this reduction in demand will not occur.

For 2Co's EOR project in the North Sea, the primary limit to volume of CO_2 injected is reservoir pressure. 2Co considered it prudent to limit the reservoir pressure during the life of the CO_2 EOR project to below the initial reservoir pressure before production began. This reservoir pressure defines the upper limit of total CO_2 that can be injected.

The second factor affecting CO_2 management in the EOR storage project is the requirement to separate and re-inject any CO_2 reproduced with the additional oil. This process is costly, both in terms of capital cost and in terms of power usage on the platform. Consequently, there is likely to be an economic limit to the volume of CO_2 that can be recycled, which in turn will limit oil production (any oil production with associated CO_2 that cannot be re-injected will need to be shut in). An example CO2 injection profile over the project's life is shown in Figure 13 below.

While in the case of DVPP there could be a backup saline storage reservoir developed by NGC, it is not generally considered necessary to have a separate backup or reserve storage reservoir in addition to the CO_2 EOR reservoir, for two reasons.

- Given the inability to ensure continuous availability of the facilities necessary for CO_2 injection, particularly in a hostile environment such as the North Sea, the EOR storage project

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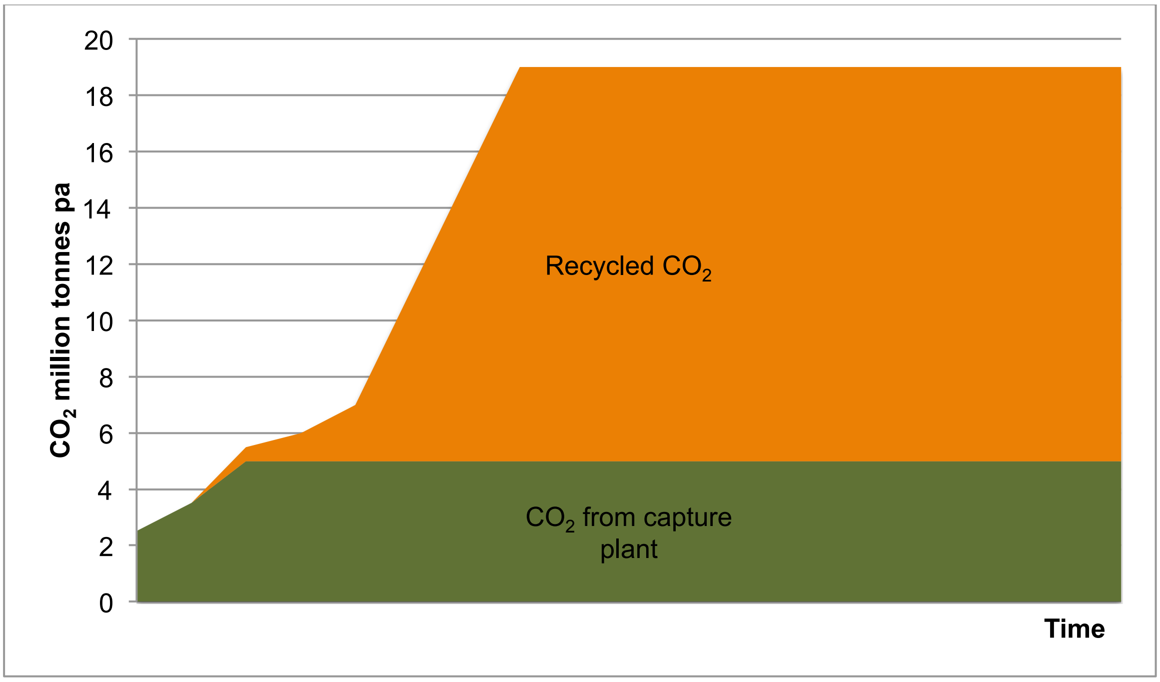
is designed to be able to cope with interruptions in supply. This means the project will not require backup CO_2 to continue operating in the event of interruption in supply from the capture plant.

- The storage sites selected for DVPP are large enough, and injectivity is high enough, that significant amounts of redundant injection and storage capacity can be created within the field itself through the drilling of backup wells.

Figure 13 Example CO_2 injection profile over project life



7. The financing challenge

7.1. Introduction

With a capital expenditure of approximately £5 billion for the full value chain, 2Co's CCS project will require the mobilisation of significant volumes of funding from a range of sources if it is to successfully reach financial close. This chapter outlines the current environment for financing large scale, low-carbon assets, and then sets out the key types of risks that funders are likely to take into account when assessing projects of this nature. The chapter then considers alternative sources of funding and concludes by outlining the project's anticipated funding plan, which is expected to include a mixture of debt, equity and grant funding.

7.2. Funding requirements

Total project costs across the full CCS chain are expected to be approximately £5 billion (inclusive of financing fees and interest during construction). **Error! Reference source not found.**Below is a summary breakdown across the three components of the CCS chain. These are discussed briefly in turn below:

Table 7: Estimated total project costs (excluding financing fees)

Component	Share (%)
Power plant	68%
Transport (2Co share)	0%
Storage	26%
Sub-total	**94%**
Financing costs*	6%
Total	**100%**

Table 8: Estimated power plant cost breakdown

Component	Share (%)
CCS	59%
Non-CCS	26%
Other	7%
Sub-total	**91%**
Financing costs*	9%
Total	**100%**

** Financing costs comprise fees and interest accrued during construction*

- **Capture**: capital expenditure on DVPP (power plant and carbon capture) is estimated to be approximately 68% of total funding requirement. As is shown**Error! Reference source not found.** above, the CO_2 capture component of the power plant accounts for a significant proportion of this requirement. In addition to these components, there will be other costs incurred primarily related to development costs and working capital requirements. All financing related costs are allocated to DVPP. This reflects the proposed financing structure and is discussed in more detail below.

- **Transport**: National Grid is expected to be responsible for constructing and funding the pipeline and other CO_2 transportation infrastructure required to support the project. As a result, 2Co does not expect to be exposed to any capital expenditure requirement, although it will have to pay a usage fee for access to the transportation infrastructure.

- **Storage**: The estimated capital expenditure relating to storage amounts to 26% of the total requirement. 80% of this relates to facilities (including platform refurbishments), the remainder to expenditure on wells. However, there remains some significant uncertainty on final costs, which will depend primarily on the development option chosen and the outcome of detailed engineering.

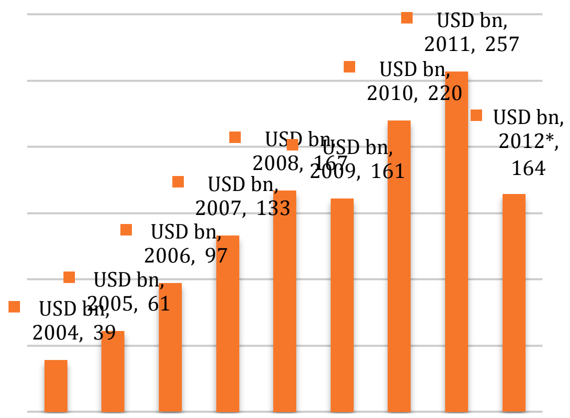
There remain a large number of uncertainties in relation to the costs set out in the tables above. As the project progresses through its Value Assurance FEED (VAF) process towards financial close, and discussions with contractors and suppliers develop, these numbers will become more certain.

7.3. The current market for low carbon finance

Total global investment in clean energy has increased significantly over the last decade, growing from USD34 bn in 2002 to USD257 bn in 2011 and despite the impact of the credit crunch in 2009 has continued to grow since[25]. The majority of this investment has been in wind and solar projects in a concentrated number of countries (led by China, the USA, Germany and Italy) although funding for other technologies and other countries across Europe, the Americas and Asia has also increased over the same period. Both debt markets (primarily in the form of commercial bank limited-recourse loans) and equity investors have each played key roles in funding these projects. The overall availability of funding has typically been greater for those projects that:

1. Are led by experienced developers;
2. Have employed a proven technology; and
3. Exist within an apparently stable and transparent regulatory regime (most particularly in relation to subsidy support mechanisms).

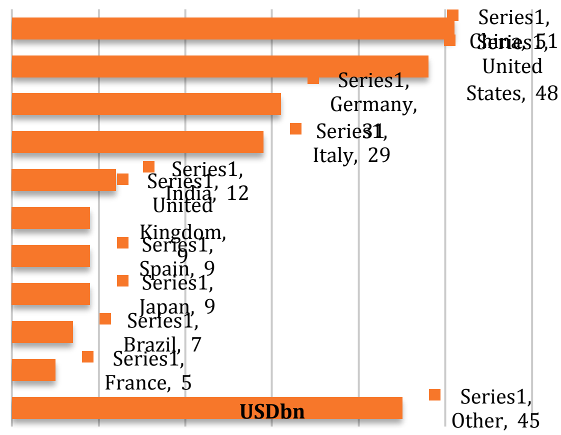
Figure 14: Global investment in clean energy (USD bn)



* 2012 – Q1-Q3

Source: Frankfurt School of Finance and Management, Bloomberg New Energy Finance

Figure 15: 2011 investment in clean energy (USD bn) by region / country



Source: Frankfurt School of Finance and Management, Bloomberg New Energy Finance

The global financial crisis, which first emerged in 2008 and which has continued through into 2012, has had a significant impact on the overall availability and terms of funding for large capital projects in the clean energy sector:

- The global slowdown in economic activity growth has put both public finances and the cost to consumers of providing subsidies to low carbon projects under scrutiny. In some markets (such as Spain), this has resulted in retrospective changes to subsidies payable to operational projects.

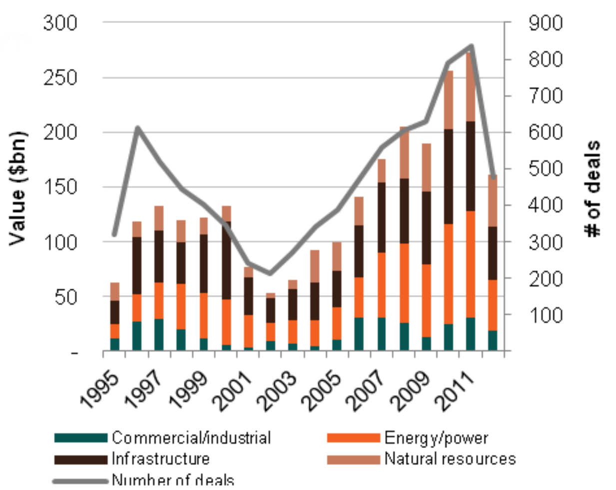
25 Bloomberg New Energy Finance 2012

Such actions have reduced the perceived stability of regulatory regimes in markets hitherto seen as representing attractive investment opportunities.

- Liquidity in the commercial bank debt market has reduced significantly. Some banks which had previously been active in lending to the low carbon sector have exited the market altogether (e.g. Belgian bank Dexia which was bailed out by government in 2008). More recently the Greek debt crisis and nervousness over a potential contagion effect have resulted in other lenders remaining cautious. Evidence of this can be seen in the global Project Finance market where, as shown in Figure 16 below, it is expected that 2012 volumes will be significantly below those of 2010-11. Whilst projects have been able to secure debt finance, banks have generally become more selective and the terms of such funding have become less attractive (both in terms of reduced tenor and increased margins). This is confirmed by a survey of lending banks carried out in 2012, the results of which were presented in a report entitled 'Implications of the global financial crisis for CCS'. The survey found that funding from commercial banks to major infrastructure projects has become more difficult since the start of the crisis.[26]

This challenging economic environment is affecting overall sentiment towards the clean energy sector. Based on market activity over the first nine months of the year, overall investment in clean energy in 2012 is expected by many observers to be lower than 2011, which would represent the first year-on-year fall in eight years. Meanwhile clean energy stock indices (for example the Wilderhill New Energy Global Innovation Index (NEX)), which provide an alternative barometer of general market sentiment towards the sector, have underperformed in recent years when compared to more conventional stock indices such as the S&P 500.

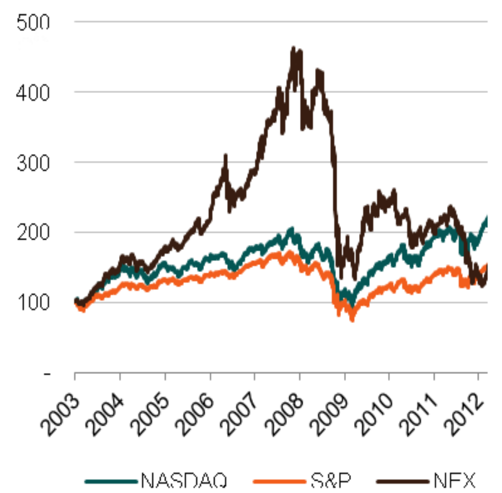
Figure 16: Global project finance volumes (USD bn)



2012: Q1-Q3*

Source: Dealogic

Figure 17: Performance of the NEX versus S&P500 and NASDAQ



Source: yahoo finance, Bloomberg

The international nature of the clean energy sector and the general exposure of commercial banks to problems in the Eurozone, mean UK-based projects seeking finance are clearly impacted by these issues. In addition to these immediate challenges, there are also a number of other important issues which will impact the future funding plans of UK-based projects, including:

26 'Implications of the global financial crisis for CCS', authors Geoff Rumble, Christopher Short, Klaas van Alphen and Gwendaline Jossec of the Global CCS Institute

- There is expected to be significant competition for capital within the energy sector over the next decade, both from within and outside the UK. 20 GW[27] of the UK's existing power generation capacity is scheduled to close and will need to be replaced. At the same time the development of significant volumes of large scale low-carbon projects (particularly in offshore wind and nuclear) and the need to upgrade the existing electricity transmission network, results in an estimated GBP 110 bn of investment being required across the UK energy sector in the period to 2020. Furthermore, each Member State within the EU has a mandatory 2020 renewable energy target and there are consequently large volumes of projects competing for funding;

- Under Basel 3 (a global regulatory standard on bank capital adequacy) banks will in future be required to hold greater levels of capital and match the tenor of their assets with their funding. This is expected to result in the current trend of shorter tenors remaining a common feature of debt facilities in large capital projects;

- For the last decade, the UK clean energy sector has benefited from a subsidy support mechanism (the Renewable Obligation) that is transparent, stable and well understood by stakeholders. As discussed in the previous chapter, this is set to be replaced by a CfD FIT which will be introduced over the period 2013-17. Many of the operational details of the scheme have yet to be determined. Until this happens, funders are less likely to provide firm commitment to those projects that are set to reach operations phase beyond that period. If the proposed mechanism is not seen to be working effectively in the initial transitional period, this could result in further deferment of funding commitments.

Despite these challenges, funding is still available for large-scale, low-carbon projects. This is best evidenced by a number of European offshore wind market financings that have taken place in the period 2010-12, both within and outside the UK. In February 2012, for example, the UK-based 270 MW North Lincolnshire offshore wind project secured approximately GBP 1.2 bn of debt facilities from commercial lenders. The offshore wind sector exhibits some similar characteristics to 2Co's own project: projects are large scale (for example the cost of the offshore wind London Array 1 project is expected to require circa GBP 2 bn), it is an immature sector (employing emergent technologies) and projects are complex to complete (involving multiple contracting parties operating in a challenging marine environment supported by an immature supply chain). An additional important consideration relates to the strength of relationships that the large technology suppliers have with their respective lending banks. The participation of large suppliers in the ownership structure and construction of a large capital project can assist the process of securing bank funding. The implication for 2Co and other CCS developers is that funding is available to those projects that are best able to identify and allocate project risk to the satisfaction of potential funders.

7.4. Investors' perception of risk

There is a wide range of potential international equity and debt funders who have invested in infrastructure-type assets, both within and outside the low-carbon energy sector. However, each type, or group, of funder displays certain preferences for the type of investment they are willing to consider and at what stage of a project's life they are likely to consider investing. These preferences reflect their assessment of the risks to which they are likely to be exposed. Figure 18 summarises some of the risks that potential funders will be thinking about in their assessment of 2Co's project. Some key factors to consider include:

- **Project versus external risks**: some risks are specific to the project itself whilst others are outside the control of the project stakeholders. Funders will want to identify all risks and understand who is exposed to each risk and how, and at what cost, it can best be mitigated;

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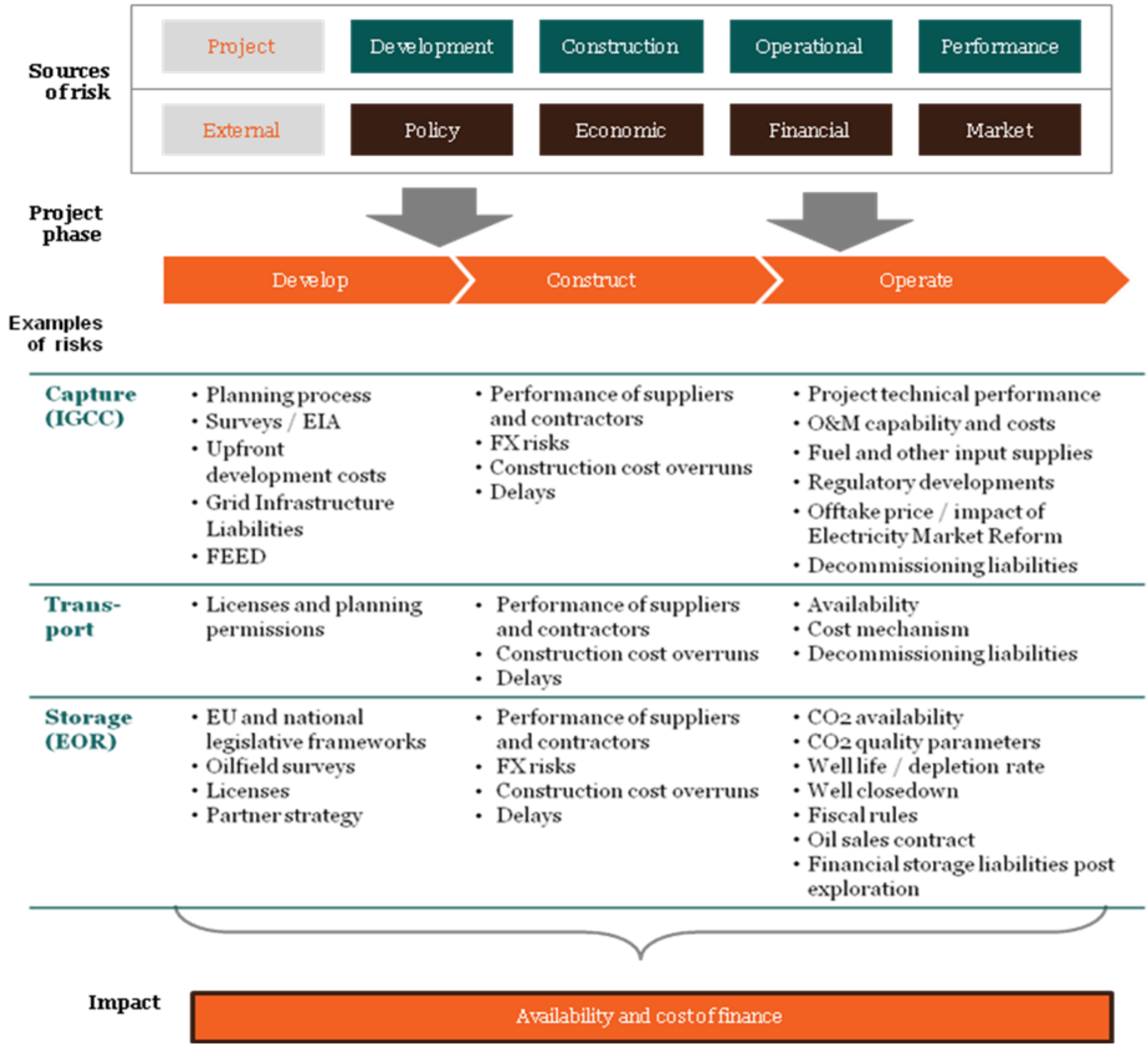
- **Project phase**: a project's lifecycle can be crudely broken into set stages (development, construction and operations/decommissioning). The development phase, during which activities such as project design, consenting and securing construction finance take place, represents the most uncertain period in a project's lifecycle. Although relatively limited funding is required compared to the total project capital cost, the lack of certainty surrounding the project's future success means that these activities will typically be funded by the developers themselves (although grants are sometimes made available). The availability of different types of funding to support the construction phase will depend on a number of factors. In general terms however, the more experienced the developer, the greater the number of precedent projects and the stronger the terms of any construction contracts (for example through caps on costs), the larger the available pool of capital. During the operations phase, and once a project has demonstrated it is operating in line with expectations, more risk-averse investors may be willing to invest in the project, thereby releasing or reducing the capital invested by those funders that supported the development and construction phases;

- **The CCS chain**: different risks will apply to 2Co's project depending on which part of the CCS chain is being considered. Although the project comprises three distinct components, the success of each is linked to the others. Some of this risk may dissipate over time, for example with the future emergence of additional sources of CO_2 in addition to those from DVPP. However this clustering of CO_2 sources is not expected to occur in the early part of the project's lifecycle and can therefore be effectively discounted from a funder's perspective.

Figure 18: Risks for potential funders



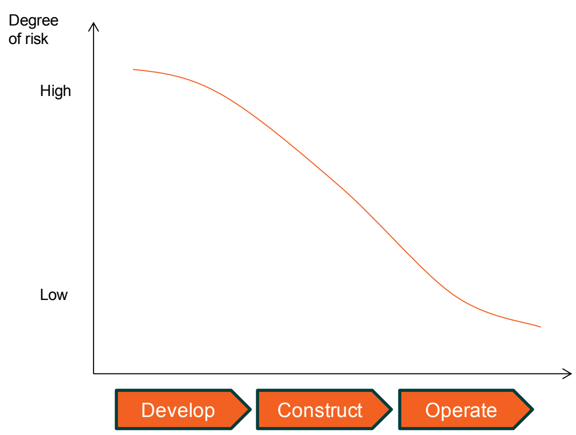
7.5. Potential sources of funding

The risk profile of the proposed project has a direct impact on the type, source and cost of funding that can be expected in 2Co's project. In this section, the potential range of both equity investors and debt funders is considered. We focus on potential investors in the carbon capture part of the value chain rather than the EOR investment, where the profile of equity investors is expected to be different, with for example, more presence from oil and gas sector players.

7.5.1. Equity investors

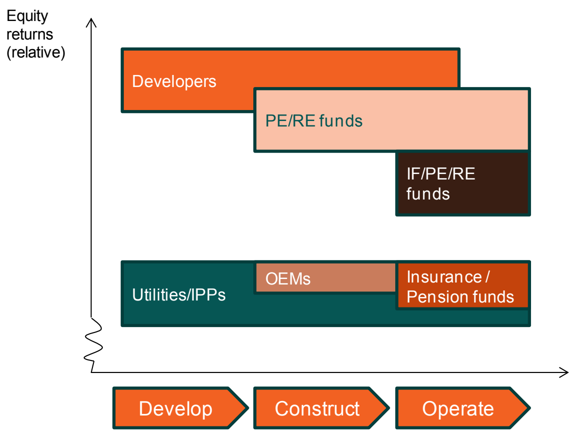
The overall risk profile of the project can be summarised as shown in Figure 19 below: as discussed above, during the development phase of the project the perceived level of risk is at its greatest. This falls as the project completes construction and then reduces further as it proves itself operationally. Investor return requirements broadly mirror this profile, reducing over time as the project moves through successive phases. Figure 20 maps out a potential universe of equity investors in a project of this nature, in terms of their relative return expectations and the project phase in which they are typically like to invest. This 'map' reflects the experience to date of the low carbon sector, particularly in relation to large-scale projects.

Figure 19: Typical risk profile of an infrastructure asset



Source: 2Co

Figure 20: Map of return expectations by investor class and project phase



Source: 2Co

Some key observations on equity investors that influence 2Co's funding plan:

Source	Expected appetite	Comments	Example organisations
UK Utilities	Medium	• Highly experienced in developing large-scale power generation projects. • Other funders often seek their participation, particularly in less mature sub-sectors such as offshore wind and CCS. • However each UK utility currently has a large capital expenditure programme that needs funding over the next decade. If they are to protect their credit ratings, as a group they have limited capacity to raise additional funds from the capital markets without some balance sheet restructuring.	SSE, Scottish Power, Centrica
International Utilities/IPPs	Medium	• There are a number of international companies familiar with funding and operating large scale power projects that could represent an important source of funding. • However, many face the same challenges to their credit ratings as the major UK utilities.	GdF, International Power, Summit Power
Original Equipment Manufacturers (OEMs)	Medium	• Often represent important sources of funding, particularly in sectors such as offshore wind and CCS where technology is less mature. • Their participation in construction is often considered to provide assurance to other investors.	Samsung, Siemens
PE, IF, RE funds	Low	• Private Equity ("PE"), Infrastructure ("IF") and Renewable Energy ("RE") funds have all previously invested in low carbon projects. • However, not all funds are willing to take construction risk and the scale of 2Co's funding requirement lies outside of the capacity of many funds.	Macquarie, Hg Capital
Insurance/ pension funds	Low	• These funds are demonstrating interest in low carbon assets (e.g. offshore wind) that meet certain investment criteria (such as stable, predictable operational cash flows). • These funds typically have large pools of capital available but do not typically take construction risk.	Ontario Teachers Fund, Calpers

7.5.2. Debt funding

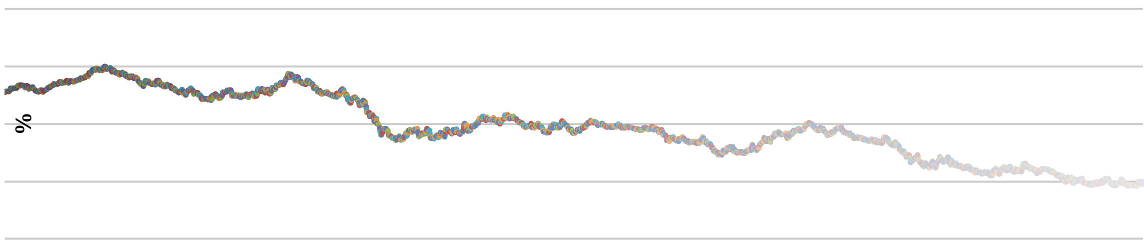
Debt funding is expected to represent a core component of 2Co's funding plan. There a number of potential sources of debt that could be used to support the construction programme. Due to the scale of the project and the current status of the international project finance market, 2Co expects to consider a range of sources. The table below summarises the main sources of debt finance and their anticipated appetite for supporting the construction phase of the project:

Source	Expected appetite	Comments	Example organisations
Commercial banks	Medium	• A long history of supporting large power / infrastructure projects. • The financial crisis has reduced capacity and appetite for lending over long maturities and outside of home countries/core markets, particularly for European banks. Currently tenors of 10 years are a common feature of the market, although funding restrictions on Asian banks have been more limited. • Overall appetite will be largely driven by the strength of the construction and operation contracts, perceived technical risks and the identity of other project funders (debt and equity).	Europe: RBS, BNP Paribas, Lloyds Banking Group, HSBC Asia: Bank of Tokyo-Mitsubishi, Mizuho, Sumitomo-Mitsui Banking Corp
Export Credit Agencies (ECAs)	High	• ECAs are government agencies that seek to support export from their own country through the provision of funding to buyers of the exports. • Provide either direct loans or provide credit enhancement (i.e. a form of insurance) to other lenders. • Funding is commonly made on a long-term basis.	K-Exim (Korea), K-Sure (Korea), US-Exim (USA), EkF (Europe)
Multinational Finance Institutions	High	• Commonly used as a source of finance in recent offshore wind transactions. • Can be expected to seek participation from other senior lenders (e.g. commercial banks). • The UK has to date under-utilised its potential share of EIB funding (which is determined by its respective contribution to funding the organisation). • The EIB launched a bond initiative in 2011 that seeks to invest up to EUR 20 bn over the period to 2020 in infrastructure. However, construction risk is likely to remain a key issue for potential investors and therefore unlikely to be of relevance to 2Co.	EIB
Capital markets	Low	• Whilst Project Bonds have been used to fund infrastructure assets, this is usually in a portfolio of operational assets, not in single development assets.	N/A
Green Investment Bank	Low	• Tasked with supporting investment in the UK green economy, the GIB is expected to be operational in Q4 2012. However, its balance sheet will initially be limited to GBP 3 bn and will have limited capacity to lend to 2Co.	N/A

The total price of any debt funding will depend on a number of factors but can be summarised as comprising a base rate plus a margin:

1. **'Base rate'**: the 10 year GBP swap rate, which is an appropriate proxy to the fixed component of the base rates used for commercial loans with a 10-year average life, is at an historic low (reaching 2.5% in early 2012).

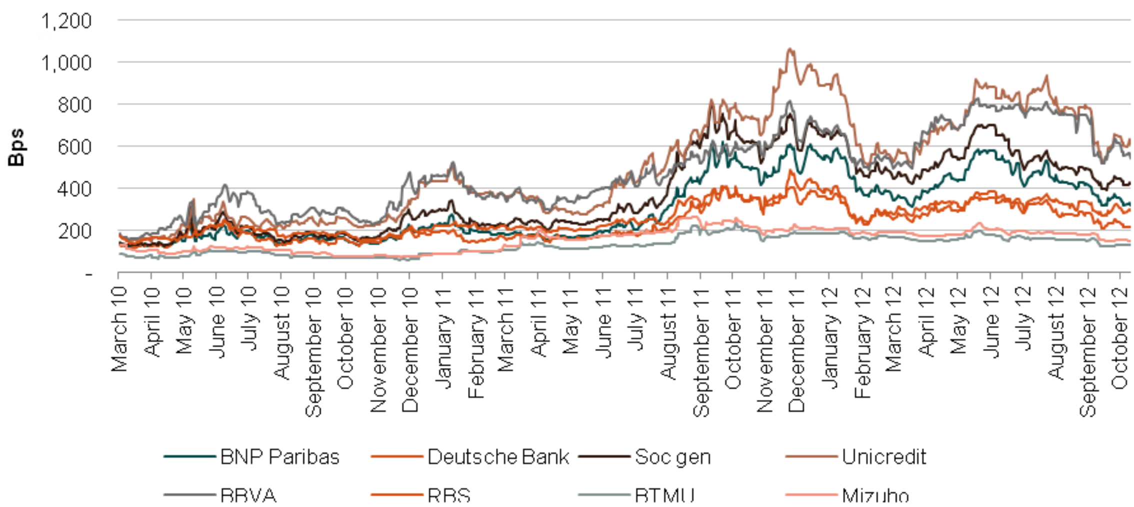
Figure 21: 10-year GBP SWAP RATE



Source: Datastream

2. **Margin**: The margin applied will depend on how lenders perceive the riskiness of the project relative to other assets. At the very least, margins applied will need to be sufficient to cover the lending bank's own cost of funds. Credit Default Swap ("CDS") prices of banks provide a good proxy for this funding cost: as is shown in Figure 22 below CDS prices have grown over the last 30 months. It is also evident that European banks are more expensive than some other non-European banks (Japanese banks are a case in point). In addition, the project will be considered as a 'first of a kind' ("FOAK"), and it is therefore likely to incur a slightly higher cost than other large-scale construction facilities (such as offshore wind where there are precedents in the market). Pricing for Multilateral Financing Institution (MFI) debt is sometimes slightly below that of commercial bank debt but it will in part be driven by the commercial structure of any agreed financing package.

Figure 22: Credit Default Swaps (10-year EUR and JPY) - selected European and Japanese banks



Source: Datastream

3. **Fees**: In addition to the above costs of debt financing, the project can be expected to incur arrangement and commitment fees. In addition, if ECAs provide insurance to third party debt, then

there will an additional upfront fee payable. Fees are typically charged as a percentage of the total facilities provided.

7.5.3. Grant funding

In addition to debt and equity funds, 2Co anticipates having access to some capital grant funding. There are three main sources from which the project has received or sought grant funding:

Grant	Source	Confirmed recipient?	Value (GBP est.)	Comments
EEPR	EU	Yes	GBP 90 m	• DVPP was awarded a total of EUR 180 m (approximately GBP 150 m). This is being used to fund pre-development expenditure. EUR 60 m of the funding is shared with National Grid Carbon to fund its feasibility studies and design for the transportation and a storage option.
NER300	EU	Yes, if UK supports project	Up to EUR 337 m	• DVPP is one of up to three European CCS and 16 renewable projects that could be awarded grant funding. DVPP was ranked # 1 in the CCS evaluation process. • Grant money will be derived from the sale of 300m carbon credits for overall programme. It has been indicated that each CCS project should expect to receive a maximum of EUR 337 m (approximately GBP 270 m).
CCS Grant	DECC (UK government)	No	Up to GBP 1 bn	• 2Co entered into a competition for funding for share of up to GBP 1 bn of UK government grant funding. • It was understood that DECC's competition might support the construction of up to 2 CCS plants, one of which might be gas-fired. A decision over funding was expected in late 2012. However, no decision on funding was made and DVPP was not taken forward in DECC's process.

7.6. Funding strategy

DVPP will be directly owned and developed by a subsidiary of 2Co, 2Co Power (Yorkshire) Limited (2Co Power). 2Co's CO_2 storage and EOR activities will be developed by a separate subsidiary, 2Co Oil Limited (2Co Oil). This structure will enable the capture and storage activities to be developed and funded separately.

7.6.1. DVPP funding strategy

Table 9 summarises a potential funding structure that the DVPP (power plant and carbon capture) project is currently exploring. The company is still in the early stages of discussions and, as discussed above, there are many uncertainties in the current market for infrastructure funding. Consequently the final agreed funding structure could be significantly different to what is presented in the table.

Table 9: Potential sources of funding for DVPP

	Share (%)
Grants	26%
Equity	14%
Debt	60%
Total	**100%**

Table 10: Potential sources of debt funding

	Share (%)
MFI	24%
ECA	58%
Commercial	18%
Total	**100%**

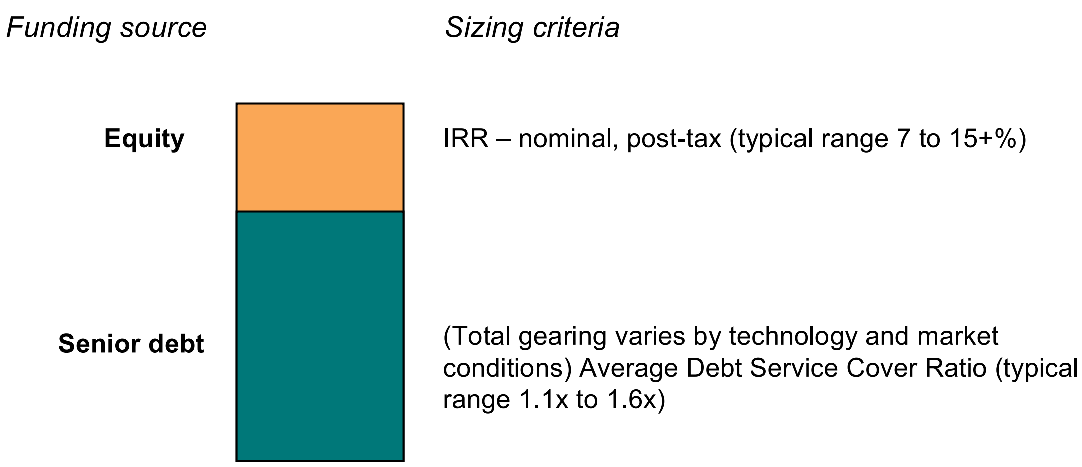
Each of the main sources of funding are discussed briefly in turn:

- **Grants**: the final allocation of funding under NER300 and DECC's CCS funding programme has yet to be determined. It was assumed in the base case that, along with EEPR funding, these sources would total 26% of the funding to the project. However, DVPP has not proceeded in DECC's process for grant allocation (the lack of UK support also means NER funding will not be available to DVPP), so the share provided by grant funding is likely to fall, and be mostly replaced by additional equity, and potentially some additional debt.

- **Debt:** The base case assumes that DVPP can achieve a gearing of approximately 60%. As shown in Table 10 above, it is anticipated that debt will be funded from a range of sources. ECAs are expected to play a key role (with a current assumed share of 58% of the total debt); however, it is anticipated that significant additional funding will be required from both MFIs and commercial banks.

- **Equity**: DVPP's shareholders include Samsung C&T Corporation (which is also expected to be the EPC contractor), and The BOC Group (contractor for the plant's air separation unit (ASU), and ultimately the operator) in addition to 2Co. Whilst there may be changes in the shareholding structure before Financial Close is achieved, the current structure reflects the observations made in section 7.5.1 about the types of equity investor attracted to a project of this nature, given its complexity, scale and risk profile.

The diagram below illustrates a typical project financing structure and some indicative parameters that investors would use to help make decisions around funding. However the exact metrics are purely illustrative and would depend on their assessment of the risks of each individual project:



7.6.2. EOR / Storage funding

2Co anticipates that all capital expenditure related to the EOR and storage facilities will be funded by equity, given the similar investment and return profile to traditional oil and gas projects. As a result, no bank debt, or government grant, is assumed to be required.

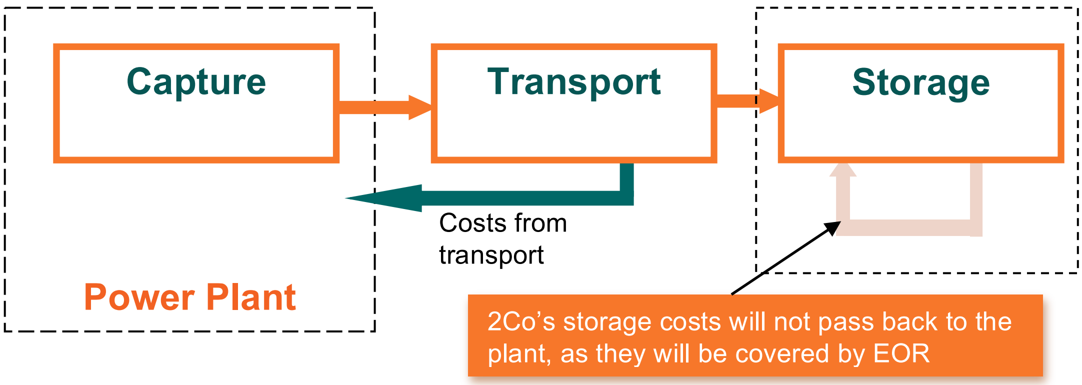
8. 2Co Business Plan

8.1. Introduction

This chapter focuses on the business plan and project economics of the two major components of 2Co's CCS project: the power and capture plant (DVPP) and the storage (and related EOR) facilities (2Co Oil). The business model is summarised in Figure 23 below: as discussed in the previous chapter, the capture and storage components are effectively being developed and funded by 2Co as two separate businesses, whilst the transport components of the CCS chain will be developed and owned by National Grid, and funded through charges for use by the power plant.

It is envisaged that the power plant will pay for the transportation of the CO_2 as government funding for carbon capture would be delivered to the capture facility. Funding transport from the storage project, which would likely then charge the capture facility an increased storage fee, would simply add complexity.

Figure 23: DVPP and CCS process



As with many large, complex infrastructure projects, the overall economics of the project will be determined ultimately by a wide number of variables including construction and operating costs, technology performance and sales/revenue assumptions. There are however some variables which are either specific to the development of CCS projects in the UK in general or peculiar to 2Co's project:

- **Allocation of CCS related operating costs:** The incurred costs to 2Co from using National Grid's CO_2 transportation facilities will be borne by DVPP as an operating cost. Storage facility costs are recovered by 2Co Oil through the EOR facility (i.e. carbon is stored at zero cost to DVPP). This makes EOR different from other types of CO_2 storage, where both transport and storage costs are typically recovered through a fee charged to the capture facility.

- **Financial support**: As was discussed in the previous sections, DVPP is seeking financial support in the form of capital grant funding and a revenue subsidy payable on the sale of units of output where CO_2 is captured as part of the generation process. The revenue subsidy will be provided through the CfD FIT mechanism. A key focus of the DVPP business case is therefore to ensure that the agreed Strike Price under the CfD is set at a level that ensures that all costs are covered whilst providing a return to investors that is in line with expectations. We explore this further below.

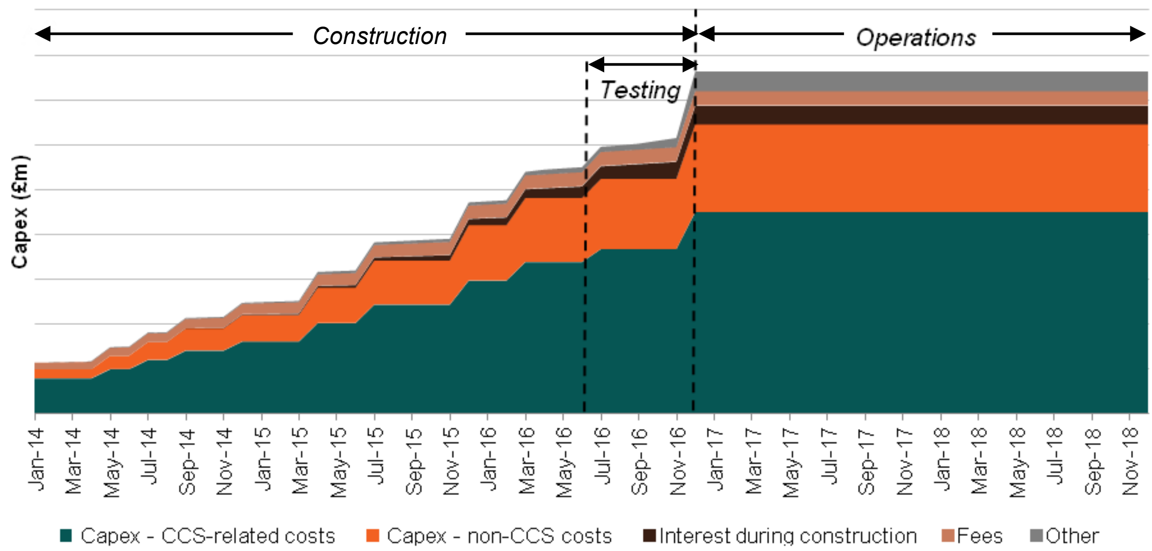
In Sections 8.2 to 8.4, the project economics of DVPP are explored, before attention is turned to the storage & EOR project in Section 8.5. Finally in Section 8.6 consideration is given to the anticipated contribution that 2Co will make to the development of CCS as an industry and its economic impact on the UK economy.

Linking DVPP and the storage project is a CO_2 transfer price; this could be a sale of CO_2 to the storage facility, a payment of a storage fee to the storage facility, or a zero cost transfer. The transfer price will be set based on the relative economics of the different parts of the project and will be finalised before Final Investment Decision is made, but the current expectation is DVPP will have zero cost storage because of the value EOR brings to the storage operation.

8.2. Don Valley Power Plant construction phase

2Co currently anticipates that financial close of the DVPP project could be achieved by late 2013, with the construction phase then commencing at the beginning of 2014. As illustrated in Figure 24 below, the construction phase would then last approximately 36 months. The actual cost profile associated with the construction phase will depend on the final terms of the related construction contracts but it is expected that it will be aligned to key project construction milestones. Commissioning of the plant is expected to take place over the final six months of the construction phase. During this period both the IGCC and CGGT modes of operation will be tested resulting in relatively small volumes of CO_2 being generated during those few months.

Figure 24: Uses of funding for capex by year



8.3. Don Valley Power Plant operations phase

There are several key technical and financial (cost and revenue) assumptions underpinning the financial modelling of DVPP's operating cashflow and profitability. This section describes these assumptions and highlights potential risks to their viability.

8.3.1. Production profile

Figure 25 below summarises DVPP's production profile during the first twenty years of its operation. As described previously, the plant can run either in:

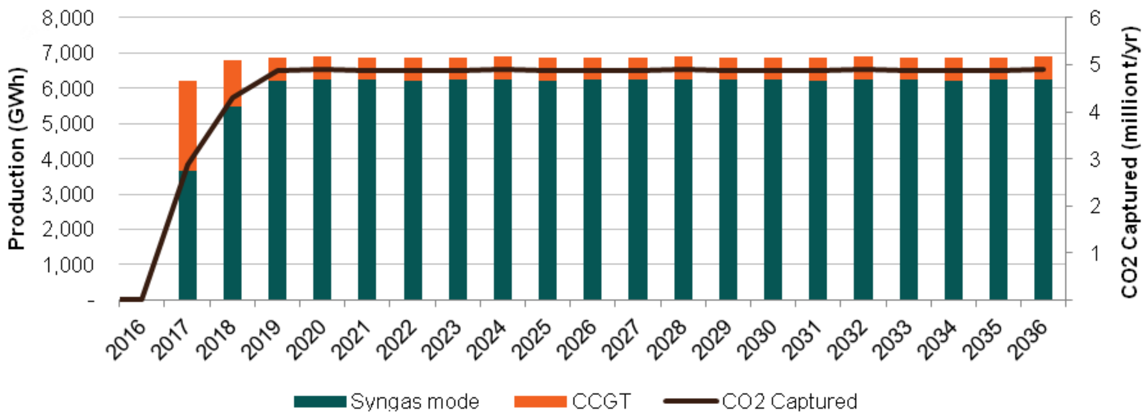
- (coal-fired) IGCC, or syngas, mode during which approximately 91% of all carbon in the coal will be captured as CO_2 and transported to the storage/EOR facilities. Any emitted CO_2 is subject to CO_2 tax; or
- (gas-fired) CCGT, or natural gas, mode during which no CO_2 is captured. All CO_2 is emitted and therefore subject to CO_2 tax.

Figure 25: Running the plant as 'baseload' (i.e. continuously) in IGCC mode would therefore allow for maximum flows of CO_2 to the EOR facility. As a result, operation in IGCC mode is expected to dominate overall generation volumes. However,

- During the early years of operation, the project's business plan is factoring in relatively low IGCC/syngas availability. This allows for the resolution of any technical problems that are commonly incurred in the first part of an IGCC power plant's operating phase. Consequently, the project anticipates significant volumes of CCGT-fired generation during this period.

- Once any initial technical issues have been resolved, approximately 91% of output is expected to be derived from operating in IGCC mode. The plant is expected to switch to CGGT only in those periods when the IGCC is not available (for example due to maintenance issues), and then only when it is economic to do so.

Figure 25: Potential production profile of DVPP



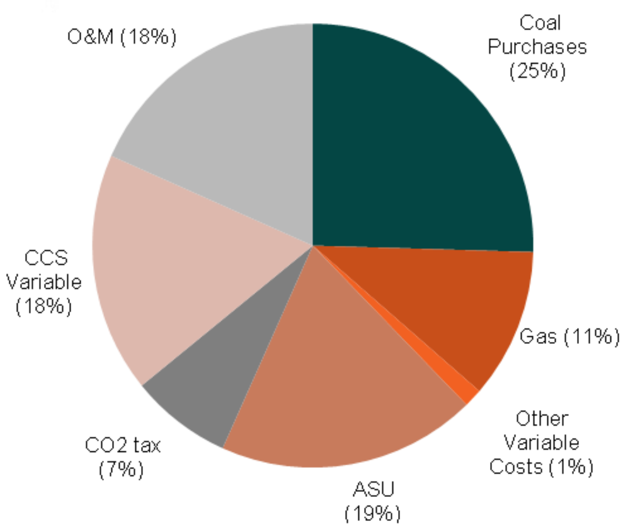
Minimising the time taken to achieve steady state baseload generation in IGCC mode will be crucial, since:

1. Firstly it affects the volumes of CO_2 available for EOR-related activities, and
2. Secondly it could impact the level of subsidies payable under the CfD mechanism. As highlighted above, the principle of the CfD is that it is supports the economics of CCS related activities. However, regardless of whether DVPP is operating in IGCC or CCGT mode, it will need to ensure that it can cover all its fixed and variable costs, including CCS-related. This risk around this ultimately will depend on the agreed terms of the CfD.

8.3.2. Operating costs

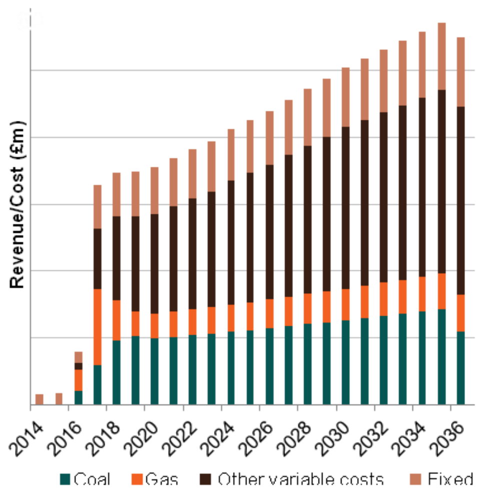
The operating costs for the plant in steady state are broken down in Figure 26.

Figure 26: DVPP operating costs by share



Source: 2Co model

Figure 27: DVPP revenue versus cost (£m)



Source: 2Co model

- **Fuel costs**: nearly half of the operating costs will come from purchasing fuel (primarily coal and natural gas, which is needed even in IGCC mode to facilitate coal drying). It is therefore important that DVPP can manage its exposure to any volatility in fuel prices. This is discussed in greater detail in Section 9, but essentially it will be necessary to mitigate this risk through measures such as long term supply contracts and by indexing the CfD Strike Price to fuel prices.

- **Non-fuel costs:** a wide range of non-fuel operating costs will be incurred, including CO_2 tax for the balance of CO_2 not captured but emitted, ASU costs, CCS transport costs and operations and maintenance (O&M) costs. Total ASU costs are primarily driven by the amount of power consumed in the ASU process. As a result, wholesale power prices, which are forecast to rise in real terms over the operational life of the project, have a significant impact on total operating costs. The exact nature of the O&M contract for the plant has yet to be decided, but it will be important that the project can engage with an experienced operator and have long-term visibility on costs, particularly in relation to any potential replacement capital expenditure that may be incurred over the operating life of the plant.

The base case profile of operating costs over time is shown in Figure 27. As can be seen, nominal costs are expected to increase significantly over time, reflecting assumptions around commodity price trends and general price inflation.

8.3.3. Revenue

DVPP's revenue (as distinct from EOR/storage revenue) will be derived from the sale of electricity from the plant. The price received will depend primarily on:

- **CfD Strike Price**: When the plant is operating in IGCC mode, it will receive the value as determined under the agreed terms of the CfD;

- **Wholesale power prices**: Once the CfD contract has expired, all IGCC-generation will be sold at the wholesale power price. Furthermore, during instances where syngas is unavailable and the plant is running in natural gas-fired CCGT mode, any output will be sold at the wholesale price of electricity.

- **Other**: in addition to these sources of revenue, DVPP has some potential to earn revenue from balancing mechanism revenues and ancillary services. The contribution of these sources is not currently expected to be material.

To reach Financial Close, these combined sources of revenue must fund all costs and meet the return expectations of investors in DVPP, including both debt funders and equity investors. These issues are explored in more detail below.

8.3.3.1. CfD Strike Price

As outlined in Section 6.3.2, under the terms of the CfD the DVPP plant will sell qualifying electricity into the market and receive the wholesale power price for doing so: if this wholesale price is below the CfD Strike Price, it will also receive payment to make up the difference. If the wholesale price exceeds the Strike Price, DVPP must pay back the difference between the two values. As set out earlier, CCS-related components represent 59% of total capital costs. The CfD is designed to recover this CCS capital expenditure and any related operating costs (regardless of the time taken to achieve steady state baseload operation). Although the plant avoids paying tax on the CO_2 emissions that are abated by the capture and storage process, this cost saving in not sufficient in itself to compensate the plant for the costs incurred in the abatement process. Furthermore, it will need to meet the required returns of those who finance the CCS related activities. Setting the Strike Price at an appropriate level will be critical to the economic success of the plant.

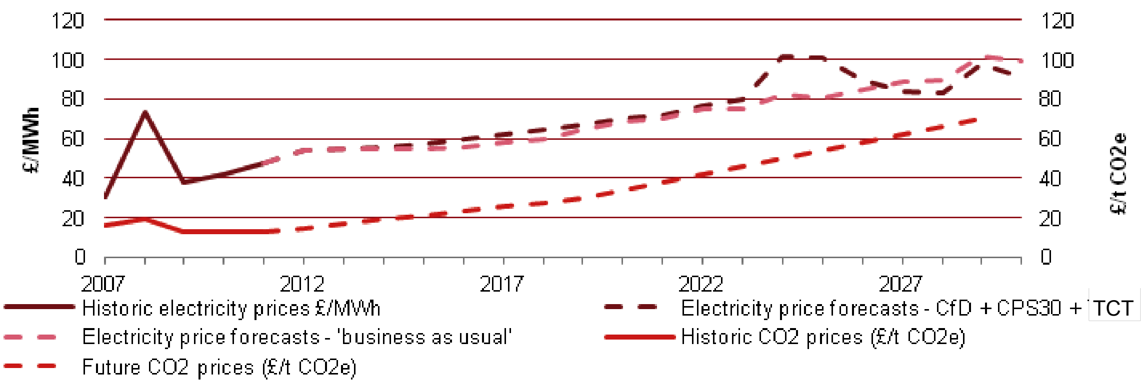
The Strike Price can be thought of as “Levelised Cost of Energy” (“LCOE”) of the project. Although the exact details of the CfD are yet to be finalised, it is expected that the average CfD Strike Price over the life of DVPP will be competitive with the current LCOE of other new low-carbon technologies such as offshore wind, at around £140-£160/MWh. There are however a number of variables that will impact this value:

- **CfD structure:** Given the risks faced by DVPP as the first project of its kind, a Deemed Generation payment (i.e. a payment is made regardless of whether the DVPP has generated CCS-qualifying output or not) as part of the CfD would reduce risk for the project and help to ensure cost recovery in the commissioning period.
- **CfD Term (or tenor)**. A shorter term means that there is less time to recover CCS-related costs and associated investor returns. As a result, a shorter CfD term will necessitate a higher CfD Strike Price. The DVPP business plan would work best with a twenty year CfD.
- **Source of funds**. The higher the return expectations of those who have funded the project, the higher the required Strike Price. Different sources of funds carry different costs of capital: as a general rule, equity funding is more expensive than debt funding and grant funding commonly contains no return on investment expectations.

8.3.3.2. Wholesale power prices

The proposed changes to the UK electricity market that were discussed in Section 6.3 are being designed to influence the composition of the country’s power generation fleet. Forecasts prepared for the government as part of its market reform consultation process indicate that wholesale prices will rise significantly (in real terms) over the period 2012-2030. This is illustrated below:

Figure 28: UK wholesale power and carbon price forecasts under EMR



Source: Her Majesty's Revenue and Customs, Point Carbon, EEX, DECC, Redpoint Consulting

Although this upward price trend is comparable to forecasts under the government's 'business as usual' scenario, there are a number of issues that add a high degree of uncertainty to these price forecasts:

- **Price volatility**: UK wholesale power prices have historically been volatile. The anticipated addition of significant volumes of intermittent, renewable generation (primarily onshore and offshore wind) could lead to large swings in the supply of low marginal cost generation. This could create additional volatility in the wholesale market.

- **Commodity prices**: Natural gas is expected to remain the (electricity) price setting plant for some time. However changes in the international commodity markets for natural gas and coal are making long term electricity price forecasting increasingly challenging.

The key issues are summarised in Table 11 below. However, most of these issues will become most relevant once the CfD expires, and at which point DVPP's revenues will be determined by the wholesale power price. The overall impact of wholesale prices on the project will therefore depend on:

1. **The length of the CfD contract**. The shorter the term, the more quickly DVPP becomes exposed to wholesale power price uncertainty. As previously mentioned, a twenty year CfD is preferred by the project;

2. **Post-CfD route to market**. Once the CfD tenor expires, DVPP will be exposed to variations in the wholesale power price to the same extent as any non-CCS power plant. As the UK has a bilateral contract market, the onus is on buyers and sellers to contract for sale of their output ahead of real time delivery. One such way of securing a route to market is through a power purchase agreement (PPA) although no decision on this is expected until shortly before the expiry of the CfD. The terms of a PPA can vary but the price paid for electricity generated is likely to be index-linked to wholesale power prices.

Table 11: Potential risks affecting future wholesale power price

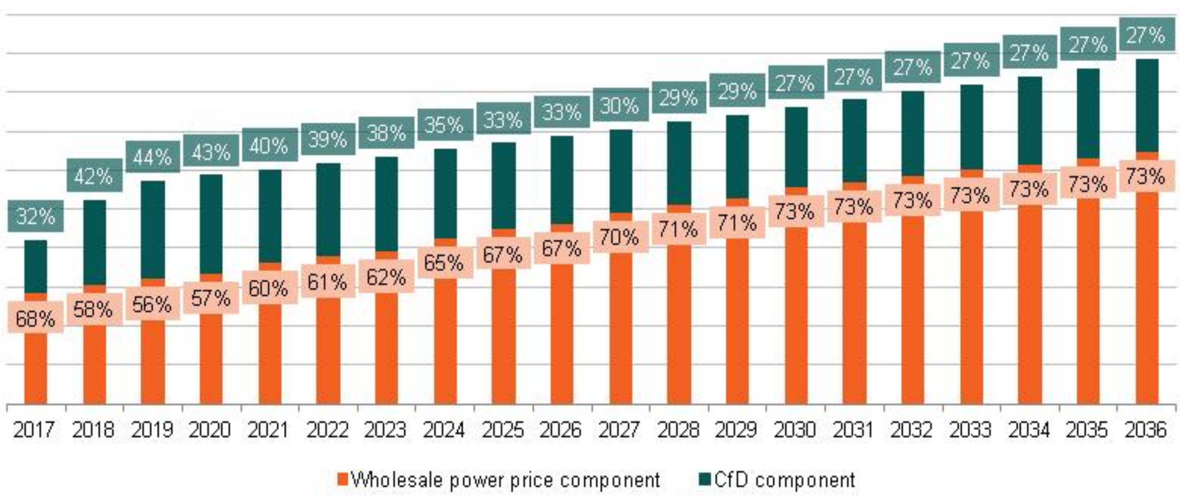
Factor	Effect on Wholesale Prices	Risk/Uncertainty
Fuel prices	Investment in low carbon generation based on assumption of rising fuel costs.	While gas currently sets the wholesale price, the merit order is unpredictable and dynamic.
CPS	Carbon Price Support (CPS) put upward pressure on costs of coal and gas plant.	Uncertainty about which plant will be marginal in the future.
CfD	Availability payments to intermittent generators when reference prices are negative.	High uptake of CfDs could increase build rate, altering the generation fleet, leading to higher settlement and wholesale costs.
Capacity Mechanism	The capacity market will subsidise unused capacity.	CM support will increase wholesale prices. The timing of capacity auctions is not certain.
EPS	Emissions Performance Standards (EPS) exemption for new gas plant should put downward pressure on rising wholesale costs.	EPS will make unabated coal plant impossible to consent.
Changing energy mix	Balancing will drive up wholesale prices. The shift to intermittent energy sources like wind will drive greater volatility in prices.	The rate of change of generation mix caused by the EMR policies is an unknown, as is the precise impact on intermittency. Delivery on nuclear policy is still uncertain.

Due to the high costs of early CCS projects, like that of 2Co, the CfD mechanism will be a critical feature in attracting both equity and debt funders. Over time it is anticipated that as more projects are delivered, capital costs will reduce and developers will be able to leverage the experience of the early projects, thereby also potentially reducing operating costs. Consequently, a project that reaches FID in 2030, for example, may not be dependent on the CfD mechanism to attract funding, instead relying only on wholesale power prices (which are forecast to increase and will be supported by an increasing CO_2 tax).

8.3.3.3. DVPP revenue profile

The chart below summarises the base case revenue assumptions. As is evident, CfD revenues make a significant contribution to the market project, representing some 32% of total revenue over 20 years of operations.

Figure 29: DVPP revenue profile (£m)

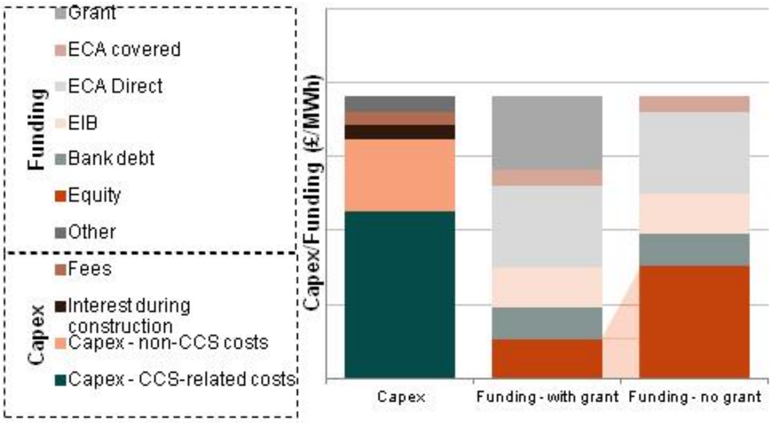


8.3.3.4. Impact of CfD tenor and grant funding on the Strike Price

As previously discussed, DVPP's funding is expected to come from a range of sources comprising debt, equity and capital grants. The base case assumes a substantial portion of capital grant funding. This grant funding has a number of important impacts on the economics of the plant:

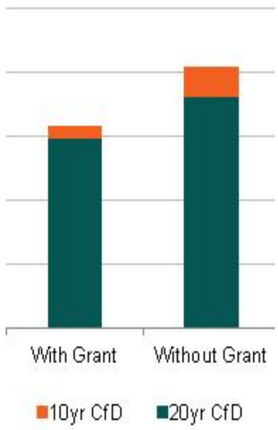
It reduces the level of funding required from private (debt and equity) sources. As shown in Figure 30 below, if this source of funding was not available, it is likely that it would have to be substantially sourced from equity investors, as it is considered unlikely (though possible) that significantly greater level of debt than already assumed (60% of total funding) would be available. This would require total equity funding up to three times greater than is assumed in the base case business plan. Sourcing this volume of additional equity funding clearly could be challenging, particularly in the current economic environment.

Figure 30: Total capex and required funding - with and without grant



Source: 2Co model

Figure 31: Required Strike Price under 10 and 20 year tenor (£/MWh)



Source: 2Co model

1. The provision of capital grant funding effectively reduces the price required for each unit of power generated by DVPP (i.e. its LCOE). Whilst both equity investors and debt funders require a return on their respective investments, capital grant funding assumes no such 'cost of capital'. In the absence of grant funding, the additional funds provided by equity would require a return: this would have to be derived by charging a higher price for each unit of power generated.

The combined impact on the Strike Price due to removing all grant funding, combined with reducing the assumed CfD tenor from twenty to ten years, is shown above in Figure 31. Overall 2Co expects that, in order to meet assumed investor returns, the Strike Price would need to be increased substantially.

8.3.4. DVPP Operating Cashflows

Figure 32 below summarises DVPP's base case capital expenditure and operating cash flow profile from the start of construction through to the close of operations. The operating costs comprise all DVPP's variable costs (such as coal, gas, running the ASU and CO_2 costs, including CO_2 transportation) and fixed costs. The operating margin will be used to cover other costs such as debt financing, tax and returns to equity investors.

Figure 32: Predicted DVPP cashflow – 20 year CfD tenor (£m)

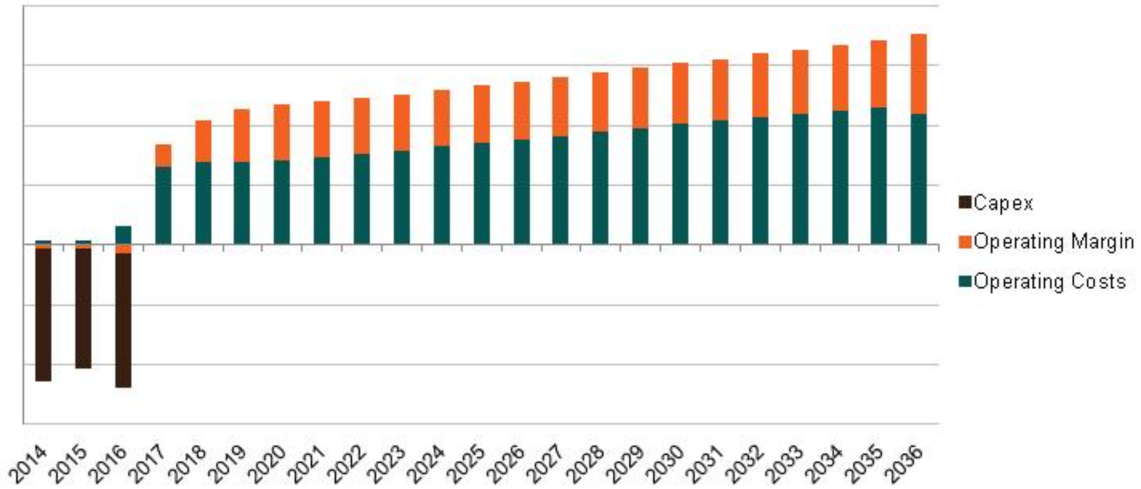
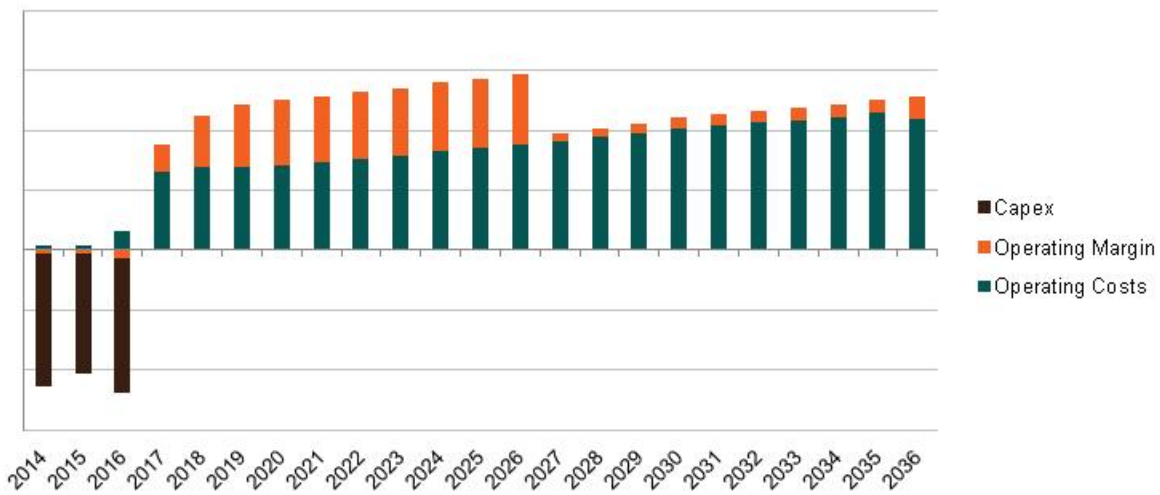


Figure 33 illustrates the same variables but assumes a 10-year CfD. As is evident, the plant is forecast to operate in an environment of low operating margins post expiry of the CfD. This reinforces the discussion on the importance of establishing an appropriate CfD Strike Price in order to recover CCS-related costs and associated investor returns.

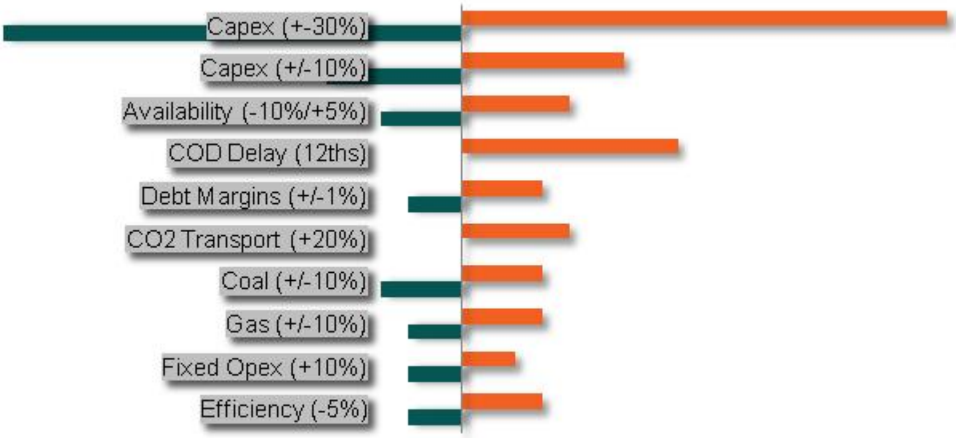
Figure 33: Predicted DVPP cashflow - 10 year CfD tenor (£m)



8.4. Sensitivity analysis of the project

2Co has conducted a sensitivity analysis on a range of factors influencing DVPP, in order to understand their potential impact on the required CfD Strike Price. The results are summarised in Figure 34 below. As is evident, an increase in capital expenditure or delay in the start of commercial operations has the greatest impact on the project, followed by availability and CO_2 transportation costs.

Figure 34: Indicative sensitivity analysis on required CfD Strike Price (£/MWh in 2012)



8.5. Enhanced Oil Recovery (EOR)

Section 8.3 covered the operations of only the CCS power plant, DVPP. The objectives of the storage and EOR operation are two-fold: firstly, the operation must store all CO_2 captured by DVPP; secondly, it must generate enough revenue from EOR to fund the storage operation in its entirety (and offer an appropriate rate of return to investors). The metrics determining the success of the facility lie primarily in the storage capacity of the hydrocarbon field (which is expected to be larger than required for DVPP), as well as the effectiveness of transportation and storage technology.

8.5.1. Drivers of revenue and cost

The drivers behind the ability of EOR to make a profit alongside the CO_2 storage operation can be characterised as follows:

- **Brent crude price:** The higher the oil price, the higher the profit that can be achieved from EOR. Risk-sharing strategies such as hedging are available to mitigate any risk posed by the volatility in oil prices, however many investors in oil production wish to take oil price risk. The EOR storage project may hedge against the oil price or it may take full oil price risk depending on the appetite of its investors.

- **CO_2 supply:** In order to derive the benefits of EOR, it is critical that a reliable stream of CO_2 is available for injection, particularly in the early years of the operation while there is limited CO_2 available for recycling. The commissioning period at DVPP is the time when CO_2 will be most liable to interruption, as the IGCC used to generate power is prone to early instability. Consequently low volumes of CO_2 in early years are expected and will be planned for. If volumes of CO_2 were even lower than expected, the timing of recovery of the incremental EOR reserves would be impacted (although in most cases there would be limited impact on total volume recovered over time). This delay to production represents a risk to the economics the EOR facility and to the CCS project as a whole.

- **The costs of EOR and storage:** Through detailed modelling of a range of different facilities options, as well as effective funding from private sources, it is expected that costs will be controlled effectively and limited to manageable levels.

- **Liability issues in CO_2 storage:** 2Co has factored in the necessary funds and financial security requirements as established under both UK and EU law, as well as the permitting requirements for CO_2 storage designated by DECC, in their financial modelling. As such, the project should be fully covered against any storage liabilities. Oil and gas companies operating offshore routinely shoulder liabilities similar to those established under the storage regulations, for example a responsibility to meet all costs of an oil leak from a reservoir, both during operations and after production has ceased.

8.5.2. Cashflow

Cashflow of the EOR business is shown in Figure 35. As can be seen by comparison with Figure 36, the revenues and margins of the operation are driven by the amount of oil recoverable per year. As would be expected, EBITDA margins peak at the height of oil production in 2020-2025, but decline as the amount of recoverable oil decreases. In order to facilitate the dual goals of oil extraction and CO_2 storage, the amount of CO_2 injected during EOR stays relatively constant over the operation. After fresh CO_2 injection ceases at the end of life of the capture plant; the EOR business would continue recycling CO_2 and producing oil until the EOR cashflow turns negative, which could be several years later.

Figure 35: Predicted EOR cashflow (£m)

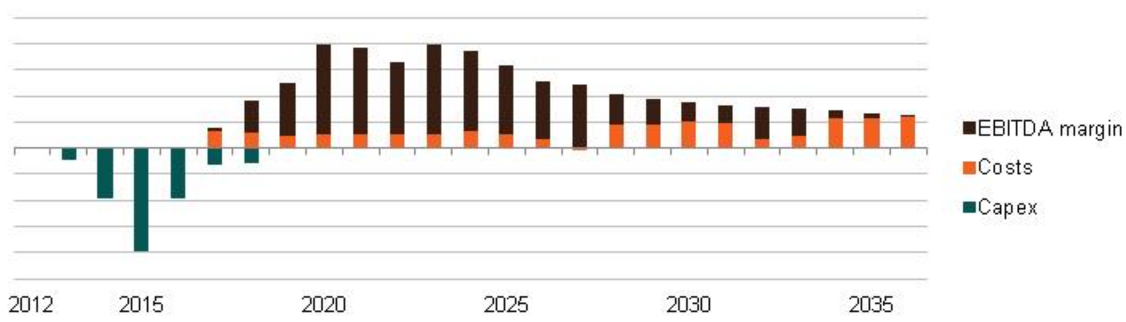
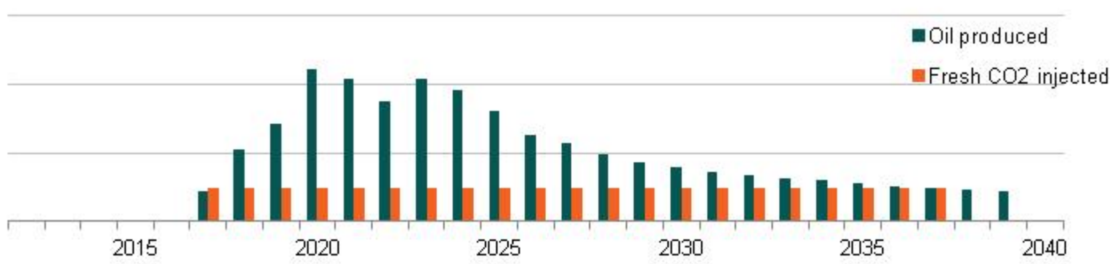


Figure 36: Predicted EOR production profile - Oil production (Million barrels/yr) / CO_2 (Mt/yr)



Overall, the EOR operation offers an innovative method to mitigate the costs of CO_2 storage and contributes towards making the entire CCS project economically viable.

8.6. Don Valley Power Plant contribution to cost reduction for future CCS projects

8.6.1. The overall impact of DVPP

There are a number of overall project outcomes that are important to the local community as well as wider tax and environmental benefits as set out in the table below.

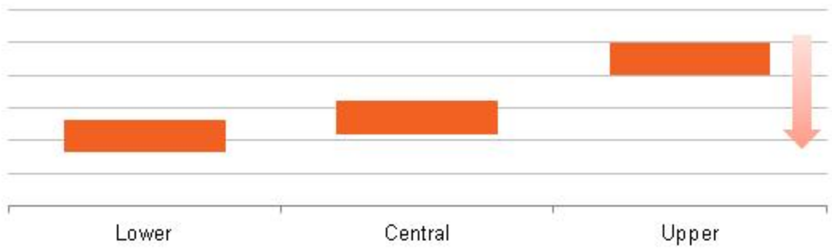
Table 12: DVPP key metrics

Metric	Description
Job creation	Construction phase 2013 - 2016: 3,800 (3,000 onshore + 800 offshore) Permanent after 2017: 600 (300 onshore + 300 offshore) Related direct and indirect supply chain employment during operations and maintenance after 2017: c. 360 (+ c. 225 during construction)
Tax receipts to UK Government	£1.25 billion from the power plant plus c. £1.25bn from EOR (depending on exact tax structure which is yet to be decided) = c. £2.5 billion from 2017 to 2042
No fee for CO_2 storage	The cost to capture and store sequestered carbon in the ground could otherwise range from £10 – 50 per tonne of CO_2 depending on the storage location.
Abated CO_2	95 million tonnes from 2017 – 2042
Infrastructure	Pipeline infrastructure in Yorkshire/Humber cluster of CO2 emitters available as a cost saving for future projects. Infrastructure could also attract inward investment from industry needing to tackle CO_2 emissions
Skills	Creation of UK skills in both carbon capture and offshore EOR that will enable export market etc

8.6.2. Future CCS Projects

2Co considers that DVPP will contribute significantly to the possibility that the CCS sector will provide cost-competitive low-carbon electricity by the early 2020s. While it is difficult to assess what CfD Strike Price would be competitive in the early 2020s, the recent work by DECC's offshore wind taskforce has set a benchmark CfD Strike Price of £100/MWh for the technology by 2020, which gives a directional target for CCS in achieving a commercialisation outcome.

Figure 37: Required CfD Strike Price for DVPP CCS Project (£/MWh)

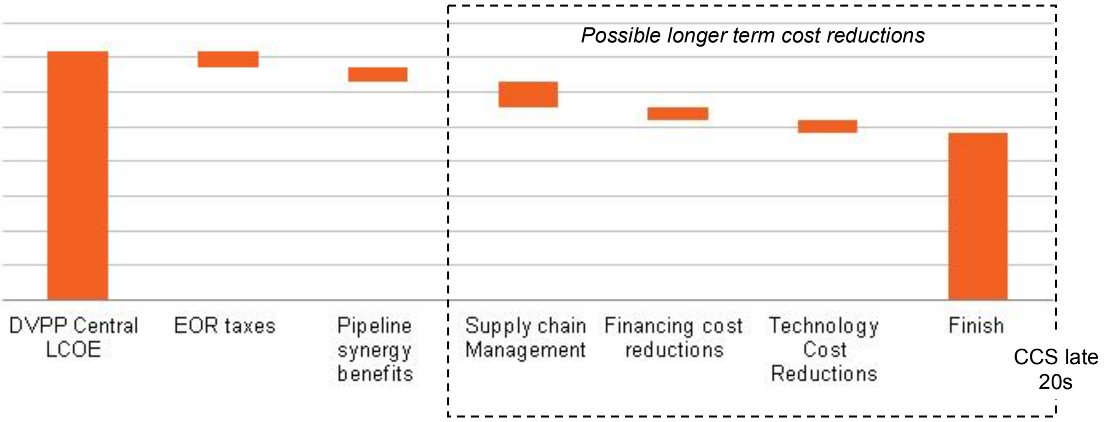


The first step to bridging the gap is to factor in the benefit of EOR tax revenue, which effectively reduces the net cost of the project to government. Additional reductions of the required CfD Strike Price could come from the direct use of the CO_2 transportation and storage infrastructure established for DVPP by additional sources of CO_2. It is expected that this increased throughput will lead to a reduced unit cost per unit of CO_2, as well as more tax revenue from oil recovered through EOR using this additional CO_2. These benefits could result in the reductions set out in Table 13, reducing LCOE towards the £100/MWh target. These trends would be reinforced by future potential cost reductions, such as lower costs resulting from the global deployment of CCS, improved technology, and reduced cost of capital as projects are demonstrated.

Table 13: DVPP CCS project cost benefits

	Project Cost Reduction	Benefit range
Current potential cost reductions	EOR tax benefit from additional CO_2 Volume	£ 5-15/MWh
	Pipeline synergy benefits	£ 5-10/MWh
	Total	£ 10–25/MWh
Future potential cost reductions	Supply chain Management	£ 10-20/MWh
	Financing cost reduction	£ 5-10/MWh
	Technology Cost Reductions	£ 5-10/MWh
	Total	£ 20-40/MWh

Figure 38: Effect of DVPP on LCOE for CCS: Medium impact (LCOE £/MWh)



9. Project risks and mitigation plans

9.1. Introduction

Chapter 7 identified that there are a large number of potential commercial and non-commercial risks during the lifecycle of the project. Whilst many risks are common to other infrastructure projects, early CCS projects are relatively complex, given their size and first-of-a-kind nature and there will be bespoke risks that need to be managed. Furthermore, whilst the profile of DVPP's risks will change (and reduce) as the project moves through its successive phases (development, construction and operations), there are a wide range of stakeholders who will seek to mitigate their respective potential exposure to these risks. These stakeholders and their key areas of concern can be summarised as follows:

Figure 39: Stakeholder concerns

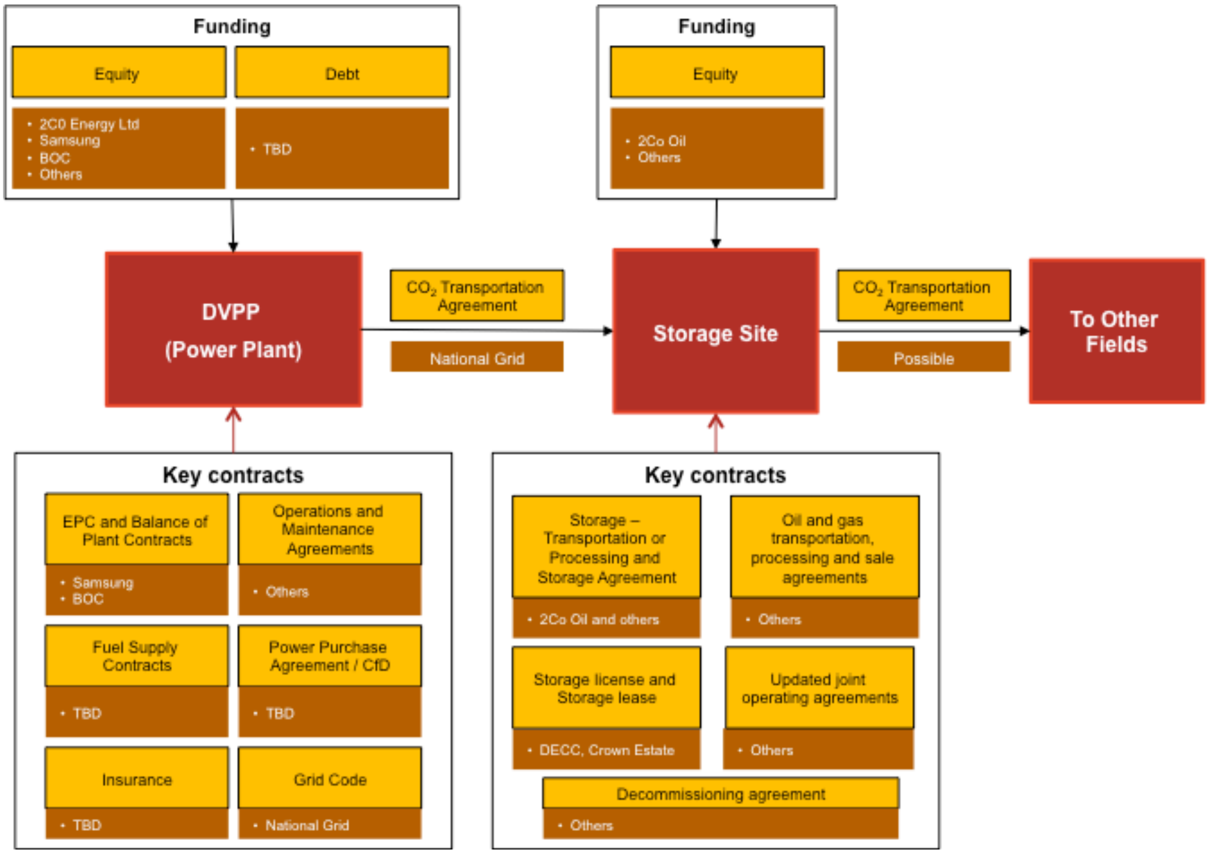
Stakeholder	**Shareholders**	**Debt funder**	**Contractor / suppliers**	**Government / consumer**
Key areas of concern	• Total investment required • Return on investment	• Funding required • Certainty of, and time to repayment	• Financial liability • Reputation	• Security of energy supplies • Climate change agenda • Cost to consumer / taxpayer • Safety and environmental impact of project

The identification, treatment and reduction of risk are critical components of reducing the overall cost of CCS projects. Risk is inherent in many aspects of a CCS project, ranging from the uncertainty around capital and operational costs, to variation in generation performance (particularly during the commissioning phase), and from broad economic and energy market risk to timing delays and policy uncertainty. Reducing downside risk can help to attract different types of investors and increase the amount of debt finance that can be used. Reallocation of risks between the project participants across the value chain is also possible, passing risk to those best able to manage and bear such risks.

The cost of capital is a key determinant of the overall cost of electricity for CCS projects going forward, and so understanding and mitigating risks such as those set out in this section will further progress the CCS industry towards the GBP 100/MWh target set out in Section 8.6.

In this chapter, 2Co's proposed approach to managing these risks is discussed. The risks set out below are based on those faced by a project which is beyond the point of determining a commercial framework, but which still faces significant uncertainty around the contractual agreements between parties. As an example, risks to the project associated with transportation are in many cases limited, as 2Co will have a tolling type arrangement with its transport partner National Grid Carbon (NGC). It is likely that a risk profile for the same issues created by NGC would identify many risks not identified here. The chart below summarises the project structure and the key interface agreements that are likely to be put in place. The list is by no means exhaustive but is intended to provide an indication:

Figure 40 Summary Structure Chart



As shown in Table 14 below, these risks can be separated out by source of risk (from within the project, or external risks) and also by stage of development and part of the value chain. Each of these themes is discussed in turn in the subsequent subsections.

Table 14: Project and external risks by project phase

		DVPP	Transport	Storage and EOR
Project	Pre-financial close (risk to FID)	• Insufficiently understood regulatory and funding environment, leading to an inability to reach financial close	• Failure to agree appropriate terms and location with transport operator	• Offshore North Sea environment not understood by the power plant operator
	Construction and completion	• Cost overruns • Delays • Inexperience of EPC contractor for CCS plant • Interface risk between EPC contractor and other parties	• Little to no risk as constructed by transport operator (but will depend on introduced agreements and any risk transfer)	• Cost overruns • Delays • Inexperience of EPC contractor for offshore CO_2 EOR projects; and interface with third parties
	Operations & Maintenance	• Fuel quality and delivery • Contractor inexperience	• Little to no risk as operated by transport operator	• Failure of source to supply regular, reliable CO_2 for EOR, especially in early years of CO_2 storage • Contractor inexperience of offshore EOR
	Performance	• Worse than expected performance (especially gasifier) leading to low capture rates • Plant efficiency lower than expected • Dispute between plant owners and operator • Warranty/Liquated Damages package is inefficient	• Inability of transport operator to transport CO_2 (pipeline availability risk will need to be understood)	• Lower than expected injection rates and storage of CO_2 • Lower than expected oil recovery • Higher than expected costs
	Decommissioning	• Potential closure earlier than expected • Cost of decommissioning greater than decommissioning provisions	• No real risk as operated by transport operator	• Remaining $CO_{2,}$ storage liability • Decommissioning risks of oil field

		DVPP	Transport	Storage and EOR
External	Policy	• Change in CCS regulations • Change in public funding mechanisms	• Transport regulations and classification of CO_2 as waste/commodity	• Licensing • Liability for storage leakage over mid, long and very long term
	Economic	• Foreign exchange variation (for both capex and opex) • Interest/inflation rates variation (cost of debt) • Underperformance of UK pound	• Inflation variation (real value of transport costs)	• Foreign exchange variation
	Financial	• Inability to secure funding from debt market • Higher than expected cost of debt funding • Inability to secure refinancing arrangements • Changes to tax regime	• Pricing uncertainty in tolling arrangements	• Inability to secure adequate financing and refinancing • Changes to tax regime
	Market	• Coal price • Wholesale power price	• Pricing uncertainty in tolling arrangements	• Oil price

9.2. Project risks

9.2.1. Pre-FID risks

Pre-FID Risks across the value chain of the project include:

- **Power plant:** There is a risk of an insufficiently understood regulatory and funding environment leading to investor uncertainty and an inability to reach financial close. Full regulatory consent must also be received, creating further risk prior to FID.

- **Transportation of CO_2:** There is a risk of failing to agree appropriate terms and pipeline location with transport operator. Delays in grid connection are a further risk to transportation.

- **Offshore facility:** There may be a risk that the offshore environment is not sufficiently understood by the power plant operator. There is also a risk that as the storage facility gets more technical definition it becomes apparent that EOR revenues are not sufficient to cover the costs of storage.

Some pre-FID risks can be mitigated by gaining a deep understanding of the regulatory and funding environment, and applying that knowledge in such a way that all required pre-FID steps are undertaken at the appropriate time. However getting a project to the point of FID remains an inherently risky process, and many risks may need additional resources (for example, retaining experts in plant permitting and commercial negotiations), or simply time and an experienced development team, to be overcome.

9.2.2. Construction and completion risks

Risks across the value chain of the project include:

- **Power plant:** The risks include inexperience of CCS on the part of the EPC contractor or other major contractors, which could lead to cost overrun or delay, and an interface risk between the EPC contractor and other parties.

- **Transportation of CO_2:** Any impact at project level will depend on risk transfer mechanisms within the agreement for CO_2 transportation. For example, there may be a risk of non-completion of the transport pipeline in time for commencement of DVPP. In this case, risk mitigation would be the same as for the other parts of the value chain.

- **Offshore facility:** Risks are the same as for the power plant (namely, inexperience of the EPC contractor with the relevant technologies, which could lead to cost overrun or delay, and an interface risk between EPC contractor and other parties). Lowering the likelihood of this risk is the significant UK experience in offshore rig construction as compared to the first of a kind carbon capture technology in the power plant. Offsetting this reduced likelihood, however, is the substantial brownfield modification work likely to be necessary on existing oil production platforms.

For both the power plant and the offshore facility, these risks can be mitigated by putting in place contractual arrangements that protect against EPC inexperience, delays and cost overruns, such as a fixed price contract or including a liquidated damages clause. These will reduce the risks to the project but will be reflected in a higher EPC price.

9.2.3. Operation and maintenance risks

For DVPP, O&M represents nearly 20% of total costs. O&M risks across the value chain of the project include:

- **The quality and security of coal supply and other inputs:** Coal supplied to the plant should be of an appropriate quality. With regard to supplies, by engaging in a long-term contract with a reliable supplier, with appropriate contractual obligations, the risk of receiving inferior quality of products or of supply interruption can be limited. This risk may be easier to manage for coal sourced from the Hatfield mine adjacent to DVPP as opposed to international coal supplies, however, large coal fired generators have successfully managed this risk for many years.

- **Contractor experience and ability to perform duties:** It is necessary that the providers of the services are well equipped to keep the plant at maximum efficiency. There is a risk of higher incidence of breakdowns, where a lack of early warning could result in more costly problems or repairs later in the project life.

  As a mitigation strategy, it is necessary to ensure an adequate contract to provide O&M services is supplied in the most efficient way by the most effective and capable people. This can be ensured by engaging in a long-term contract, possibly based on an incentives mechanism to ensure the alignment of objectives for both the plant owner and O&M contractor.

- **Poor project management:** This is a difficult risk to quantify but is a common theme for first-of-a-kind technologies, for example in offshore wind. Particularly for multi-contract construction, strong project management is required to ensure interface risks and co-ordination activities between contractual packages are managed appropriately with clear allocation of responsibility between all contractual parties and adequate decision and dispute-resolution processes in place to assist with a smooth and efficient project.

- **Transportation of CO_2:** Availability of pipelines is normally high hence this is a low probability risk, but one that needs to be dealt with in the transportation agreements.

- **Offshore facility:** Many of the risks associated with the power plant will also apply here when considering an O&M contract for offshore EOR. However, there is an additional risk of loss of supply of CO_2 from the power plant. The risk of intermittent CO_2 supply during ramp up may have a substantial impact on the O&M programme for the EOR operations. Once operations commence, a certain level of costs related to O&M must be incurred regardless of how much oil is actually produced. However, a long term O&M contract that anticipates some level of uncertainty during the ramp up period will mitigate this risk to some extent.

9.2.4. Performance risks

Performance levels throughout the lifecycle of the project are a key area of risk for all parties. There is currently uncertainty around the impacts of the performance of one part of the value chain on the other parts of the value chain. These risks will need to be appropriately identified, quantified, and allocated between the parties in a contractual framework. We have identified some key performance risks areas below.

For the power plant, there are performance risks throughout the operation of the project. However, these risks are higher and more critical during the commissioning period:

- **Power plant commissioning:** It may take longer than expected to reach full availability using the IGCC, as outlined in Section 8.3.1. This could necessitate producing a greater proportion of power from natural gas (which would not involve carbon capture), leading to greater costs associated with carbon emissions. It could also interrupt the supply of CO_2 to the EOR facility, potentially reducing oil production and revenues there. The liability for loss of earnings in this scenario is something that must be contractually agreed between the plant and EOR operators;

The CfD should be designed in a way to account for both this availability risk and the risks associated with completing construction on time and on budget, as well as around fuel costs that need to be managed. Whatever the arrangements that are agreed, the structure of the CfD must reflect these risks appropriately; it must ensure that all investors recover all of their investment in the carbon capture component of the plant over the term of the CfD, subject to meeting certain performance criteria. This approach will ensure that after the CfD term, investors are not exposed to extended costs associated with the power and capture plant.

There are also a number of performance risks facing the ongoing operations of the project, across the CCS value chain:

- **Power plant operations:** There is a risk that the capture plant performs worse than expected, leading to a lower than expected CO_2 capture rate and/or higher operating and fuel costs. There is also a risk that the performance of the plant, and the way it is run, may result in a dispute between plant owners and operator.

  These risks can be mitigated by ensuring that warranties are available for key items of equipment, and the CfD terms allow for adjustments associated with lower than expected plant physical operating characteristics. Agreements as to how the plant will be run should be agreed contractually between the plant owners and operators, with a dispute resolution mechanism in place. A further mitigant could be contractual provisions linking any de-rating of the plant to a lower EPC price or liquidated damages.

- **Transportation of CO_2:** The key risk is an inability of the transport operator to transport CO_2 between the power plant and the offshore facility. A damages clause in the agreement between the power plant and the transport operator would mitigate the financial aspects of this risk, which may include the loss of CfD benefits and the imposition of carbon taxes if the CO_2 were released or the capture plant became unavailable.

  However, if the lack of effective transportation prevented CO_2 from reaching the EOR site, it is unclear if the resultant fall in EOR revenue would be passed back to operators of the power plant, who are ultimately responsible for the supply of CO_2. The liability issues around this risk must be appropriately set out in CO_2 supply agreements between the power plant, transportation provider and offshore facility to allocate this risk.

- **Offshore facility:** There is a risk that there is lower than expected (or no) injection rates as a result of a loss of flows further upstream (either at the power plant or in the transport system). There is also a risk of lower than expected oil recovery due to either lower than expected CO_2 injection, or as a result of other factors such as lower than expected levels of oil available to recover, or other technical issues. There may also be a lower than expected ability to store CO_2 in the storage site due to unforeseen technical or geological factors.

  Liquidated damages payments set out in an agreement between the power plant and the offshore facility may mitigate against the risk of loss in the event of low CO_2 flows to site. Sufficient appraisal of site by appropriately qualified persons should mitigate against many of the technical risks set out above.

9.2.5. Decommissioning risks

Risks across the value chain of the project include:

- **Power plant:** There is a risk that there are insufficient funds to cover the costs of decommissioning. Although a power plant operator would rarely have to prepare a fund in preparation for decommissioning (unlike, for example, an offshore wind installation) it is generally expected that they should be able to cover the costs of decommissioning through the sale of any remaining assets. These assets may have too low a value to cover the cost of decommissioning and so either a fund could be maintained to cover this possible shortfall, or care should be taken to preserve the value of equipment (for example through diligent O&M).

  There is also some risk that the plant may be forced to close early. Risk mitigation here could come from fully understanding the regulatory and political environment (external factors) in order to lobby where possible for longer-life programmes such as grandfathering, and taking action to prevent early closure.

- **Transportation of CO_2:** There is limited risk to 2Co as decommissioning of the pipeline is the responsibility of the transportation owner/operator.

- **Offshore facility:** Risk of leakage is extremely low, but there will be a Government requirement[28] for continued monitoring for a number of years after injection of CO_2 finishes due to the continued need to demonstrate the security of the storage reservoir. The risk of large costs being incurred during this phase of the project becomes lower over time[29] as CO_2 is more likely to remain in the reservoir if it has already done so in the short term. However, there remains the low probability high impact risk of a leakage of CO_2, with associated remedial costs. There could also be decommissioning risks from a health and safety perspective associated with the oilfield.

  In order to mitigate these offshore risks, regulations require that a fund be built up over the duration of the plant life to cover potential leakage liabilities and decommissioning costs.

9.3. External risks

9.3.1. Political and regulatory risks

Risks across the value chain of the project include:

- **Power Plant:** Much of the detail associated with the key pieces of legislation designed to enable CCS is not yet known, and the conclusion of several key debates over regulation and legislation of the following issues will have a large impact on the viability of this type of facility:

  a) The carbon price/tax – this will determine how economically viable CCS is in comparison to other forms of fossil-fuel generation. In Norway, for example, a high carbon price has favoured CCS projects for many years, whereas in most European states it has typically been cheaper to pay to emit carbon than pay to capture it;

  b) The exact nature of the CfD, as set out in Section 6.3.4. along with the exact nature of grant funding provided to CCS.

28 2009 EU CCS Directive Storage of Carbon Dioxide (Licensing etc.) Regulations 2010 (2011 for Scotland)

29 http://www.moraassociates.com/reports/0701%20Carbon%20capture%20and%20storage.pdf

There is also the potential for future changes in policy to present risks - whilst these are largely issues that will affect the project in the funding and development stages, it is possible they could be important going forward:

c) The level of support for alternative low-carbon generation technologies (for example renewables like solar PV or wind) may affect the available funding for CCS;

d) The wider level of government and public support for CCS. Environmental groups in the UK have been broadly tolerant of CCS as a climate change mitigation technology but do not universally embrace it, and key stakeholders in UK government often appear divided over the issue. For a project which relies heavily on this backing, and given the failure of earlier UK projects, such as Longannet and the original Peterhead project, significant changes in the perceived deliverability of the project could pose a large risk.

Furthermore, policy regarding coal as a UK energy source remains uncertain. There are large volumes of coal available in Europe, but its use may be restricted in the future in a similar way to the current Large Combustion Plant Directive (LCPD), which is already resulting in early plant closures.

Mitigation of these regulatory and political issues may be difficult, so the developer must ensure key stakeholders stay informed of risks to the project as a result of regulatory indecision, delays or changes. Further, communication with wider stakeholder groups and the media will educate these groups on potential benefits of the project.

For DVPP, this risk recently, in part, materialised with the decision of the UK government not to select the project for grant funding under its planned CCS Demonstration Programme.

- **Transportation of CO_2**: The principal legal issue raised by transportation is the legal definition of CO_2, and whether it is considered a waste or a commodity. A particular concern is whether supercritical CO_2 is considered by the Health and Safety Executive (HSE) to be a 'dangerous fluid' in the Pipeline Safety Regulations, a matter which is currently under consideration[30]. This would largely determine the nature of liability and required legislation.

- **Offshore CO_2 EOR facility:** Current legislation and regulation contains some uncertainties in the context of CCS. Some of the most important areas of legislation are listed in Table 15 along with areas where the current legislation is lacking or in need of clarification.

  2Co has already consulted with DECC about the appropriate format of liability sharing both during and after CO_2 injection, which reduces the exposure to certain gaps in the current legislation, which are described in Table 15. However there is a degree of uncertainty surrounding the requirements of the project in developing adequate Measuring, Monitoring & Verification (MM&V) standards. It is unclear whether this will be carried out by other stakeholders, or if CCS operators will be expected to fund some of the technological developments.

30 www.hse.gov.uk/carboncapture

Table 15: Regulation of storage and possible areas for improvement

Key requirement of legislation	Current legislation	Areas for improvement	Finalisation level
Granting legal permission to store CO_2	2009 EU CCS Directive Storage of Carbon Dioxide (Licensing etc.) Regulations 2010 (2011 for Scotland)		High
Establishing who is fit to store CO_2	As above The Crown Estate permitting process	Clarifying exact requirements in regard to being 'financially sound and technically competent' (EU Directive)	High
Outlining short term obligations of site operator and authorities	Storage of Carbon Dioxide (Licensing etc.) Regulations 2010 (2011 for Scotland)	Improving innovation and standards in MM&V	Med
Outlining long term obligations of site operator and authorities	2009 EU CCS Directive Storage of Carbon Dioxide (Licensing etc.) Regulations 2010 (2011 for Scotland)	Possibly introducing a standard post-closure contract to guarantee liability is effectively distributed. Improving innovation and standards in MM&V	Med
Establishing framework to guarantee long term safety	As above	Improving MM&V across the CCS chain and establishment of global standards in site safety	Low

Whilst it is difficult to mitigate against future policy changes, it will be important to maintain awareness of political discussion and where possible influence the debate through effective lobbying and representation of CCS, both in the UK and to the EU institutions.

9.3.2. Economic risks

Risks across the value chain of the project include:

- **Power plant:** The macroeconomic climate is likely to have a significant impact on a wide range of variables. The major risks would appear to come from:

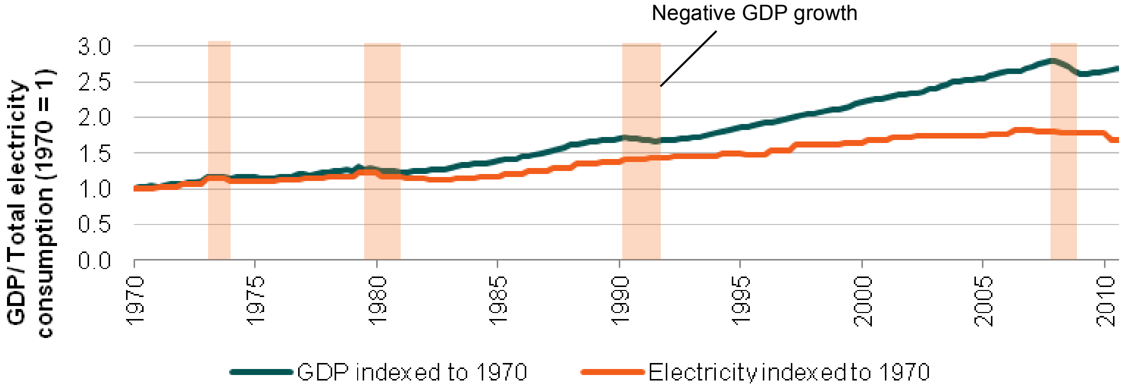
    a) Wider GDP growth and stability of the economy tends to affect demand for energy. As can be seen in Figure 41 below, UK electricity consumption has followed a growth path similar to GDP since 1970, and in particular has tended to level off or dip when the economy does likewise (except for in the early 1990s). It will also affect the level of private investment. A crucial concern for continued private investment and equity lies in the confidence of investors still reeling from the global financial and Eurozone crises.

    b) Foreign exchange rates. Many plant components making up the overall power plant capex (for example gasifiers) will be technology procured from overseas, given the UK's limited manufacturing capacity in these areas. As such, foreign exchange rates can cause substantial volatility in overall capex. Ongoing operating expenditure will also be affected.

    c) Interest rates will affect the project cost of debt. Given the importance of debt in the construction phase of the project, a small change in the interest rate could have a large impact on the level of debt.

    d) Inflation may impact the project, in several ways. Firstly, it will affect the real value of the CfD strike price, though this will be mitigated by indexing the contract to an inflation measure. Secondly, it could impact plant costs such as wages, costs associated with replacing equipment and other opex-related variables. However, inflation impacts cost inputs and project earnings differently. Where inflation causes cost inputs to rise faster than output prices, then this is a downside risk, but above-expectations inflation could also erode the real value of debt, making it easier to pay off.

Figure 41: UK GDP and total electricity consumption



Source: DECC, Bank of England

Foreign exchange rate risk can be mitigated by factoring it into the project's financial modelling. It is normal practice to undertake hedging of exposed costs to mitigate the foreign exchange risk. A similar approach should be taken for interest rate risks. Indexing contracts to an appropriate inflation index can mitigate inflation risks. For opex cost increases, a mitigation strategy will again lie in ensuring long-term contracts with appropriate suppliers.

- **Transportation of CO_2:** Inflation variation risks, which will affect the real value of transportation costs, will need to be mitigated against through appropriate hedging strategies and inflation indexed contract setting.

- **Offshore EOR and CO_2 storage facility:** Exposure to macroeconomic risks is likely to be similar to that of the power plant. In particular, given the capex will be funded entirely from private sources, the level of negotiated interest rates and the mechanism by which it is linked to the UK real interest rate will be important. Given a large proportion of this funding is likely to come from Asia, foreign exchange rates may also be a particular concern.

9.3.3. Financial risks

Risks across the value chain of the project include:

- **Power plant:** For a power plant development that has reached FID, there may be opportunities to refinance once the plant has proved itself operationally. At this point a new class of investor may be attracted - particularly those that do not like to take construction risk. This refinancing would allow early investors to extract some or all of their capital and reinvest in similar or other asset classes. There is a risk however that the plant owner would be unable to secure refinancing arrangements either due to the economics of the plant itself or the state of the wider economic environment.

- **Transportation of CO_2:** There may be pricing uncertainty in the tolling arrangements between the power plant and transportation owner. However these will be agreed as part of the contractual arrangements so may be risk limited;

- **Offshore EOR and CO_2 storage facility:** For the offshore facility, the risks posed are similar to the power plant, in terms of refinancing and taxation. However, taxation is likely to be a higher risk in the offshore environment, and understanding the ongoing tax environment and taking appropriate mitigating strategies is crucial.

9.3.4. Market risks

If this was a fully commercial power project then the market risks for DVPP would relate to the 'spread' that the plant could achieve in the market, i.e. value of the power generated less the cost of coal consumed (plus some carbon costs). However, as discussed previously the project will require a CfD to ensure that the plant earns sufficient revenue to make the business case work.

The CfD has the ability to allow for risk transfer or risk sharing between the project and the consumer who pays for the subsidised power price. The plant will receive a forward price for its electricity, determined by negotiations with wholesale buyers, plus the difference between the agreed Strike Price and an index of average market prices (the exact nature of this index is still a matter of some uncertainty). The risk to 2Co, therefore, lies in ensuring the forward price it receives for the electricity is not below the price specified in the index. If this were the case, 2Co would not receive a sufficient 'top up' from the FIT CfD to reach the overall headline price necessary to make the project economically viable.

Risks across the value chain of the project include:

- **Power Plant:** Overall profitability relies to some degree on certain market variables over which it may have little direct control. These include:

    a) The price of wholesale power: The price of wholesale power is historically volatile, as discussed in Section 8.3.3.2. However, the CfD should mitigate this risk, by presenting 2Co with one price regardless of market conditions. Risks would emerge, however, if the tenor is too short. If it expires part way through operations, 2Co will be exposed to risk after the tenor ends, and will require a higher CfD Strike Price to compensate (though this is more of a contractual risk than a market risk per se).

    b) Fuel Prices: The price of gas will carry some influence, particularly if the plant is forced to generate more power from the CCGT during the commissioning period. However, the primary source of fuel will be coal, and the way its price changes in the future will be crucial. Price changes in coal will by driven by both demand and supply factors:

        - Demand: Globally, the Energy Information Administration (EIA) predicts that coal's share of overall electricity generation will fall to 39% over the next 25 years, well below the 49% share seen in 2007.[31] This is largely due to competition from natural gas and renewable plants and the need to comply with new environmental regulations. However, high oil prices in 2011 steered a 5.4% rise in coal consumption, marking above-average growth and demonstrating the volatility of prices[32]. In the longer term, the rapidly increasing demand from Asian countries for cheap coal is expected to result

31 Early Release 2012 Annual Energy Outlook, Energy Information Administration (EIA)

32 2012 Statistical Review - BP

in less coal being available for European markets. It will also be interesting to monitor the effects of UK Government policy on coal prices, especially with the introduction of the carbon price floor potentially lowering demand in the longer term.

- Supply: European coal supplies are expected to come primarily from Russia, Colombia, USA and South Africa in the medium to long term, as other large producers will tend to export to Asia. As a result, Russian and US marginal price drives supply. The IEA (in the Annual Energy Outlook as before) predicts that, despite cost savings from technological improvements in coal mining, prices will be driven up by the need to move into reserves that are more costly to mine.

Given the array of variables affecting both supply and demand for coal, fuel and power prices are expected to be volatile over the life of the plant, and as such a CCS developer could mitigate risks caused by this volatility by indexing CfD to fuel prices, as well as potentially engaging in other hedging strategies.

- **Transportation of CO_2:** There may be pricing uncertainty risk inherent within in the tolling arrangements which could be mitigated through clear long term contracts which contain an appropriate methodology for dispute resolution.

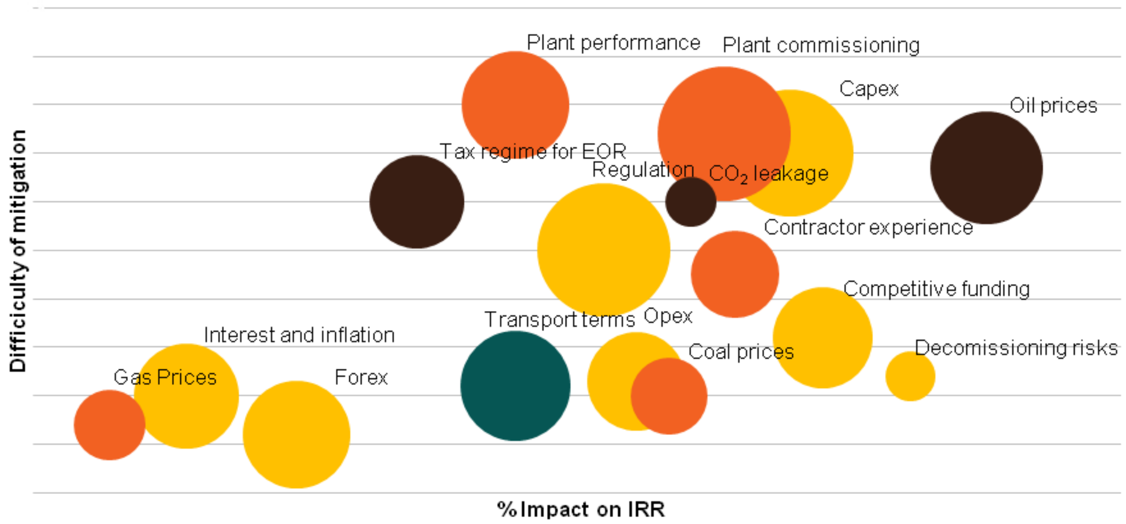
- **Offshore EOR and CO_2 storage facility:** The key risk here relates to the Brent Crude price. Drivers of the oil price include global supply and demand for oil products. According to BP's 61st Statistical Review of World Energy, oil remained the world's leading fuel with a 33.1% share of the global energy mix. It also states that in 2011 global oil production increased 1.3% to 83.6mmb/day compared with 2010. Potential future upside price opportunities are OPEC's limited spare capacity and geopolitical events, as well as rising costs of production and stronger future economic growth. By contrast, BP's review (as above) commented that in 2011 OECD consumption declined 1.2% to 45.9mmb/day, the lowest level since 1995.

  By engaging in risk-sharing contracts or alternative hedging strategies it is possible to limit the exposure to this historically volatile market price, although typically oil producers rarely engage in this form of hedging. As such, it will be difficult to guard entirely against this risk. However, it is worth noting that the risk goes both ways: if the oil price is higher than predicted, this represents a gain for EOR.

9.4. Risk mitigation

The chart below, Figure 42, sets out the level of mitigation able to be applied to the key risks listed above, and takes into account the potential size of the risk in terms of both its likelihood, and the extent to which it could affect the project Internal Rate of Return (IRR).

Figure 42: Project risks by size



Size		Low likelihood of risk			Medium likelihood of risk		High likelihood of risk	
Colour		Risk to Power and Capture Plant		Risk to Transportation		Risk to EOR/Storage		Risk to all or several

As those bubbles on the right represent a larger impact on IRR, and those higher on the Y axis represent those risks less able to be mitigated, those risks in the top and right parts of the graph should be given extra consideration. The size of the bubble, indicating a likelihood of the risk occurring, suggests that costs relating to oil prices, capex, and plant commissioning and performance, should be the priority for planning against and for taking appropriate action.

10. Conclusion – next steps

At the beginning of this report it was mentioned that if DVPP's financing and risk strategies are implemented effectively, and the UK government implements its planned regulations supporting CCS, 2Co is confident that the DVPP can be one of the first successful large-scale CCS projects to be built in Europe.

For DVPP, the risk represented by 'competitive funding' recently materialised with the decision of the UK government not to select the project for grant funding under its planned CCS Commercialisation Programme. This risk in turn impacts the funding strategy, by reducing the grant funding available and increasing the requirement for debt or equity.

Therefore 2Co is now working to manage the impact of this materialised risk and to establish the best way for DVPP to proceed in the absence of UK government grant funding. Once 2Co is confident that it has a funding strategy and business case that is suitable, it will move on with development of the project.

This will include working with government on agreeing the details of the required power premium for the project, based on the draft bill published at the end of 2012.

At the same time, it includes working to achieve greater technical definition on both DVPP and the EOR storage project, which will in turn enable some of the more important risk mitigation strategies to be implemented, for example passing much of the capex risk to the EPC contractor. Agreeing commercial terms for the key contractual relationships along the value chain will assist in this endeavour.

A final key area of focus is to enter into more detailed conversations with debt providers to the project, to ensure that the envisaged project cash flow and risk profile is at all times a financeable prospect.

If success is achieved on each of these next steps, then 2Co remains confident that DVPP can successfully become one of the first large-scale CCS projects in Europe.

Glossary

BSC	Balancing and Settlement Code
Capex	Capital expenditure
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCSA	Carbon Capture and Storage Association
CDM	Clean Development Mechanism
CfD	Contracts for Difference
CO_2	Carbon Dioxide
CPS	Carbon Price Support
DECC	Department of Energy and Climate Change
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
EPS	Emission Performance Standard
EC	European Commission
EMR	Electricity Market Reform
EPC	Engineering, Procurement and Construction
FID	Final Investment Decision
IGCC	Integrated Gasification Combined Cycle
IRR	Internal Rate of Return
LCOE	Levelised Cost of Energy
NGC	National Grid Carbon
NGG	National Grid Gas
Ofgem	Office of Gas and Electricity Markets
OOIP	Original Oil In Place
Opex	Operational expenditure
PPA	Power Purchase Agreement
RO	Renewables Obligation

TINA	Technology Innovation Needs Assessment
UKCS	UK Continental Shelf