Assessment of the range of potential funds and funding mechanisms for CO_2 transportation networks

May 2008

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DRAFT REPORT

CO_2 Capture Project

Assessment of the range of potential funds and funding mechanisms for CO_2 transportation networks

May 2008

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Environmental Resources Management

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EXECUTIVE SUMMARY

BACKGROUND AND RATIONALE

This report has been prepared for Phase II of the CO_2 Capture Project (CCP2) by Environmental Resources Management (ERM).

The basis for the research was the view that pipelines for CO_2 transport could evolve in two ways:

1. On a point-to-point basis, which match a specific source to a specific storage location; or
2. Via the development of pipeline networks, including backbone pipeline systems, which allow for common carriage of CO_2 from multiple sources to multiple sinks.

A combination of the two will likely prove to be the most optimised approach, with individual projects driving the scope for development on a network basis. However, establishing such a network of CO_2 transportation infrastructure will require long-term planning and adopting a strategy that takes into account the potential magnitude of future deployment scenarios for CCS (i.e. 100's $MtCO_2$ being transported over long distances).

As such, future strategies for private business and policy-makers should take account of the following:

- That whilst point-to-point pipelines may be readily funded on a project-by-project basis by individual developers, there may be a need for public policy that encourages the development of optimised networks. Development on this basis can help to broaden participation and deepen deployment of CCS; (1)
- The incremental cost of building optimised networks ahead of point-to-point pipelines may not pass project-specific commercial evaluation criteria;
- Consequently, other forms of criteria and financial support which overcome commercial barriers may be needed to ensure optimised development of CO_2 pipelines networks.

Two further elements were also considered to influence the way pipeline networks are promoted and deployed, namely: geography and geo-political factors; and, the nature of policy tools used to incentivise CCS.

The approach taken to address these questions was as follows:

(1) As it will lead to reduced unit transportation costs, reducing entry costs for new entrants , especially for smaller emitters which may not have the capacity to self-finance or raise capital from the financial markets for an individual pipeline.

1. To review the rationale, models and mechanisms used to promote and finance large oil & gas backbone pipelines;
2. To review the same issues for other types of large public infrastructure works, such as road and rail projects;
3. To undertake economic analysis of the relative risks and opportunities associated with developing point-to-point pipelines or backbone pipeline networks; and,
4. To hold discussions with a range of potential financiers for CO_2 pipeline development.

A summary of each is provided below.

O&G AND PPP CASE STUDIES

This study highlighted that various factors enhance project financeability, yet there are also issues which inhibit financeability. Factors which enhance financeability include: that pipeline technology is well established and as such can be seen as a proven technology; major oil and gas sponsors are likely to be creditworthy and are experienced in pipeline development; and that a future stream of cash flows is identifiable in pipeline projects. On the other hand, while the risk of transportation of commodities such as oil and gas presents a relatively low market risk, inhibiting factors include: security issues; regulatory intervention; and, transit and cross-border risks (transit-fee uncertainty). Such issues can result in an increased cost of capital, which in turn may affect the cost of the delivered hydrocarbons.

Public-Private Partnership structures are widely used for the delivery of public goods and services. PPP's, which include large transportation projects, have the advantage that they provide benefits not only to the promoter, but also to the public sector (such as attraction of foreign investment). There are also a variety of financing mechanisms for PPP projects and each case study reviewed used different funding options. These ranged from government bonds and other guarantees to private debt and equity.

Clear specifications of outputs are important in PPP projects and as such they tend work well for simpler projects. The development of a CO_2 transportation network could potentially be quite complex and require a large number of parties to be involved, which is one of the potential downsides of PPP's.

COMMERCIAL AND ECONOMIC ISSUES

A range of commercial factors were identified for CCS projects, covering policy approaches to incentivising CCS and regional strategic considerations. The former includes options such as: mandating CCS; fiscal policy; market based approaches, or through provision of public subsidies for the uptake of a technology. The latter includes geographical/geopolitical factors, such as whether regions have low emissions and good storage potential; high emissions and poor storage potential: or have commercial incentives for enhanced hydrocarbon recovery. These factors could impact the way governments and commercial operators act.

The oil & gas pipeline case studies also provided strong evidence to suggest that different incentives – or market "push" or "pull" factors – are strong influencing factors on how projects are structured. On this basis, it was concluded that:

- the commercial environment for CCS, based on either an upstream or downstream point of incentives (i.e. market push or pull characteristics), could determine how a CO_2 backbone pipeline project is structured and deployed;
- strategic factors will also play a role in influencing decisions regarding deployment, and also the terms and nature of financing sources; and
- in turn, these will influence the structure of CO_2 pipeline project development.

Depending on how the above factors all play out in different deployment scenarios, they could influence whether CO_2 backbone pipeline projects emerge ahead of simple point-to-point pipelines deployed on a project by project basis.

A pipeline economic model was built to quantitatively evaluate options for connecting ten (10) power plants with a storage site located on average 600 miles away. Options included four (4) point-to-point pipelines or one (1) backbone network pipeline to connect the power plants with the storage site.

The results of the evaluation suggest the following main deployment challenges for the development of a backbone pipelines:

- System capacity utilisation; a backbone pipeline would need a sufficient utilisation of its capacity in order to be economical.
- Marginal benefits for a first mover might be relatively small compared to potential risk/financial loss if full capacity is never realised;
- Financeability issues such as high capital investment requirements combined with revenue uncertainty.

Risk mitigation options that can manage the challenges presented may be required to promote successful deployment of backbone pipelines. Analysis undertaken suggests that there is an opportunity for governments to provide the support that is needed in the first few years of operation to help first movers to build pipelines with excess capacity for new entrants and realise economies of scale. Favourable financing options could enable the financeability of a pipeline network and take up some of the risks associated with excess capacity.

Financing support can be provided in the form of capital grants, recycling of environmental tax revenues (i.e. auction revenues of carbon allowances) and/or low cost government financing like guaranteed bonds, etc.

Project revenue guarantees or cost of service subsidies for an operator that builds a pipeline with excess capacity in order to accommodate future users could be another type of support.

Direct government involvement, in terms of ownership, could be another support option where the government would assume the project entirely.

Any adopted fiscal incentives have to be long term, as investors will be reluctant to participate in the development of CO_2 infrastructure if there is uncertainty that these can be changed during the project lifetime. In principle, once the price of carbon is stable and high enough to cover the aforementioned risks, the incentives would no longer be needed.

FINANCING

Economic analysis undertaken suggested that a CO_2 pipeline network developed by individual operators would expose a single entity to significant first-mover risk and additional up-front costs.

The first-mover risk project participants would be exposed to is likely to be much higher during the demonstration stage of CCS. As pipeline networks start to develop, the risk could gradually phase out as new entrants enter the market.

The interviews with the financial sector suggest that private and public banks are closely following the development of CCS. The broad impression that ERM gained from these interviews was that the financial sector would look to become involved once there is more certainty around the current regulatory and policy issues affecting CCS. Particular risks and uncertainties perceived by banks include: uncertainty over carbon price; CCS technology risks; contractual risks; project coordination risks (coordination between sources and sinks is complex); throughput risks – due diligence covering issues such as how throughput would be contracted, how CCS policy fits into government's energy policy, capacity build-up for backbone pipelines and storage risks; and environmental and social risks.

1 INTRODUCTION

This report has been prepared for Phase II of the CO_2 Capture Project (CCP2) by Environmental Resources Management (ERM). It has been written over the period August 2007 – March 2008. It provides an assessment of the range of potential funds and funding mechanisms for CO_2 transportation networks, covering a review of analogue projects in oil & gas and infrastructure development, and stakeholder analysis.

A range of discussions and interviews with a range of stakeholders have been undertaken in compiling the report. These include:

- *For oil and gas pipeline financing case studies*: Kinder Morgan CO_2 Company, Chevron and Shell.
- *For financial sector perspectives on CO_2 pipeline financing*: a range of public (multilateral) lending institutions and private banks.

The authors gratefully acknowledge the support received in-kind from those individuals and institutions that made a valuable contribution to shaping this report.

1.1 PROJECT BACKGROUND

The most cost effective way to transport large quantities of CO_2 from source to storage will be though high pressure pipelines [(1)]. Pipelines for CO_2 transport may evolve in two ways:

1. On a point-to-point basis, which match a specific source to a specific storage location; or
2. Via the development of pipeline networks, including backbone pipeline systems, which allow for common carriage of CO_2 from multiple sources to multiple sinks.

A combination of the two will likely prove to be the most optimised approach, with individual projects driving the scope for development on a network basis. However, establishing such a network of CO_2 transportation infrastructure will require strategic long-term planning, adopting a paradigm that takes into account the potential magnitude of future deployment scenarios for CCS (i.e. 100's $MtCO_2$ being transported over long distances).

As such, future strategies for private business and policy-makers should take account of the following:

(1) Other forms of transport such as road, rail and ship tankers are unlikely to prove economic at the sort of scale of deployment under consideration.

- That whilst point-to-point pipelines may be readily funded on a project-by-project basis by individual developers, there may be a need for public policy that encourages the development of optimised networks. Development on this basis can help to broaden participation and deepen deployment of CCS;

- The incremental cost of building optimised networks ahead of point-to-point pipelines may not pass project-specific commercial evaluation criteria;

- Consequently, other forms of criteria and financial support which overcome commercial barriers may be needed to ensure optimised development of CO_2 pipelines networks.

Two further elements will also influence the way pipeline networks are promoted and deployed, namely: that geography and geo-political factors are likely to influence the scope and drivers for promoting the development of CO_2 pipeline networks (i.e. different regions will have varying combinations of sources and sinks, which will determine how they promote CCS network development); and, the nature of policy tools used to incentivise CCS (i.e. whether incentives apply to the emitting source of the storing site). Demand for, or promotion of, CO_2 for use in Enhanced Oil Recovery (EOR) may also be a factor in determining the way in which CO_2 networks are developed. It is against this background that this project has been undertaken.

1.2 *APPROACH, AIMS AND OBJECTIVES*

The aim of this study is to better understand the commercial preconditions under which CO_2 pipeline networks might be developed, focussing on the basis upon which such networks might be financed. In order to achieve this aim, the project team considered that the following approach and objectives would be most effective:

1. *To review the rationale, models and mechanisms used to promote and finance large oil & gas backbone pipelines*. The oil & gas case studies provide a practical understanding of the funding models and mechanisms presently employed by industry that could potentially be applicable for the development of CO_2 pipeline networks.
2. *To review the same issues for other types of large public infrastructure works, such as road and rail projects.* Specific to this context, the role of public-private partnerships (PPPs) was also considered. The case studies provide an understanding of how public infrastructure projects are developed as a means to assess how governments might play a role in helping to deploy CO_2 networks [(1)];
3. *To undertake quantitative analysis of the relative risks and opportunities associated with developing point-to-point pipelines or backbone pipeline networks.*

(1) Taking into account that CO_2 emissions are an externality, and consequently climate change mitigation is a form of public good in which governments have a key role to play.

The objective of this exercise was to develop quantitative estimates of the relative costs of taking either approach, based on the development of a scenario, pipeline economic model and comparison of results. Assessment of the commercial factors affecting decision-making is also made; and,

4. *To hold discussions with a range of potential financiers for CO_2 pipeline development*. This provides an initial view on how project financiers consider the options for financing CO_2 networks.

To set the scene for understanding the issues related to pipeline funding, a brief review of financing models and sources is provided in the next section.

1.3 PROJECT FINANCING OVERVIEW

Project financing consists of two main structural components:

- *The financing model*. This can be based on either: a corporate finance model; a project finance model; or a public-private partnership model; and
- *The sources used for financing*. This can consist of: sponsor equity/investment; commercial (senior) bank loans; third-party funds; bonds and capital market loans; mezzanine finance; public financial support, and combinations of these.

These components of the project financing structure are important in influencing items such as: access to – and cost of – capital; risk exposure of project sponsors and lenders; and project complexity. A more detailed review of each is provided below.

1.4 FINANCING MODELS

Financing models involve a number of parties but they can usually be placed into two broad categories:

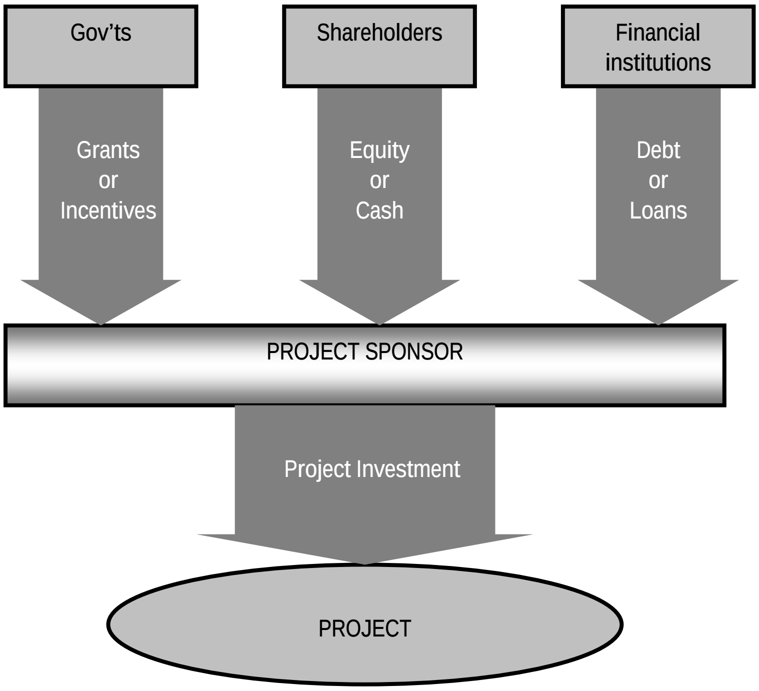
- the financing partners (banks, shareholders, the state) which provide the financing; and
- the project sponsors or promoters (corporation, special purpose vehicle etc.) that receive financing.

1.4.1 Corporate Finance

In the corporate finance model, the financing partners provide funding directly to the project sponsors. In this sense, investors are exposed to the credit risk of the sponsors and not of the project itself. This structure means that there are limitations on the type and level of risks lenders and borrowers can be exposed to.

The promoter's financial strength and creditworthiness is the main factor that can determine project financing decisions. A project promoter can differ depending on the circumstances and can be a company, a consortium of companies, an institution, a national government, or a combination thereof.

Figure 1.1 Corporate Finance Model



Major characteristics:

- Financing partners provide funding to the promoter on the basis of its financial strength.
- A promoter can be a company, a consortium of companies or an institution
- The financing partners are exposed to the credit risk of the promoter, not of the project.

A typical example of a corporate finance model is where a company seeks financing to develop, at its own risk, a new product. It is not typically applied in the financing of infrastructure type projects, and thus will not be considered further in this report.

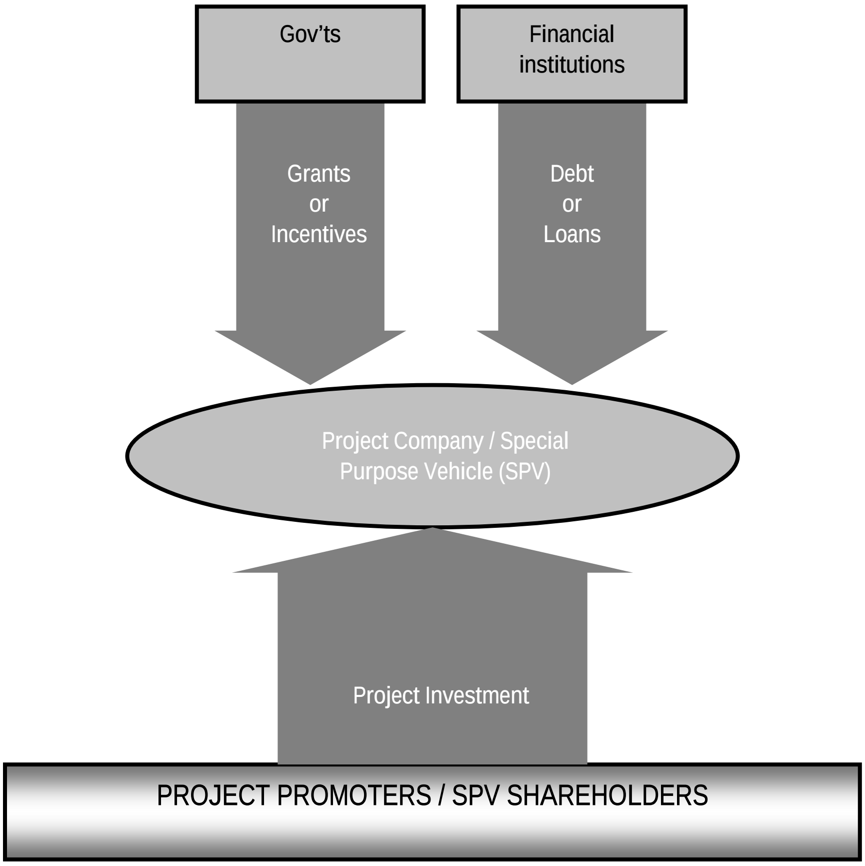
1.4.2 *Project Finance*

The project finance model involves the establishment of a new company usually called a special purpose entity (SPE) or a special purpose vehicle (SPV) to develop, finance, construct and operate a specific project. The most common structures that are used for establishing an SPE are:

- Joint venture or other similar unincorporated association
- Partnership
- Limited partnership
- Incorporated body (i.e. limited company)

By using a project company to promote a project, project sponsors limit their financial exposure to the project up to the value of their equity and/or debt contributions. This contrasts with the corporate finance model where the sponsors are fully exposed to the full value of the company. Project lenders secure debt financing against the project's assets (collateral) and loan repayments from the cash flow generated by the project, as opposed to the general assets or creditworthiness of the owners of the project SPE/SPV.

Figure 1.2 The Project Finance Model



Major characteristics:

- Financing partners provide funding to the promoter on the basis of its financial strength.
- A promoter can be a company, a consortium of companies or an institution
- The financing partners are exposed to the credit risk of the promoter, not of the project.

A project finance model example could be one where a consortium of energy companies would like to develop an IGCC power plant and in order to share the risk they create a designated project company. The project finance model is more complicated and initially probably more expensive than alternative financing methods, however it provides a level of security to project sponsors due to the credit risk limitations.

Some of the benefits of the project finance model are outlined below:

- Provides insulation of sponsors from project debt and the risk of any failure of the project;
- Sponsors are not required to consolidate the project's debt on to their own balance sheets (although that depends on accounting and/or legal requirements applicable to each sponsor);
- Enables project risk-sharing as smaller companies' balance sheets may not be strong enough to raise the necessary investment;

- Removes corporate borrowing constraints (e.g. due to corporate loan documentation or borrowing restrictions in entity's statutes);

- Has a risk-sharing basis for investment that is easy to agree on;

- Provides tax advantages in a particular jurisdiction (e.g. in the form of tax holidays or other tax concessions).

1.5 PROJECT FINANCING SOURCES

Project financing sources will vary according to certain specific project factors such as location, type and size of project. These sources can be private, public or both.

1.5.1 *Private Funding Sources*

The main private funding sources available for project finance are outlined in *Table 1.1* below.

Table 1.1 Private Funding Sources for Project Finance

Type	Description	Investment Objectives
Project Sponsor(s) Investment	In this arrangement, the project sponsors are shareholders of the project SPV/SPE company, and therefore contribute financial support in various forms to the project. Typically support includes comfort letters, cash, equity and other capital contributions, guarantees as well as management and technical assistance. For CCS these could be corporate and compliance investors.	Carbon acquisition or trading for compliance or profit
Commercial Bank Loans	Whilst projects may be financed either partly or wholly by way of commercial bank loans, for large infrastructure projects that require large amounts of initial capital investment funding, loans are usually syndicated across a group of banks. Depending on the loan size, syndicated loans may involve one or a small group of lead banks (i.e. the arranger(s) or agent(s)) which are the original signatories to the loan agreement and can underwrite all or a percentage of the loan and syndicate the rest to other banks.	Certainty on cash-flows
Third-Party Funds	Third party funds (e.g. infrastructure funds) consist of financial support from investors that are willing to place finance into a project alongside the original project sponsors. They can often be a valuable funding source for capital intensive projects, are typically in the form of equity, and may require some presence on the board of the SPE/SPV.	Stable long-term yield

Type	Description	Investment Objectives
Bonds and Capital Market Funding	A project company can raise finance via an initial public offering (IPO) of debt securities (bonds) or equity securities (stocks). Examples of projects funded by bonds do exist, for instance, in connection with the UK Government's Private Finance Initiative (PFI) and for some US based projects in locations where a robust local bond market exists. The main benefit of the bond market is that it offers fixed rate funding at generally cheaper rates than bank loans.	Diversification
Mezzanine Debt	Mezzanine finance consists of a form of debt that is subordinate to senior bank loans. It often also includes quasi-equity interest in a company, which can be a form of payment in the event of loan default. The benefits are that it is a cheaper form of capital than pure equity, although it is generally a more expensive form of finance than senior bank loans. Public banks can also play a role in supporting mezzanine finance. Mezzanine finance can be an attractive form of financing for projects which contain levels of risk that are not considered acceptable for commercial bank loans to tolerate, whilst the management team are still able to maintain their own equity interest. Traditionally, mezzanine capital is used to fund growth opportunities (i.e. acquisitions, plant expansions etc.) but it can and it has been employed in (mainly Greenfield) infrastructure development. (1)	Relative certainty on cash flows

1.5.2 *Public Funding Sources and Guarantees*

Infrastructure projects that are of strategic importance to a country can be given financial support through direct government loans, multilateral agency support and through regional development banks. These institutions can offer grants and guarantees as well as loans and equity if needed to promote project completion. Sometimes this support is provided in the context of a Public-Private Partnership (see *Section 3*). *Table 1.2* summarises the main public financial support mechanisms for a project.

Table 1.2 Main Public Funding Sources and Support Mechanisms

Type	Description
Loans	Governments can share the project's financial risks by providing funding in the form of loans via designated financial institutions (i.e. export credit agencies, known as ECAs) or other organizations such as multilateral agencies and development banks (i.e. EIB, World Bank, IFC, etc.). The European Investment Bank (EIB), the World Bank or its private sector lending arm, the International Finance Corporation (IFC), the European Bank for Reconstruction and Development (EBRD) and Export Credit Agencies (ECAs) are significantly engaged in joint financing of projects particularly in the area of energy infrastructure and development of pipeline networks. Examples would include the Baku-Tbilisi-Ceyhan (BTC) pipeline that was partly funded by the European Investment Bank (EIB), ECAs and the Government of Azerbaijan.

(1) Asian Development Bank (ADB), Investing in Clean Energy and Low Carbon Alternatives in Asia, 2007 www.adb.org/Documents/Studies/Clean-Energy-and-Low-Carbon-Alternatives-in-Asia/default.asp

Type	Description
Grants	Grants are also available in the form of bilateral or multilateral assistance and support in cases where a project is considered important for the promotion of strategic interests. A European example is the INOGATE programme which aims to promote the regional integration of oil and gas pipeline systems in order to facilitate oil and gas transport towards the EU markets and encourage private investment and international financial institutions' support. (1)
Guarantees (2) (3)	Guarantees provided by multilateral agencies and development banks (e.g. World Bank) have the purpose of facilitating project financing by providing risk coverage to projects which would otherwise be unattractive due to the level or nature of associated risk which the market either cannot bear or assess. In that sense Guarantees can increase access to funding sources and reduce the financing costs of the project as this enables lenders to commit to longer term loans (cheaper than shorter-term) with important implications for long-term infrastructure projects such as pipelines.

Financing high-profile infrastructure projects not only requires lenders to commit for long maturities (4), but also makes them particularly exposed to the commercial and regulatory risk and political interference by host governments. Typically capital intensive large infrastructure projects are exposed to three different types of risk:

- Commercial risk (e.g. commodity price and volume)
- Regulatory (e.g. market rules and regulation)
- Political risk (uncertainty regarding political stability etc.)

Typical forms of a guarantee that a project can take in order to mitigate the above risks are described in *Table 1.3*:

Table 1.3 Forms of Guarantees

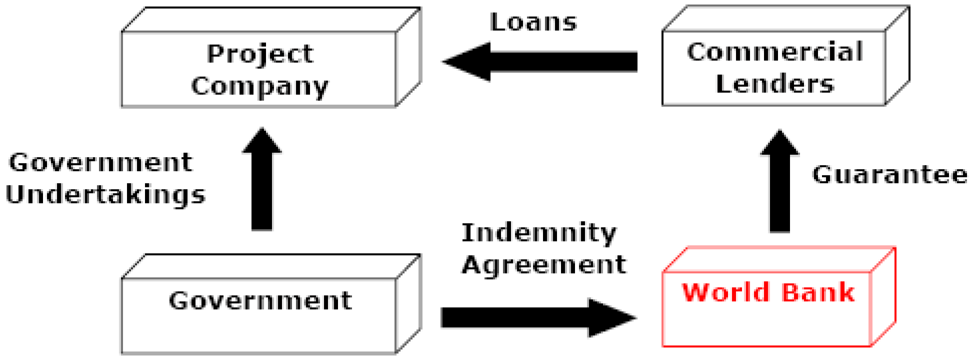
Type	Description
Credit Guarantee	A credit guarantee covers private lenders against the full or a designated portion of their financing (partial credit guarantee) against all risks during a specific period of the financing term regardless of the cause of default (i.e. both political and commercial risks are covered). These are used typically for limited recourse private projects. An example is the West African Gas Pipeline (WAGP).
Partial Risk Guarantee (PRG)	Partial risk guarantee ensures payment in the case of debt service default resulting from the non-performance of contractual obligations undertaken by the government or their agencies in private sector projects. PRGs cover commercial lenders in private projects. They typically cover the full amount of debt.

Figure 1.3 shows a relatively simple structure in which a joint venture (i.e. Project Company) develops an oil or gas pipeline and delivers the commodity

(1) http://www.inogate.org
(2) The World Bank Guarantee Program, http://rru.worldbank.org/Documents/Toolkits/Highways/pdf/extract/E16.pdf
(3) A Guide to Project Finance, Denton Wilde Sapte, April 2004
(4) Maturity refers to the final payment date of a loan or other financial instrument, at which point all remaining interest and principal is due to be paid.

(oil or gas) to a state owned oil and gas company (i.e. government). The government-owned company, which the project lenders perceive as a weak financial credit, enters into a commercial agreement with the project company. The project lenders agree to underwrite a loan to the project company on the condition that the World Bank guarantees the loan against the risk of government breaching its agreements and causing an interruption in repayment. In case of a default, the World Bank would then demand reimbursement from the government under the terms of an indemnity agreement. (1)

Figure 1.3 *Partial Risk Guarantee*



Source: http://siteresources.worldbank.org/INTGGFR/64168360-1121105776335/20578314/ScottSinclairOPEC2005.pdf

Project lenders are increasingly making use of guarantees, especially in emerging economies where the level of risk is considered unacceptable (discussed later in the West African Gas Pipeline - WAGP case study).

Table 1.4 presents how a partial risk guarantee can facilitate the financing of projects through risk mitigation.

Table 1.4 *Instrument Availability and Relevant Risk Coverage*

	Credit Guarantee	Export Credit Guarantee or Insurance	Political Risk Guarantee or Insurance
Sovereign Debt			
Political Risk	X	X	X
Commercial Risk		X	
Corporate Debt			
Political Risk	X	X	X
Commercial Risk		X	
Equity Investment			
Political Risk			X
Commercial Risk			

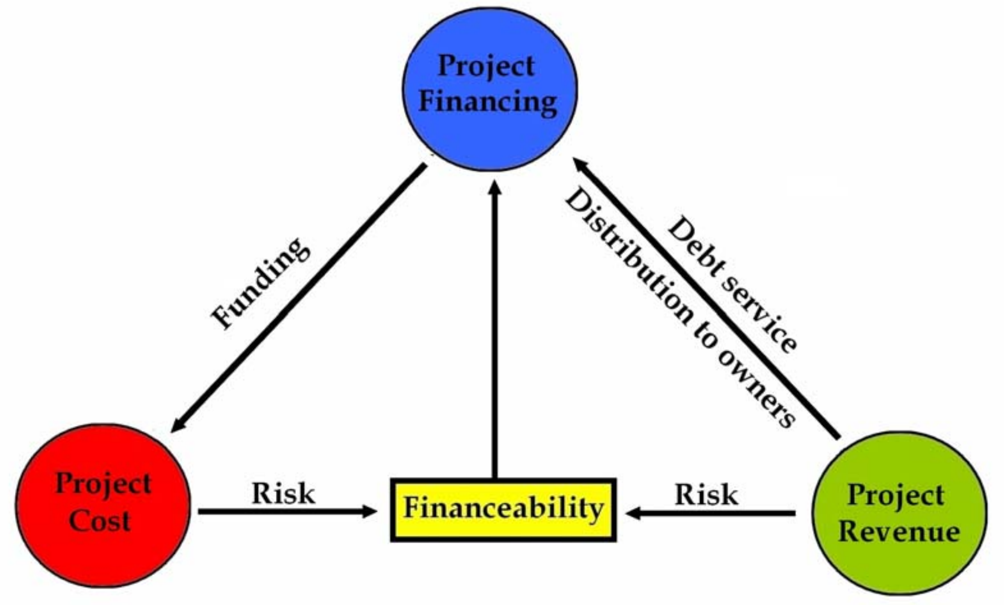
Source: Review of Risk Mitigation Instruments for Infrastructure Financing and Recent Trends and Developments, Tomoko Matsukawa and Odo Habeck, IBRD/World Bank, http://www.ppiaf.org/Trends&policyseries/Riskmitigationinstruments.pdf

(1) Please note that World Bank guarantees are not insurance policies, http://rru.worldbank.org/Documents/PublicPolicyJournal/157sincl.pdf

1.6 CONTEXT OF THE ANALYSIS PROVIDED IN THE REPORT

As broadly described above, project costs and revenues are the cornerstone of any investment appraisal. These make up the financeability of project, based on how much it costs versus how much money it will generate, and over what time period. An underlying element of both parts of the financeability formula is project risk, which can underpin costs and revenues. In turn, the combination of costs, revenues and risk, will influence the availability of capital and its cost (i.e. the cost of borrowing money to finance a project). It is these themes that underlay the analysis presented in this report (*Figure 1.4*). The simple business model developed for CO_2 pipelines in Chapter 4 also follows this structure.

Figure 1.4 Project Financeability Model



1.7 REPORT STRUCTURE

The remainder of this report is organised as follows:

- *Section 2* outlines the key findings of the oil and gas pipeline case studies.
- *Section 3* discusses the findings from Public-Private Partnership case studies.
- *Section 4* explains how a simple business model for a backbone CO_2 pipeline would work and presents the results of ERM's model.
- *Section 5* includes a review of green investment funds and interview results that ERM undertook with the financial sector.
- *Section 6* highlights the overall key findings of this study and provides recommendations and issues for further discussion.

- *Annex A* includes the documentation of oil and gas Pipeline case studies.

- *Annex B* includes the documentation of Public-Private Partnership projects case studies.
- *Annex C* provides an overview of available carbon and clean-energy funds and a relative high-level assessment of their criteria in relation to applicability for CCS financing.
- *Annex D* provides further information on the assumptions that were made in relation to the pipeline business model.
- *Annex E* is a brief glossary of mainly financial terms used throughout this report.

2 KEY FINDINGS OF PIPELINE CASE STUDIES

2.1 INTRODUCTION

Oil and gas pipelines present a great source of practical knowledge as they share a lot of similarities with CO_2 pipelines in terms of materials used, construction, operational characteristics (with the only difference that CO_2 pipelines require higher pressures, roughly 2,000-3,000 psi for CO_2 as opposed to 1,000 psi for gas). Additionally there is some experience in the United States where CO_2 pipelines have existed for more than thirty years for Enhanced Oil Recovery (EOR) activities.

The main characteristics of the reviewed pipeline case studies are presented below (*Table 2.1*). A detailed review of each case study is presented in Annex A.

Table 2.1 Oil & Gas Pipeline Case Study Summary

Pipeline	Route Description	Type	Length	Maximum Capacity	Cost
BTC	From Azeri-Chirag-Guneshli oil field in the Caspian Sea, through Azerbaijan and Georgia, to the Ceyhan terminal on Mediterranean coast of Turkey	Oil (onshore)	1760 km.	1 mbd	$3.6 billion
WAGP	From Nigeria's Escravos region of Niger Delta area to Ghana, Togo, and Benin	Gas (offshore)	678 km.	12.8 million m3/day	$0.6 billion
Langeled	From the Nyhamna terminal in Norway via the Sleipner Riser platform in the North Sea to Easington, England	Gas (offshore)	1200 km.	74-80 million m3/day	$3.5 billion
Nabucco	From Georgian/Turkish and/or Iranian/Turkish border respectively, leading to Baumgarten in Austria	Gas (onshore)	3300 km.	85 million m3/day	$7.1billion (est.)
Alliance	From eastern British Columbia and north-western Alberta, to Chicago	Gas (onshore)	3000 Km.	37.5 million m3/day	$3.0 billion
Maghreb –Europe	From the Hassi R'Mel field in Algeria, across Morocco and the Strait of Gibraltar, to Spain and Portugal	Gas (on and offshore)	1620 Km.	22 – 50.6 million m3/day	$2.2 billion

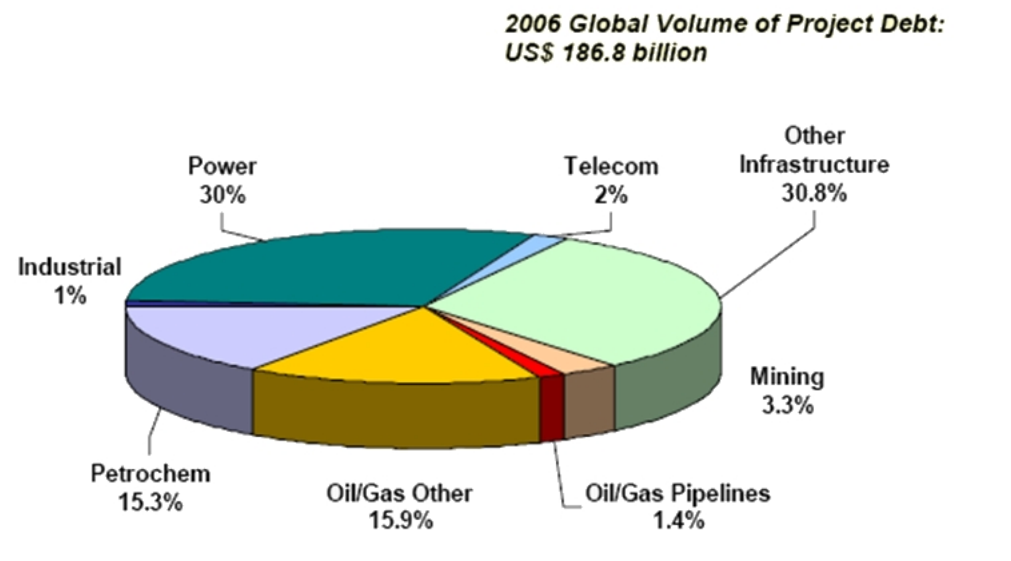
Pipeline	Route Description	Type	Length	Maximum Capacity	Cost
CO_2 EOR Pipelines	Permian Basin region of West Texas and Southeast New Mexico	CO_2 (onshore)	Total 3500 Km.	80,000 tons of CO_2/day	At least $1.0 billion (in 2001 dollars)

2.2 *PROJECT STRUCTURE AND POSITIONING*

The majority of pipeline case studies reviewed were financed using the project finance model, where a SPV company was established by the project sponsors for the development of the project.

As described in *Section 1.4.2*, the project finance model is better at carrying the risks presented by the high capital costs involved with infrastructure development (as discussed previously), and is therefore widely used in the power, mining, infrastructure and, oil and gas industries (*Figure 2.1*).

Figure 2.1 2006 Global Project Debt Finance by Sector

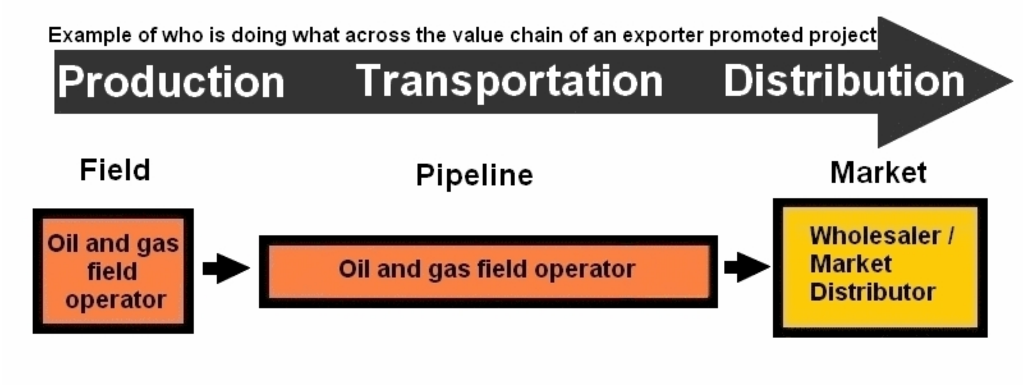


Source: http://lba.legis.state.ak.us/agia/doc_log/2007-04-25_intro_to_project_finance_for_oil_gas_pipelines.pdf

A pipeline project can fall within the three following categories, according to it's positioning towards the final market: exporter promoted, importer promoted and midstream promoted project.

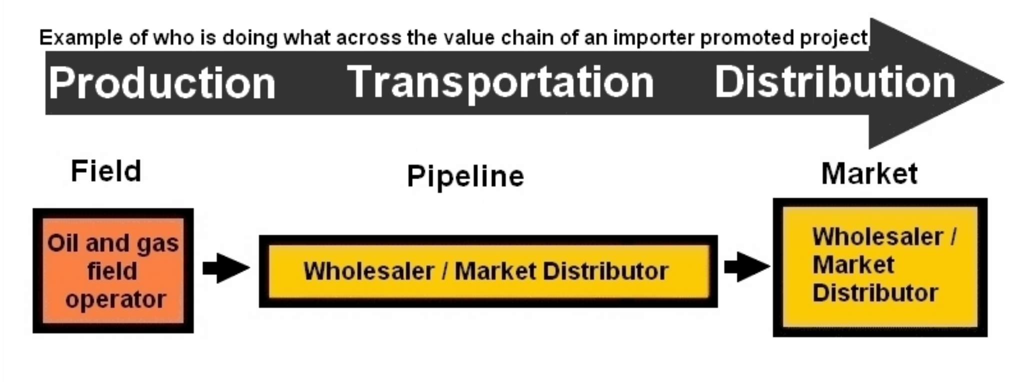
- *Exporter promoted projects:* Exporter promoted projects are generally jointly developed with production fields or the development of new producing regions (Figure 2.2) by the field owners/operators. These are typically big, long term projects that aim to cover long term export market development. Exporters with a large market share on the wholesale market are able to cope better with investment risk associated with a pipeline development. Some examples of pipeline case studies (Annex A) that follow the exporter promoter model are the Langeled Pipeline, the Baku-Tbilisi-Ceyhan (BTC) and West African Gas Pipeline (WAGP).

Figure 2.2 *Exporter Promoted Model*



- *Importer promoted projects*: These are developed by oil and gas market wholesalers and distributors that want to secure their supply (e.g. to reinforce and diversify in order to improve the security of their current energy supply base) and strengthen their market position. Their exposure to market risk is generally considered small since these projects are part of big supply networks (see *Figure 2.3*). A relevant example of an importer promoted pipeline would be Maghreb-Europe Pipeline (GME).

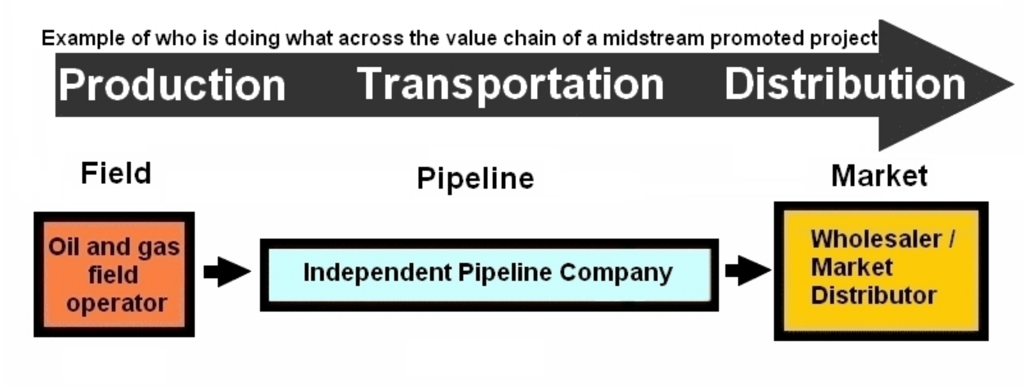
Figure 2.3 *Importer Promoted Model*



Exporter and importer promoted projects are relatively the least difficult to complete due to their ability to reduce investment risks through large market share and financing capacity of investors.

- *Midstream promoted projects:* These are developed with a "pure" market-based approach, usually by an independent (from the upstream and downstream) pipeline company, who aim at penetrating more markets, rather than consolidating a downstream or upstream-based position (see *Figure 2.4*).

Figure 2.4 Midstream Promoted Model



Midstream projects usually carry higher investment risk and are the most difficult to realize, compared to the importer or exporter promoted schemes as they are under threat from both developments in the upstream and the downstream. Nonetheless, midstream projects can promote competition and diversity of supply, and they can often require political support in order to be realised. Examples of pipelines operating in a midstream position is the Alliance pipeline in the US and the planned Nabucco pipeline (see *Annex A*).

Project position in the value chain related characteristics are summarised in *Table 2.4*.

2.2 *Main Characteristics of Project Promoter by Category*

	Exporter	Importer	Midstream
Exporting Companies	Leader	Partner	Partner / Not involved
Importers (incumbents)	Partner	Leader	Partner / Not involved
Private producers / Shippers	Partner (sometimes)	Partner	Leader / Partner
Government	Partner / Not involved	Leader/Partner	Not involved
Timeframe	Very long term	Long term	Mid term
Size	Big	Medium-small	Big-medium-small
Number of partners	Small	Small	High
Vertical integration	High	High-limited	Limited
Rationale	International relations	Security of supply	Competition

Different companies involved in the development will have different objectives depending on their position in the value chain. For example a pipeline operator that is part of a vertically integrated entity aims to facilitate the commodity delivery to the end market. On the other hand, a midstream operator is typically interested in maximizing throughput at the highest tariff they can charge.

Sometimes pipeline projects are considered to have national strategic importance, and therefore will often be promoted partly or wholly by a state-owned company (e.g. GME, BTC, WAGP). As a result, they can also have different objectives, depending on where the state promoter sits (i.e. exporter, importer). The GME pipeline (importer promoted) that received support from the Spanish government (during the initial construction phase) has different strategic objectives (security of supply) than the WAGP pipeline, (exporter promoted) that was supported by the Nigerian National Petroleum Corporation and Chevron (see relevant case studies in *Annex A*). (1)

Reviewed pipeline projects are categorised in terms of their relative position on the value chain in *Table 2.3*.

Table 2.3 Summary of Pipeline Case Studies Positioning

Pipeline	Promoter Model	Senior Sponsor(s)	Rationale
Langeled	Exporter	Norsk Hydro, Shell	Integral part of the overall Ormen Lange field development and diversification of UK Gas supply.
BTC	Exporter	BP, State Oil Company of Azerbaijan	Development of landlocked Caspian Sea oil and of an additional energy corridor (i.e. concerns over reliability of oil supply from Russia and Iran).
WAGP	Exporter	Chevron, Nigerian National Petroleum Corporation	Provide Nigeria and foreign investors in Nigeria an additional commercial market for natural gas and reduce wasteful gas flaring.
GME	Importer	Enagas	Promote integration of energy grids within the EU and between the EU and its suppliers and enhance energy security.
Nabucco	Midstream	One sponsor with equal share to the project from each transit country (5 in total)	Diversify EU gas supplies (Norway, Russia and Northern Africa) and develop "fourth corridor" pipeline, bringing alternative gas from Central Asia, the Caspian region and Middle East
Alliance	Midstream	Enbridge Inc., Fort Chicago Energy Partners L.P.	Purely Commercially Driven

(1) http://siteresources.worldbank.org/INTOGMC/Resources/crossborderoilandgaspipelines.pdf

2.3 PROJECT RISK

As described previously, a project's ownership structure can affect the overall project risk. Risk is strongly influenced by different "positions" of the promoter in the value chain. This can influence project financeability as investments can be undertaken when market, regulatory and construction risks are minimised through hedging instruments (e.g. guarantees or other ways by the infrastructure developer).

Project position in the value chain and related risks are present in *Table 2.4*.

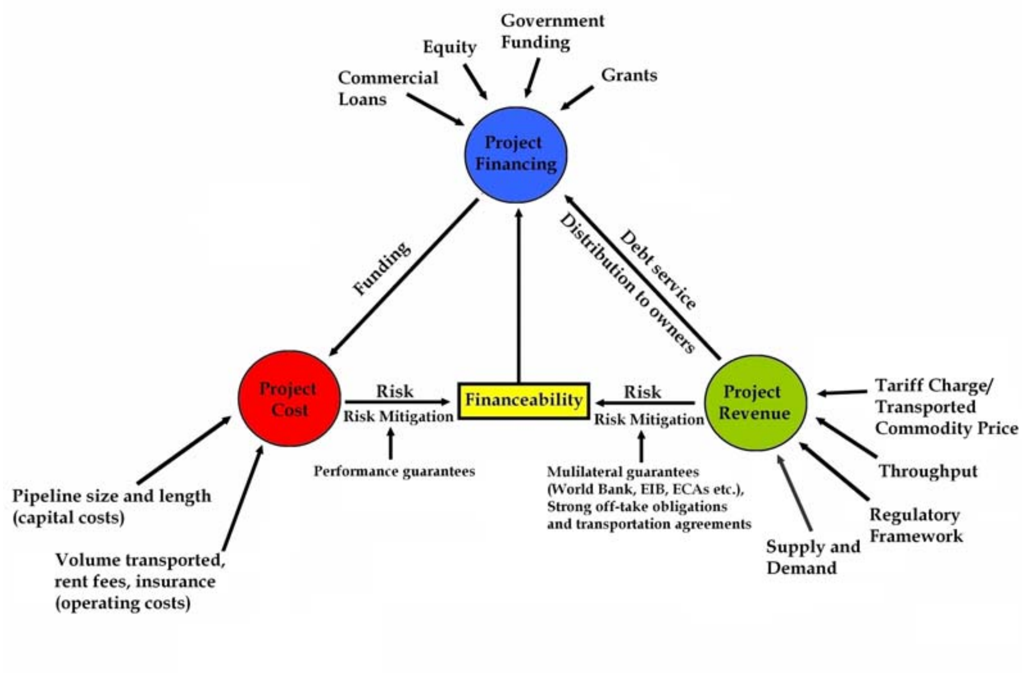
Table 2.4 Type of Investment Risks by Project Promoter by Category

	Exporter	Importer	Midstream	Example
Market risk	Low	Low	High	Price and demand developments
Regulatory risk	Few risks	Importer market share	Third party access	Change in policy or regulation (change in gas tariff and access regulations)
Macro-economic risk	Project Specific	Project Specific	Project Specific	Change in inflation rate or exchange rate
Construction risk	Low	Low	Medium	Project delay or overrun of costs

Sources: Energy corridors: European Union and Neighbouring countries, EC, EUR 22581, 2007, ec.europa.eu/research/energy/pdf/energy_corridors_en.pdf, De Joode and Boots, 2005, http://www.infraday.tu-berlin.de/fileadmin/documents/infraday/2006/papers/vanOostvoorn_deJodde-coair2006-paper-INVESTMENT_IN_GAS_CORRIDORS_FOR_THE_EU-v01-19_09_2006.pdf

Even though ownership structure affects overall project risk, each project needs to be analysed on case-by-case basis. Project costs determine the level of financing that a project company would require and project revenue is vital for securing the service of the financing capital. Risk and subsequent risk mitigation relating to the cost and revenue streams of the project is essential in order to ensure financeability (*Figure 2.5*).

Figure 2.5 ***O&G Pipeline Project Financeability Model***



Factors that influence the elements which determine financeability (i.e. cost, revenue) are discussed in detail in the following sections.

2.4 *Oil and Gas Pipeline Costs*

Pipeline costs, as for any project, are split into two phases: construction phase and operational phase. Pipeline projects are capital intensive, requiring a large amount of investment as up-front capital outlay, whilst ongoing operational costs are significantly lower.

2.4.1 *Capital Costs*

A summary of the capital costs associated with the case studies documented can be found below in *Table 2.5*.

Table 2.5 ***Pipeline Case Studies Costs***

Pipeline	**Cost**
BTC	\$3.6 billion
WAGP	\$0.6 billion
Langeled	\$3.5 billion
Nabucco	\$7.1billion (est.)
Alliance	\$3.0 billion
Maghreb–Europe	\$2.2 billion
CO_2 EOR Pipelines	At least \$1.0 billion (in 2001 dollars)

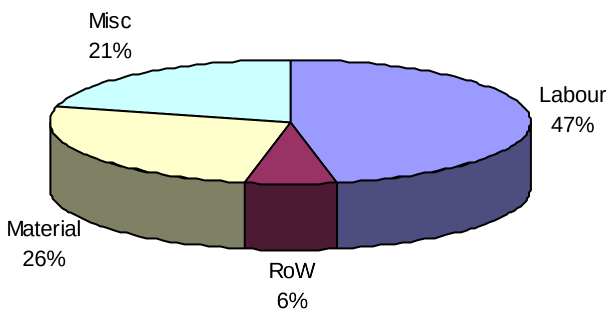
Pipeline capital costs can be segmented in to four basic categories:

1. *Labour*: covering wages, etc;
2. *Materials and equipment*: covering pipework, pipe coating, protection facilities (coating plus cathodic protection), possible booster stations including pumps, valves and flanges, meter stations and telecommunication equipment;
3. *Right of way costs*: covering legal and land costs, permitting costs, consultations, etc; and
4. *Miscellaneous costs*: covering design and project management, regulatory filling and other fees, special limitations, insurance, contingencies allowances, construction delays, new construction supporting infrastructure, highway crossings expenses, etc.

The relative contributions clearly vary on a case-by-case basis, due to varying needs in respect of items such as the local terrain and required crossings, the product transported, the sensitivity of surrounding environments, resettlement needs, royalties, and the construction technique employed, etc.

Indicative estimates of the relative contributions of each category to overall capital costs are provided below (*Figure 2.6*).

Figure 2.6 Pipeline Cost Breakdown



Source: R.W Beck Inc, 2006

2.4.2 *Operating Costs*

Operating costs are analyzed on a per unit basis (1) and can be split between those that are dependent (variable cost) and those that are independent (fixed cost) of volume transported.

The fixed costs can include, among others, depreciation, wages and salaries, maintenance, cost of diagnostics, security, transportation service fees, taxes, insurance, payments for land, and can reach up to 75% of all unit delivery costs for an oil pipeline.

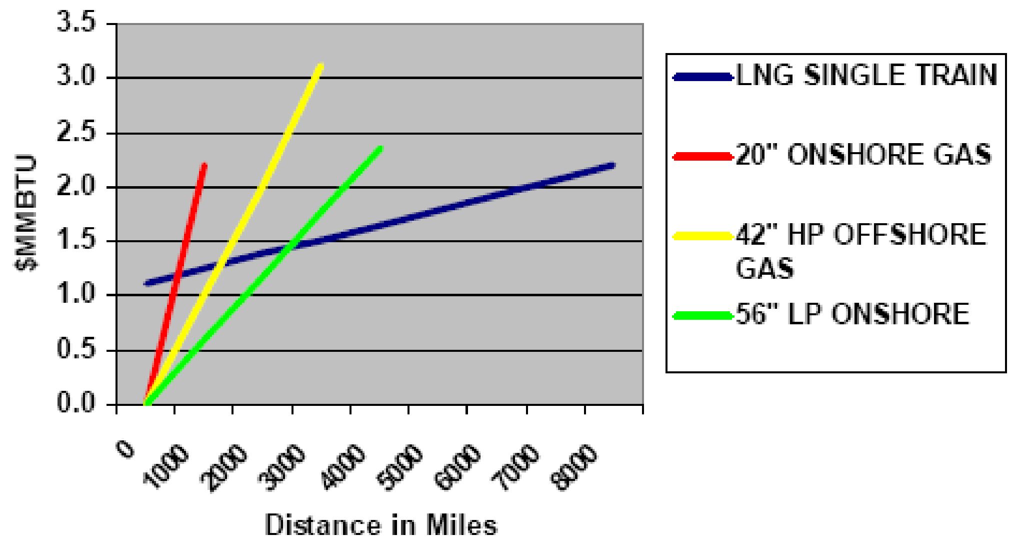
(1) In this sense a unit delivery cost is equal to a ratio of the total operating costs divided by the volume transported.

The variable costs are mainly related to payments for power supply and fuel for operation and this is often provided at concessional rates (practically all variable costs are payment for energy consumption). These costs vary depending on the pipeline's capacity utilization, but for a fully loaded oil pipeline they do not exceed 25-30% of total unit delivery cost at current (2007) energy prices. (1)

An additional delivery cost for trans-border pipelines could be transit fees or government charges for the right to transport gas or oil through a country. These fees are highly dependent upon bargaining and can vary significantly.

Figure 2.7 shows operating costs of transporting fuel for various pipeline types and sizes.

Figure 2.7 ***Relative Costs of Transporting Gas***



Source: http://siteresources.worldbank.org/INTOGMC/Resources/crossborderoilandgaspipelines.pdf

2.5 *OIL AND GAS PIPELINE REVENUES*

Pipeline operators generally realise revenue from user fee payments (tariffs) agreed through firm transportation agreements between the operator and the shipper (i.e. the pipeline user).

Tariff methodologies can vary depending on pipeline specific regulations but we can broadly categorise them in two basic approaches:

- Cost-of-Service Approach
- Market-Based Approach

(1) From Wellhead to Market: Oil Pipeline Tariffs and Tariff Methodologies in Selected Energy Charter Member Countries, Energy Charter Secretariat 2007, http://www.encharter.org/index.php?id=212

2.5.1 *Cost-of-Service Approach*

Tariffs are usually calculated using a bottom up cost-of-service approach so that the pipeline operator meets set revenue targets. The basis for a cost of service approach is that tariff revenue, either from an individual oil pipeline or from a section, needs to break even at a minimum, and be in accordance with the overall financing model for the pipeline. At the design stage a pipeline economic study is undertaken to determine the viability of the pipeline system configuration for all modes of volumetric flows in association with project costs. The appropriate tariff to charge shippers depends on the selected pipeline size, a pre-agreed rate of return for the project but most importantly the volume of throughput (either actual or contracted). As such tariffs can have an upward trend (as a result of demand build up) and the tariff generally decreases as the throughput increases. This methodology is mostly used when the pipeline is vertically integrated (see West African Gas Pipeline and BTC *Annex A*).

2.5.2 *Market-Based Approach*

The market-based approach derives from the tariff chargeable to shippers, operating on the basis of the specific markets linked to the pipeline system. Long-term tariffs are established on a commercial basis for shippers who present guarantees to pipeline companies for transportation of minimum volumes of oil or gas as a pledge, at the time of new construction or pipeline capacity expansion. The period of validity of the long-term tariffs can be 5, 10 and 15 years and can entail more risk than a cost of service approach since often the total revenue stream is not wholly secured. Stable, transparent long-term agreements and tariffs are crucial for project success and as such correspond to the interests of the producer, transporter and buyer, and ensure investment gains and repayment of investment-related credits for the operator. This approach is usually used in midstream pipelines (see Alliance pipeline, *Annex A*) or in more competitive and less regulated environments (e.g. US). [(1)]

The main factors that can impact oil and gas pipeline revenue (market based approach) or the level of associated tariff charges (cost-of-service approach) are:

- Supply and demand
- Capacity and rate of throughput
- Transported commodity price and
- Regulatory framework

These are presented in more detail below:

(1) From Wellhead to Market: Oil Pipeline Tariffs and Tariff Methodologies in Selected Energy Charter Member Countries, Energy Charter Secretariat 2007, http://www.encharter.org/index.php?id=212

2.5.3 *Supply and Demand*

Supply and demand for the intended transported commodity is key for any pipeline operation. Among the most important project factors that determine the commercial supply and demand risks of a pipeline project are the contractual undertakings between the project sponsors, the project host government(s), the supplier and the buyer. These contractual arrangements (off-take, ship-or-pay, supply-or-pay contracts) are of major importance to lenders because, depending on the creditworthiness of the parties involved, can secure the revenue stream of the project.

2.5.4 *Capacity and Rate of Throughput*

The capacity of a pipeline is exponentially related to its diameter, meaning a small increase in diameter leads to potentially large economies of scale.

Due to high fixed costs, full-capacity operation is extremely important for any pipeline diameter. Operating a pipeline in partial capacity utilization, due to the predominant share of fixed over variable operating costs, will result in a higher cost per unit transported and this subsequently can result either in an increase in tariffs in a regulated environment, or reduction of profits or loss in a non-regulated environment. While it is normal for a pipeline, during the early stages of operation, to operate at less than full capacity, below-capacity operation for a prolonged period can seriously damage the pipeline's economic sustainability.

Typically the best way to ensure full-capacity operation is for the pipeline owner to produce oil or gas at one end and to ship at the other. This is because ownership of the throughput is a better guarantee than contracted throughput. As such pipelines that are part of a vertically integrated operation have less revenue associated risks with the transportation operation as was discussed in *Section 2.2* [(1)] [(2)].

Sometimes other arrangements can be made, especially by midstream operators (e.g. Alliance pipeline) to minimise throughput risks. In those arrangements operators have long term firm transportation agreements with shippers (i.e. pipeline users) and receive a monthly demand charge from shippers based on contracted capacity (i.e. not actual transported volume). These arrangements are solely related to the physical capability of the pipeline, to transport volumes to the shipper's contracted capacity regardless if it is used or not. As such they can provide insulation to midstream transporters from downstream and upstream market risks. The shippers are relieved of this obligation only to the extent that the pipeline is unable, for reasons related solely to its theoretical ability, to transport the contracted volumes.

(1) Nonetheless overall risk exposure of a vertically integrated entity might be higher for commodity market risks.
(2) http://siteresources.worldbank.org/INTOGMC/Resources/crossborderoilandgaspipelines.pdf

2.5.5 *Transported Commodity Price*

Transportation fees and tariffs are sometimes volatile in unregulated markets principally due to the differences in the pricing of the oil or gas being transported and this can impact the pipeline's profitability. Pipeline companies operating in unregulated (and especially midstream) markets use commodity price swaps, futures and options to manage the value of commodity purchases and sales that arise from capacity commitments on their pipelines as is the case for the Alliance Pipeline (see *Annex A*).

2.5.6 *Regulatory Framework*

Such regulations may relate to pipeline design in terms of determining capacity, or to pipeline operation, once built. Other regulatory rules may be imposed on the pipeline sponsor(s) to ensure that the new project will foster competition. According to the Council of European Energy Regulators, these include [(1)]:

- A minimum capacity share reserved for short-term bookings;
- A minimum capacity share reserved under regulated tariffs; and
- Rules for allocation of unused capacity and development of secondary markets.

All of the above can result in capacity or throughput limitations and subsequently to related impacts that were discussed earlier under "capacity and rate of throughput".

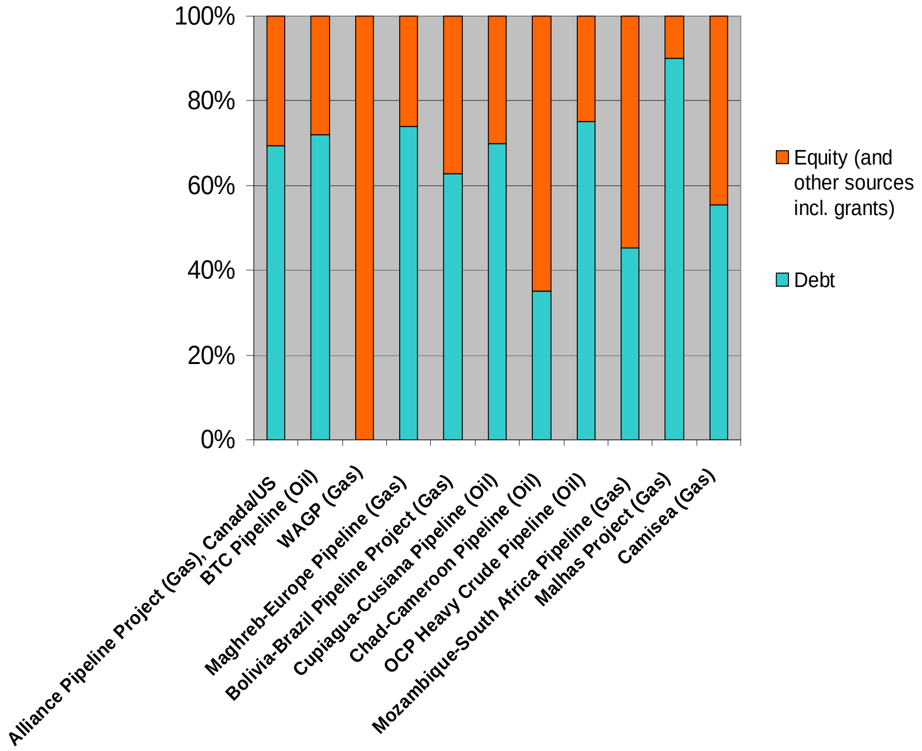
2.6 PIPELINE FINANCING

In the oil and gas industry over 50% of the total value of projects consists of investments exceeding $1 billion for a single project and for backbone pipelines costs usually exceed $2 billion.

Equity financing varies but it typically lies within the range of 20 - 40% of total project costs. The return on capital (especially in importer or exporter promoted projects) can be justified based on the value of the product being transported.

(1) Investment in Gas Infrastructure and role of EU National Regulatory Authorities, Council of European Energy Regulators, May 2005. http://www.seerecon.org/infrastructure/sectors/energy/documents/300905gas/CEERINVESTMENTGASINFRASTRUCTURE12-05-2005_FINAL1.pd

Figure 2.8 *Debt Structuring in the top Oil and Gas Pipeline Project Financings (as of 2007)*



Source: Raw data are based on Dealogic Database for pipelines not included in ERM's case study review (http://lba.legis.state.ak.us/agia/doc_log/2007-04-25_intro_to_project_finance_for_oil_gas_pipelines.pdf).

Overall, oil and gas pipelines are financed mainly through debt and commercial/syndicated loans (*Figure 2.8*). The only exemption to this general rule was notably the West African Gas Pipeline that was funded entirely by equity. This was on account of project specific factors, as described in greater detail in Annex A. Projects with higher perceived political risk or market risk (e.g. buyer defaults) such as the Chad-Cameroon and the Mozambique-South Africa pipeline have less percentage of their required funding coming in the form of senior debt loans, relative to more secure investments. This is wholly driven by the low appetite of investment banks for taking on political risk.

To overcome this hurdle, financial guarantee instruments can be used to mitigate market, regulatory and political risk and subsequently allow companies to raise necessary investment funds for the project.

Guarantees were extensively used to promote sponsor investment for the West African Gas Pipeline (WAGP) and sponsor and bank investment for the Baku-Tbilisi-Ceyhan (BTC) pipeline. Projects with very low perceived risk such as the Alliance and the Langeled pipeline were financed mainly though senior debt loans without the use of guarantees. The Alliance pipeline was in fact the biggest non-recourse debt financed project in North American history, requiring the participation of more than 40 banks worldwide.

2.7 CONCLUSIONS

The case studies share a number of characteristics that enhance project financeability such as proven technology, creditworthiness of sponsors, pipeline cash-flow structure, low-market risk for transported commodity and the strategic importance of projects. The reviews also presented other factors such as intensive up-front capital investment, longevity of project life time, nature and timing of risk, project complexity, security issues, regulatory intervention and transit issues, which make their financing particularly challenging. These factors are presented in *Figure 2.9* and discussed in more detail in below.

Figure 2.9 Enabling and Inhibiting Factors for Oil and Gas Pipeline Financeability

ENABLERS Proven Technology Sponsor Creditworthiness and Experience Cash-flow structure Low Market Risk for Transported Commodity Strategic Importance
PIPELINE FINANCEABILITY
BARRIERS Capital Investment size and concentration Longevity of Project Lifetime Complexity Security Issues Regulatory Intervention Transit and Cross-Border Issues

2.7.1 *Factors enhancing project financeability*

Proven Technology

Pipeline technology has been applied for many years, it is well-proven and so far, experience has been very good.

Sponsor Creditworthiness and Experience

The sponsors tend to be major oil and gas companies that are usually highly creditworthy and have significant experience with similar projects in the past.

Cash-flow structure

Project financing is particularly suited to projects that, through cash-based credit analysis, present an identifiable future stream of cash flows, and pipelines fall into that category.

Low Market Risk for Transported Commodity

Pipelines transport commodity products with very low market risk such as oil and gas. Even in some cases where the associated parties might default, credit-worthy off-take and transportation agreements and guarantees can ensure lenders that there will be a reliable source of cash flow for repayment of the debt (e.g. WAGP pipeline and the government of Ghana, Annex A).

Strategic Importance

Lenders are typically interested participating in strategically significant projects such as oil and gas pipelines, which are important for energy security.

2.7.2 *Factors inhibiting project financeability*

Capital Investment size and concentration

Large infrastructure projects, such as oil and gas pipelines, require large amounts of capital investment concentrated in a single-purpose asset. This approach is generally not favoured by banks and other financiers that are looking for investment diversification, and as a consequence pipeline project loans are usually syndicated.

Longevity of Project Lifetime

Pipelines, subject to both maintenance and the nature of the throughput, have an operating life of at least 20 years. The agreements that govern the building and operation of a pipeline are vital for project success. They must be sustainable over that long period of time and through changing circumstances.

The greater the confidence of investors of the conditions under which the project is financed, the lower the risk will be, and therefore the financing costs.

Complexity

Pipeline projects are typically too big to be developed or financed by one project sponsor or lender. Usually a consortium of companies is involved in the sponsorship side and a syndication of banks, multilateral development banks and agencies on the financing side.

Other parties might be involved such as host government(s) that have a sponsorship or a supportive role, (e.g. Maghreb-Europe pipeline, West African Gas Pipeline, Langeled pipeline), the buyer of the commodity transported, producers, governments of transit countries, potential pressure from NGOs and civil society (e.g. BTC pipeline).

The complex balancing act between the interested parties and the coordination effort is vital for project success. A relevant example would be the Nabucco pipeline (see *Annex A*) where it remains difficult to complete because of the complexity of transit issues and the difficulties in coordinating investments in production and transit infrastructure.

Security Issues

Vulnerability to disruption and conflict presents another common characteristic for many oil and gas pipelines, due to the important nature of the transported commodity and the fact that hydrocarbons are usually transported through "sensitive" areas of the world.

While it is true that most operating pipelines have avoided such problems, this negative perception sometimes may prescribe the use of guarantees from multilateral or state institutions for financing to proceed.

Regulatory Intervention

A potential energy supply market failure has clear implications for national security and economy of countries and a clear regulatory framework and government intervention is sometimes required as part of a robust energy policy. Intervention in the oil and gas transportation sector is not uncommon and the justification for this is the natural monopoly dimension to pipelines and the strategic importance of the commodity transported.

Regulations might address either third-party access or common carriage, to ensure that other parties have access to use of the pipeline.

Box 2.1 Third-party access and common carriage rights

Third-party access rights permit an owner of potential throughput to demand access on commercial terms, if necessary with government enforcement, providing there is surplus capacity on the line.

Common carriage rights apply where no excess capacity exists, and require existing users to reduce their throughput on a pro rata basis to allow access.

However, regulated access can carry important implications for financing pipelines because when political risk is high, project financing is likely to be heavily dependent on upstream producer equity, as was the case in the WAGP. In these situations it is almost certain that equity holders will demand preferential access as the price for investing. Regulating access, especially in projects that carry a high level of risk, can discourage investment in both the pipeline and the upstream. (1)

Transit and Cross-Border Issues

Projects that involve pipelines crossing third "transit" countries, bring a political dimension to the project, make negotiations more complex and introduce a new element of risk (i.e. transit fee uncertainty).

(1) http://siteresources.worldbank.org/INTOGMC/Resources/crossborderoilandgaspipelines.pdf

Transit fee (i.e. a fee or government charge for the right to transit gas through a country) uncertainty is a risk that exists in trans-border pipelines because it varies and is highly dependent upon bargaining.

In these types of bargaining situations, the economic problem of 'hold-up' is applicable. The hold-up problem pertains in a situation where the commodity considered is highly asset specific, to such a degree that the government of the transit country or the owner of the infrastructure used for transit will always have an incentive to behave opportunistically (for an example see Box 2.2). When the pipeline investment is undertaken and is fully operational, both can be tempted to demand a higher fee or charge than agreed upon previously. (1)

Box 2.2 Transit Fee "hold-up" example

Enrico Mattei Gas pipeline (EMG) connecting Algerian gas production facilities with Italy via Tunisia was built in 1983 and operated by ENI. When bargaining with Tunisian government on the transit of gas, the Tunisian government demanded a transit fee of 12%. Suggestions by ENI to consider LNG connection with Algerian gas assets ultimately led the Tunisian government to settle for little below 6%.

Source: http://www.infraday.tu-berlin.de/fileadmin/documents/infraday/2006/papers/vanOostvoorn_deJodde-coair2006-paper-INVESTMENT_IN_GAS_CORRIDORS_FOR_THE_EU-v01-19_09_2006.pdf

The above risks perceived as inherent in cross-border pipelines may increase the cost of finance in addition to threatening the viability of pipeline projects. Furthermore, higher financing costs can also impact the cost of the delivered fuel.

The Maghreb-Europe Pipeline is a notable example where the need to transit across a third-party (i.e. Morocco) was dictated by technological limitations, since technology to lay large transport pipelines at great depth under the sea was not as developed at that time. Current projects such as the WAGP can directly connect the country of origin of gas to the market, as a consequence of technological improvements that allow laying long undersea pipelines (e.g. West African Gas and Langeled Pipelines) at increased depths under acceptable economic conditions. (2)

(1) Source: http://www.infraday.tu-berlin.de/fileadmin/documents/infraday/2006/papers/vanOostvoorn_deJodde-coair2006-paper-INVESTMENT_IN_GAS_CORRIDORS_FOR_THE_EU-v01-19_09_2006.pdf

(2) www.ecn.nl/fileadmin/ecn/units/bs/ENCOURAGED/WP/ENCOURAGED-report-WP2.pdf

3 KEY FINDINGS OF PRIVATE-PUBLIC PARTNERSHIP CASE STUDIES

3.1 INTRODUCTION

Public-Private Partnerships (PPPs) are joint ventures or partnerships between the public and private sector for the delivery of public infrastructure or other services and public goods. CO_2 pipelines may not share a lot of technical similarities with public-private partnership projects such as roads or bridges, nonetheless climate change mitigation – with an integral part being the associated CCS transportation network - can be considered within the scope of public goods delivery. For this reason, ERM documented three case studies of PPPs and highlighted some of the main characteristics of this type of project delivery.

3.2 BACKGROUND

In the past two years, the level of investment for PPPs has grown to almost $2 trillion when counting all forms of infrastructure. *Figure 3.1* shows the extent of PPP investment in infrastructure projects worldwide between 1985 and 2004.

Figure 3.1 Worldwide PPP Infrastructure Projects since 1985 by Project Type*

Project Type	Total Planned & Funded Since 1985				Total Funded & Completed by 10/04				% Funded & Completed by 10/04	
	#	%	$Billion	%	#	%	$Billion	%	% of #	% of $
Road	656	31%	$324.7	37%	359	32%	$157.3	35%	55%	48%
Rail	247	12%	$280.6	32%	107	10%	$143.7	32%	43%	51%
Airport	182	9%	$88.0	10%	67	6%	$49.5	11%	37%	56%
Seaport	142	7%	$39.5	4%	44	4%	$10.6	2%	31%	27%
Water	616	29%	$95.4	11%	391	35%	$62.8	14%	63%	66%
Building	253	12%	$59.2	7%	153	14%	$27.0	6%	60%	46%
Total	2096	100%	$887.4	100%	1121	100%	$450.9	100%	53%	51%

* Based on total Public Works Financing database, including projects with partial information
Source: Federal Highway Administration, "Synthesis of Public-Private Partnership Projects for Roads, Bridges&Tunnels from Around the World – 1985-2004", August 30, 2005, p. 4, http://www.fhwa.dot.gov/PPP/int_ppp_case_studies_final_report_7-7-07.pdf

The largest proportion of global PPP funding is generally for road projects, with rail projects being he second largest user of PPP financing for project delivery. This is true for each region of the world, except for Africa and the Middle East, where water projects dominate.

PPPs are also employed for the construction of prisons and courts, hospitals, military facilities, IT systems, street lighting, schools, sports facilities, waste management, social housing, accommodation, universities and government buildings.

ERM undertook a review and prepared three case studies of public-private partnership projects with a special focus on public infrastructure works. The full case studies can be found in *Annex B* and include a high-speed railway line (Channel Tunnel Rail Link, UK), a toll road (South Bay Expressway, US) and a bridge (Oresund Bridge between Denmark and Sweden). The following sections provide a brief introduction to PPP structure and a summary of the case study key findings.

3.3 *STRUCTURE*

PPP structures usually involve a long term (20-40 years) contract between a public body and the PPP contractor and generally for large projects the project contractor or promoter is a special purpose vehicle (SPV) established by a company or a sector consortium.

The main characteristic of a PPP is the granting of concession by the project principal (i.e. owner), usually a government, to the project promoter for a specified period of time for which the project remains under the ownership of the PPP contractor (i.e. concession period). During the concession period the project promoter is responsible for the arranged contractual obligations (e.g. construction, financing, operation, maintenance, etc.) of the project. After the end of the concession period the project is transferred, usually at no cost to the principal.

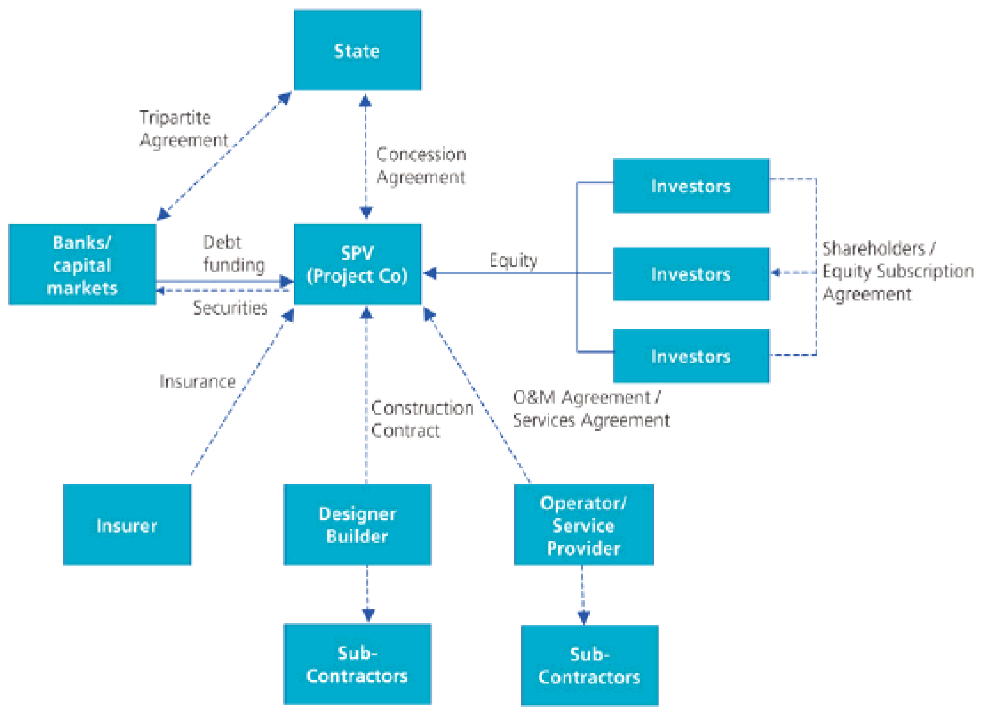
During the concession period the project promoter expects to collect revenue in order to cover investment costs and make a margin of profit. A successful PPP provides benefits not only to the promoter but also to the public sector (1) such as attraction of foreign investment, acquisition of private sector skills and know-how, reduction of public sector borrowing requirements, possibility of development of otherwise non-priority projects and education and training for local workforce. (2)

A structure of a typical PPP is presented schematically in *Figure 3.2*.

(1) A Guide to Project Finance, Denton Wilde Sapte, April 2004

(2) Traditional Financing Instruments for ICT Projects, Annex 6 http://www.regulatel.org/miembros/publicaciones/ESTU%20DIOS/SERV%20UNIV/PPIAF/informe%20final/draft%20vf/New%20Annex%206%20Financing.v.1.pdf

Figure 3.2 *Structure of a Typical PPP*



Source: http://www.mallesons.com/publications/Asian_Projects_and_Construction_Update/images/6847534W-26.gif

PPPs come in a wide variety of arrangements, representing a broad spectrum of private and public sector involvement in the various phases of project development, finance, implementation, operations, maintenance, and preservation (1).

There are four basic public-private partnership structuring approaches based on project ownership and operational models that are presented in *Table 3.1*

Table 3.1 ***Public-Private Partnerships Structures***

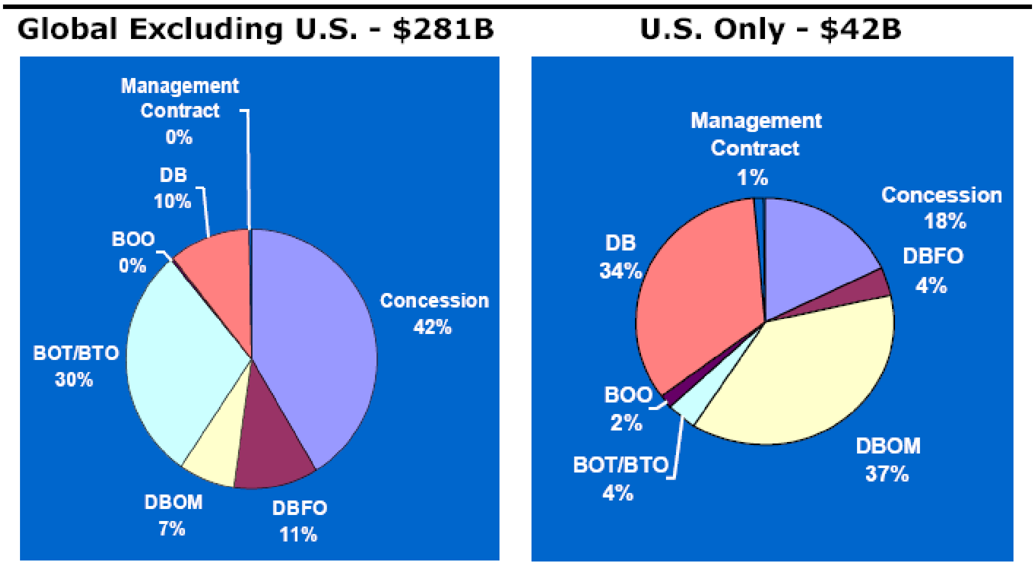
Type	Ownership	Operation	Partnership Agreement Term	Typical Model
I	Public	Private	3 to 5 years	Operations Only
II	Public	Private	5 to 25 years	Design/Build/Operate
III	Private	Private	25+ years	Design/Build/Operate/Own with possible transfer
IV	Private	Private	Various	Design/Build/Operate/Own

Source: National Council for Public-Private Partnerships, http://ncppp.org/

Widely used models in PPP project delivery include the BOT (build, operate, transfer) and DBOM (design, build, operate, maintain) as it can be seen in *Figure 3.3*.

(1) "Synthesis of Public-Private Partnership Projects for Roads, Bridges&Tunnels from Around the World – 1985-2004", prepared at the request of the Federal Highway Administration, August 30, 2005, p. 4, http://www.fhwa.dot.gov/PPP/

Figure 3.3 *Global Road-Related PPP Projects by Contract Type - 1985-2004*



Source: Federal Highway Administration, "Synthesis of Public-Private Partnership Projects for Roads, Bridges & Tunnels from Around the World – 1985-2004", prepared at the request of the Federal Highway Administration, August 30, 2005, p. 4, http://www.fhwa.dot.gov/PPP/int_ppp_case_studies_final_report_7-7-07.pdf

Nonetheless there is a great number of model variations such as the DBFO (design, build, finance, operate), the BOO (build, own, operate) and other model variations that can be found in *Table 3.2*.

Table 3.2 *Project Model Variations in PPPs*

Acronym	Description
BOD	build, operate, deliver
BOO	build, own, operate
BOOST	build, own, operate, subsidise, transfer
BOL	build, operate, lease
BOT	build, operate, transfer
BRT	build, rent, transfer
DBFO	design, build, finance, operate
DBOM	design, build, operate, maintain
DBOT	design, build, operate, transfer
FBOOT	finance, build, own, operate, transfer

An example of Build-Operate-Transfer (BOT) PPP could be an airport where the private developer builds, maintains and operates the terminal during the concession period (e.g. Antalya Airport International Terminal A.S.) and a Build-Rent-Transfer (BRT) PPP example could be a public hospital where the developer builds and maintains the hospital during the concession period and the government operates it by providing medical services.

In the above examples, the developer receives return on investment by contract payments that may include user fees (e.g. airport example) and government payments (e.g. rent payments in the hospital example).

Associated key parameters for these two fictional examples are presented in *Table 3.3*.

Table 3.3 *Examples of BOT and BRT Model*

	BOT	BRT
Project	Airport	Public Hospital
Sponsor	Developer	Developer
Principal	Government	Government
Sponsor Obligations (concession Period)	Build, maintain and operate	Build and maintain
Principals obligations/role (concession period)	Provide guarantee of no direct/indirect political and regulatory impacts to project	Operation of hospital (medical services
Revenue Model	User fees	Rent

A brief description and of the case studies, the development models used and the concession period for each project can be found in *Table 3.4*.

Table 3.4 *PPP Case Studies Summary*

	Channel Tunnel Rail Link	South Bay Expressway	Oresund Bridge
Description	108 km (67 mile) high-speed railway line from London through Kent to the British end of the Channel Tunnel	10-mile toll road extending from SR 54 in Spring Valley to Otay Mesa Rd./SR 905 near the International Border	Combined two-track rail and four-lane road bridge that connects the two metropolitan areas of the Danish capital of Copenhagen and the Swedish city of Malmo
Model	BOT	DBFO	FBOO
Concession Period	90 years (ending in 2086)	35 years commencing from opening (2007 - 2042)	Not limited

The concession period can enhance the project's overall commercial attractiveness and as such it can be subject to bargaining, as for example was the case for the Channel Tunnel where the original concession of 55 years (including construction) was extended to 90 years at a time of crisis in the financing side of the project. The concession period for the Oresund Bridge is not limited as the project company is wholly and jointly owned by the Swedish and Danish States.

3.4 PROJECT COST AND FUNDING

In PPPs where the project promoter is self-financing the project (i.e. no design-bid-build model) project financing is generally done in the same way as in the "project finance model" with the establishment of a Special Purpose Vehicle for the project. SPV Financing usually involves high levels of non-recourse debt although the existence of government support is likely and was evident in all of the case studies.

A summary of the associated costs for the PPP projects reviewed can be found in *Table 3.5* below.

Table 3.5 *PPP Case Studies Summary*

	Channel Tunnel Rail Link	South Bay Expressway Toll Road	Oresund Bridge
Cost	$12.1 billion	$635 million	$5.7 billion

Costs can vary depending on the project size and for infrastructure projects the upfront capital outlay needed initially in the design and construction stage is disproportional to maintenance costs that tend to be a smaller fraction of total costs.

All of the PPP projects documented in the case studies (in Annex B) are characterised by high levels of debt and relatively low levels of equity.

Generally these project companies are structured to absorb a reasonable level of risk in order to meet financeability requirements and to raise necessary funding. Nonetheless, instrumental changes in key project parameters (e.g. overestimation of future revenue) may test the project structure as was the case for Channel Tunnel Rail Link where the project ran into financial difficulties on many occasions and was restructured several times.

The Oresund bridge was largely funded by bonds issued by the project company in the European Bond Markets that were guaranteed by the Swedish and Danish Government. The Channel Tunnel Rail link was financed more than 60% by UK government guaranteed bonds.

The South Bay Expressway was financed with a mix of government loans and assistance, equity and commercial loans.

A summary of financing structure of the case studies can be found in *Table 3.6*.

Table 3.6 *Summary of Financing Structures of PPP Case Studies*

Project	Financing Structure
Channel Tunnel Rail Link	Government guaranteed bonds, Development Bank (EIB, KfW) loans, commercial bank loans
South Bay Expressway	Government loans and guarantees, equity, commercial bank loans, grants by local developers
Oresund Bridge	Government guaranteed bonds issued in European and Swedish bond market, commercial bank loans

3.5 *REVENUE*

PPP revenue tends to be based on project outputs and there may be contractual arrangements in the form of annual payments from governments to support inadequate revenues on projects or involve user charges, such as road tolls, rail fares and access charges.

The reviewed projects generate revenue from real tolls, shadow tolls, availability payments, access charges or a combination. The Oresund Bridge and the South Bay Expressway generate revenue mainly from road tolls while the Channel Tunnel Rail link from user access charges (see *Annex B*).

PPP projects can typically be structured and financed on the basis of the above revenues; nonetheless, government support, guarantees and non-compete clauses prove to be instrumental in some cases where the risk associated with the revenue stream is considered unbearable by investors. On the other hand, while a satisfactory rate of return for investors is ensured, caps on project's rate of return may be introduced to protect users from unreasonable charges especially in monopolistic situations.

The South Bay Expressway is a good example of a partnership that combines government financial support and non-competition clauses but at the same time caps the project's internal rate of return at 18.5% over the 35 year concession period.

3.6 *SUMMARY OF CASE STUDY FINDINGS*

A widely used method of funding long term public sector projects that involve a significant amount of capital expenditure is the Private Finance Initiative (PFI). PFI provides financial support for "Public-Private Partnerships" (PPPs) and although PFI was developed initially by the UK government in 1992 with the aim of achieving closer partnerships between the public and private sectors it has now been adopted by parts of Canada, France, the Netherlands, Portugal, Ireland, Norway and Finland as well as Australia, Japan and Malaysia. Each PFI project is different depending on local project parameters. A notable example of a PPP that was delivered through the Private Finance Initiative (PFI) is the Channel Tunnel Rail Link project in the UK.

PPPs are widely used mostly in Europe, nonetheless the recent South Bay Expressway toll road (see *Annex B*) - the first PPP in US history which won Euromoney's "Deal of the Year 2003" (1) - highlighted that PPP approach could be applied successfully in the US as well and more PPP projects could well be on the way (2) .

A potential downside for application of a PPP structure to a complex CO_2 transportation network development could be the high number of parties that would need to be involved in the project which could entail coordination problems.

On the upside, Public-Private Partnership structures are widely used for the delivery of public goods/services and climate change mitigation – with an integral part being the associated CCS transportation network - can be considered as such and at least during initial deployment, a PPP can offer an attractive alternative model for CO_2 "backbone" pipeline development.

(1) http://ncppp.org/councilmembers/alpha.shtml
(2) A Guide to Project Finance, Denton Wilde Sapte, April 2004

4 BUSINESS MODEL FOR CO_2 PIPELINES IN A CCS CHAIN

4.1 *INTRODUCTION*

Building on the analysis of oil & gas pipeline and public-private partnership funding case studies presented previously, this section considers two key elements of developing commercially viable CO_2 backbone pipelines:

1. *Commercial business models*: considering who the actors would be in a commercial CO_2 pipeline network development; the drivers and motivation for sponsoring such developments; how different promoters might interact; and more generally the overall commercial environment within which promoters will need to operate; and
2. *Economic business models*: considering the micro-economic appraisal of commercially workable approaches to financing CO_2 pipeline network development, considering barriers and opportunities to facilitate commercial deployment.

One of the main considerations overarching both aspects is the role of governments in supporting deployment. Emissions of CO_2 are a business externality, and as such, its control is contingent on the evolution of public policy to incentivise deployment. This affects the regulatory and/or commercial environment under which operators will be incentivised to deploy CCS. In addition, governments can also play a key role in promoting the deployment of optimised pipeline network systems, which – as reviewed below – may not necessarily evolve absent of some form of government intervention or support. This subject is a core theme underlying the following sections.

4.2 *COMMERCIAL BUSINESS MODEL*

4.2.1 *Policy approaches to incentivising CCS*

Public policy on GHG emission controls will likely determine the way in which CCS promoters act to deploy CO_2 pipeline networks. Options for public policy include: mandating CCS; fiscal policy; market based approaches, or through provision of public subsidies for the uptake of a technology. These are described further below.

Mandatory requirement for CCS

Mandatory approaches would involve the development of regulations which require point sources of CO_2 to capture and store emissions. In taking this approach, a qualifying threshold on emissions, or prescription of the technology to certain activities and/or CO_2 sources streams would be required. Under such an approach, *emitters* may be able to cover incremental costs of CCS by passing it on to consumers of their product (e.g. through electricity price increases), although for some industry sectors involved in international markets, this may be more challenging in the absence of global approaches.

Market-based approaches

Market-based approaches cover several different potential policy and regulatory incentive mechanisms, targeted at either actual CO_2 emissions or through setting a low carbon portfolio standard for operators. A basic outline of approaches is provided below:

- *Cap-and-trade schemes*: These involve governments setting an emissions cap on *emitters* that obliges them to either purchase emission rights (e.g. via an auction) or receive an allocation of free emissions rights to the cap level. Exceedance of the cap means that they are required to purchase extra rights in order to comply. Trading between operators is a cornerstone of this approach, where operators who emit less than their cap sell emission rights to operators exceeding their cap. An example is the EU Emission Trading Scheme. Voluntary cap-and-trade schemes are also possible, but can be considered to be unlikely to deliver the level of incentive required to deploy CCS on a large scale at a time in the near future.
- *Project-based schemes*: involve the issuance of credits to *emitters* based on reducing emissions below an agreed baseline. This could involve the creation of direct incentives for both *emitters* and *storers* working in consortium. Conceivably, a baseline could be excluded, and credits be provided to a *storer* on the basis of the mass of CO_2 stored. Examples include voluntary emissions programmes such the Chicago Climate Exchange, or the Kyoto Clean Development Mechanism.
- *Low carbon portfolio standard with tradable permits*: involves the setting of a minimum level of supply of products from certain qualifying source types into the market (most typically applied in electricity markets). Operators exceeding the supply across their portfolio could sell surplus permits to operators who do not meet the level set in the standard. An example would be renewable portfolio standards/green certificate trading schemes operating in various parts of Europe and the US.

Project-based schemes would be dependent on having a demand side driver, and thus would require linkage into a voluntary or regulatory based cap-and-trade scheme; credits would be sold into the market on the basis of being an offset mechanism. In the case of cap-and-trade or low carbon portfolio standards, operators would likely pass the cost of CCS on to consumers where possible.

Fiscal measures

Fiscal measures could involve using several schemes, including:

- *Carbon taxes*: whereby emissions are taxed at a certain level, and avoided through emissions abatement.

- *Tax relief*: through the wavering of certain taxes for low carbon technology deployment.

In either case, the focus of the incentive mechanism would most likely fall with the CO_2 *emitter*, although royalty relief on incremental oil produced using CO_2 flooding may act as an incentive for *storers*.

Subsidy support

Governments may also develop public policy which provides direct subsidies to operators. Funds may be distributed on a percentage share of cost basis, via a competition, or through revenue subsidies. Approaches could include capital grants to cover the construction of projects, or the provision of financial support against products sold or emissions avoided. Examples of the latter might include the use of a guaranteed carbon price underwritten by governments; the former would include the UK CCS Competition (which potentially offers both capital support and the option of underwriting revenues).

Commercial operations

In certain instances, EHR may offer commercially viable opportunities for CCS deployment, largely absent of government incentives. Such instances are rare, and are in reality are often also underwritten by fiscal policy, such as royalty relief on hydrocarbons produced by way of CO_2 flooding. In any case, the incentive will in most circumstances be given to the CO_2 *emitter* by way of being able to apply a charge for CO_2 delivered. In some cases, midstream operators can evolve to operate networks (e.g. Kinder Morgan in the US), although – as shown in the case study of the US CO_2 pipeline network in *Annex A* – the capital investment required to build such infrastructure is unlikely to evolve absent of an upstream or downstream promoter or by offering a set of incentives that make these projects a commercial proposition; in the case of the US pipeline network, the main incentive was royalty/tax relief on the incremental oil produced.

4.2.2 *Strategic considerations*

Strategic and geographical/geopolitical factors are also likely to play an important part in how CO_2 pipeline networks may evolve and deploy. In this context, the following scenarios are possible:

- *Regions with low emissions and good storage potential*: such locations might be where a country has significant subsurface assets suitable for storing CO_2, but limited emission sources to utilise these assets. Governments and operators in such zones will potentially be interested in supporting the development of pipeline infrastructure in order to facilitate emitters to store CO_2 (at a given price). Examples include: Norway, Saskatchewan, the Middle East, and US plains.

- *Regions with high emissions and poor storage potential*: typically zones where large industrial developments exist with limited access to sufficient large storage in close proximity (especially at reasonable development costs or in zones where public acceptance or environmental controls may be a feature). Governments and operators will clearly need extensive pipeline networks in order to employ CCS. Examples include central and Eastern Europe, Japan, Korea (technical storage constraints), the US East coast and Midwest (technical constraints and public acceptance), and US West coast (public acceptance and environmental controls).

- *Drivers for enhanced hydrocarbon recovery*: depleting indigenous oil and gas reserves, and/or the promise of enhanced coal-bed methane recovery, will also play a feature in governments' interests in promoting deployment of CCS in some regions. Examples include most of the US mature oil provinces (Texas and the Gulf of Mexico), offshore UK, offshore Norway, Romania and the Middle East.

In each circumstance, governments and operators are likely to act differently in supporting the deployment of pipelines, or in the case of poor storage resources, they may potentially use such influences to temper the development of CCS networks in order to avoid transferring value from the national economy.

Consequently, strategic factors could play a major role in shaping the nature of CO_2 pipeline network deployment in the future.

4.2.3 *Project structures for CO_2 pipeline development*

The oil & gas pipeline case studies provided strong evidence to suggest that different incentives – or market "push" or "pull" factors – are strong influencing factors on how projects are structured. They also suggested that strategic factors play an important role in shaping the way in which oil and gas pipelines are realised, including: the rationale (e.g. energy security); the sources of funding (especially the nature of government funding and multilateral lending agency support); the provision of export credit guarantees; and simplified permitting rules.

Thus, it is reasonable to assume that:

(a) the nature of the incentives offered for reducing GHG emissions – as reviewed above – will determine the point in the CCS chain where value is created (i.e. market push or pull characteristics);
(b) strategic factors will also play a role in influencing decisions regarding deployment, and also the terms and nature of financing sources; and
(c) in turn, these will influence the structure of CO_2 pipeline project development.

Therefore, depending on how these all play out in different deployment scenarios – as will be shown in the analysis in the next section – will be a major factor in whether CO_2 backbone pipeline projects emerge ahead of simple point-to-point pipelines deployed on a project by project basis.

It also important to note that in the case of project based emission reductions – where incentives could be spread across the whole CCS value chain amongst a consortium of participants – it is more challenging to envisage such consortiums being motivated to invest a backbone pipeline. This is because the motivations for investment are project specific and opportunistic. Thus the justifications for scale-up to backbone pipeline deployment in such circumstances (i.e. absent of blanket policy approach to similar operators across a region) would require extensive co-ordination between a ranges of interested actors, which seems unlikely.

On this basis, it is therefore possible to envisage the following market actors and motivations for acting:

- *Emitters of CO_2*: operators might act as CO_2 pipeline project sponsors in response to market or regulatory "push" factors (cap-and-trade; fiscal policies; portfolio standards, etc.) and to a lesser extent from market "pull" factors (generation of tradable carbon credits as part of a project based consortium). Emitters could participate as project sponsors in the development of the pipeline, contribute equity and, depending on their standing, increase the creditworthiness of any special purpose vehicle established (as a reliable source of CO_2 for the pipeline). These could all serve to enhance the possibility of – and reduce the cost of – debt financing for a backbone pipeline;

- *Storers of CO_2*: might act in response to both market "push" (e.g. in response to government encouragement, or even incentives, to develop CCS infrastructure to support public policy) and "pull" factors (to extend the life of or utilise existing subsurface reservoirs - oil, gas or saline aquifers for storage; utilising CO_2 for enhanced hydrocarbon recovery). A market pull may also be created as a result of market push factors acting on emitters (i.e. to use existing subsurface experience and knowledge to create new business models for CO_2 storage). These factors create incentives for storers to participate directly in the development of a pipeline as an investor and shareholder of a pipeline project special purpose vehicle company. Involvement of major oil companies will also increase the likelihood and reduce the cost of debt financing, because of their creditworthiness and access to requisite CO_2 storage skills and knowledge;

- *Shippers of CO_2*: it is difficult to envisage scenarios involving midstream pipeline project promoters focussed solely on the shipping of CO_2, as there is no clear value proposition, beyond acting on behalf of emitters or storers. As suggested by the case studies for oil and gas pipelines, sole financed midstream projects will be the hardest to realise, an issue which is probably augmented in nascent markets such as CO_2 value chains.

In all cases, the value of the CO_2 emissions avoided would need to be sufficient to cover the following costs items:

- *CO_2 capture*: including both capital and operating costs of the plant, taking into consideration the extra fuel requirements linked to the energy penalty;

- *CO_2 pipeline tariffs*: assuming that a carriage charge would be levied for transporting CO_2;

- *CO_2 storage costs*: in some cases emitters could pay directly to the storer; or in other cases the carriage fee charged by CO_2 shippers could include the storage fee (i.e. the shipper includes the costs paid to a storage operator within their tariff charge); and

- *Longer term liability*: for the storage site will need to be factored into the overall cost of CCS services along the value chain, to cover the cost of future monitoring and any remediation requirements. In reality, this is likely to be born by storers, under influence of prevailing regulatory regimes, and thus they will need to factor this into their cost of service passed back up the chain.

Thus, some commercial arrangements will need to be established by which costs, revenues and risks may be shared on a commercial basis between all actors in the chain.

4.2.4 *Commercial arrangements*

Recognising that value will most likely be created at a single point in the chain, commercial contracts between emitters, shippers and storers will be very important in distributing revenues and allocating risks between parties. Types of risks to be considered in commercial contracts include:

- *Non-delivery risk*: where an emitter is unable to provide contracted amounts of CO_2 to the shipper or storer. The precise nature of the risk will depend on how the contracts are structured in respect of whether there is a severed or joint chain between emitter and storer (i.e. whether bilateral contracts exist between emitter and shipper, shipper and storer, and whether the emitter also contracts with directly the storer);

- *Non-take risk*: where a shipper or storer is unable to take CO_2 from the upstream operator; and

- *Non-containment risk*: for CO_2 released at some point along the chain. In these circumstances, liability could be determined by the way in which governments create the chain of custody for CO_2 (e.g. does the liability fall back to the emitter, or is at the source?).

Types of potential agreements that could be required for pipelines in order to mitigate the above risks depending on probable project drivers and models are presented in *Table 4.1* below.

Table 4.1 *Type of Agreements Required Depending on Pipeline Sponsorship Structure*

Promotion Model	Pipeline Promotingg entity	Probable project drivers	Contract required	Perceived Project Risk
Exporter	CO_2 supplier (e.g. power plant)	Regulation (cap and trade) and avoided cost (auctioning system)	Take–or-pay with storage site operator, Transportation agreement with pipeline SPV company	Medium
Importer	CO_2 buyer (e.g. owner of storage rights for depleted oil field)	Commercial combined with storage site crediting mechanism	Supply-or-pay with producer, Transportation agreement with pipeline SPV company	Medium
Midstream	Independent pipeline developer	Commercial	Through put transportation agreement (ship-or-pay) usually based on contracted capacity (not actual transported volume), appropriate supply-or-pay and take-or-pay arrangements between other parties can increase pipeline credit	High
Midstream	Government	Development of "backbone" network, Demonstration	Through put (ship-or-pay)	Low
Integrated Project Partnership	All the above	Demonstration, Commercial	Complex arrangements; could be a combination of all the above on a risk sharing basis	Low

The above contractual arrangements can increase pipeline credit and should be in place prior to project commencement to guarantee revenue and enable financeability.

Such risks are fairly typical of existing pipeline development projects, and modification of existing contracts is likely to provide the basis for structuring commercial arrangements across CO_2 pipelines development and operation.

4.2.5 *The role of governments in financing*

Taking this range of factors into account, governments will clearly play a major role across a number of areas of wider CCS development, and more specifically, backbone pipeline development. These roles include:

- *Incentive frameworks*: creating the public policy to sufficiently incentivise CCS deployment, taking into consideration local, regional and national strategic considerations; and ensuring deployment in the most effective way and at the lowest cost through creation of effective enabling frameworks;

- *Regulatory frameworks*: in defining liability and the chain of custody for CO_2;

- *Financial support*: in potentially providing the appropriate financial mechanisms for deployment, such as partial or full public funding, soft loans, government guarantees, etc. in order to promote commercially viable value propositions to private entities;

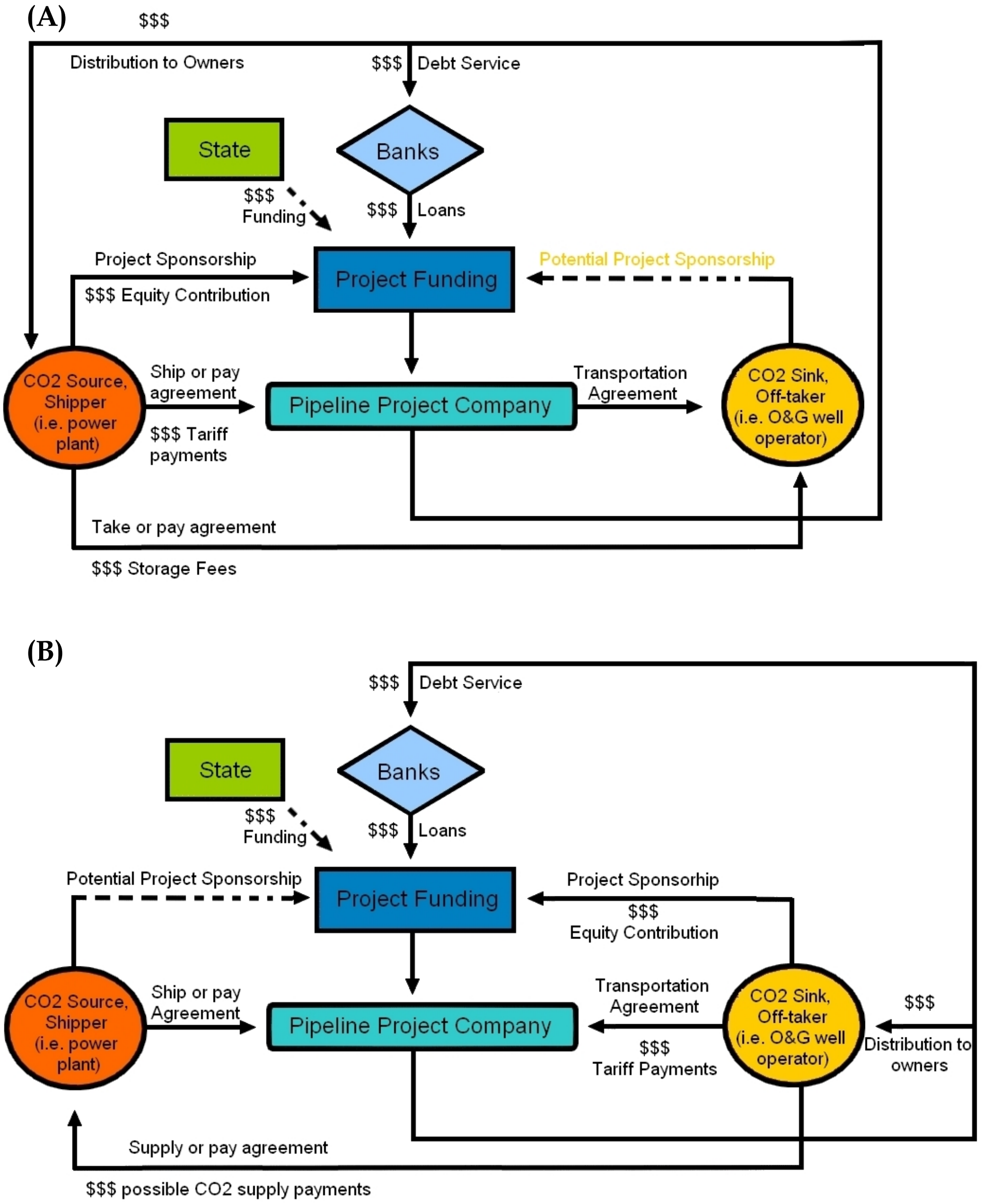
- *Coordination and ensure competitiveness*: in coordinating actors, especially in respect of developing the backbone pipeline infrastructure, so as to promote an optimised and integrated CCS network development that can allow CO_2 transport at the lowest cost to pioneer developers and new entrants. In this context, governments will play a role in ensuring the creation of a CCS market open to many players (both large and small) in order to ensure widespread deployment; and,

- *Underwriting risk and liability*: in the event of technology failures, and over the long term with respect to storage site liability.

On this basis, the next section of the report considers how these interrelationships may play out in a commercial sense, but providing quantitative economic analysis of a CO_2 backbone pipeline development under different commercial conditions.

Based on the discussion outlined in previous sections, a graphical depiction of how the commercial environment for CO_2 pipelines may evolve – based on either an upstream or downstream point of incentive – is show below (*Figure 4.1*).

Figure 4.1 Project Structure and Cash Flows (A) Emitter Incentive and (B) Storer Incentive



4.3 ECONOMIC PIPELINE MODEL

4.3.1 Rationale

The purpose of the economic modelling exercise is to attempt to answer some fairly basic questions potentially posed to a project developer (or project consortium) in considering the option of developing a backbone CO_2 pipeline infrastructure. Principally, the key question faced by a developer is whether to develop a backbone system ahead of a point-to-point pipeline, and what are the commercial considerations in this context. Thus, the questions that the modelling exercise aims to answer include:

- Is a backbone system the most optimised way of deploying CO_2 pipelines?
- Are there technical and commercial advantages to deploying a backbone system?
- Are there commercial barriers to deploying backbone pipelines?
- Are there options to overcome any commercial barriers?

In order to try and answer these questions, a methodology was developed based on several potential deployment scenarios, with each scenario tested using a pipeline financing model to test the most appropriate option, as described below.

4.3.2 *Modelling methodology and assumptions*

The modelling approach adopted to undertake the analysis consists of two core components, namely:

(1) *The modelled scenario*: consisting of the physical (i.e. sources of CO_2, storage site availability; and distance between the two) and temporal (i.e. the timeline for development) aspects of a hypothetical CCS value chain development. This also includes the different options for connecting sources and storage sites; and
(2) *The economic assumptions*: in terms of the construct of the underlying economic model used to appraise the two options (i.e. the basis of the pipeline cost model).

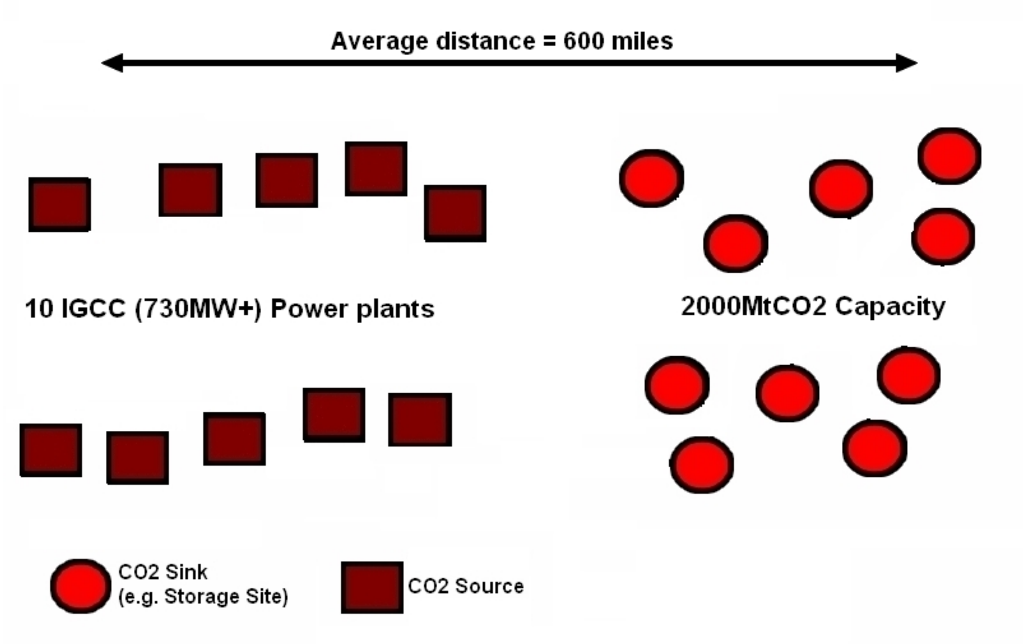
These are described in more detail in the next sections.

The modelled scenario

The hypothetical scenario consists of possibly 10 new coal-fired power plants being developed over a seven year period, by four different independent power producers. Developer ***"One"*** will bring on stream four new plants together in year one, with subsequent tranches of plant following in later years. All operators are assumed to be suitably incentivised to deploy CCS under the types of policy regimes described above. Each tranche of deployment is assumed to be clustered close together, although collectively, the tranches are dispersed over approximately a 60-120 mile radius.

A saline formation suitable for CO_2 storage has been identified within 600 miles or so of all the power plants. The formation has an estimated 2000 $MtCO_2$ storage capacity, sufficient to take all the CO_2 from all the plant for 40 years.

Figure 4.2 *Scenario Overview*



In terms of connecting the power plants to the storage formation, two options exist, namely:

(1) *Point-to-point pipelines*: each tranche of power plants independently develops a pipeline, designed to only take the CO_2 from that tranche to the storage formation at 98% capacity utilisation.
(2) *Backbone pipeline:* the developer of tranche 1 develops a backbone network with the option for subsequent tranches to connect, so as to reach 95% capacity utilisation after year 7 when the final tranche of plants are completed.

Details of the characteristics of the hypothetical scenario are outlined below (*Table 4.2*).

Table 4.2 *Summary of the Scenario for Modelling*

Feature	Characteristics
CO_2 source	10 x 730MW Integrated gasifier combined cycle (IGCC) coal-fired power plants, ~5MtCO_2/year/plant (1)
Timeline for deployment	The projects will be developed over an 8 year period as follows: • Year 1. Tranche 1: 4 x IGCC in close proximity completed • Year 3. Tranche 2: 2 x IGCC in close proximity completed. • Year 5. Tranche 3: 2 x IGCC in close proximity completed. • Year 7. Tranche 4: 2 x IGCC in close proximity completed. Each tranche is being developed by different developers.

(1) IPCC, Special Report on Carbon Capture and Storage, Table 3.10, new IGCC power plants using current technology.

Feature	Characteristics
Timeline for operation	• All plants are assumed to operate for a 40 year+ period. • During design of tranche 1, it is not assured that subsequent tranches will be realised i.e. there is uncertainty over whether new power plants will come on stream.
Total CO_2	• Tranche 1: 20 million tonnes CO_2/year • Tranche 2: 10 million tonnes CO_2/year • Tranche 3: 10 million tonnes CO_2/year • Tranche 4: 10 million tonnes CO_2/year Total CO_2 per annum in year 7 = ~ 50/year Total CO_2 following 40 years operation = ~2000MtCO_2
CO_2 store	• Large saline formation with around 2000 MtCO_2 storage capacity. • Each injection well has a capacity of 1 Mt/year, which means 45 injection wells will be needed in total.
CO_2 pipeline	All plants with an average distance from the formation = 600 miles Interconnectors detailed below.
Options for pipeline development	*Option 1. Point to point:* Each new tranche of plant seeks to connect directly to the storage formation in isolation of earlier or subsequent tranches. Tranche 1 builds a backbone pipeline (operating at 97.5% capacity utilisation), operating with an inter-connecting hub on average 60 miles away. In addition, a centralised receiving hub is built at the storage formation, with inter-connectors built to individual wells with an average distance of 10 miles from the hub. Tranche 2 builds a small backbone pipeline to take-up CO_2 from the two power plants in year 3 and with an interconnecting hub similar as the one for Tranche 1. Tranche 3 and 4 follow the same pattern as Tranche 2. *Option 2. Backbone:* Tranche 1 builds a backbone pipeline system in year 1 (operating at ~40% capacity utilisation), with a view to take up CO_2 from all the new potential tranches coming on stream through an inter-connecting hub, on average 120 miles away. In addition, a centralised receiving hub is built at the storage formation, with inter-connectors built to individual wells with an average distance of 20 miles from the hub. This is necessary to avoid interference between each injector.

What is described here is unlikely to play out in reality, but provides a useful basis with which to test the two options for pipeline development in the context of advantages and barriers, as well as options to overcome those barriers.

Economic assumptions

The pipeline economic model includes three key elements:

- *Construction and operating costs (Capex/Opex)*: details underpinning the pipeline cost model for Options 1 and 2 are outlined in Table 4.5 and Table 4.8 respectively.

- *Financing characteristics and structure*: this covers the metrics used to estimate both the cost of different types of capital used to finance the project, and the economic metrics used to appraise the different investment options. Further details on the assumptions used are provided below.

- *Project revenues*: project revenues have been estimated by calculating the cost of service for each different pipeline option, based on achieving a break-even tariff charge for a 20 year net present value (NPV) using cash flow analysis. The financial analysis assumptions are outlined below.

The project revenues form the basis for comparing different options. A summary of financing assumptions is provided below (*Table 4.3*).

Table 4.3 ***Assumptions Underpinning Financial Analysis***

Feature	Characteristic and assumptions
Project financing structure	Debt to equity ratio: 70:30 Based on analysis of oil and gas pipeline case studies (see ***Figure 2.8***)
Timeline for financial appraisal	20 years (financial)
Cost of equity	15% - typical rate
Cost of debt	9.57% (US libor + 4%) – London Interbank Offered Rate (LIBOR) is the interest rate at which banks can borrow funds, in marketable size, from other banks in the interbank market.
Discount rate	7.5% - Discount rate is the weighted average cost of capital (WACC), a combination of equity and debt for this scenario that also accounts for inflation

The results of the economic modelling exercise applied to the different pipeline financing options are described in the next section.

4.3.3 Model Results - Option 1 – Point to Point Pipeline

Under this scenario the private developer of Tranche 1 builds a backbone *pipeline 1,* and associated interconnector pipelines source and sink pipelines to transport emissions from the 4 new coal-fired power plants that are in operation in year 1 to storage sites. Subsequently, independent of Tranche 1, when Tranches 2, 3, and 4 come in operation they develop separate *pipelines 2, 3 and 4* respectively to transport CO_2 to the same storage site.

Further information on the specifications of the above pipelines can be found in *Table 4.4*.

Table 4.4 *Option 1 Pipeline Specifications*

	Tranche 1	Tranche 2	Tranche 3	Tranche 4
Backbone	*Pipeline 1*	*Pipeline 2*	*Pipeline 3*	*Pipeline 4*
Diameter	24 inch	18 inch	18 inch	18 inch
Length	600 miles	600 miles	600 miles	600 miles
Transported CO_2 / per year	~20MtCO_2	~10MtCO_2	~10MtCO_2	~10MtCO_2
Source pipelines	*For pipeline 1*	*For pipeline 2*	*For pipeline 3*	*For pipeline 4*
Diameter	4 x 14 inch	2 x 14inch	2 x 14inch	2 x 14inch
Length	60 miles	60 miles	60 miles	60 miles
Sink pipelines	*For pipeline 1*	*For pipeline 2*	*For pipeline 3*	*For pipeline 4*
Diameter	18 x 8 inch	9 x 8inch	9 x 8inch	9 x 8inch
Length	10 miles	10 miles	10 miles	10 miles

The capex and opex for each of the tranches and cumulatively for Option 1 is presented in *Table 4.5* below:

Table 4.5 *Capex and Opex ($000s) for each Tranche and for Option 1*

	Tranche 1	Tranche 2	Tranche 3	Tranche 4	Total Deployment
Backbone Pipeline					
Capex	$777,216	$567,072	$567,072	$567,072	$2,478,432
Opex (per year)	$2,995	$2,995	$2,995	$2,995	$11,978
Source pipelines					
Capex	$173,464	$86,732	$86,732	$86,732	$433,660
Opex (per year)	$1,198	$599	$599	$599	$2,995
Sink pipelines					
Capex	$80,262	$40,131	$40,131	$40,131	$200,655
Opex (per year)	$898	$449	$449	$449	$2,246
Total					
Capex	$1,030,942	$693,935	$693,935	$693,935	**$3,112,747**
Opex (per year)	$5,091	$4,043	$4,043	$4,043	$17,219

Table 4.6 presents the cost of service that the developer of each tranche will have to charge the system users in order to operate commercially.

Table 4.6 *Cost of Service (Tariff Charge) for each Tranche and Average for Option 1 (in $/t$CO_2$)*

	Tranche 1	Tranche 2	Tranche 3	Tranche 4	Average for deployment
Backbone	$6.0	$9.4	$9.4	$9.4	$8.4
Source	$1.4	$1.4	$1.4	$1.4	$1.4
Sink	$0.7	$0.7	$0.7	0.7_2$	$0.7
Total	**$8.1**	**$11.5**	**$11.5**	**$11.5**	**$10.5**

4.3.4 *Model Results - Option 2 – Integrated Backbone Network*

Under this scenario, the private developer would build large backbone *pipeline 1* and associated interconnector pipelines source and sink pipelines to transport emissions from the four new coal-fired power plants that are in operation in year 1 to storage sites. This pipeline is built with excess capacity to subsequently accommodate the new users in the system when Tranches 2, 3, and 4 come in operation. Further information on the specifications of the above pipelines can be found in *Table 4.7.*

Table 4.7 ***Option 2 Pipeline Specifications***

	Tranche 1	Tranche 2	Tranche 3	Tranche 4
Backbone pipeline for all tranches				
Diameter	34 inch			
Length	600 miles			
Transported CO_2	~20MtCO_2			
Source pipelines	*For Tranche 1*	*For Tranche 2*	*For Tranche 3*	*For Tranche 4*
Diameter	4 x 14 inch	2 x 14inch	2 x 14inch	2 x 14inch
Length	120 miles	120 miles	120 miles	120 miles
Sink pipelines	*For Tranche 1*	*For Tranche 2*	*For Tranche 3*	*For Tranche 4*
Diameter	18 x 8 inch	9 x 8inch	9 x 8inch	9 x 8inch
Length	10 miles	10 miles	10 miles	10 miles

The capex and opex for each of the tranches and cumulatively for Option 2 is presented in *Table 4.8* below:

Table 4.8 ***Capex and Opex ($000s) for each Tranche and for Option 2***

	Tranche 1	Tranche 2	Tranche 3	Tranche 4	Total Deployment
Backbone Pipeline					
Capex	$1,053,184				$1,053,184
Opex (per year)	$2,995				$2,995
Source pipelines					
Capex	$346,932	$173,466	$173,466	$173,466	$867,330
Opex (per year)	$2,396	$1,198	$1,198	$1,198	$5,989
Sink pipelines					
Capex	$160,506	$80,253	$80,253	$80,253	$401,265
Opex (per year)	$1,797	$898	$898	$898	$4,492
Total					
Capex	$1,560,622	$253,719	$253,719	$253,719	**$2,321,779**
Opex (per year)	$7,187	$2,096	$2,096	$2,096	$13,476

Table 4.9 presents the cost of service assuming that all tranches eventually connect to the system as planned.

Table 4.9 ***Cost of Service (Tariff Charge) for Option 2 (in $/tCO_2$)***

	Average for Option 2
Backbone	$3.5
Source	$2.8
Sink	$1.4
Total	**$7.7**

4.3.5 *Comparative analysis*

In this section we consolidate the model results in order to compare the two options using as metrics the cost of service associated with their use and the capital investment required for their development.

Cost of service

Table 4.10 shows the average cost of service for *Option 1* and *Option 2* for the whole system (i.e. for all tranches) and from a first mover perspective (i.e. in year 1).

Table 4.10 ***Cost of Service for Option 1 and Option 2 (in $/tCO$_2$)***

	Cost of Service (for all tranches)	Cost of Service (in year 1)
Option 1	$10.5	$8.1
Option 2	$7.7	$11.3

Key findings of the research can be summarised as:

- The cost of service for *Option 2* (i.e. backbone pipeline) presents the cost effective scenario for the system.

- Cost of service for the system is higher for *Option 1* than *Option 2* because additional smaller pipelines are developed separately for Tranches 2, 3 and 4.

- From a first mover perspective the reduction to the cost of service for the operator of Tranche 1 (cost of service in year 1) that follows Option 2 is small $0.4 ($8.1 vs. $7.7).

- There is a risk that if the first mover opts for *Option 1* then additional tranches may not be able to carry out CCS due to prohibitive costs, absent of a backbone pipeline (i.e. *Option 2*).

Capex

Table 4.11 presents the capital required for the development of *Option 1* and *Option 2* for the whole system (i.e. for all tranches) and from a first mover perspective (i.e. in year 1).

Table 4.11 ***Capital Required for Option 1 and 2 (in $000s)***

	Capex (for all tranches)	Capex required (in year 1)
Option 1	$3,112,747	$1,030,942
Option 2	$2,321,779	$1,560,622

Key findings of the research can be summarised as:

- The capital required for the deployment of the *Option 1* system is almost 35% more when compared with *Option 2*.

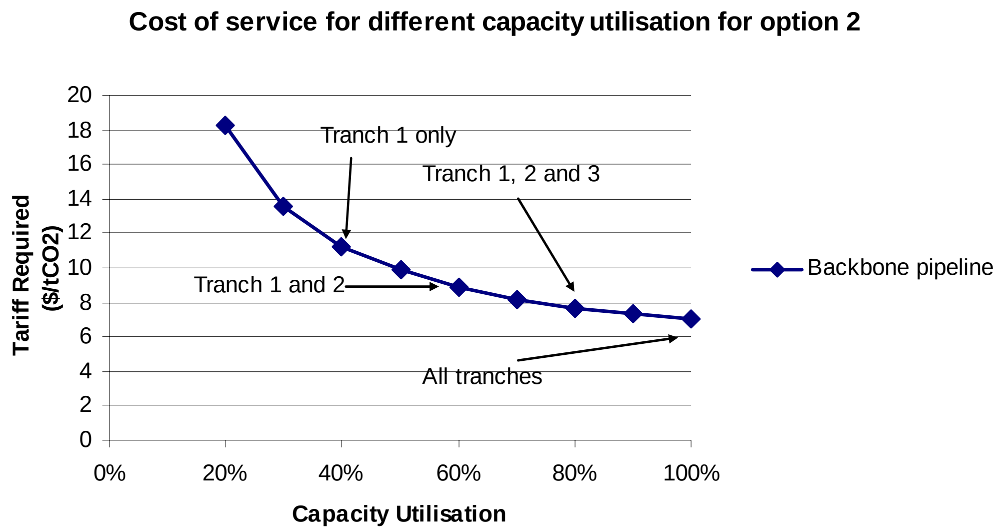
- From a first mover perspective the operator of Tranche 1 would need to raise an additional $500 million in year 1 to develop *Option 2*.

4.3.6 *Sensitivity analysis*

Capacity Utilisation

ERM undertook a sensitivity analysis in order to understand the economic risks for a first mover (i.e. Tranche 1) pursuing a backbone pipeline with excess capacity (*Option 2*), when some or all subsequent tranches are not deployed. *Figure 4.3* shows that the above scenario effectively results to an increase in the cost of service due to under-utilisation of the backbone pipeline capacity.

Figure 4.3 *Cost of Service for Different Capacity Utilisation for Option 2*



The above results are summarised along the equivalent cost of service for *Option 1* in *Table 4.12* in order to understand the risk in the context of the both scenarios.

Table 4.12 includes:

- Under *Option 1*: The cost of service for Tranche 1 and for the system when more tranches build separate pipelines.
- Under *Option 2*: The cost of service for the backbone pipeline depending on how many tranches eventually connect to the system.

Table 4.12 *Average Cost of Service of Deployment of Option 1 and 2 (in $/tCO_2$)*

	Tranche 1 only	Tranches 1 and 2 only	Tranches 1, 2 and 3 only	All Tranches
Option 1	$8.1	$9.2	$9.8	$10.5
Option 2	$11.3 (40% capacity utilisation)	$9.2 (60% capacity utilisation)	$8.2 (80% capacity utilisation)	$7.7 (Full capacity utilisation)

Table 4.12 shows that it would be cheaper for a first mover (i.e. Tranche 1) to pursue *Option 1* for $8.1/tCO_2$ over Option 2 unless they are sure that **all tranches** will eventually connect to the backbone as this will bring the cost down to $7.7/tCO_2$ for *Option 2*..

In this sense, the Tranche 1 operator would need to weight the probability of future capacity realisation, along with the marginal cost benefit that will be received in this scenario, versus the probability of non-realisation along with the associated costs.

Financing Structure

Different financing structures influence the cost of capital and can subsequently affect the cost of service. For this reason the model was run for alternative financing structures in order to evaluate the cost of service in relation to *Option 2*.

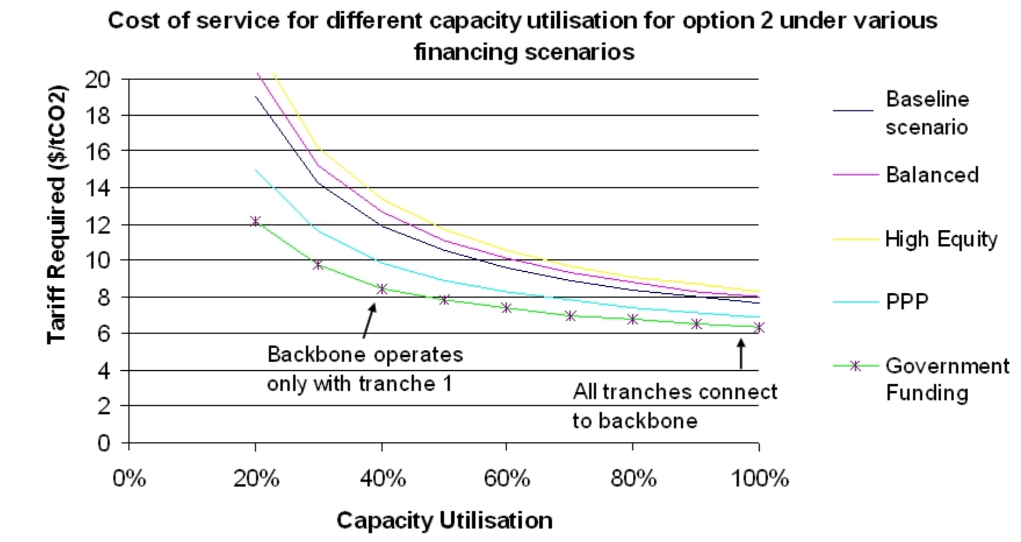
The alternative financing scenarios that ERM built are presented below in *Table 4.13.*

Table 4.13 Financing Scenarios

Scenario	Financing Sources	Comments
Baseline Scenario (typical)	70% Debt, 30% Equity	Projects are typically leveraged with 70/30 debt to equity ratios or higher.
Balanced	50% Debt, 50% Equity	Similar to the base scenario the medium scenario is structured with less debt and more equity.
High equity	30% Debt, 70% Equity	As the cost of debt is usually cheaper that that of equity this can be considered as the pessimistic scenario where the project company could only partially raise the necessary debt to finance the project.
PPP	40% Debt, 10% Equity, 50% Government Guaranteed Bonds	Public private partnership scenario where the government would agree to guarantee bonds issued by the project company in the capital markets.
Government funding	100% Government Guaranteed Bonds	Government entirely funds the project.

The cost of service for different capacity utilisation for *Option 2* under various financing scenarios is presented in *Figure 4.4*.

Figure 4.4 *Cost of Service for Different Capacity Utilisation for Option 2 under Various Financing Scenarios*



Government funding can enable the project to operate commercially at a comparative cost of service (~8$t/$CO_2$) to *Option 1* even when Tranches 2, 3 and 4 are not realised (i.e. see *Figure 4.4* at 40% capacity utilisation). In this sense, governments through favourable financing or other types of support can provide security to first mover over future capacity up-take and mitigate risks in order to promote optimised deployment options for a CCS scenario such as the one modelled.

4.3.7 *Conclusions*

The three main deployment challenges for the development of a backbone pipeline can be summarised as:

- *System Capacity Utilisation:* A backbone pipeline would need a sufficient utilisation of its capacity in order to be economical. It was highlighted in the model that it is still marginally cheaper for Tranche 1 to pursue a smaller pipeline with no excess capacity, (i.e. *Option 1*) unless all tranches connect to the backbone pipeline (i.e. *Option 2*).

- *Marginal benefits for a first mover might be relatively small compared to potential losses:* The potential reduction of cost of service for a first mover in building a backbone might be relatively small in comparison to potential losses from unrealised capacity. It was shown in the model if all tranches connect to the backbone pipeline the operator of Tranche 1 benefits from a cost reduction of \$0.4/tCO_2 (see *Table 4.10*). On the other hand their potential losses from unrealised capacity stand at four times more at \$3.2/tCO_2 if Tranches 2, 3 and 4 are not realised.

- *Financeability issues:* Financing could present challenges because investment decisions (especially project finance) for high capital outlay are justified by economic analysis based on revenue certainty as was highlighted during the review of oil and gas pipeline case studies.

Risk mitigation options that can manage the challenges presented above may be required to promote successful deployment of backbone pipelines.

Our analysis suggests that there is an opportunity for governments to provide the support that is needed in the first few years of operation to help first mover operators to build pipelines with excess capacity for future users and realise economies of scale.

This support can come in many forms such as:

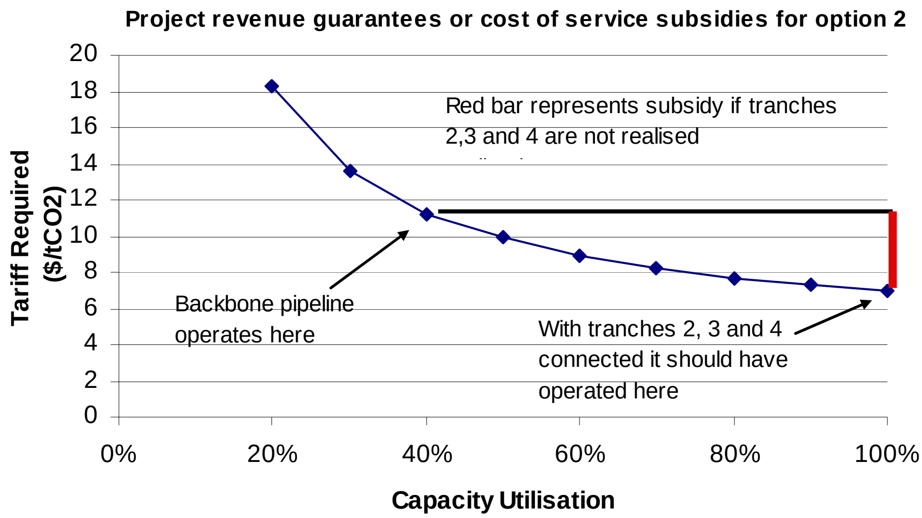
- Favourable financing options
- Project revenue guarantees or cost of service subsidies
- Project sponsorship and delivery by State

Favourable financing options could enable the financeability of a pipeline network and take up some of the risks associated with excess capacity as was shown earlier *Figure 4.4*. An example of this is the GME pipeline where the Spanish public sector, during the initial phase of the project, guaranteed the Spanish section of the pipeline by assuming a 91 percent share to the project company to insulate the pipeline from project risks (see *Box 6.2, Annex A*).

Financing support can be provided in the form of capital grants, earmarked revenues generated by auctioning allowances in cap and trade systems (e.g. EU-ETS) and/or low cost government financing like guaranteed bonds, etc. Bonds could be very well-suited for pipelines given the regularity and predictability of cash flows, and the long life and large size of required investment.

Project revenue guarantees or cost of service subsidies for an operator that builds a pipeline with excess capacity in order to accommodate future users could be another type of support. Under this arrangement governments would guarantee the revenue, or alternatively cover the additional cost of the operator when subsequent tranches do not come into the system. In our model governments could guarantee the revenue of the first mover (Tranche 1) if Tranches 2, 3 or 4 are not realised through a cost of service subsidy (i.e. represented as a red line in *Figure 4.5*).

Figure 4.5 Revenue Guarantee or Cost of Service Subsidy



A project example where revenue guarantees were used by the UK government is the Channel Tunnel Rail Link (see *Annex B*).

Lastly, **direct government involvement,** as another type of support, could be an option where the government would assume the project entirely. An infrastructure that would help mitigate climate change could be developed and delivered by states to kick-start large scale CCS deployment and help them achieve their international reduction obligations. Additionally, government's ROI requirements that are generally lower than those of the private sector would effectively translate into lower CO_2 transportation tariff charges giving this way a competitiveness boost to the rest of the CCS value chain.

Any adopted fiscal incentives have to be long term, as investors will be reluctant to participate in the development of CO_2 infrastructure if there is uncertainty that these can be changed during the project lifetime. In principle, once the price of carbon is stable and high enough to cover the aforementioned risks, the incentives would no longer be needed.

5 FINANCIAL SECTOR INTERVIEWS

5.1 OVERVIEW

If large scale CCS technologies are to achieve widespread deployment, thousands of kilometres of dedicated CO2 pipeline networks will be required. For that to happen, traditional investors such as banks and private equity houses will need to be involved to support the commercial funding of these projects.

In order to gain a deeper insight into the overall interest on the issue, and assess the readiness for using funds from the financial sector for this type of activity, ERM undertook interviews with individuals in appropriate organizations. In order to achieve this, ERM used its existing range of contacts in private banking, venture capital and private equity houses in order to gain contacts with key investment fund managers.

A structured questionnaire format was developed and a formal interview process was implemented. Following the gathering of information from 10 different key financial institutions representatives, ERM here reports on their perspectives and comments in this section.

Part of this section provides a review of different investment funds held by various types of institutions (private investment banks; venture capital; private equity; and quasi governmental lending facilities such as EIB, World Bank etc.).

Additionally we provide details regarding the size of the fund, its scope and applicability conditions and other relevant criteria.

5.2 INTERVIEWS

The financial institutions that were involved in the interview process are presented in *Table 5.1* below:

Table 5.1 Financial Institutions Involved in the Interview Process

Organization
Royal Bank of Scotland
Merrill Lynch
European Investment Bank
Mizuho Corporate Bank
Sumitomo Mitsui
Fortis Bank
WestLB

The main intended questions and outcomes of the interview process were, inter alia, to understand and explore:

- Key factors that determine the financeability of infrastructure schemes
- The main associated risks, uncertainties, information requirements and other issues that would be required before investing in CCS pipelines
- Appropriate funding mechanisms for CCS pipelines that financial institutions could assist with
- Aspects of a CO_2 CCS chain that financial institutions would feel (more) comfortable providing finance
- Funds that currently are available for financing pipeline projects
- Overall interest in helping in CCS pipeline financing
- Organisation involvement in other investments associated with climate change

ERM fully respected the requirement that was posed by financial institutions for part or the whole of the results of this survey to remain strictly confidential. For this reason, ERM is not attributing responses to specific individuals or organisations; nonetheless we use our interview findings to provide consolidated views below.

5.3 *INTERVIEW KEY MESSAGES*

Overall most banks expressed great interest in CCS as they realise that related infrastructure will require significant amounts of capital that could only come from traditional financing sources.

ERM's overall impression was that banks are closely following developments surrounding CCS, and would like to be further involved once there is more certainty around policy and regulatory issues affecting climate change and CCS.

ERM summarised the key messages from the interviews that are presented below in 3 main sections:

- Risk and uncertainty issues
- Prerequisites to financeability
- Financing Mechanisms and Funds

5.3.1 *Risks and uncertainty Issues*

The main associated risks and uncertainties that were highlighted during the interviews in relation to the development of a CCS pipeline are:

- *Carbon price:* Banks are not usually exposed to market risk (i.e. carbon price), but in a financing scenario they would be exposed to commerciality of the project. An appropriate and stable carbon price must be established as a basis for calculating future cash flows.

- *Technology associated with CCS:* According to interviewees successful demonstration projects could alleviate such risks.

- *Contractual arrangements:* especially on how rent and tariffs would be distributed across the CCS chain, and the nature of penalty clauses, costs of termination agreements, force majeure events, etc.

- *Project coordination risks:* for backbone pipelines deployment coordination between multiple CO_2 sources and sinks and associated risks, seem to be of high importance for project success.

- *Risk of throughput:* throughput depends on sourcing and storing capabilities and therefore a fair amount of due diligence would be needed in this area. More clarity would be required regarding:

  - How throughput would be contracted?

  - Potential CO_2 sourcing risks associated with energy policy decisions need to be explored (e.g. how CCS prospective power plants fit into governments' overall electricity generation planning).

  - Capacity build-up for "backbone pipelines"; It was understood that it might be too risky for commercial banks to provide loans on the basis of estimated future capacity build-up, due to uncertainty reasons. On the other hand, the approach that multilateral might take when considering a loan to a "backbone" CO_2 pipeline sponsor(s) could include a strategic element around considerations for future capacity. In this sense, projects would still need to be examined on a case by case basis by multilateral banks, depending on the actual potential for demand build-up for the pipeline from other local users. However it would be possible for an operator to submit an application for a loan linked to building a pipeline, with a view to future take-up of capacity.

  - Storage risks such as regulatory requirements, adequate size of sinks for planned project stream and site maintenance & aftercare costs.

- *Environmental and social risks:*
  - World Bank Guidelines and Equator Principles; Pipeline Environmental Impact Assessment (EIA) issues etc.
  -
  - NGOs; Logic behind this follows the historical trend of NGO protests for environmental and social impacts of oil and gas pipelines (e.g. BTC, WAGP, etc.)

5.3.2 *Prerequisites for financeability*

According to the interviewees, the main factors that banks would need to assess in order to determine the financeability of a CCS pipeline are:

- *Standard financeability requirements for project finance (e.g. visibility and certainty of future revenue streams):* These have been discussed in previous sections of this report.

- *Regulatory framework for CCS:* the majority of interviewees expressed the opinion that there is a need to understand how a future regulatory framework for CCS pipelines might evolve in potential project host countries. This will make a difference in understanding the size and type of a project's future revenue stream (i.e. regulated or market driven).

- *International long-term carbon regulatory regime:* Infrastructure projects are long-term, low-risk investments. There should be a clear and long-term regulatory regime for carbon to provide certainty and match the long-term project related repayment period (20-30 years).

- *Contractual structure of the project along with creditworthiness of parties*: Firm and long-term off-take agreements provide cash flow visibility and predictability which is the basis upon which project financeability is determined. Furthermore, creditworthiness of parties is required in order to secure the aforementioned off-take agreements.

It is worth noting that Fortis Bank, (one of the banks interviewed) project-financed the first CO_2 pipeline company in the Netherlands (OCAP). OCAP Company supplies pure CO_2 to greenhouses for cultivation, which would otherwise be emitted into the atmosphere, via an existing pipeline and a new distribution network. The project met the above project finance prerequisites and was financed purely on commercial terms on the basis of cash flow analysis with the CO_2 off-take agreements by greenhouses securing the revenue stream (1). Prior to the OCAP project, greenhouses used to generate CO_2 for their operations through natural gas combustion while now they buy the CO_2 from OCAP which is supplied at a much cheaper/unit price compared to the previous process.

5.3.3 *Applicable Financing Mechanisms*

Project Finance (PF)

Project finance seems to be the best option for financing CCS infrastructure according to most banks. Some issues were highlighted regarding project finance in relation to CCS:

(1) It is worth noting that the Shell refinery is allowed to report the 170,000 tonnes of transferred CO_2 as non-emitted for the purpose of the EU ETS compliance, thus representing an avoided cost. However, this was not one of the financial considerations in the investment decision.

- Project finance usually depends on the risk appetite of the investors but it is generally suited for lower risk projects; this might not fit well with current uncertainty over CCS and post-Kyoto framework.

- The repayment period is 20-30 years (long term policy required) that suits infrastructure projects well; again concerns over long term certainty of climate change regulatory framework were raised.

- Debt financing is the preferred form of funding for project finance but due to risks mentioned above it might not be easy to provide; governments can provide a level of risk mitigation through:
    - Export Credit Agencies;
    - Multilateral Agencies and Banks
    - Special funds from government agencies.

Public Private Partnerships

Some interviewees expressed the opinion that Public-Private Partnerships could be a good way of promoting project development as it can provide a level of security to investors.

Others pointed out that PPPs have mainly been successful in the delivery of simpler projects such as schools, prisons and hospitals, and as such would not be generally recommended for the development of a complex transportation network for CCS because of project coordination issues that may arise. In this context, central governments (such as the US Federal Government, the EU, etc.) or oil and gas consortiums might be better suited to coordinate the development of such a network especially for trans-border pipelines.

Government funding

Another option was for the backbone pipeline to be developed entirely as a government project (i.e. via public sector borrowing) and delivered by governments as a public good. Most of the interviewees expect a high level of receptiveness from governments regarding the use of government funds for CCS financing.

5.3.4 Applicable Funds

Debt Financing

It was made clear from the interviews that the most likely part of the CCS value chain to be financed through debt, would be the pipeline infrastructure. Such financing is already tried and tested for oil and gas pipelines, contrary to CCS technologies that are far more risky. On the other hand it was noted that a pipeline represented limited collateral, with limited value in alternative uses, should the project collapse.

The general consensus from the interviews with banks was that it is too early for banks to finance such a CO_2 pipeline network on a limited recourse basis, until such process/technology is well established and/or until contractual framework can be put in place with creditworthy entities ensuring a throughput revenue for undertaking for such pipelines.

Multilateral Bank Financing

Overall multilateral banks such as the EIB suggested that they are ready to finance CCS demonstration plants and other experimental clean coal technologies (primarily as RDI projects) provided they meet the EIB's environmental, economic, technical and financial criteria, including credit risk criteria. A few examples among include:

- *EIB - Climate Change Financing Facility (CCFF):* The CCFF was initially designed to help EU companies covered by the EU ETS to comply with their CO_2 emission allowance allocations by financing investment in emission reduction projects. However, the EIB has recently broadened the scope of the Facility to also support investments not covered by the EU ETS that significantly reduce greenhouse gas emissions, regardless of the region sector or type of greenhouse gas.

- *European Commission, EIB - Risk Sharing Finance Facility (RSFF):* The European Commission and the European Investment Bank (EIB) have joined forces to set up the Risk Sharing Finance Facility (RSFF). The RSFF is a credit risk sharing facility between the EC and the EIB that extends the ability of the Bank to provide loans or guarantees for investments that involve financial risks above those normally accepted by investors.

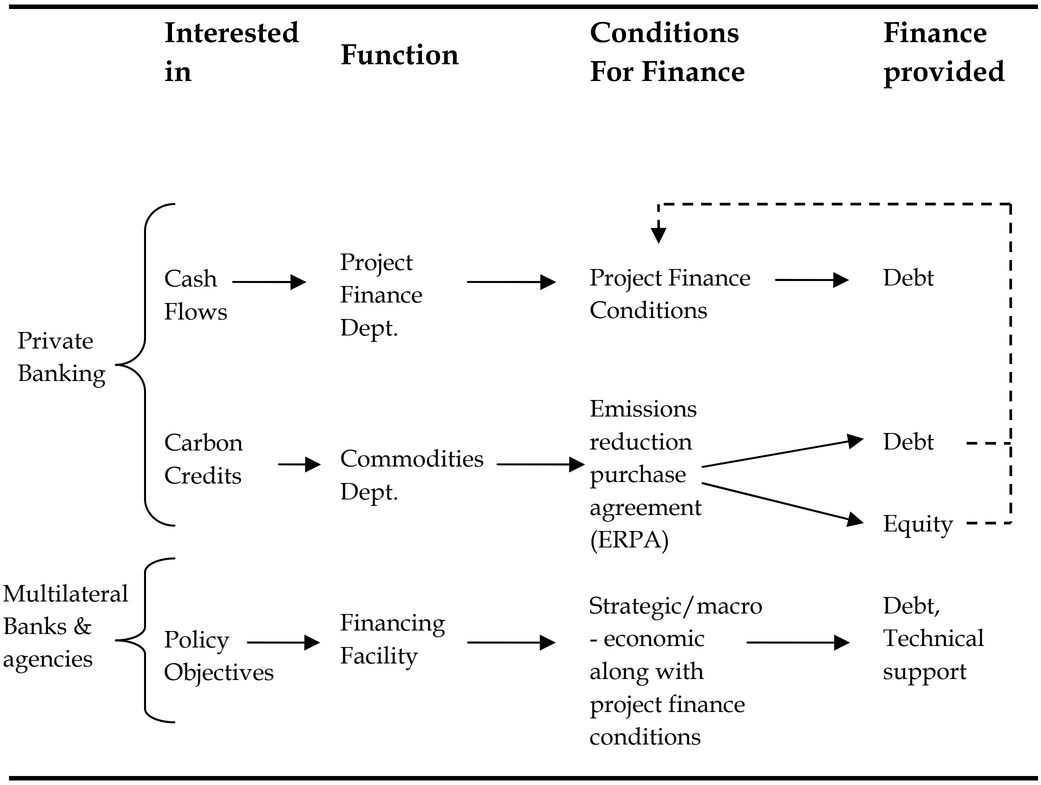
Due to their goal of furthering government policy objectives through favourable lending terms, guarantees and other risk sharing tools multilateral banks (EIB, World Bank, etc.) have an important role to play in future CCS infrastructure development.

Carbon Finance

While the business models of carbon funds and carbon finance in general can vary, their main goal is to acquire and trade carbon credits. Carbon finance does not generally provide loans for large infrastructure projects but in some cases banks could provide finance (debt and/or equity) to projects that deliver GHG emission reduction in return for an offtake of carbon credits that can facilitate their commodities trading business. This is common practice for other more developed commodity markets, for example banks can hold physical assets in coal freight, LNG or gas pipelines to support the trading of coal and gas. On the same basis they can provide project finance for the origination of emission reduction credits, which could conceivably be applied to CCS projects. On this basis carbon can credits can act as a credit enhancement and result in improvement of financing terms and conditions, e.g. a CCS pipeline could potentially be funded on the basis of an emissions-reduction purchase agreement (ERPA) for future delivery of carbon credits (CERs/ERUs).

ERM undertook a desk-study research in order to identify available carbon and clean-energy funds and performed a high-level assessment of their criteria in relation to applicability for CCS financing. These are presented in *Annex C*. *Figure 5.1* summarises schematically the financing mechanisms and sources available from the banking sector that could potentially be applicable for CCS infrastructure funding.

Figure 5.1 ***Financing Mechanisms and Sources from the Banking Sector***



Sovereign Wealth Funds (SWF)

Sovereign Wealth Funds (SWF) generally take positions in the operational side of infrastructure projects and look for a long-term (e.g. 20 year) relatively low-medium but secure return on investment (14-15%) that could be interested in providing some funding in a more mature carbon market. There are several Middle East and Far East funds of this nature.

5.4 INTERVIEWS CONCLUSIONS

Banks are closely following the development of CCS. ERM's impressions from the interviews was that the financial sector would look to become involved once there is more certainty around the current regulatory and policy issues affecting CCS. Particular risks and uncertainties perceived by banks include: uncertainty over carbon price; CCS technology risks; contractual risks; project coordination risks (coordination between sources and sinks is complex); throughput risks – due diligence covering issues such as how throughput would be contracted, how CCS policy fits into government's energy policy, capacity build-up for backbone pipelines and storage risks; and environmental and social risks.

Banks need to further assess the standard financeability requirements for project finance with respect to project risks; the regulatory framework for CCS; international long-term carbon regulatory regimes; and contractual structure of projects, in order to determine the financeability of a CCS pipeline.

There is a need for a more clear and long-term regulatory regime for carbon to provide certainty and match the long-term project related payment period, and furthermore, the creditworthiness of parties is required to secure any off-take agreements.

According to the interviews, the Project Finance model appears to be the best option for financing CCS pipelines. However, a few respondents preferred Public-Private Partnerships as they could provide a level of security to investors. It is worth noting that PPPs were also criticized as in the past they have only been applied to relatively simple projects, and a CCS network would result in project coordination issues (described earlier). Government funding is also expected to be a potential option by the banks.

From the interviews, it was made clear that the pipeline infrastructure could be financed through debt (as is common practice for oil and gas pipelines), but it may be too early for banks to finance CO_2 pipelines until there is a carbon price signal for CCS.

However, multilateral banks such as the EIB are ready to fund pilot CCS projects (provided that the required standards are met). A CCS pipeline could also potentially be funded through carbon finance, e.g. on the basis of an emissions-reduction purchase agreement (ERPA) for future delivery of carbon credits (such as ERUs or CERs).

6 STUDY SUMMARY CONCLUSIONS

In this section, the study's overall findings and conclusions are presented along with other issues for further consideration in relation to developing CO_2 transportation networks.

6.1 LESSONS LEARNED FROM O&G AND PPP CASE STUDIES

This study has highlighted various factors that enhance project financeability, yet there are also issues which inhibit financeability. Factors which enhance financeability include: that pipeline technology is well established and as such can be seen as a proven technology; major oil and gas sponsors are likely to be creditworthy and experienced in pipeline development; and, a future stream of cash flows is identifiable in O&G pipeline projects. On the other hand, while the risk of transportation of commodities such as oil and gas presents a relatively low market risk, factors which could inhibit financeability include: security issues; regulatory intervention; and, transit and cross-border risks (transit fee uncertainty). Such issues can result in an increased cost of capital, which in turn may affect the cost of the delivered hydrocarbons.

Public-Private Partnership structures are widely used for the delivery of public goods and services. Mitigation of climate change can also been seen as serving a public good, and thus a CCS transportation network could potentially fall within the sphere of public/government sponsorship. PPPs, which include large transportation projects, have the advantage that they provide benefits not only to the promoter but also to the public sector (such as attraction of foreign investment, national budget relief etc.). There is a variety of financing mechanisms for PPP projects and each case study reviewed used different funding options. These ranged from government bonds and other guarantees to debt and equity.

Clear specifications of outputs are important in PPP projects and as such they tend work well for simpler projects. The development of a CO_2 transportation network could potentially be quite complex and require a large number of parties to be involved, which is one of the potential downsides of PPPs.

6.2 COMMERCIAL AND ECONOMIC ISSUES

A range of commercial factors were identified for CCS projects, covering policy approaches to incentivising CCS and regional strategic considerations. The former includes options such as: mandating CCS; fiscal policy; market based approaches, or through provisions for public subsidies for the uptake of a technology. The latter includes geographical/geopolitical factors, such as whether regions have low emissions and good storage potential; high emissions and poor storage potential: or have commercial incentives for enhanced hydrocarbon recovery. These factors could impact the way governments and commercial operators act.

The oil & gas pipeline case studies also provided strong evidence to suggest that different incentives – or market "push" or "pull" factors – are strong influencing factors on how projects are structured. On this basis, it was concluded that:

- the nature of the incentives offered for reducing GHG emissions will determine the point in the CCS chain where value is created (i.e. market push or pull characteristics);

- strategic factors will also play a role in influencing decisions regarding deployment, and also the terms and nature of financing sources; and

- in turn, these will influence the structure of CO_2 pipeline project development.

Therefore, depending on how these all play out in different deployment scenarios will be a major factor in whether CO_2 backbone pipeline projects emerge ahead of simple point-to-point pipelines deployed on a project by project basis.

In addition, recognising that value will most likely be created at a single point in the chain, commercial contracts between emitters, shippers and storers will be very important in distributing revenues and allocating risks between parties. Types of risks to be considered in commercial contracts include: non-delivery risk; non-take risk; and, non-containment risk.

A pipeline economic model was built to quantitatively evaluate options for connecting 10 power plants with a storage site located on average 600 miles away. Options included four (4) point-to-point pipelines or one (1) backbone network pipeline to connect the power plants with the storage site.

The results of the evaluation suggest the following main deployment challenges for the development of a backbone pipelines:

- *System Capacity Utilisation:* A backbone pipeline would need a sufficient utilisation of its capacity in order to be economical, especially in early years.

- *Marginal benefits for a first mover might be relatively small compared to potential losses:* The potential reduction of cost of service for a first mover in building a backbone might be relatively small in comparison to potential losses from unrealised capacity.

- *Financeability issues:* Financing could present challenges because investment decisions (especially project finance) for high capital outlay are justified by economic analysis based on revenue certainty.

Risk mitigation options that can manage the challenges presented above may be required to promote successful deployment of backbone pipelines. Analysis undertaken suggests that there is an opportunity for governments to provide the support that is needed in the first few years of operation to help first movers to build pipelines with excess capacity for new entrants and realise economies of scale.

This support can come in many forms such as:

- Favourable financing options
- Project revenue guarantees or cost of service subsidies
- Project sponsorship and delivery by State

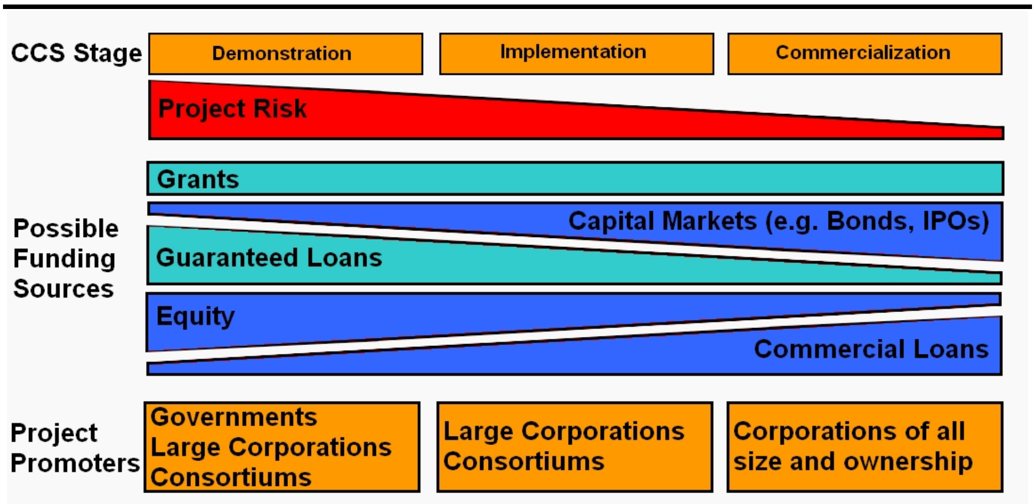
6.3 *FINANCING*

Quantitative modelling analysis undertaken, suggested that a CO_2 pipeline network developed by individual operators would expose a single entity to significant first-mover risk, and additional up-front costs. The reciprocal of the risk is that not developing a pipeline network is unlikely to represent the most cost efficient deployment pathway for CCS, in the longer-term.

The first-mover risk that project participants would be exposed to is likely to be much higher during the demonstration stage of CCS. As pipeline networks start to develop to the risk could gradually phase out as new entrants enter the capture market. This relationship could ultimately influence accessibility to funding sources for pipelines at this stage.

Figure 6.1 highlights this relationship between risk and overall CCS risks and includes an estimation of potential funding sources for CO_2 pipeline development.

Figure 6.1 CCS Overall Project Risks and Possible Funding Sources for CO_2 Pipelines



The interviews with the financial sector suggested that private and public banks are closely following the development of CCS. ERM's broad impressions from the interviews was that they would like to be more closely involved once there is more certainty around the current regulatory and policy issues affecting CCS. Particular risks and uncertainties perceived by banks include: uncertainty over carbon price; CCS technology risks; contractual risks (e.g. how rest and tariffs would be distributed across the CCS chain); project coordination risks (coordination between sources and sinks is complex); throughput risks – due diligence covering issues such as how throughput would be contracted, how CCS policy fits into government's energy policy, capacity build-up for backbone pipelines and storage risks; and environmental and social risks.

The analysis undertaken – an in particular for a backbone network – suggested that governments funding may be needed, especially in early phase demonstration, in order to mitigate first mover. Their involvement may also be necessary to ensure sufficient support and coordination to realise CO_2 pipeline networks ahead of point-to-point systems. This support can come in many forms such as, for example project revenue guarantees, favourable financing options or project sponsorship and delivery by State (see *Section 4.3.7*).

Annex A

Oil and Gas and CO_2 for EOR Pipeline Case Studies

CONTENTS

A1 BAKU-TBILISI-CEYHAN PIPELINE

A1.1 PROJECT DESCRIPTION

The Baku-Tbilisi-Ceyhan pipeline (BTC), second longest oil pipeline in the world, is a crude oil dedicated pipeline with total length of 1,776 km that extends from the Azeri-Chirag-Guneshli oil field in the Caspian Sea, through Azerbaijan and Georgia, to the Ceyhan terminal on Mediterranean coast of Turkey. The total length of the pipeline in Azerbaijan is 440 km, in Georgia 260 km and in Turkey 1076 km long totalling approximately 1760 km. The BTC can transport up to 1 million barrels per day and will complement oil transport along the two existing pipelines (i.e. Northern and Western Route pipelines). (1)

Figure 1.1 Route of the Baku-Tbilisi-Ceyhan pipeline

Source: http://www.ebrd.com/projects/eias/esia_geo.pdf

A summary of the BTC pipeline specifications can be found in *Table 1.1* below

Table 1.1 BTC Pipeline Specifications

Specifications	
Pipeline Length	1776 km
Diameter	42 inches
Daily Capacity	1 mbd
Reported Cost	$3.6 billion

A1.2 RATIONALE

Some of the main reasons that prompted for the development of the BTC pipeline are:

(1) http://www.ifc.org/btc

- The geographical position of the landlocked Caspian Sea which makes transportation of oil difficult
- The limited oil transportation capacity of the two existing pipelines—the Northern and the Western Route pipeline
- Geopolitical reasons such as reliability of oil supply from Russia and Iran.

A1.3 *OWNERSHIP STRUCTURE*

A Special Purpose Entity (SPE), in the form of a limited company, the Baku-Tbilisi-Ceyhan Pipeline Company (BTC Co) was incorporated in the Netherlands by an international consortium of 11 partners, led by BP in order to develop and operate the BTC pipeline. BTCCo is indirectly and wholly owned by the sponsors presented in *Table 1.2*.

Table 1.2 ***BTC Co Shareholders***

Company	**Share**
BP (United Kingdom)	30.10%
State Oil Company of Azerbaijan (SOCAR) (Azerbaijan)	25.00%
Chevron (USA)	8.90%
Statoil (Norway)	8.71%
Türkiye Petrolleri Anonim Ortaklığı (TPAO) (Turkey)	6.53%
Total (France)	5.00%
Eni/Agip (Italy)	5.00%
Itochu (Japan)	3.40%
Inpex (Japan)	2.50%
ConocoPhillips (USA)	2.50%
Amerada Hess (USA)	2.36%

The BTC pipeline is a good example of a public-private partnership in the cross-border pipeline transport area. States in this project are involved through the many state-owned companies that take part as shareholders (TPAO, SOCAR, Statoil) in the project company.

All the shareholders with the exception of Total, ENI and ConocoPhillips have stakes in the upstream fields and as such we can characterise BTC as an exporter promoted pipeline.

A1.4 *PROJECT COST AND FUNDING*

The total project cost was initially estimated close to US$3.6 billion (with $2.95 billion in construction costs). Originally BTCCo was going to cover project costs approximately 30% through direct shareholder equity from BTCCo own capital reserves (i.e. BP and its partners) and about 70% ($2.6 billion) through debt financing. At the end the total project cost exceeded $4.0 billion and the additional capital was provided from the sponsors in the form of equity and pari-passu [1] loans that further diluted the debt/equity ratio from 70/30 to about 55/45. Debt financing and support was provided by banks, export credit agencies, The World Bank, EBRD with "A" and "B" loans enabling further financing. A total of 15 commercial banks, 2 multilateral lending agencies, 8 Export Credit Agencies and Political Risk Insurers were involved in the financial support of the project.

Details regarding financial support for the BTC pipeline project can be found in *Table 1.3* [2]

Table 1.3 BTC Co Financial Support

Source	Amount	Description
Commercial bank loans	US$600 million (est.)	Syndicated loan of 15 commercial banks led by ABN AMRO, Citibank, Mizuho and Societe Generale as arrangers with Banca Intesa, BNP Paribas, Credit Agricole Indosuez, Dexia, HypoVereinsbank, ING, KBC, Natexis Banques Populaires, San Paolo IMI, West LB and Royal Bank of Scotland
Export Credit Agency-covered commercial bank loans	US$400-US$500 million (est.)	Loans which commercial banks will provide under this structure will not be fully commercial, as a large part of the risks will be carried by the multilateral development banks and the export credit agencies.
Senior sponsor equity Contributions	US$1,800 million (est.)	Debt and/or equity financing provided by the shareholders of BTC Co (i.e. BP, Statoil, Total and ConocoPhillips) according to their share
Multilateral lending agencies	Total "A" and "B" loans of US$500 million	The European Bank for Reconstruction and Development (EBRD) and the International Finance Corporation (IFC), the private sector arm of the World Bank each provided a US$125 million 12 year direct A* loan and a US$125 million 10 year commercial syndication B* loan.
Export Credit Agency loans	US$600-US$800 million (est.)	Japan Bank for International Co-operation (JBIC) and Nippon Export and Investment Insurance (NEXI) of Japan, the Export-Import Bank of the United States of America, the Export Credits Guarantee Department (ECGD) of the United Kingdom, the Overseas Private Investment Corporation (OPIC) of the United States, Compagnie Francaise pour le Commerce Exterieur (COFACE) of France, Euler Hermes Kreditversicherungs- AG (HERMES) of Germany and SACE S.p.A. - Servizi Assicurativi del Commercio Estero (SACE) of Italy

(*An "A loan" is advanced by a bank at its own risk whereas a "B loan" is made available by a bank but the funds are provided by commercial banks at their own risk)

Sources: IFC, www.**ifc**.org, EBRD, www.**ebrd**.com, Chevron, http://www.chevron.com/news/archive/unocal_press/release.aspx?id=2004-02-03a and "The financing of the Baku-Tbilisi-Ceyhan project", Profundo, February 2003, http://www.profundo.nl/downloads/btc.pdf

(1) Pari-Passu loans are used when two or more lenders (sponsors in this case) are lending to one borrower (the project company) and they want to be in an equal position in an insolvency event for debt recovery purposes. See glossary

(2) http://www.freshfields.com/news/dynamic/Pressrelease.asp?newsitem=433

The government of Azerbaijan equally matched State Oil Company of Azerbaijan (SOCAR) financial contribution requirements for the project in order for SOCAR to meet its equity obligations (25%) by using state funds from the State Oil Fund of Azerbaijan (SOFAZ). As of 2007, AZN298 million (USD $350 million) have been directed towards the financing of Azerbaijan's equity share in BTC. [(1)]

A1.5 PROJECT REVENUE

BTC Co generates revenue through the charge of transportation tariffs to shippers. Access to pipeline and tariff-setting is regulated by pipeline shareholders independent of national regulatory regimes. Currently, as this is a proprietary pipeline, capacity is allocated only for the project sponsors and the methodology to allocate capacity between sponsors uses the simple formula % equity = % pipeline capacity.

While government charges (transit fees) are determined in the host-government agreements, the overall transport tariff is set through negotiations between the shareholders and companies requesting access. The tariff charge is not influenced by the price of the transported commodity (oil) but it is calculated quarterly using a bottom-up approach on the basis of a set 12.5% real rate of return (inflation adjusted) required by the project sponsors for 20 years from start-up (2025). The tariff is frequently adjusted to protect returns to investors and meet set revenue targets.

Although the methodology for calculating tariff charge is a little more complex the basic concept behind it works mainly be meeting set revenue targets. The set revenue targets that the pipeline needs to generate is divided quarterly by the pipeline actual throughput and the tariff is calculated on that basis. In this sense the tariff charge level is linked with throughput volume and it practically means that for lower throughput (e.g. if there is a production slowdown) tariff charge goes up and the vice versa. Also the price may vary slightly whether or not the oil belongs to a member of the consortium.

There are a number of figures that have been quoted ranging for US$2.58 to US$6.00 per barrel." [(2)] [(3)]

A1.6 PROJECT EVALUATION

According to BP, Azerbaijan will be the main beneficiary of the sale of its oil in international markets, collecting about $29 billion per year in oil revenues, while Georgia and Turkey will collect transit fees of $600 million and $1.5 billion respectively per year.[(4)]

(1) SOFAZ, http://www.oilfund.az

(2) From Wellhead to Market: Oil Pipeline Tariffs and Tariff Methodologies in Selected Energy Charter Member Countries, Energy Charter Secretariat 2007, http://www.encharter.org/index.php?id=212

(3) Interview with Ross Rigler, Chevron

(4) http://www.hydrocarbons-technology.com/projects/bp/

Several environmental issues have been raised for BTC as the pipeline crosses the watershed of the Borjomi national park however on the positive side, it will eliminate 350 tanker cargoes per year through the sensitive and very congested Bosporus and Dardanelles strains.

A2 WEST AFRICA GAS PIPELINE

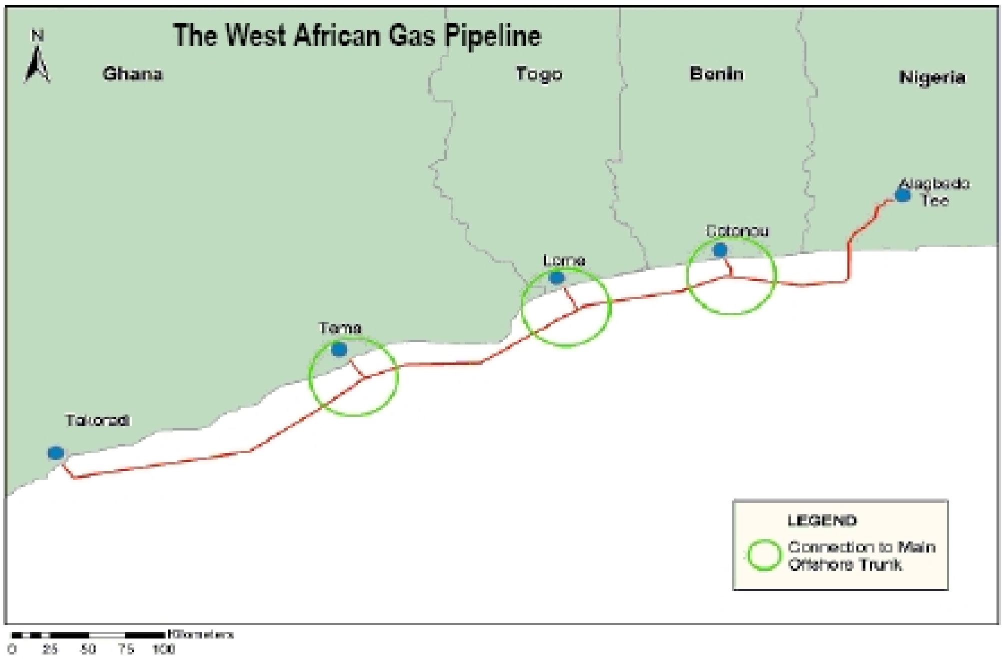
A2.1 PROJECT DESCRIPTION

The West African Gas Pipeline (WAGP) is a 678 kilometre long pipeline that will transport natural gas from from the gas reserves in Nigeria's Escravos region of Niger Delta area to Ghana, Togo, and Benin.

The West African Gas Pipeline Project (WAGP) begun in 1982 when the Economic Community of West African States (ECOWAS) proposed the development of a natural gas pipeline throughout West Africa. In the early 1990's, a feasibility report commissioned by a consortium of oil and gas companies and deemed that a project was commercially viable.

The pipeline consists three sections. The 569 kilometre long offshore section runs parallel to the coastline, approximately 15 to 20 kilometres offshore in water depths of between 30 and 75 meters. It is possible that later the WAGP will be extended to Côte d'Ivoire and in longer term even to Senegal. (1)

Figure 2.1 Route of the West African gas pipeline



Source: The World Bank Group, siteresources.worldbank.org/INTGUARANTEES/Resources/WAGPNote.pdf

The construction started in 2005 and the first gas delivery was scheduled for 2007. The main user will be the Volta River Authority's (VRA) Takoradi power plants in Ghana.

Summary of the pipeline specifications can be found in *Table 2.1*.

(1) http://www.eia.doe.gov/emeu/cabs/wagp.html

Table 2.1 ***WAGP Pipeline Specifications***

Specification	
Type	Gas (offshore and onshore)
Length	678 Km.
Max Capacity	12.8 mm3/day
Cost	$600 million

A2.2 RATIONALE

WAGP was developed in order to provide Nigeria and foreign investors in Nigeria an additional commercial market for natural gas. It also provided an opportunity to reduce wasteful gas flaring associated with the local oil production. Additionally, due to high petroleum prices, Benin, Ghana, Nigeria and Togo were also eager to speed-up the conversion from expensive liquid fuels to natural gas. (1)

A2.3 OWNERSHIP STRUCTURE

The WAGP project is a cooperative effort of the four States, the Producers, the Sponsors, the Transporters, the Foundation Customers, and the providers of political risk guarantees.

A Special Purpose Entity (SPE) the West African Gas Pipeline Company Ltd (WAPCo) was incorporated in Bermuda for the development of the pipeline and a Joint Venture Agreement was signed on August 16, 1999 in Abuja, Nigeria. The pipeline is owned and operated by a consortium of oil and gas companies with Chevron as the WAGP project manager. The shareholders of the WAPCo project company are presented in *Table 2.2*.

Table 2.2 ***WAPCo Shareholders***

Company	**Share**
Chevron	36.7%
Nigerian National Petroleum Corporation	25%
Royal Dutch Shell	18%
Volta River Authority (Takoradi Power Company Ltd)	16.3%
SoToGaz	2%
SoBeGaz	2%

Source: Chevron

Public companies, institutions and governments were also involved in the development of the project such as the state owned Nigerian National Petroleum Corporation (NNPC, Nigeria), the Volta River Authority (Takoradi Power Company Limited, Ghana), SOBEGAZ (Benin) and SOTOGAZ (Togo). The last two are public oil corporations of Benin and Togo, respectively.

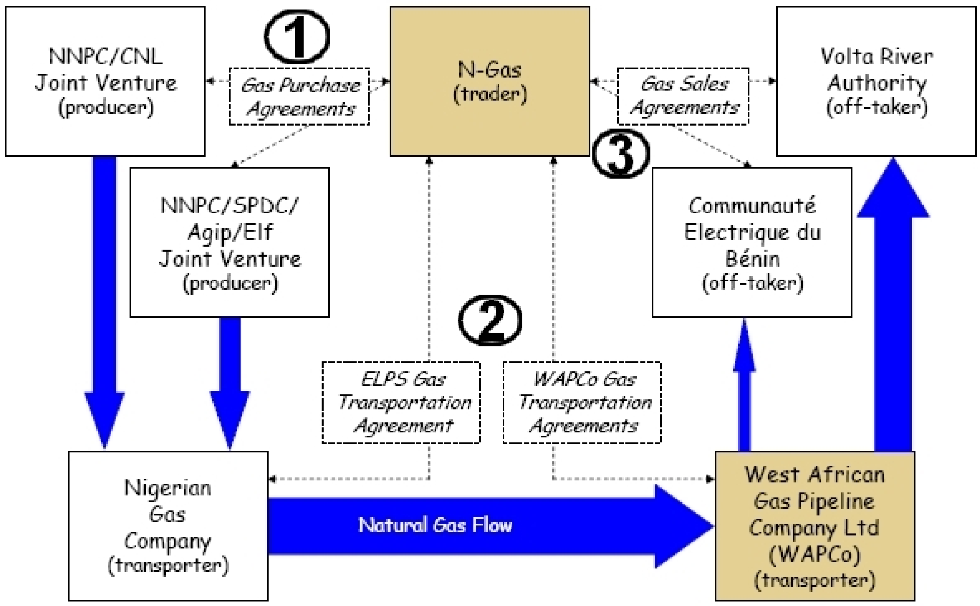
(1) http://www-wds.worldbank.org/servlet/WDSContentServer/IW3P/IB/2006/01/23/000104615_20060124091350/Rendered/PDF/PID010Rev2010Jan006.pdf

N-GAS (made up of Chevron/Texaco, NNPC and Shell) is the supplier of the natural gas from the Escravos-Lagos gas pipeline that transports natural gas from the main source, the Escravos gas field operated by Chevron in the Niger Delta region of Nigeria. N-Gas also acts as the seller of the gas having established off-take agreements with the state owned electricity companies of Benin (Communaute Electrique du Benin) and Ghana (Volta River Authority, VRA). WAPCo is the transporter of the gas. (1)

The contractual underpinnings of the Project (see *Figure 2.2*) are based on the following simplified value chain:

1. The Producers will sell natural gas to N-Gas under long-term Gas Purchase Agreements;
2. N-Gas will engage the Transporters to move the gas under long-term Gas Transportation Agreements; and
3. N-Gas will sell the gas to the Foundation Customers under long-term Gas Sales Agreements.

Figure 2.2 WAGP Project Contractual Agreements



Source : http://siteresources.worldbank.org/INTGGFR/64168360-1121105776335/20578314/ScottSinclairOPEC2005.pdf

It was agreed from the outset of the project that the pipeline will operate solely as a gas transporter, and not as a marketer of gas. One consequence of this is that regulation of pricing is restricted only to the transportation tariffs. As WAPCo is not selling gas, there is no control over the pricing of the gas itself and intends to recover its investment costs through tariff charges (see section A2.5)

(1)http://www.un.org/africa/osaa/reports/English_The%20contribution%20of%20the%20private%20sector%20to%20...NEPAD%20June%2006.pdf

A2.4 *PROJECT COST AND FUNDING*

It is anticipated that the pipeline will require a capital investment close to US$600 million for construction costs and additional compression-related costs capital costs of around US$110 million, which would be needed if the capacity requirement grows to the 450 MMcf/day (12.8 million m3/day) target by the Sponsors under the agreed demand forecast over the next 20 years.

The participants in the project were quite different in terms of funding capability. A decision needed to be made at an early stage whether project financing would be sought.

This is the only pipeline reviewed that was project finance (i.e. non-recourse debt) was not used. Rather, the sponsors have agreed that they will fund the initial development entirely with equity capital. The initial capital investment of pipeline construction cost was financed mainly through direct equity, cash contributions and loans to WAPCo from the sponsors.

The decision not resort to debt financing for this project was made following a comprehensive review of the possibilities for project financing, principally on the grounds of speed, efficiency. The three main reasons are explained briefly below:

Firstly, when the consortium engaged with a financial advisor to secure debt financing, the cost of debt service was estimated around 14.5%. With agreed tariff charges set to yield a 12-15% rate of return (see *Section A2.5*) this cost level of debt service was considered unacceptable.

A second reason for not seeking project finance even if the cost of debt service was acceptable, was the disproportional credit ratings among the sponsors (i.e. Chevron and Shell - highly creditworthy vs. the remaining sponsors). As a consequence lenders required creditworthy sponsors to guarantee the less creditworthy sponsors to enable access to debt finance and as such it was not considered as a good idea by the more creditworthy sponsors.

Finally, even if all the above inhibiting factors were mitigated the project financing arrangements were likely to require considerable time while the consortium wanted to develop the project as soon as possible (see *Section A2.2*).

Nonetheless specific project financing techniques were used to lend credit support to the gas purchase obligations, which was essential to give the sponsors the comfort to proceed.

The subsequent compression-related capital expenditures for capacity expansion are expected to be financed by cash flow from operations. [(1)]

(1) World Bank, Project Finance and Guarantees, 2005, siteresources.worldbank.org/INTGUARANTEES/Resources/WAGPNote.pdf

Due to the high political (e.g. WAGP) and commercial risk involved in the project the sponsors demanded guarantees from multilateral lending agencies for risk mitigation in order for the project to proceed. These were provided by the World Bank, EIB and other development banks.

Various forms of financial support for the WAGP project can be found in *Table 2.3* while *Figure 2.3* presents how the risk guarantee instruments were structured for the WAGP project.

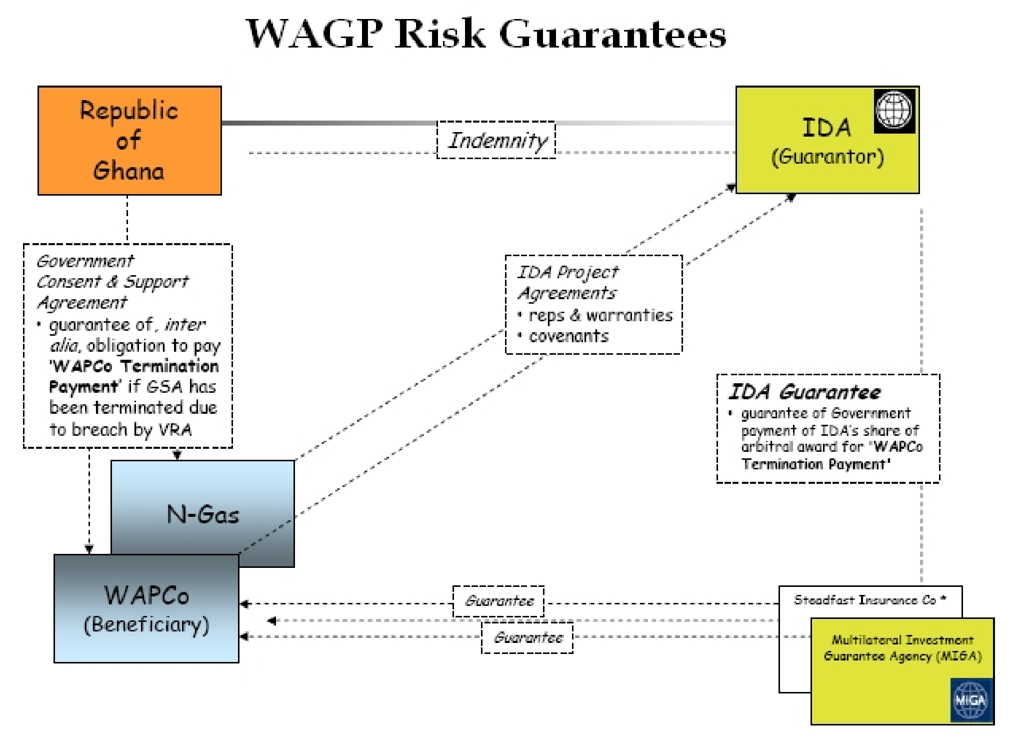
Table 2.3 Financial Support and Guarantees for WAGP project

Source	**Amount**	**Description**
Senior sponsor lenders	Approximately $590 million	Debt and/or equity financing provided by shareholders of WAPCo as sponsor lenders
Multilateral Investment Guarantee Agency (MIGA, World Bank)	$75mn political risk insurance (PRI) up to 20 years	Provides protection to project investment funds (whether acquired through loans, equity or other forms) against a number of risks such as currency transfer restrictions, inconvertibility, expropriation, war and civil disturbances and breach of contract.
International Development Association (IDA, World Bank)	$50mn partial risk guarantee for 22 years	Can be used to cover payment defaults from Volta River Authority (VRA). World Bank's indemnity guarantees will be converted into an automatic loan for Ghana under the West African Gas Pipeline (WAGP), should the Government of Ghana fail to pay N-Gas
International Bank for Reconstruction and Development (IBRD, World Bank)	US$20mn & US$10mn	Partial risk guarantee & "enclave" risk guarantee structured for export oriented foreign exchange commercial projects covering sovereign risks such as expropriation, change in law, war, and civil strife
Steadfast Insurance Company (subsidiary of Zurich Financial Services Group)	$125mn political risk insurance	Risk guarantee
Chattel Mortgage or Cash flow Pledge (VRA)	Unknown	Mortgage, Asset collateral
United States Agency for International Development (USAID)	$6mn	In the form of technical assistance
Overseas Private Investment Corporation (OPIC)	$45 million	In the form of reinsurance to Steadfast Insurance Company
West African Development Bank (WADB)	Unknown	Unknown
ECOWAS Bank for Investment and Development (EBID)	Unknown	Unknown

Source	Amount	Description
Sovereign Guarantees (ECOWAS/WAEMU Countries)	Unknown	This guarantees provide back up to World Bank's guarantees.

Sources: World Bank Group project website, European Investment Bank http://www.eib.eu.int/projects/loans/project.asp?loan=10031075, USAID www.**usaid**.gov/missions/westafrica/ecintegration/wapp/index.htm, http://www.un.org/africa/osaa/reports/English_The%20contribution%20of%20the%20private%20sector%20to%20...NEPAD%20June%2006.pdf

Figure 2.3 WAGP Risk Guarantees Structure



Source: http://www.africacncl.org/downloads/2006_IC/von%20Klaudy.pdf

A2.5 PROJECT REVENUE

WAPCo will recover its investments and its operating costs through transportation tariff charges under its Gas Transportation Agreements (GTAs) with N-Gas and other future shippers.

The entire system that spans across four countries will generate revenue streams from the entire pipeline, rather than from activities in individual countries.

A major issue for the sponsors was the creditworthiness of the payment obligations of the buyers, on the faith of which an investment decision was to be made. The position of the sponsors was that without some underlying creditworthiness or credit support for the revenue stream, investment could not proceed.

Subsequently, project revenue streams were guaranteed in the short term by rolling letters of credit, (that secure about 6 months payment obligations) and in the long term by multilateral agencies guarantees (discussed in *Section A2.4*) that secure the established off-take and transportation agreements (see *Box 2.1*) between the project parties. (1)

Box 2.1 ***Principal WAGP Project agreements***

Takoradi Gas Sales Agreement (Takoradi GSA) between VRA and N-Gas, providing for the sale by N-Gas and purchase by VRA of up to 120 MMscf/day of gas on a take-or-pay and ship-or-pay basis;

Takoradi Gas Transportation Agreement (Takoradi GTA) between WAPCo and N-Gas for the gas being sold by N-Gas under the Takoradi GSA;

VRA Direct Agreement among VRA, WAPCo, and N-Gas whereby N-Gas assigns to WAPCo (as security for N-Gas's payment obligations to WAPCo under the Takoradi GTA) the component of the VRA termination payment and arrears owing to N-Gas under the Takoradi GSA corresponding to the same component payable to WAPCo by N-Gas under the Takoradi GTA.

Source: World Bank, Project Finance and Guarantees, 2005
siteresources.worldbank.org/INTGUARANTEES/Resources/WAGPNote.pdf

Additionally, the control of the transportation tariff levels was an important issue for all of the four States (Nigeria, Ghana, Benin and Togo) and the sponsors. The States were adamant that there would be some form of regulation of transportation tariffs, but they were flexible as to exactly how this would occur. The States also wanted the project company to take some risk on market growth by creating spare capacity in the pipeline. The sponsors accepted this, but were dubious about forecasts for market growth and insisted that the tariffs had to provide a reasonable return regardless of what growth eventuated and a higher return if there significant growth was eventually realised.

The tariff methodology, set out in the International Project Agreement provides a floor rate of return to the company but shares the benefits of growth in the market with all shippers. Thus as the market grows, tariffs decline in real terms.

The tariff methodology is designed so that WAPCo will achieve its expected rate of return over about 20 years. It will achieve a lower return if the market growth is less than forecast, but this is still a return which the sponsors are prepared to accept on the basis that they are taking some risk on market growth.

WAGP tariff charges are calculated using a bottom up approach to yield a 12% rate of return on foundation contracted capacity of 134 MMcfd and a 15% rate of return for additional customers as volume will grow (up to 450 MMcfd) in

(1) Chevron, The WAGP project, Presentation Notes of Martin Byrnes, 2005 AIPN Annual Meeting and Spring Conference

the upcoming years calculated on the basis of a 20 year project lifetime for their investment. [1]

Finally, as part of the project development process, the sponsors and the States negotiated a detailed fiscal regime to apply as a single regime to the project as a whole. The regime is a normal profits-based taxation regime, with a 5 year tax holiday and all depreciation preserved until after the tax holiday ends. The agreed tax rate is 35%.

A2.6 *PROJECT EVALUATION*

WAGP is considered an attractive project by the project sponsors. From a commercial perspective the return on investment is favourable and there are regional benefits as well in terms of energy cost reduction. The World Bank estimates that Benin, Togo and Ghana can save nearly $500 million in energy costs over a 20-year period as WAGP-supplied gas is substituted for more expensive fuels in power generation. Ghana estimates that it will save between 15,000-20,000 barrels per day of crude oil by taking gas from the WAGP to run its power plants. Additionally the WAGP project will reduce greenhouse gas emissions and air pollutants by cutting down on flaring associated with existing oil production in Nigeria and according to a study, commissioned by Chevron, it is estimated that 10,000 to 20,000 primary sector jobs will be created in the region by the project. [2][3]

(1)http://www.redorbit.com/news/business/1080492/net_wagp_economic_benefit_requires_ghana_development/index.html
(2) Energy Information Administration, http://www.eia.doe.gov/emeu/cabs/wagp.html
(3) Some information for this case study was provided by Chevron

A3 LANGELED PIPELINE

A3.1 PROJECT DESCRIPTION

The Langeled pipeline, which stretches 1,200 km making it the world's longest underwater pipeline, brings Norwegian natural gas to the UK from the Nyhamna terminal in Norway via the Sleipner Riser platform in the North Sea to Easington, England and will eventually carry 70 million cubic metres per day. The connection to Sleipner will also allow independent operation of the northern and southern pipeline. Its construction required approximately a million tonnes of steel and will engage a large part of the world's pipeline production and laying resources. [1]

Figure 3.1 Route of the Langeled pipeline route and integration with existing gas transport infrastructure

Source: http://www.hydro.com/ormenlange

The project specifications of the Langeled pipeline can be found in *Table 3.1*

Table 3.1 Langeled Pipeline Specifications

Specifications	
Pipeline Length	1200km
Diameter	48 inches
Pressure	157-250 bar
Maximum Sea Depth	360m
Annual Capacity (one line)	25bcm/year
Daily Capacity	74-80mmcm/day
Reported Cost	€2.5 billion ($3.5 billion)

Source: http://www4.hydro.com/ormenlange

(1) http://en.wikipedia.org/wiki/Langeled_pipeline

A3.2 *RATIONALE*

The rationale behind the development of the Langeled pipeline is to accommodate gas transportation from the Ormen Lange field.
With gas reserves close to 400 billion cubic meters the Ormen Lange field ranks as the largest development in the European offshore arena and will help to boost British gas supplies (eventually 20% of UK's total gas demand will come from Ormen Lange) and offset the UK's own dwindling North Sea reserves.

A3.3 *OWNERSHIP STRUCTURE*

The Langeled joint venture comprises the Ormen Lange licensees as well as ConocoPhillips and Gassco.

Table 3.2 Langeled Pipeline Joint Venture Shareholders

Company	Share
Norsk Hydro	17.61 % (operator for the development phase)
Gassco	0% (operator for the production phase)
Shell	16.50 %
Petoro	32.95 %
Statoil	10.84 %
DONG Energy	10.22%
ExxonMobil	6.94 %
ConocoPhillips	0.78 %

Source:
http://www.hydro.com/en/press_room/news/archive/2007_03/subsea_comp_en.html

The Langeled pipeline joint venture project, comprising by the Ormen Lange field licensees as well as ConocoPhillips and Gassco, has been structured according to the build, operate and own model (BOO). Statoil was responsible for the planning along with Hydro that is involved in the development phase of the Ormen Lange field. From September 2006, Gassco, the Norwegian state owned company, is the operator of the pipeline and Statoil has the management of the gas export pipeline project in cooperation with Hydro. British Centrica provides the technical service provider at Easington. (1)

A3.4 *PROJECT COST AND FUNDING*

Capital costs for the Langeled pipeline are estimated close to NOK17 billion or US$3.2 billion. The principal funding of the project was provided by a syndicated loan structured by ABN AMRO (syndication agent) and subscribed by several banks, among them Barclays Bank, Royal Bank of Scotland and Defoe Fournier & Cie. (2) (3)

(1) http://www4.hydro.com/ormenlange/en/about_ormen/partners/index.html
(2) PETROmagazine, Special Edition 2007, www.petro.no/files/petro_magazine_special_edition_2007_lr.pdf

A3.5 PROJECT EVALUATION

Although this a very recent project at the time this report is written a number of factors such as good management, project execution and hitting the market at a good point of time have all helped the Langeled development to be complete about NOK 3 billion (US$550 million) below initial budget and on time. (1)

(1) http://www.rigzone.com/news/article.asp?a_id=35485

A4 NABUCCO PIPELINE

A4.1 PROJECT DESCRIPTION

The Nabucco pipeline was initiated by the European Parliament and the Council of Europe on June 26, 2003, in order to provide an alternative gas supply for Europe. Upon completion, which is estimated to be around 2012, Nabucco would carry at least 30 billion cubic meters of gas from the Caspian and Middle East to the EU's 27 members.

The envisioned Nabucco pipeline length will be approximately 3,300 km, starting at the Georgian/Turkish and/or Iranian/Turkish border respectively, leading to Baumgarten in Austria. In this respect it will represent a backbone pipeline and a reasonable amount of the gas volumes will be further transported to other European Countries. (1)

Figure 4.1 ***Route of the Nabucco Pipeline***

Source: http://www.nabucco-pipeline.com/project/project-description-pipeline-route/index.html

A summary of the main Nabucco pipeline specifications can be found in *Table 4.1* below.

Table 4.1 ***Nabucco Pipeline Specifications***

Specifications	
Pipeline Length	3300km
Type	Gas (onshore)
Diameter	56 inches
Maximum Annual Capacity (one line)	31bcm/year
Maximum Daily Capacity	85 mmcm/day
Estimated Cost	~ €5.0 billion ($7.1 billion)

(1) http://www.nabucco-pipeline.com

A4.2 *RATIONALE*

The rationale behind the possible development of the Nabucco pipeline is mainly European energy security. As such Nabucco's strategic and economic significance is that it offers Europe an alternative to Russian gas and a market for Caspian gas producers. The EU needs to diversify its current gas supplies (Norway, Russia and Northern Africa) and for that it is important to have a "fourth corridor" pipeline, bringing alternative gas from Central Asia, the Caspian region and Middle East. (1) The Nabucco gas pipeline project represents this "fourth corridor".

A4.3 *OWNERSHIP STRUCTURE*

Nabucco Gas Pipeline International GmbH (NGPI) is an Austrian company that was established in 2004 in order to serve as the project's financial special purpose vehicle (SPV). It is directly owned by the Nabucco Partners and will be responsible for the marketing of the pipeline capacity. NGPI will be the only company in direct contact with the shippers (one-stop-shop - principle), and will operate as an autonomous economic entity on the market, acting independently from its parent companies.

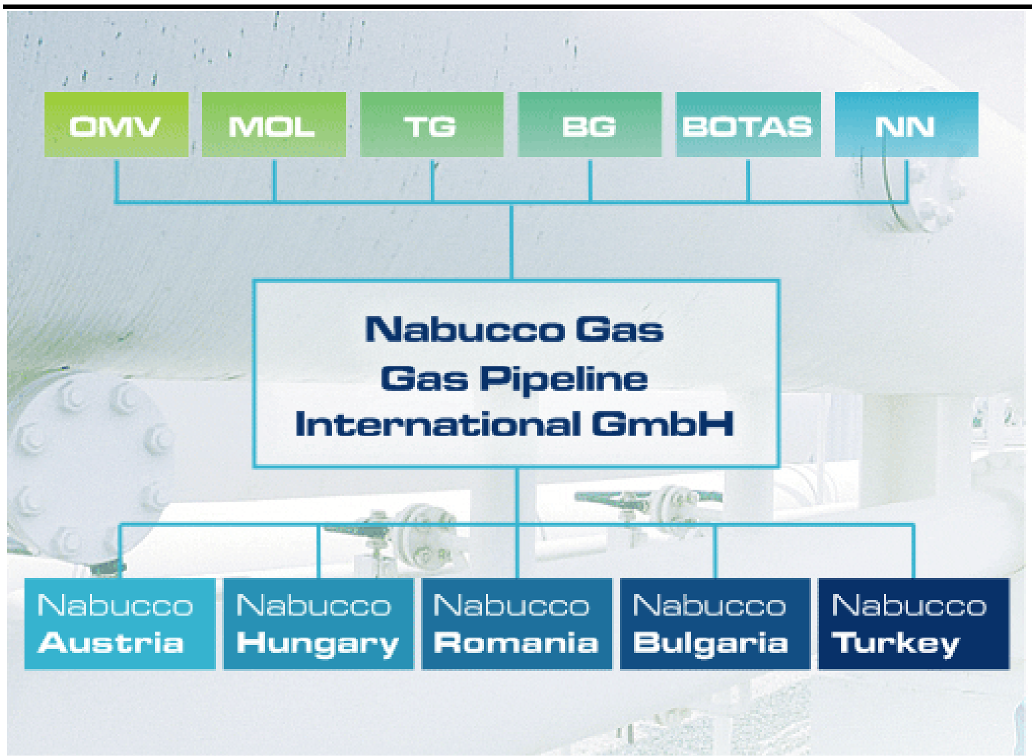
The shareholders of the company are:

- OMV (Austria)
- MOL (Hungary)
- Transgaz (Romania)
- Bulgargaz (Bulgaria)
- BOTAŞ (Turkey)

All shareholders have 20% of the shares. The structure of the Nabucco project company is presented in *Figure 4.2*

(1) Communication from the commission to the council and the European Parliament, Priority Interconnection Plan, 2007

Figure 4.2 *Nabucco Gas Pipeline International GmbH Structure*



Source: http://www.nabucco-pipeline.com

The five Nabucco National Companies will each be incorporated in their respective Nabucco Country and the Nabucco Partners are not intended to have any direct participation in the Nabucco National Companies.

The decision making process as well as the relationship between the Nabucco Partners and Nabucco Gas Pipeline International (NGPI) and the Nabucco National Companies is regulated in a Joint Venture Agreement between all present Partners of Nabucco Project. (1)

A4.4 *PROJECT COST AND FUNDING*

The pipeline project is currently estimated that it would cost around €5bn ($6.6bn) to complete. In order to finance investment, NGPI will provide 100% of the required funds to individual Nabucco National Companies but in order to do so NGPI would seek financing in the form of equity or loans from the project partners and from Investment, Development and Commercial Banks. (2)

The EU has already paid for the pipeline's feasibility study and its investment banks, the European Investment Bank (EIB) and the European Bank for

http://www.futureofeurope.parlament.gv.at/meetdocs/2004_2009/documents/com/com_com(2006)0846_/com_com(2006)0846_en.pdf

(1) http://www.nabucco-pipeline.com

(2) http://www.sofiaecho.com/article/participants-in-nabucco-pipeline-project-among-which-bulgaria-fail-reaching-agreement/id_23424/catid_69

Reconstruction and Development (EBRD), are considering funding up to 70% of the €5bn ($6.6bn) project costs. [(1)] [(2)]

The remaining project is estimated that it would be financed from direct sponsor contributions in equity or other assets. For example Turkey's Botas company a sponsor of the Nabucco pipeline proposes to build the pipeline's stretch on Turkish territory, using transit revenue from the Baku-Ceyhan oil pipeline to finance part of the costs of the gas line. [(3)]

Since this is an early stage for this project no further financial information regarding funding was available and undergoing developments would determine project's financing sources.

A4.5 PROJECT REVENUE

No information is available at this time due to the premature stage of the project but as other "midstream" promoted pipelines it is expected to generate revenue by maximizing throughput and charging access tariffs to contracted shippers.

A4.6 PROJECT EVALUATION

According to the EU Energy Corridors report [(4)] the potential benefits of this project are very significant for promoting energy security and diversification of supply and stimulating competition. Nonetheless, it remains difficult to complete so far because of the complexity of transit issues and difficulties in coordinating investments in production and transit infrastructure.

(1) http://www.bbj.hu/main/news_24844_hungary+balances+strategic+pipelines.html

(2) www.petroleum-economist.com/default.asp?page=14&PubID=46&ISS=23661&SID=681462

(3) http://www.jamestown.org/edm/article.php?article_id=2372301

(4) Energy corridors: European Union and Neighbouring countries, EC, EUR 22581, 2007, ec.europa.eu/research/energy/pdf/energy_corridors_en.pdf

A5 ALLIANCE PIPELINE

A5.1 PROJECT DESCRIPTION

Alliance is a new pipeline system in North America that transports natural gas from producing gas fields in north eastern British Columbia and north-western Alberta, directly to gas markets in Chicago.

Figure 5.1 Alliance Pipeline Route

Source: http://www.alliance-pipeline.com

The mainline of the Canadian system comprises of a 339 km (211 miles) 42-inch pipeline and a 1220 km (758 miles) 36-inch diameter steel pipeline while the US system comprises of a 1429 km (888 miles) of 36-inch diameter steel pipeline totalling to almost 3000km. The pipeline can transfer up to 1.325 billion cubic feet per day.

A5.2 OWNERSHIP STRUCTURE

The Alliance Pipeline limited partnership agreements were signed in 1996 and it took four years for the project to complete before coming into commercial service in December 2000.

Alliance Pipeline, the projects' financial Special Purpose Vehicle (SPV) comprises of a Canadian limited partnership (i.e. Alliance Pipeline Limited Partnership) and a United States limited partnership (Alliance Pipeline L.P.).

Alliance Pipeline Limited Partnership ("Alliance Canada") owns the Canadian portion of the Alliance Pipeline system and Alliance Pipeline L.P. ("Alliance USA") owns the U.S. portion of the Alliance Pipeline system.

Both "Alliance US and Canada" are privately and equally held by Enbridge Inc. (50%) and Fort Chicago Energy Partners L.P. (50%).

A5.3 PROJECT COST AND FUNDING

The $3 billion ($4.5 Canadian) project was the biggest non-recourse debt financed project in North American history, requiring the participation of more than 40 banks worldwide. Alliance Pipeline signed agreements with a syndicate of 42 international banks securing up to US$2.6 billion of non-recourse debt financing for the construction of its natural gas pipeline system. The loan facilities were structured, arranged and underwritten by the Bank of Nova Scotia (administrative agent), the Bank of Montreal, Chase Securities Inc. (syndication agents), and National Westminster Bank (documentation agent). In addition, there are 21 banks acting as co-agents, 6 as managers and 11 as participants. (1)

A5.4 PROJECT REVENUE

Alliance provides shippers firm transportation service, on a volumetric basis, for the delivery of natural gas at an aggregate contracted capacity level of 1.325 billion cubic feet per day (bcf/d). The pipeline has long-term take-or-pay contracts through 2015 to transport 1.305 bcf/d of natural gas (98.5% of the total contracted capacity) and 20 mmcf/d of natural gas contracted on a short-term basis with a group of more than 30 shippers.

Alliance pipeline receives revenue through the charge of tolls and rates to shippers that are presented in *Table 5.1*

Table 5.1 Demand Charges and Reservation Rates for Alliance pipeline (2007) per Mcf

	Alliance Canada (C$)	**Alliance US (US$)**	**Total (US$)**
Demand Charge/ Reservation Rate per one thousand cubic feet of gas (mcf)	0.78/Mcf	0.56/Mcf	1.24/Mcf

The transportation service contracts obligate each shipper to pay monthly demand charges based on their contracted firm volume, regardless of volumes actually transported. These transportation contracts are designed to provide toll revenues sufficient to recover the costs of providing transportation service to shippers, including depreciation, debt financing costs and an allowed

(1) http://aplwww.alliance-pipeline.com/contentfiles/139____newsreleases1998_06May98_andersk_20041215_v1.pdf

return on equity of 11.25 percent in Canada and 10.85 percent in the United States.

Aggregate distributions each partner received from Alliance for the year ended December 31, 2006 were $110.4 million, before deducting capital expenditure holdbacks of $3.2 million.

Financial and operational highlights of the pipeline can be found in *Table 5.2*

Table 5.2 ***Alliance Pipeline Financial and Operational Highlights – 50% Proportionate Share***

(in thousands US$)	**2006**	**2005**
Revenues from tolls invoiced	358,180	380,255
Other revenues	7,731	3,117
Total Revenues	365,911	383,372
Operations and maintenance	(44,191)	(48,388)
General and administrative	(26,320)	(22,979)
Earnings before interest, taxes, depreciation and amortizations	295,400	312,005
Depreciation and amortization	(97,120)	(100,613)
Interest and other finance	(93,312)	(99,780)
Net income before taxes	104,968	111,612
Distributions, prior to withholdings for capital expenditure and net of debt service	110,388	124,866
Total Volume (100%, bcf/day)	1.592	1.597

Source: 2006 Fort Chicago Annual Report, http://www.fortchicago.com/media/pdfs/annuals/FortChicago_AR2006.pdf

A5.5 *PROJECT EVALUATION*

Currently, Alliance has some competitive advantages that may facilitate future asset optimization opportunities, including the pipeline's initial design and construction, which permits quick expansion of its mainline system by adding infill compression and further scalable expansion scenarios employing looped pipeline. As a result, Alliance is well positioned to play a major role in transporting incremental volumes of natural gas from Alberta to markets in central and eastern North America.

Although significant volumes of incremental gas from Alaska and other Arctic reserves are expected to be a number of years away, it is likely that Alliance would consider expanding the current infrastructure to deliver natural gas supplies to southern US markets. (1)

(1) http://www.fortchicago.com/default.asp?action=article&ID=197

A6 MAGHREB-EUROPE GAS PIPELINE

A6.1 PROJECT DESCRIPTION

The Maghreb–Europe Natural Gas Pipeline Project (Gazoduc Maghreb Europe; GME) involved the construction and operation of a 1,620km pipeline system to bring gas from the Hassi R'Mel field in Algeria, across Morocco and the Strait of Gibraltar, to interconnect with the gas grids of Spain and Portugal and the rest of the western European gas transport system.

Figure 6.1 Route (Hassi R' Mel-Cordoba) of the Maghreb–Europe Natural Gas Pipeline

Source: http://energymanager-online.com/pages/ltsa_maghreb.htm

The pipeline's capacity of 8 billion cubic meters per year can be expanded to 18.5Bcm/y by means of looping and by adding compressor stations along the route. The primary gas source for the project is the Hassi R'Mel gas and condensate field, which initially held proven reserves of about 2,400Bcm, accounting for more than half of the country's total proven gas reserves of 3,500Bcm. GME is made up of five main and two secondary sections that can be found in *Table 6.1*

Table 6.1 Structure of the Maghreb–Europe Gas Pipeline

From	To	Length (Km)	Diameter (inches)
Hassi R' Mel	Algerian/Moroccan border	518	48
Morocco	Cap Spartel (Moroccan coast)	522	48
Strait of Gibraltar	Split between Morocco and Spain	35	2x22
Spanish Coast	Cordoba, Spain	269	48
Cordoba	Badajoz (Spanish/Portuguese border)	269	28
Campo Maior (secondary section)	Braga, Portugal	408	28
Braga (secondary section)	Tuy (Portuguese/Spanish border)	74	28

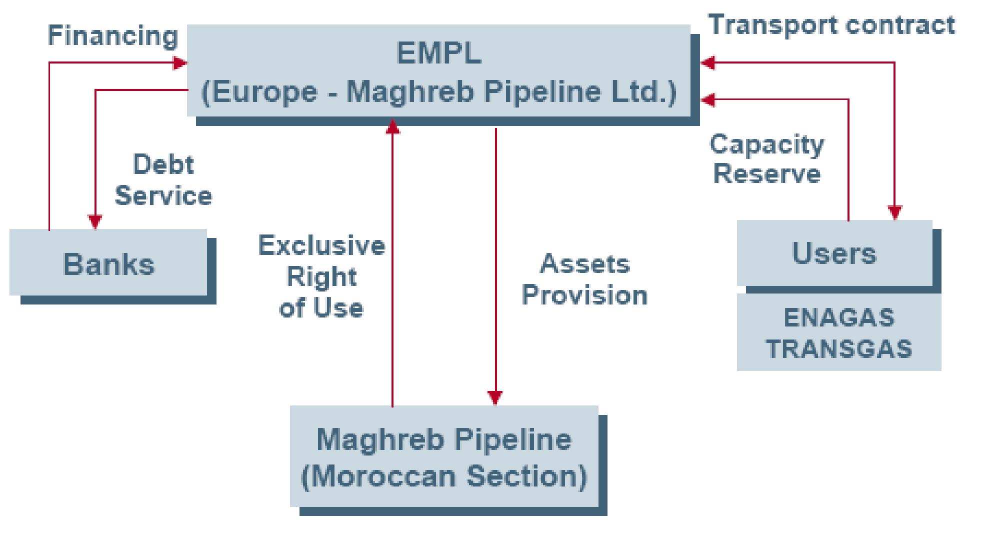
A6.2 RATIONALE

From the beginning, the GME pipeline had the support of the European Union. It was a priority of the Trans-European Network (TEN), an EU undertaking designed to promote projects that further the integration of energy grids within the EU and between the EU and its suppliers and enhance economic cooperation among the participating countries and among the countries of the Maghreb and the European Community in general.

A6.3 OWNERSHIP STRUCTURE

To finance the pipeline in Morocco and in the Moroccan portion of the Strait of Gibraltar, Enagas (9%) and the Spanish government (91%) in 1992 created a new company, Sagane SA, which in turn established Europe Maghreb Pipeline Ltd (EMPL).

Figure 6.2 GME Project Structure



Source: www.iea.org/Textbase/work/2002/cross_border/MORALED.PDF

The Special Purpose Vehicle (SPV) employed in this project, EMPL, is responsible for financing and implementing the project. EMPL was established in July 1992 by an agreement between Spain's Enagas and Algeria's Sonatrach in order to "finance, construct and operate the Moroccan and Straits of Gibraltar sections of the pipeline". The users of the gas pipeline hold EMPL's capital stock in proportion to their share in the transportation capacity, at present, 72.6 percent of EMPL is owned by Enagas and 27.4 percent by Transgas. EMPL has transportation rights to the pipeline for a period of 25 years and sells transportation rights to Enagas (now wholly owned by Gas Natural) and Transgas (and any new shippers). (1)

The Algerian section of the GME is entirely owned and operated by Sonatrach that assumed associated construction costs and cost overrun risks. Enagas

(1) http://siteresources.worldbank.org/INTOGMC/Resources/crossborderoilandgaspipelines.pdf

and Transgas were responsible for the construction of the Moroccan, Spanish, and Portuguese sections and for the section at the Strait of Gibraltar and during the construction period, Sagane, which was created by the Spanish public sector for this purpose, assumed the risks associated with construction of the Moroccan section.

Construction and operation of the pipeline was handled by Metragaz, which is owned jointly by EMPL and SNPP (see *Box 6.1*)

Box 6.1 ***Corporate Structure of the Moroccan Transit Section of the GME Pipeline***

The Société Nationale des Produits Petroliers (SNPP) holds legal title to the gas pipeline in Morocco. SNPP's capital stock is held entirely by the Moroccan state.

Société pour la Construction Gazoduc Maghreb Europe (Metragaz Construction).
Created under Moroccan law in July 1992 by an agreement between EMPL and SNPP, Metragaz Construction is responsible for managing the construction work on behalf of EMPL.

Metragaz Operation is responsible for the repair, maintenance, and operation of the pipeline on behalf of EMPL. It is jointly owned by EMPL and SNPP and is organized under Moroccan law.

Strait of Gibraltar
That part of the GME that lies under the Strait of Gibraltar has its own corporate structure. In Moroccan waters the ownership structure is the same as that of the Moroccan land segment. Domestic Spanish law governs the segment of the GME lying in Spanish waters. Enagas holds the concession and operating rights, but the pipeline is owned by Gasoducto Al-Andalus (67 percent Enagas, 33 percent Transgas).

A6.4 PROJECT COST AND FUNDING

The total cost of the GME (including the Portuguese sections) is estimated at US$2.2 billion. The European Investment Bank (EIB), the EU's long-term financing institution, found the GME project attractive because it supported the EU's policies of increasing and diversifying energy supplies and of encouraging the use of clean natural gas by industry and households.

Ultimately, the EIB provided more than 1.1 billion euros (US$1.15 billion) for various sections of the GME, including those located outside Europe. This not only met a significant part of the project's capital requirements but also acted as a catalyst for mobilizing funds from other sources. Additionally the Spanish public sector, during the initial phase of the project, guaranteed the Spanish section from specific project risks (see *Box 6.2*).

Box 6.2 ***Spanish Public Sector Guarantee***

To insulate Enagas from the specific risks posed in the initial phase of the project, particularly those related to technical risks during the startup period, Spain's state-owned National Hydrocarbon Institute (NHI) remained engaged in the project, assuming a 91 percent share in Sagane (with Enagas holding the other 9 percent of the shares). Sagane in turn assumed shares in EMPL, which financed the Moroccan part of the pipeline, and became a partner in Metragaz, which was responsible for building and operating the Moroccan sector of the GME.

Public sector ownership of Sagane was intended to be temporary, with Enagas/Gas Natural holding a purchase option on NHI's shares. That option was exercised as soon as the GME entered into operation in 1996.

Source: Cross-Border Oil and Gas Pipelines: Problems and Prospects, Joint UNDP/World Bank Energy Sector Management Assistance Programme, June 2003, http://siteresources.worldbank.org/INTOGMC/Resources/crossborderoilandgaspipelines.pdf

The pattern of financing followed the project's ownership structure: each section owner financed 15 percent of the section's cost, with the remaining 85 percent provided by multilateral agencies, export credit agencies, and commercial banks (see *Table 6.2*).

Table 6.2 ***Financing of the Maghreb–Europe Pipeline (%, unless otherwise indicated)***

Section	Owner/Operator (% Stake)	Cost (US$ millions)	Self Equity	EU Funds	European Investment Bank (EIB)	Export Credit Agencies	Commercial Banks
Algerian	Sonatrach (100%)/ Sonatrach	$675	15%	-	37%	48%	-
Moroccan	EMPL/Metragaz	$760	15%	-	49%	13%	23%
Strait	EMPL/Gasoducto Al Andalus12	$145	15%	-	49%	13%	23%
Spanish 1	Enagas (67%), Transgas (33%)/ Gasoducto Al Andalus12	$280	15%	32%	53%	-	-
Spanish 2	Enagas (51%), Transgas (49%)/ Gasoducto Al Andalus12	$170	15%	39%	46%	-	-
Portuguese 1	Enagas (12%), Transgas (88%)/ Gasoducto Al Andalus12	$220	12%	39%	46%	-	-
Portuguese 2	Enagas (49%), Transgas (51%)/ Gasoducto Al Andalus12	$40	15%	39%	15%	-	31%
Total		$2,290	15%	11%	45%	19%	10%

Sources:
http://siteresources.worldbank.org/INTOGMC/Resources/crossborderoilandgaspipelines.pdf, www.ecn.nl/fileadmin/ecn/units/bs/ENCOURAGED/WP/ENCOURAGED-report-WP2.pdf,

Operating costs for GME include maintenance and other variable costs (i.e. compressor fuel etc.), depreciation, tax and transit fees that are paid either out of gas or in cash depending on the choice of the transit country (i.e. Morocco).

A6.5 *PROJECT REVENUE*

As seen in previous case studies the pipeline operator can generate revenue from access tariff charges to pipeline users.

Sonatrach is the pipeline operator for the Algerian section of the pipeline and at the same time the operator of the Hassi R'Mel gas field, subsequently the main pipeline upstream user. As such it seeks to recover pipeline operating and capital cost from revenues generated from gas export.

The same applies partly for Enagas, part of a major energy network in Spain that is likely to generate revenues through the sale of gas downstream.

The main terms and conditions for the transport of natural gas and the tariff prices applicable for EMPL to charge are regulated by law. The following three factors are mainly taken into consideration when calculating the applicable tariffs and fees for third-party access:

- Depreciation of the investment throughout 25 years
- Operating and financial costs, including Morocco's transit fees
- Rate of return of the project

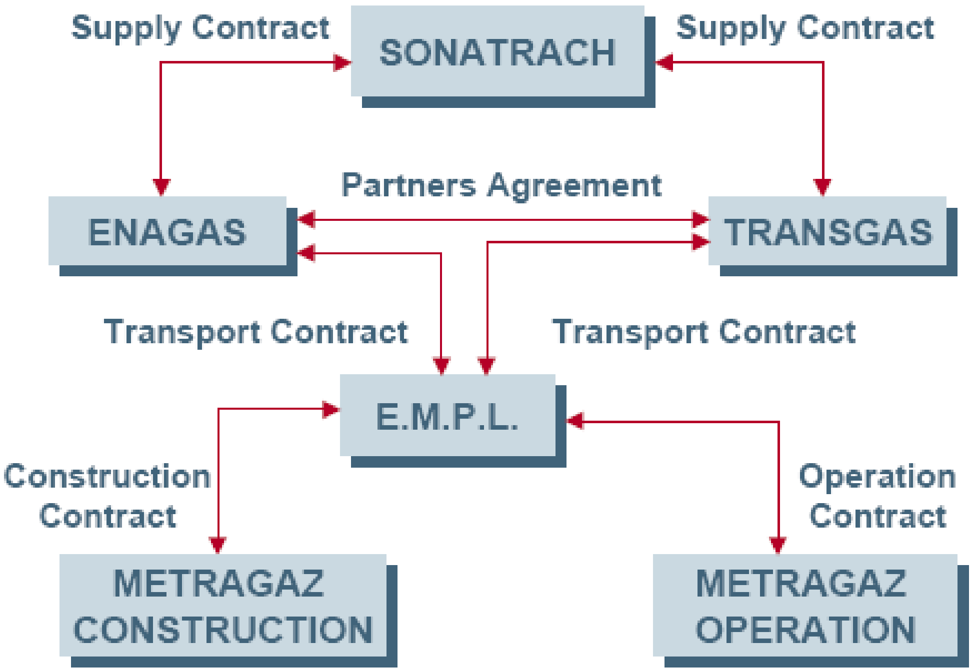
Tariffs are determined annually by the Spanish Government based on a calculation methodology. Tolls and fees paid by third parties are based on costs; however they are set as ceilings to provide an incentive to improve productivity. [1]

Pipeline revenue is secured through transportation contracts between Enagas, Transgas, and EMPL. The principal contract in the GME project is the sales agreement between Sonatrach, Enagas, and Transgas. The contractual responsibilities of Enagas and Transgas are roughly in line with their throughput therefore these contracts cannot be considered to be a risk. Nonetheless the risk of non performance is additionally mitigated by many other clauses.

The contractual agreement structure can be found in *Figure 6.3*

(1) http://www.iclg.co.uk/index.php?area=4&country_results=1&kh_publications_id=42&chapters_id=1063

Figure 6.3 *Contractual Agreement Structure*



Source: www.iea.org/Textbase/work/2002/cross_border/MORALED.PDF

A6.6 EVALUATION

Given the limited demand for gas from this pipeline in Algeria and Morocco compared to the capacity of the GME project, the market risk in the GME project stems from the fact that the pipeline is dedicated to the Spanish and Portuguese markets. Sonatrach, which assumed the construction cost and cost overrun risks for the Algerian section of the GME, is depending on growth taking place in the Spanish and Portuguese markets as forecasted by Enagas and Transgas. So far the Spanish government has played a critical role in the development of the natural gas market in Spain through its National Energy Plan (PEN) In the Portuguese case, EU agencies have aided in the development of the natural gas markets by providing assistance and loans for the construction of gas transmission and gas distribution networks.

A7 EOR CO_2 PIPELINES IN THE US

A7.1 DESCRIPTION

The use of CO_2 for enhanced oil recovery (EOR) was first established in conjunction with mature reservoirs in the Permian Basin (see *Figure 7.1*) during the early 1970's.

At that time EOR projects were stimulated by special tax concessions—and price control exemptions—as an incentive during a period when US domestic oil production was beginning to decline rapidly. These "tax-floods", although being commercially successful, were not optimal with respect to their technical aspects, but did provide the operators with considerable insight regarding reservoir behaviour, CO_2- handling, corrosion mitigation, and recycling following breakthrough of CO_2 into the production wells.

Figure 7.1 Map showing CO2 sources, transportation pipelines and extent of CO2-EOR in the South and South-West United States

The first floods were initially based on industrial (anthropogenic) CO_2 sources; however the use of naturally occurring CO_2 was the only source that could accommodate increasing demand for rapidly expanding EOR operation. Naturally occurring CO_2 had to be transported over longer distances through extensive pipeline infrastructures as illustrated in *Figure 7.1*.

A7.2 PERMIAN BASIN INFRASTRUCTURE

Annually, CO_2 volumes in excess of 40 million tons/year are transported in the United States through a 3,500 miles long onshore infrastructure network. High pressure (100-200 bar) carbon steel pipelines have been constructed and more than 2,200 miles of those pipelines are located in the Permian Basin region of West Texas and Southeast New Mexico. About 80,000 tons of new CO2 is injected daily for Enhanced Oil Recovery production into 50 reservoirs in this region. [1]

The first pipeline development in the Permian Basin was the Canyon Reef Carriers Pipeline (CRC) pipeline built in 1970 and is currently owned (89%) and operated by Kinder Morgan CO_2 Company. The CRC extends 222Km from McCamey, Texas, to Kinder Morgan CO2's SACROC field. This pipeline is 16 inches in diameter and has a capacity of approximately 240 MMCFD.

In 1972 Chevron started the first commercial CO_2 flood at the SACROC oil field in the Permian Basin of west Texas. SACROC and Shell operated North Cross field that also started injection in 1972, were supplied CO_2 from anthropogenic sources. The major owners of SACROC paid for the Canyon Reef Carriers pipeline.

In the 1980s CO2 flooding expanded rapidly. Based on the success of the initial floods, operators began looking for large, inexpensive sources of CO2. Nearly pure (98%+) underground sources at McElmo Dome, Bravo Dome and Sheep Mountain were identified in order to source the Permian Basin.

Subsequently, Shell and Mobil developed McElmo Dome and built the Cortez Pipeline (805Km.) to supply their CO_2 needs.

Amoco developed Bravo Dome and built the Bravo pipeline (402Km.) to supply its needs.

Arco and Exxon developed the Sheep Mountain field and built the Sheep Mountain pipeline (657Km) to supply their needs. Shell sourced its Mississippi and Louisiana fields from Jackson Dome and built the Choctaw pipeline.

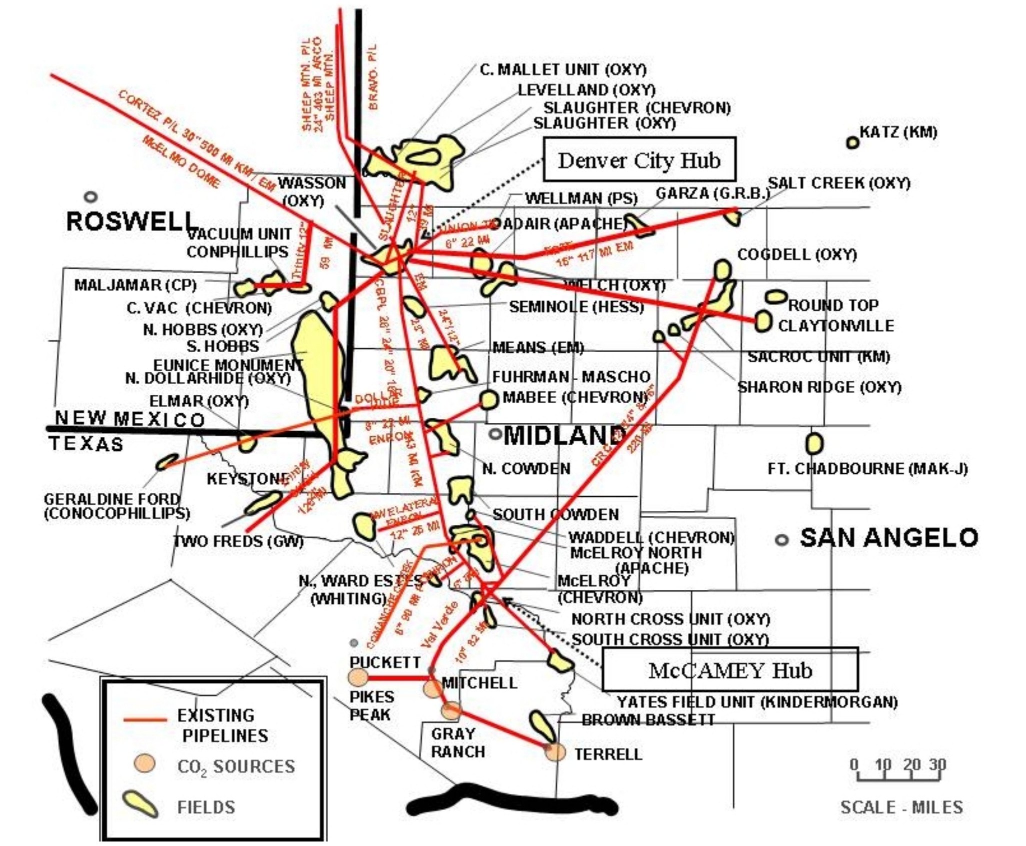
Exxon utilized waste CO_2 from the LaBarge natural gas field to source Chevron's Rangely field in Colorado and Amoco's fields in Wyoming. This was one of the few times that pipelines were built to supply a third party.

In 1997 Pan Canadian Petroleum Ltd. announced plans to flood the Weyburn field with CO_2. The source of CO_2 is Dakota Gasification Company's Great Plains coal gasification complex at Beulah, N.D. DGC will own and operate the 10 and 12 inch, 202 mile pipeline. CO_2 injection began in 2000.

A detailed presentation of existing CO_2 pipelines in North America can be found in *Figure 7.3*

Figure 7.2 ***Permian Basin CO2 Pipeline Infrastructure***

(1) European Technology Platform on Zero Emission Fossil Fuel Power Plants, WG3, Infrastructure and Environment draft report dd. 3 May 2006, http://www.zero-emissionplatform.eu/website/library/index.html#etpzeppublications



Source:http://melzerconsulting.com/index.php?option=com_content&task=view&id=15&Itemid=30&limit=1&limitstart=1

A7.3 *COST AND FUNDING*

It has been estimated that these pipelines represent a cumulative capital investment in 2001 dollars of just over $1bn. (1)

Much of the existing CO_2 EOR pipeline network in the Permian Basin was built with capital investment resulting from high oil prices during the late 70s and through incentives given in various ways from the U.S government.

These are presented in *Table 7.1*:

Table 7.1 Incentives for EOR activities

Incentive	Description
Market Incentives	Oil price projections of the time of $50/barrel justified investment model
Government incentives	Oil produced in the 1970s through the use of EOR was exempt from oil price controls Extraction of naturally occurring CO2 may qualify for percentage depletion allowance under I.R.C. § 613(b)(7). Accelerated depreciation rules (these apply to any capital investment including oil and gas pipelines)

(1) The Permian Basin CO_2 Sequestration Model, L. Stephen Melzer, June 2002 www.searchanddiscovery.net/documents/abstracts/2002sw/images/melzer.pdf

Incentive	Description
	The Internal Revenue Code provides for a 15% income tax credit for the costs of recovering domestic oil by one of nine qualified EOR methods, including CO2 injection (I.R.C. § 43). (while this tax credit is part of current federal tax law, its phase out provisions mean that presently it is not available — the credit is zero — due to high crude oil prices) CO2 pipeline infrastructure during the 1980s benefited from tax advantages to EOR oil under the "crude oil windfall profits tax law" that was in effect from 1980 to 1988

Source: Carbon Dioxide (CO2) Pipelines for Carbon Sequestration: Emerging Policy Issues, CRS report for Congress, April 2007
http://www.nleonline.org/NLE/CRSreports/07May/RL33971.pdf

The above regulations along with relevant incentives (although never explicitly made for CO_2-EOR pipelines) were instrumental in the pipeline network development and interestingly the expansion of EOR pipelines starting around 1986 coincides with the introduction of the U.S. Federal EOR Tax Incentive.

Furthermore there are currently eight states in the U.S. that offer additional EOR tax incentives on incremental oil produced and while there is no EOR tax credit, per se, the state of Texas offers under Rule 50 a severance tax exemption on all the oil produced from a CO2-flood reservoir, so perhaps it is not coincidental that the Permian Basin, West Texas is currently producing more than 80% of all CO_2-EOR production in the US.

A7.4 *REVENUE*

Independent CO_2 transportation companies such as KinderMorgan receive payments based on the amount of CO_2 delivered. The 1,500 km pipeline infrastructure from McElmo, Sheep Mountain and Bravo Dome delivers more than 23 $MtCO_2$/yr. In year 2000 the average price of delivered CO_2 was $12 /t CO_2

Therefore, EOR CO_2 pipeline profitability is dependent upon the demand among oil producers for CO_2 in connection with enhanced oil recovery programs which in turn are sensitive to the level of oil prices.

According to Shell CO_2 Company, although CO2 floods are initially capital-intensive, they have relatively low ongoing operational costs and many existing floods can remain economic at oil prices even as low as $5 per barrel. [1]

Since most of the pipelines were developed by the users of CO_2, there were generally justified and "financed" as a part of the CO_2 flood. Transportation sold to third parties was an extra source of revenue.

(1) http://www.secinfo.com/dUUaj.714.htm#22k0

A7.5 *PROJECT EVALUATION*

Experience in the Permian Basin EOR pipeline network has demonstrated that large volumes of CO_2 can be injected and stored in mature oil reservoirs and project funding for infrastructure construction becomes readily available when the cash flows of the project are positive. In the case of EOR the positive cash flows result from the additional EOR production.

The major difference between the natural gas and liquids pipeline business and the CO_2 pipeline business is that CO_2 has to be dedicated to a specific flood. There is not a general market for the product and this is why there have not been many speculative pipelines built. The only pipeline built within a speculative context is the Central Basin Pipeline in West Texas where its original owners did not make a good rate of return on their investment.

Figure 7.3 North American CO2 Pipelines

North American CO2 Pipelines

Pipeline	Owner/Operator	Length (mi)	Diameter - in	Location
Anadarko Powder River Basin CO_2 PL	Anadarko	125	16	WY
Anton Irish	Oxy	40	8	TX
Bravo	Oxy Permian	218	20	NM,TX
Canyon Reef Carriers	Kinder Morgan	139	16	TX
Centerline	Kinder Morgan	113	16	TX
Central Basin	Kinder Morgan	143	26-16	TX
Chaparral	Chaparral Energy	23	6	OK
Choctaw	Denbury Resources	110	20	MS
Cordona Lake	ExxonMobil	7	6	TX
Cortez	Kinder Morgan	502	30	TX
Dakota Gasification	Dakota Gasification	204	12	ND/Sask
Dollarhide	Pure Energy	23	8	TX
El Mar	Kinder Morgan	35	6	TX
Enid-Purdy (Central Oklahoma)	Anadarko	117	8	OK
Este I - to Welch, Tx	ExxonMobil, et al	40	14	TX
Este II - to Salt Creek Field	ExxonMobil	45	12	TX
Ford	Kinder Morgan	12	4	TX
Joffre Viking	Penn West Petroleum Ltd.	8	6	Alberta
Llano	Trinity CO_2	53	12-8	NM
Pecos County	Kinder Morgan	26	8	TX
Raven Ridge	ChevronTexaco	160	16	WY/Co
Sheep Mountain	British Petroleum	408	24	TX
Shute Creek	ExxonMobil	30	30	WY
Slaughter	Oxy Permian	35	12	TX
Transpetco	TransPetco	110	8	TX
Val Verde	PetroSource	83	10	TX
W. Texas	Trinity CO_2	60	12-8	TX,NM
Wellman	Wiser	25	6	TX
White Frost	Core Energy, LLC	11	6	MI
Wyoming CO_2	ExxonMobil	112	20-16	WY

Reference: Melzer, L.S. , Personal Data Tabulations (2004).

Source:
http://www.netl.doe.gov/technologies/carbon_seq/partnerships/phase1/pdfs/Web_CarbonCaptureandStorageReportandSummary.pdf

*Table 7.2 10 Largest Oil and Gas Pipeline Project Financings**

Project Name/Location	Total Capital Cost (Senior Debt Portion)	Sponsors	Financial Advisers to the consortium
Alliance Pipeline Project (Gas), Canada/US (3,000 km)	US$3.73 billion ($2.59 billion debt)	Coastal, IPL,Williams, Fort Chicago Energy, Westcoast Energy	Goldman Sachs, Scotia, Paribas.
BTC Pipeline (Oil), Azerbaijan/Georgia/ Turkey (1,730 km)	US$3.6 billion ($2.59 billion debt)	Amerada Hess, ConocoPhillips, INPEX, SOCAR, Unocal, BP, Eni, Itochu, Statoil, TPAO	Lazard
Bolivia-Brazil Pipeline Project (Gas), Bolivia/Brazil (3,075 km)	US$2.23 billion ($1.4 billion debt)	PETROBRAS, BG, El Paso, YPFB, BHP, Enron Corp., Shell	Credit Suisse First Boston, Kleinwort Benson
Cupiagua-Cusiana Pipeline (Oil), Colombia (800 km)	US$2.2 billion ($1.54 billion debt)	Ecopetrol, BP, Total, Triton, TransCanada, IPL	Goldman Sachs, Credit Lyonnais
Chad-Cameroon Pipeline (Oil), Chad (1,070 km)	US$2.0 billion (pipeline only) ($700 million debt)	Exxon Mobil, Petronas, Chevron	Citibank
OCP Heavy Crude Pipeline (Oil), Ecuador (503 km)	US$1.2 billion ($900 million debt)	Alberta Energy, Repsol YPF, Occidental, Agip, Pecom Energia, Techint, Kerr-McGee	Chase Manhattan Bank
Mozambique-South Africa Pipeline Project (Gas), Mozambique (865 km)	US$1.2 billion ($543 million debt)	Republic of South Africa, Republic of Mozambique, Sasol Polymers	Dresdner Kleinwort Wasserstein
Malhas Project (Gas), Brazil (expansion)	US$1.0 billion ($900 million debt)	PETROBRAS, Mitsui, Itochu, Mitsubishi	
Kern River Expansion II (Gas), United States (part refinancing)	US$875.0 million loan	Williams, Tenneco	
Camisea (Gas), Peru	US$865.0 million ($480 debt)	Techint, Sonatrach, PlusPetrol, SK, Hunt Oil, Tractebel	Citi

*excludes acquisition financing and refinancings and upstream projects with an integrated pipeline component.

Source: Based on Dealogic Database, http://lba.legis.state.ak.us/agia/doc_log/2007-04-25_intro_to_project_finance_for_oil_gas_pipelines.pdf

Annex B

Public-Private Partnership Case Studies

CONTENTS

B1 CHANNEL TUNNEL RAIL LINK

B1.1 PROJECT DESCRIPTION

The Channel Tunnel Rail Link (CTRL) project is a 108 km (67 mile) high-speed railway line from London through Kent to the British end of the Channel Tunnel. The second section of the CTRL, travelling across the River Thames and into London St Pancras was opened in November 2007. (1)

Figure 1.1 Channel Tunnel Rail Link Route

Source: CTRL Risk Transfer and Innovation in Project Delivery, Harvard Design School, Prof. Spiro N. Pollalis, November 2006, http://www.gsd.harvard.edu/people/faculty/pollalis/cases/CTRL-V5.pdf

B1.2 RATIONALE

The key objectives of the CTRL project are:

- Build extra rail capacity between the Channel Tunnel, Kent and London
- Reduce international and domestic journey times
- Stimulate regeneration in inner London, the Thames Gateway and Kent Thameside (2)

B1.3 STRUCTURE

London & Continental Railways (LCR) was selected in 1996 by the Government to design build and finance the high speed Channel Tunnel Rail Link (CTRL), and to operate the UK arm of the international train service. The

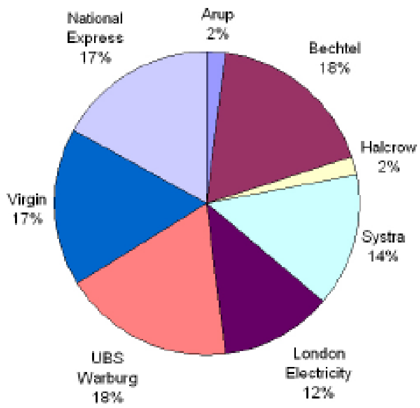
(1) http://www.highspeed1.co.uk/consumerpage.php?page=hs1
(2) www.omegacentre.bartlett.ucl.ac.uk/.../CTRL/RelatedLinks/1-1.6%20LCR%20CTRL-detailed%20overview.doc

concession period during which LCR will have rights over the commercial opportunities created along the route will be until 2086.

LCR is the special purpose entity (SPV) that was incorporated by its eight project sponsors. LCR's shareholders are Bechtel, Arup, Systra, Halcrow, National Express Group, SNCF, EDF and UBS investment bank. LCR is responsible for the whole of the project management, engineering design, procurement, construction management, services during construction and commissioning of the CTRL.

The percentage of equity controlled by each company is illustrated in *Figure 1.2*.

Figure 1.2 LCR Shareholders

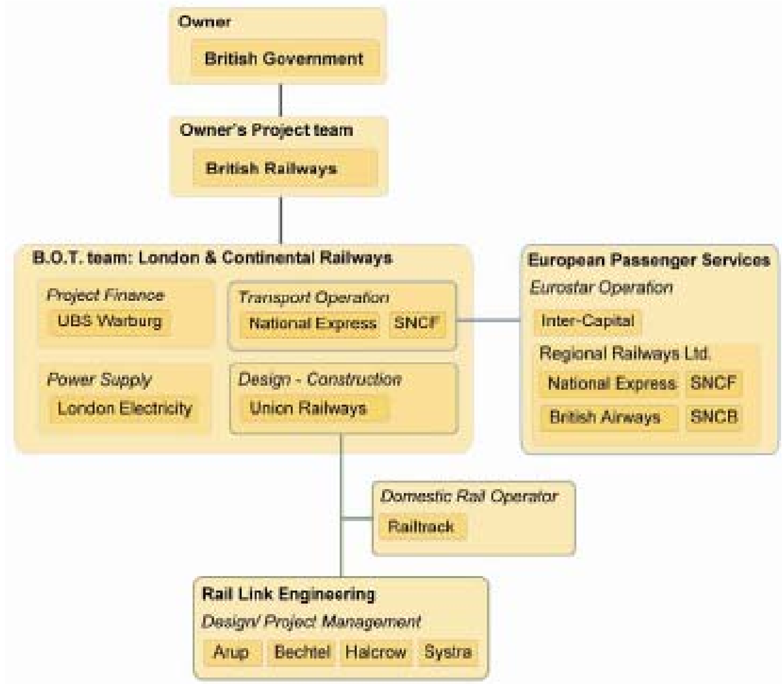


Four of these eight partners, Arup, Bechtel, Halcrow and Systra, formed a consortium between them called Rail Link Engineering and it was appointed by LCR as its Project Manager and Engineer to carry out design and procurement, manages the contractors who are building the railway and to meet the overall requirements of Union Railways.

The operating risk is shared under a management contract with Inter-Capital and Regional Railways Limited, the latter being a consortium including two train operators, National Express and French Railways (SNCF), which are holding equity shares in LCR, the Belgian rail operator SNCB and British Airways.

Although the project went through a major restructuring in 1998 due to financing difficulties associated due to unwillingness of financiers to undertake risks related with the overall project structure, the current contractual relationships can be found in *Figure 1.3*

Figure 1.3 CTRL Build Operate Transfer Project Model



Source: CTRL Risk Transfer and Innovation in Project Delivery, Harvard Design School, Prof. Spiro N. Pollalis, November 2006, http://www.gsd.harvard.edu/people/faculty/pollalis/cases/CTRL-V5.pdf

As part of the 1998 rescue plan it was agreed that, while LCR remained contractually committed to build the CTRL in its entirety, Railtrack Group, through a special purpose subsidiary Railtrack UK (RTUK), committed to purchase the infrastructure assets of Section 1 and entered into an option to purchase Section 2.

In 2001, Railtrack announced that due to its own financial problems it would not undertake to purchase section 2 once it was completed and this triggered a second restructuring. The 2002 plan agreed that the two sections would have different infrastructure owners (Railtrack for section 1, LCR for section 2) but with common management by Railtrack.

Following yet further financial problems at Railtrack its interest in the CTRL was sold back to LCR who then sold the operating rights for the completed line to Network Rail, Railtrack's successor. Under this arrangement LCR will become the sole owner of both sections of the CTRL and the St Pancras property, as per the original 1996 plan.

B1.4 PROJECT COST AND FUNDING

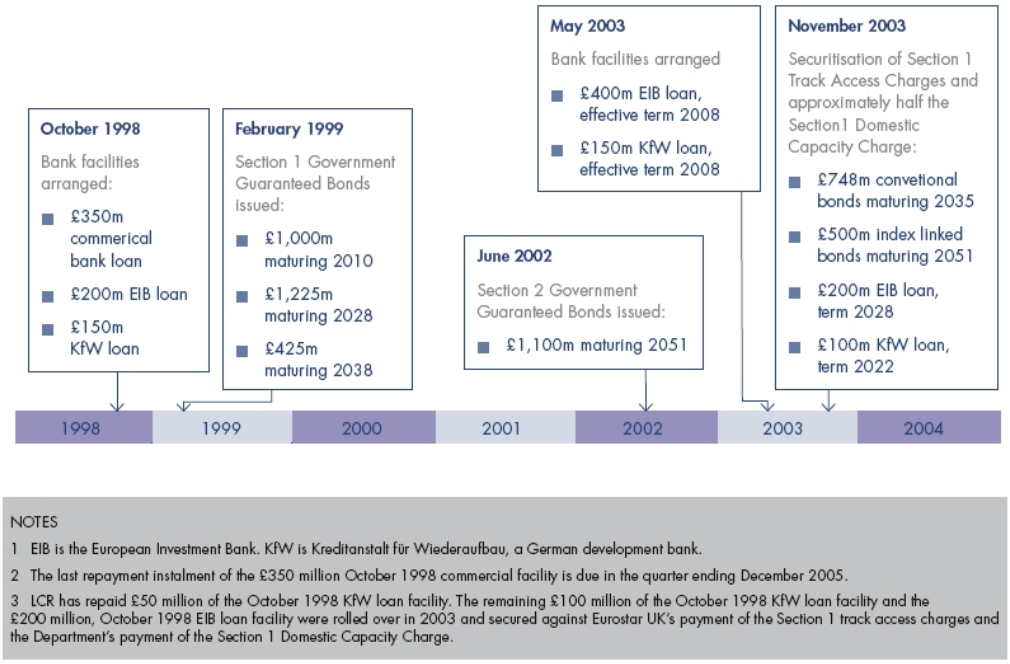
Initially the project was funded through promoter's equity, government grants, revenues from Eurostar train services, development rights over land at Kings Cross Station and loans from banks and other financial institutions however after project restructuring in 1998 a substantial part of the funding was backed by Government guarantees.

According to the Department for Transport (DfT), the total cost of the project is expected to be approximately £5.9 billion, of which the Department for Transport is committed to give a total of £1.8 billion (NPV) of grants after taking account of the expected net recoveries from the Government's share of property sale profits and rental income. [3] It was agreed that the remainder of the money would be raised by the promoter who would be given permission to issue Government Guaranteed Bonds to raise £3.75 billion.

Between 1998 and the end of 2003, LCR raised nearly £6,250 million of debt in the capital markets comprising about £950 million of medium-term bank facilities and just under £5,300 million of longer dated debt maturing between 2010 and 2051. The project also received EU support through EIB loans and funding under the TENS (trans-European Networks) Programme.

All of the projects funding sources are presented in detail in *Figure 1.4*

Figure 1.4 ***LCR Debt Financing Sources and Timeline***



Source: National Audit Office, DfT, Progress on the Channel Tunnel Rail Link Report, 2005, www.nao.org.uk/publications/nao_reports/05-06/050677.pdf

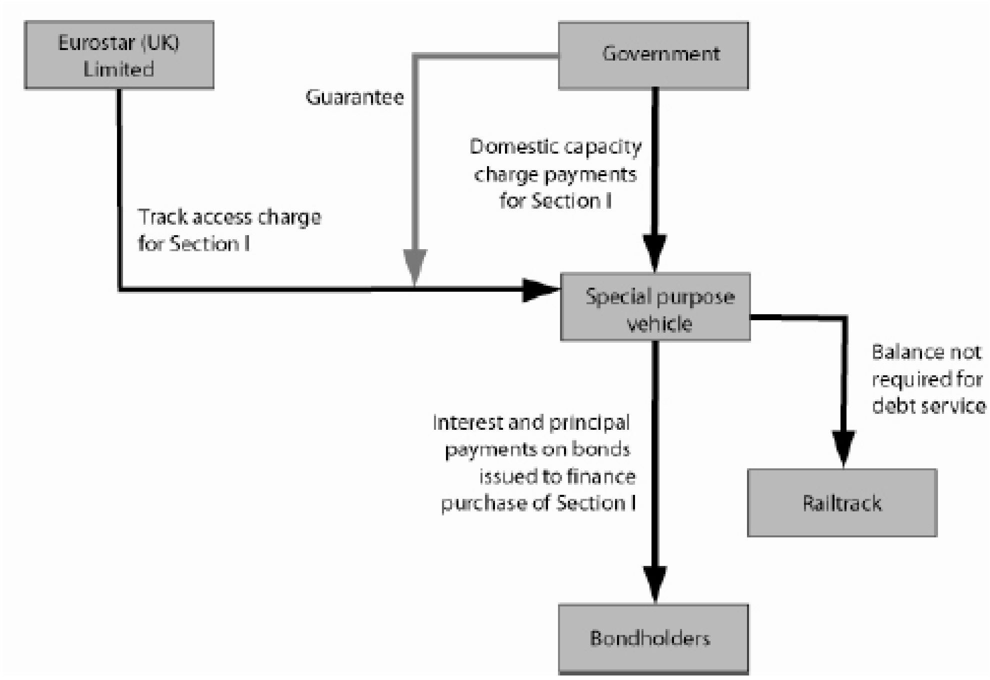
B1.5 *PROJECT REVENUE*

The project aims to generate revenue from access charges to Eurostar UK and domestic capacity charge payments from the Government.

Both of the above sources of revenues have been guaranteed by the UK Government and according to the cash-flow structure presented in *Figure 1.5* LCR was able to secure its debt and finance the project.

(3) www.dft.gov.uk/pgr/rail/pi/ctrl/backgroundinformationonthech341

Figure 1.5 *Cash flow structure for the securitization of debt*



Source: CTRL Risk Transfer and Innovation in Project Delivery, Harvard Design School, Prof. Spiro N. Pollalis, November 2006, http://www.gsd.harvard.edu/people/faculty/pollalis/cases/CTRL-V5.pdf

B1.6 *PROJECT EVALUATION*

The project has been completed on time before the end of 2007 and within the upper limit budget of £6.1 billion. This was achieved according to LCR executives by transferring much of the project's performance risks (e.g. over-runs and delays) to contractors.

From the financing side, the UK Government was prepared to contribute to the project provided the expected overall benefits could be expected to outweigh the Government's financial contribution. The project, one of the largest infrastructure projects in Europe, required considerable investment and even the most optimistic projections currently indicate that passenger revenues alone will not be sufficient to make the project commercially viable and a possibility remains that the high-speed could be sold in an auction in the future.

The section 2 of the project was opened in November 2007 and further time would be required for sufficient project evaluation.

B2 SOUTH BAY EXPRESSWAY TOLL ROAD

B2.1 PROJECT DESCRIPTION

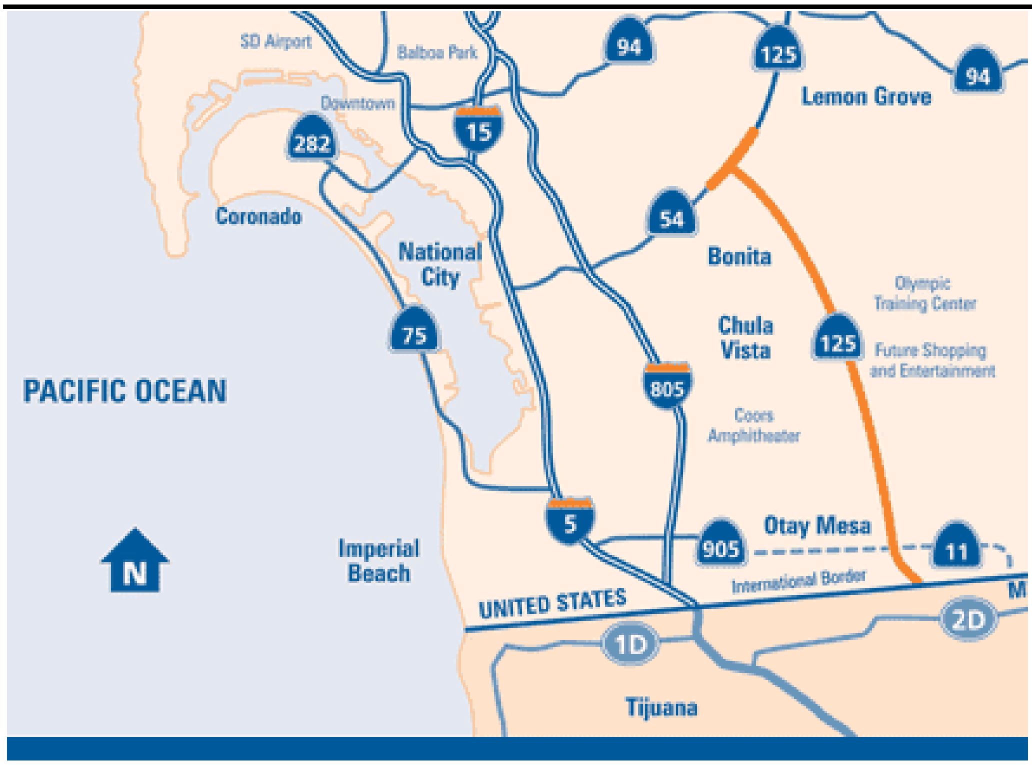
State Route 125 currently runs from State Route 54 in San Diego to State Route 52 in Santee, USA and construction is underway to extend Route 125 from Route 54 south to State Route 905 and State Route 11 in order to directly connect Otay Mesa, the largest area of industrial zoned land remaining in San Diego County , with Eastern Chula Vista Otay Mesa near the U.S.–Mexico border.

This new 12.5-mile highway portion is called the South Bay Expressway toll road and is scheduled to open in November 2007. The South Bay Expressway will be California's first road built by a public-private partnership.

B2.2 RATIONALE

South Bay Expressway will drastically reduce commute times for those travelling between these two areas, and provide convenient access to Downtown, Sorrento Valley, Santee, I-8 and I-15, Mexico and will complete the missing link in San Diego's third north-south freeway corridor.

Figure 2.1 ***South Bay Expressway SR-125 Route***



Source: http://www.southbayexpressway.com/picpg/Areamap.html

B2.3 *PROJECT STRUCTURE*

The southern 9.5-mile section of South Bay Expressway is being privately constructed, financed and will be operated as a toll road. The toll road is currently being developed under California 's AB 680 legislation passed in 1989 however this project has been in the region's plans since 1959 but there was never appropriate funding available for construction due to other regional transportation priorities. A concession for the portion of State Route 125 south of SR 54 was granted to California Transportation Ventures (CTV) in 1991.

The project was realised using the -Build-Finance-Operate (DBFO) model through a limited partnership. San Diego Expressway, LP, holds franchise rights with the State of California under which it finances and builds the highway, then leases back, operates and maintains the facility for 35 years after which ownership is transferred to the State at no cost. (4)

B2.4 *PROJECT COST AND FUNDING*

The northern 3.2-mile public section of the Expressway, mainly connector and interchange routes, cost approximately $138 million and was publicly funded. It was financed with a mix of federal (FHWA) and local sales tax funds (San Diego Association of Governments).

The total cost for the southern 9.5-mile private section of South Bay Expressway is estimated at around $635 million.

The private toll road is being funded by the private company California Transportation Ventures, Inc. and the following public agencies: the United States Department of Transportation, CalTrans, San Diego Association of Governments (SANDAG), and the City of Chula Vista.

Both the private and publicly funded portions will be built by the same contractor under two different design-build contracts. California Transportation Ventures, Inc. (CTV), the general partner, manages the project and will administer the contracts. Washington Group International is the selected contractor with a joint venture of Parsons Brinckerhoff Quade and Douglas, Inc and J. Muller International is the Design-Builder subcontractor.

The financing sources for the private portion of the project are presented in *Table 2.1* below:

Table 2.1 *Financial Support for California Transportation Ventures Inc. Project Company*

Source	Amount	Description
Transportation Infrastructure Finance and Innovation Act (TIFIA)*	$140 million	38 year loan with a fixed rate borrowing cost equal to 30- year treasuries
Macquarie Infrastructure Group (California Transportation Ventures, Inc. is a wholly owned subsidiary of Macquarie Infrastructure Group)	$160 million	Equity
Local developers	$48 million	Right-of-way grants
Commercial debt	Unknown	Loan

* TIFIA established a Federal credit program for eligible transportation projects of national or regional significance under which the U.S. Department of Transportation (DOT) may provide three forms of credit assistance – secured (direct) loans, loan guarantees, and standby lines of credit, http://tifia.fhwa.dot.gov/

B2.5 PROJECT REVENUE

The main revenue sources for this project would be toll revenues during the 35 year concession period. The State of California granted the project company full discretion over toll rates charges and con-compete clauses assurance (in the form that the parallel I-805 a few miles west won't be widened) but capped the project's return to a maximum 18.5% return on total investment with additional allowed incentive return for action to increase average vehicle occupancy on the toll road.

The tolls are currently calculated on the distance travelled and the number of axles of the vehicle. For example 2-axle vehicles neighbourhood trips are 75 cents, medium trips are $1.50 to $2.50 and through trips are $3.50. (5)

B2.6 PROJECT EVALUATION

When construction began in September 2003 the initial plan was for the project to be delivered by the end of 2006 but due to construction delays the toll road was finally scheduled to open at November 19 of 2007. At the time that this report was written by ERM the project's performance could not be properly evaluated. (6)

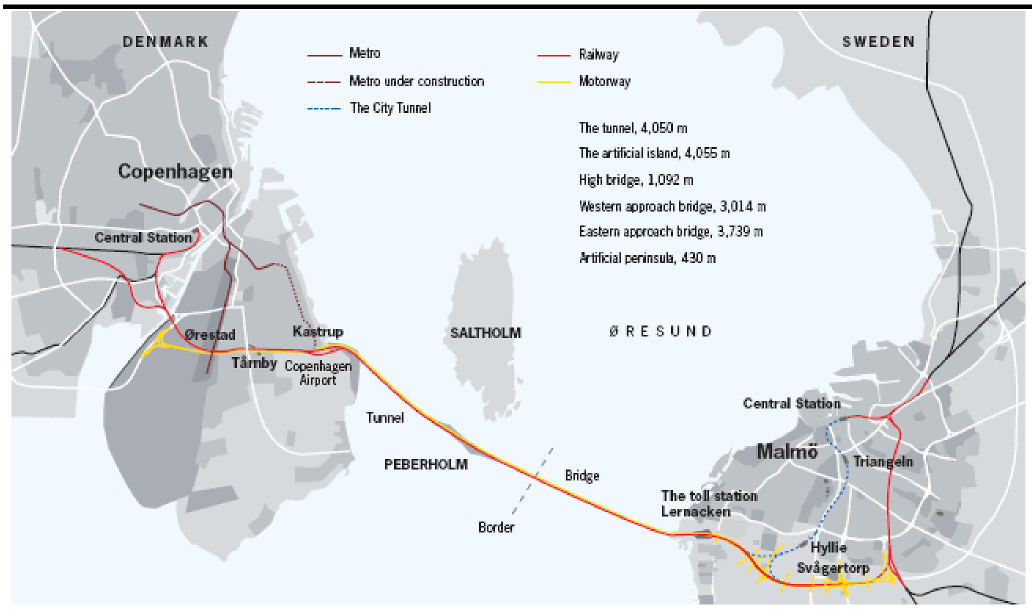
(4) http://www.innovativefinance.org/projects/highways/125.asp
(5) www.southbayexpressway.com
(6) United States Department of Transportation - Federal Highway Administration http://www.fhwa.dot.gov/ppp/sr125.htm

B3 ORESUND BRIDGE

B3.1 PROJECT DESCRIPTION

The Oresund Bridge is a combined two-track rail and four-lane road bridge across the Oresund strait. The bridge-tunnel is the longest combined road and rail bridge in Europe and connects the two metropolitan areas of the Oresund Region: the Danish capital of Copenhagen and the Swedish city of Malmo. The international European route E20 runs across the bridge, as does the Oresund Railway Line. Bridge construction began in 1995 and the last section was constructed on August 14, 1999. (7)

Figure 3.1 Route of the Oresund Bridge



Source: http://osb.oeresundsbron.dk

B3.2 PROJECT STRUCTURE

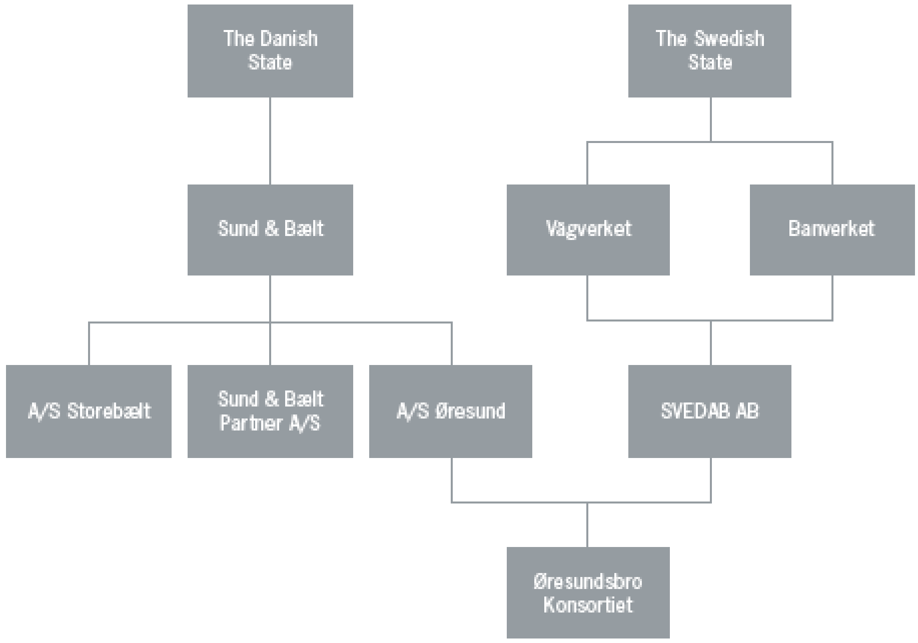
Øresundsbro Konsortiet, the project company, is a Danish-Swedish company jointly owned by the Danish and Swedish states, that owns and operates the Øresund Bridge between Denmark and Sweden.

Øresundsbro Konsortiet is jointly owned by the two companies, A/S Øresund and Svensk – Danska Broförbindelsen (SVEDAB AB). The two companies are also responsible for the ownership and operations of the landworks on their respective sides of the Øresund Bridge. The collaboration between the two companies as far as Øresundsbro Konsortiet is concerned is laid down in a consortium agreement approved by the two governments. A/S Øresund and Svensk – Danska Broförbindelsen SVEDAB AB are jointly and severally responsible for Øresundsbro Konsortiet's commitments. Øresundsbro Konsortiet is charged with the commercial, traffic and technical management

(7) http://en.wikipedia.org/wiki/Oresund_bridge

of the Øresund Bridge between Denmark and Sweden, including marketing, sales, customer and toll services, financial administration, road and rail operations, maintenance, development, and administrative functions.

Figure 3.2 *Ownership Structure of the Oresund Bridge*



Source: http://osb.oeresundsbron.dk

B3.3 *PROJECT COST AND FUNDING*

Total construction costs and accumulated interest during the construction period were approximately DKK 19.6 billion at the time of the opening of the bridge in 2000. At the close of 2006, Øresundsbro Konsortiet's net borrowings totalled DKK 19.7 billion. Current expectations are that the Øresund Bridge will have repaid its debts after 33 years of operations. As part of the Øresund fixed link, landworks (approach roads and rail links) were built on the Danish side at the cost of DKK 7.9 billion and on the Swedish side for DKK 2.6 billion (2000 prices). These are financed by loans and will be repaid from the revenue from Øresundsbro Konsortiet.

Table 3.1 ***Total construction costs for the Øresund Bridge***

	In bn DKK (in bn USD)
The Øresund Bridge (Øresundsbro Konsortiet)	19.6 (3.7)
Danish landworks (A/S Øresundsforbindelsen)	7.9 (1.5)
Swedish landworks (SVEDAB AB)	2.6 (0.5)
In total	30.1 (5.7)

Note: Construction costs are shown as net debt in 2000 prices.

Source: http://osb.oeresundsbron.dk

Øresundsbro Konsortiet (the legal entity raising money for the bridge) was almost entirely financed by debt through loans and bond issues in the domestic as well as the international capital markets.

The loan types employed have a structured content, including loan types with an option of early redemption, dual currency loans and constant maturity loans etc. However, under the guidelines from the guarantors and the financial policy, such loan types are hedged at the time of the transaction so that the final exposure is always current and accepted loan types.

Øresundsbro Konsortiet has established standard MTN (Medium Term Note) loan programmes directed towards two of the most important bond markets for the Consortium, the European and the Swedish bond market. Funding sources for the Øresundsbro Konsortiet project company are summarized in *Table 3.2*

Table 3.2 Funding Sources for Øresundsbro Konsortiet

Source	Amount	Description
European Bond Market	Maximum borrowing limit of $3 billion of which 1.9 billion is currently used	European Medium Term Note Loan Programme arranged by Nomura International including. ABN AMRO, Citigroup, Handelsbanken Capital Markets and Mizuho International plc as dealers
Swedish Bond Market	Maximum borrowing limit of $1.5 billion of which $1.0 billion is currently used	Swedish Medium Term Note Loan Programme arranged by SEB (Skandinaviska Enskilda Banken) including ABN AMRO, Swedbank Markets, Danske Bank, Nordea and Handelsbanken Capital Markets as dealers
Loans	$0.7 billion	Loans (including the European Investment Bank and commercial banks)

These debt instruments will be repaid through income from the users that will pay a toll for passing the bridge. Additionally the project company debt is jointly and severally guaranteed by the Kingdom of Denmark and the Kingdom of Sweden, giving a very high credit rating on the bonds. [(8)]

The Consortium's financing costs depend on interest rate exposure, in that the ongoing borrowing for refinancing maturing debt claims liquidity from operations and investments, and fixing interest on floating rate debt is executed at market rates that are not known beforehand. In addition to the general uncertainties relating to interest rate developments, financing costs are influenced by the composition of the debt between fixed and variable nominal debt and real interest debt. Moreover, the debt composition determines the term and currency breakdown of the debt. The Company's interest rate risk is actively managed through the use of swaps and other financial instruments. Besides representing an isolated balancing of financing costs and interest uncertainties on the debt, Øresundsbro Konsortiet's risk profile is also affected by the connection between revenue and financing costs. A debt composition with a positive correlation between revenue and financing costs can have a lower risk profile when revenue and financing costs are assessed in context. [(9)]

(8) Bonds issued by the company has obtained the highest possible long term rating from Standard & Poors (AAA).
(9) http://osb.oeresundsbron.dk/library/?obj=5034

B3.4 *PROJECT REVENUE*

The Øresund Bridge must be self-financing, i.e. the fees paid by users for crossing the link must cover all construction and operating costs, including maintenance, and any new investments and revenues must cover ongoing financing costs and secure the long-term repayment of the loans. As was noted earlier the Consortium's financing costs depending on interest rate exposure and traffic development the bridge will be repaid in as follows:

Table 3.3 Payback Period Scenarios for Oresund Bridge

Real Interest Rates	**2.5%**	**3.0%**	**3.5%**	**4.0%**	**4.5%**
Growth Scenario	2027	2028	2028	2028	2029
Middle Scenario	2032	2032	2033	2033	2034
Stagnation Scenario	2039	2040	2040	2041	2041

Source: http://osb.oeresundsbron.dk

As of 2006 a single car ride across the bridge costs DKK 235, SEK 290 or € 32 ($43.52 or £21.84) and a train ride SEK 90.[10]

B3.5 *PROJECT EVALUATION*

The opening of the Øresund Bridge in 2000 has significantly enhanced the infrastructure between the Scandinavian Peninsula and the European continent. In particular, travelling times across Øresund between Zealand and Sweden have become faster. The opening of the Øresund Bridge in July 2000 has resulted in a very strong increase in traffic across Øresund. While in the 1990s, between two and three million cars crossed Øresund each year, in 2006 the figure was 8.2 million vehicles and 32 million travellers by car, train or ferry.

(10) http://en.wikipedia.org/wiki/Oresund_bridge

Annex C

Carbon and clean energy funds with potential CCS applicability

1. 1 *Carbon Investment Funds*

Name	Sponsors	Size	Description of Investment Style	Applicability for CCS	Reference
European Carbon Fund	Numerous banks (http://www.europeancarbonfund.com/shareholders.php)	€142.5m	Finances CDM/JI projects by buying carbon assets (credits) on a forward basis.	X	http://www.europeancarbonfund.com
Asia Carbon Fund	Asia Carbon Group	€200m	Primarily renewable energy projects that are eligible to generate Carbon Credits under the Kyoto Protocol & EU ETS	X	
Carbon Fund for Europe	World Bank, EIB	€50m	Purchases CDM and JI GHG reductions from climate-friendly investment projects from either bank's portfolio as well as self-standing projects.	X	http://carbonfinance.org
Prototype Carbon Fund	World Bank	$180m	Invests in project-based greenhouse gas emission reductions	?	http://carbonfinance.org
Cleantech Private Equity (CPE) Fund	Climate Change Capital	?	CPE targets investments in the high growth clean technology areas including cleaner fossil fuels.	√	http://www.climatechangecapital.com/pages/cpe.asp
Biocarbon Fund	World Bank	$53.8m	Funds projects that sequester or conserve carbon in forest and agro-ecosystems	X	http://carbonfinance.org
Multilateral Carbon Credit Fund (MCCF)	EBRD, EIB	€165m	Involved in project-based carbon credits in EBRD countries	X	http://www.eib.org/projects/topics/environment/climate-change/index.htm
Carbon Fund	KfW Bankengruppe, EIB	?	Purchases emission credits from JI- and CDM-projects	X	http://www.kfw-foerderbank.de/EN_Home/Carbon_Fund/KfWCarbonF.jsp

Name	Sponsors	Size	Description of Investment Style	Applicability for CCS	Reference
Climate Change Financing Facility (CCFF)	EIB	€1bn + €200m sub-window	Designed to help EU companies covered by the EU ETS to comply with their CO2 emission allowance allocations by financing investment in emission reduction projects. However, the EIB has recently broadened the scope of the Facility to also support investments not covered by the EU ETS that significantly reduce greenhouse gas emissions, regardless of the region sector or type of greenhouse gas.	?	http://www.eib.org/projects/documents/climate_change_financing_facility_en.htm
Risk Sharing Finance Facility (RSFF)	European Community and EIB	?	The European Commission and the European Investment Bank (EIB) have joined forces to set up the Risk Sharing Finance Facility (RSFF). RSFF is involved in enabling investment in the area of Research, Development and Innovation (RDI) and improve access to debt financing in the fields of research, technological development, demonstration and innovation investments. RSFF is a credit risk sharing between the EC and the EIB and extends the ability of the Bank to provide loans or guarantees with a low and sub-investment grade risk profile (involving financial risks above those normally accepted by investors).	?	http://www.eib.org/products/loans/special/rsff/index.htm
Post 2012 Carbon Fund	EIB	?	Expected to be active in the second half of 2007, the fund would acquire Post 2012 credits only, thereby supporting the development of environmentally beneficial projects by extending their carbon-based revenue stream	?	http://www.eib.org/projects/topics/environment/climate-change/index.htm
Core Carbon Group	Core Carbon Group	?	Brings equity investments to CDM/JI projects and finances all steps of the process	X	

Name	Sponsors	Size	Description of Investment Style	Applicability for CCS	Reference
arkx carbon fund	arkx	$250m	The arkx Carbon Fund will focus on the clean energy & renewable energy sectors. ***Portfolio Construction:*** • Clean energy equities : up to 100% • Global carbon credits : up to 50% • Global carbon projects : up to 50% • Unlisted clean energy companies : up to 10%	?	http://www.arkx.com.au
Clean Energy Financing Partnership Facility (CEFPF)	Asian Development Bank	$ 250m	The facility provides a platform to provide support for clean energy projects under technical assistance, investment products (grants, low-interest loans, guarantees, or other forms of contributions)	?	http://www.adb.org/Documents/Others/Cofinancing/R61-07.pdf

Annex D

CO_2 Pipeline model: Specifications and assumptions

D1 MODEL SPECIFICATIONS

Table 1.1 and Table 1.2 present in more detail the project specification for the deployment scenarios that were explored:

Table 1.1 Point to Point Pipeline Specifications

Specification	Base Scenario
CO_2 Stream Source	1 IGCC Power Plants (730MW+)
Pipeline Length (in miles)	600
Diameter (in inches)	14
Construction Material	Steel
CO_2 Stream	Supercritical
Annual Actual Throughput (in MtCO2/pipeline)	4.80
Annual Maximum Pipeline Capacity (in MtCO2/pipeline)	4.85
Capacity Utilization	99%

Table 1.2 Backbone Network Specifications

Specification	Base Scenario
Backbone pipeline	
Length (in miles)	600
Diameter (in inches)	36
Construction Material	Steel
CO_2 Stream	Supercritical
Annual Throughput (in MtCO2, normalised for 40yrs.)	52.1
Annual Maximum Nominal Capacity (in MtCO2)	56.5
Capacity Utilization over project lifetime	92%
Source pipelines	
CO_2 Stream Source	10 IGCC Power Plants (730MW+)
Connector Pipelines Required	10
Average Pipeline Length (in miles)	120
Diameter (in inches)	14
Construction Material	Steel
CO_2 Stream	Supercritical
Annual Actual Throughput (in MtCO2/pipeline)	4.80
Annual Maximum Pipeline Capacity (in MtCO2/pipeline)	4.85
Capacity Utilization	99%
Sink Pipeline Specifications	
CO_2 Stream Sink	43 Injection Wells
Assumed Maximum Injection Rate (in $MtCO_2$/yr.)	1.3
Assumed Actual Injection Rate (in $MtCO_2$/yr.)	1.1
Total storage capacity required(in $MtCO_2$)	~2000
Connector Pipelines Required	43
Average Pipeline Length (in miles)	60
Diameter (in inches)	8
Construction Material	Steel
CO_2 Stream	Supercritical
Annual Actual Pipeline Throughput (in MtCO2/pipeline)	1.1
Annual Maximum Pipeline Capacity (in MtCO2/pipeline)	1.15
Capacity Utilization	98.8%

Some of the above specifications are presented in more detail below:

- **Pipeline Capacity Utilisation and Throughput Escalation;** For our backbone pipeline scenario we assumed that power plants are not all connected from day one of the project but keep connecting and contracting capacity during the first 7 years of the operational period when a 95% capacity is reached. The starting point is a CO_2 demand scenario where the CO_2 pipeline has ~40% capacity utilisation for years 1-2 of the operation, ~60% % for years 3-4 and ~80% % for years 5-6. From there on the pipeline reaches 95% capacity utilization and continues to operate in this way for the lifetime of the project.

- **CO_2 Phase;** Pipeline transportation options include CO_2 in gas phase, liquid CO_2 lines and supercritical phase. Most of the CO_2 pipelines in the world today are high pressure, supercritical phase lines and economics dictate that large CO_2 volumes being moved long distances are moved most efficiently in supercritical phase. For the purpose of this study it is assumed that the pipeline will transport CO_2 in the supercritical phase. [(1)]

- **Injection rate;** Injection rate is influenced by type of site (i.e. oil field, gas field, saline aquifer), given geology and permeability issues and can vary from site to site. ERM used an average value of approximately 3000t/day or 1MtCO_2/yr. per injection well which is typical for O&G fields and consistent with actual injection rates of similar sequestration projects (e.g. Weyburn, In Salah). As a result this maximum injection rate assumed indirectly prescribes the number and the size of the sink pipelines.

(1) European Technology Platform on Zero Emission Fossil Fuel Power Plants, WG3, Infrastructure and Environment draft report dd. 3 May 2006, http://www.zero-emissionplatform.eu/website/library/index.html#etpzeppublications

D2 ASSUMPTIONS

D2.1 COST

In order to build the cash-flow model, estimates were made for the overall capital investment requirements and associated operating costs of the pipeline system. These cover all phases from planning to operating and maintaining the pipeline over the course of its life. Capture and storage site costs were beyond the scope of this study and are not included. Costs figures for the pipelines are presented in further detail in tables 2.4 – 2.7 in Annex D.

D2.1.1 *Capital Costs*

Assuming the best case and least cost path the construction costs can be found in Table 2.1 and Table 2.2.

Table 2.1 Point to Point Pipeline Construction Costs Breakdown (in $USD)

Type of Cost	% of total costs	Cost
Labour	47%	$174 million
Materials and equipment	26%	$96 million
Right of way	6%	$22 million
Miscellaneous	21%	$77 million
Total	**100%**	**$87 million**

Table 2.2 Backbone Network Pipeline Construction Costs Breakdown (in $USD)

Type of Cost	% of total costs	Base Scenario
Backbone Pipeline		
Labour	43%	$446 million
Materials and equipment	32%	$412 million
Right of way	6%	$57 million
Miscellaneous	19%	$200 million
Total	**100%**	**$1115 million**
Source Connector Pipeline		
Labour	43%	$35 million
Materials and equipment	32%	$32 million
Right of way	6%	$5 million
Miscellaneous	19%	$15 million
Total	**100%**	**$87 million**
Sink Connector Pipeline		
Labour	43%	$11 million
Materials and equipment	32%	$10 million
Right of way	6%	$1 million
Miscellaneous	19%	$15 million
Total	**100%**	**$27 million**

D2.1.2 *Operating Costs*

Operating costs include maintenance, labour, compression and fuel costs, depreciation and taxes and have a constant. For a trans-border pipeline rents, royalties, transit fees and other taxes could be applicable but in our scenario it is assumed that pipeline is located within a single country. Fixed and variable annual operating costs were estimated for the each scenario and were included in the model calculations. These can be found in table XX

Table 2.3 *Annual Operating Costs for Point to Point Pipeline Breakdown ((in $USD)*

Pipeline	Operating Cost
Point to point	$3.0 million

Table 2.4 *Annual Operating Costs for Pipeline Network Breakdown ((in $USD)*

Pipeline	Operating Cost
Backbone	$3 million
Source	$0.6 million
Sink	$0.3 million
Total	$3.9 million

D2.2 *REVENUE*

For calculating pipeline revenue ERM decided used a simple version of the cost-of-service tariff calculation methodology that is used for O&G pipelines (see Annex A) where the transportation tariffs that the operator charges are calculated to meet set revenue targets.

These targets represent a set revenue stream required by the pipeline operator in order to pay for capital, operating and other costs and receive a satisfactory return on investment. Although the methodology is a bit more complex the basic concept behind it that the tariff charge it is not influenced by the price of the transported commodity (CO_2) nor it is negotiable in any other way but it is formed as part of an agreed rate of return required for the project and agreed before the project is developed. Here arises the question of whether or not these charges are realistic and can be competitive within the overall carbon market. This is discussed briefly in the conclusions section of the report.

Tariff levels can vary depending on throughput to meet the aforementioned set revenue targets and can be calculated on the basis of the following simple formula in Box 2.1:

Box 2.1 *Tariff Calculation Formula*

$$\text{Tariff Charge for year X (in \$/ton of CO2)} = \frac{\text{Total cost of service for year X}}{\text{Annual throughput of CO2 for year X}}$$

Tariff charges can be calculated either based on actual volume transported (rarely used and only for oil pipelines) or on contracted capacity where the users pay for allocated capacity whether used or not.

The above formula shows that as throughput, either actual or contracted, increases tariff levels fall and vice versa.

D2.3 *FINANCING*

In the base financing scenario we assumed that the project sponsors would raise approximately 70% of project finance through debt, mainly loans, and contribute the rest 30% in equity or other forms. This is generally considered as a typical project finance structure. Other assumptions include:

- **Cost of Equity;** a set 15% return on equity was assumed required by the project sponsors for the duration of their equity contributions.

- **Cost of Debt;** a 9.57% (Libor + 4%) rate was assumed;

- **Weighted Average Cost of Capital (WACC) rate;** is the overall return the project must achieve in order to meet the requirements of all its sponsors/investors. For our base scenario for the backbone pipeline this is calculated to be 7.5%. Capital sources, such as debt financing, equity and bonds all have different expected return and are adjusted for inflation and weighted accordingly in the calculations in order to reflect their relative prominence in the project's capital structure.

- **Project time length;** from a financial perspective the project financial lifetime was defined to be 20 years in the base scenario (i.e. the sponsors would be interesting in recovering their investment in 20 years) and from an operational perspective 40 years (this does not influence cash flows and NPV). It is worth noting that contrary to oil and gas where pipeline lifetime is limited by the upstream (i.e. hydrocarbon field depletion assuming HC demand outstrips supply), for CO2 pipelines the project is limited by the downstream and the maximum storage capacity of the geological formations.

Annex E

Glossary

Bond: a form of interest bearing security issued by governments, companies and other institutions - usually a form of long-term financing.

Bond issue: A method of borrowing by which debt is raised from a wide variety of individual or institutional investors. Bonds usually carry a fixed coupon payable by the issuer (borrower) to the bondholder (investor) and have a predetermined repayment date.

Cash flow: Cash generated from a business activity.

Cost of capital: The return the company must obtain on a certain source of capital, for example debt or equity, to satisfy those investors.

Cost of equity: The return stockholders require on their investment in the stock.

Depreciation: The amount of an asset's purchase price that is taken as an expense during each reporting period over the life of the asset.

Discount rate: The percentage rate applied to cash flows to enable comparisons to be made between payments made at different times. The rate quantifies the extent to which a sum of money is worth more today than the same amount in a year's time.

Equity: The value of a company or project after all liabilities have been allowed for.

Floating interest rate: A rate of interest which varies periodically in accordance with a stated market reference, usually the London Interbank Offered Rate (LIBOR).

Government Guaranteed Bonds: Bonds issued by a party other than Government but carrying a Government Bonds Guarantee (GGBs) to honour the bond in the event of the issuer being unable to do so.

Hedging Instruments: Instruments used by companies to manage the risk of variations in future interest rates. In most cases, the company will choose to fix its future interest rate thereby providing it with certainty about what its financing charges will be.

Non-Recourse Debt: Debt that is secured by a pledge of collateral, typically real property, but for which the borrower is not personally liable.

Pari-Passu: A legal term that is used when different series of debt (whether intermediated or disintermediated) have equal ranking in terms of repayments rights.
Return on equity: Net income/Shareholders' equity.

Shareholder: Someone who owns stock in a company. The shareholders are the owners of a company.

Yield: The rate of return that an investor would realize on a bond held to maturity.

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