Ministry of Environment and Water Resources, Trinidad & Tobago

Feasibility of Carbon Capture & Storage Projects in Trinidad & Tobago

FINAL REPORT

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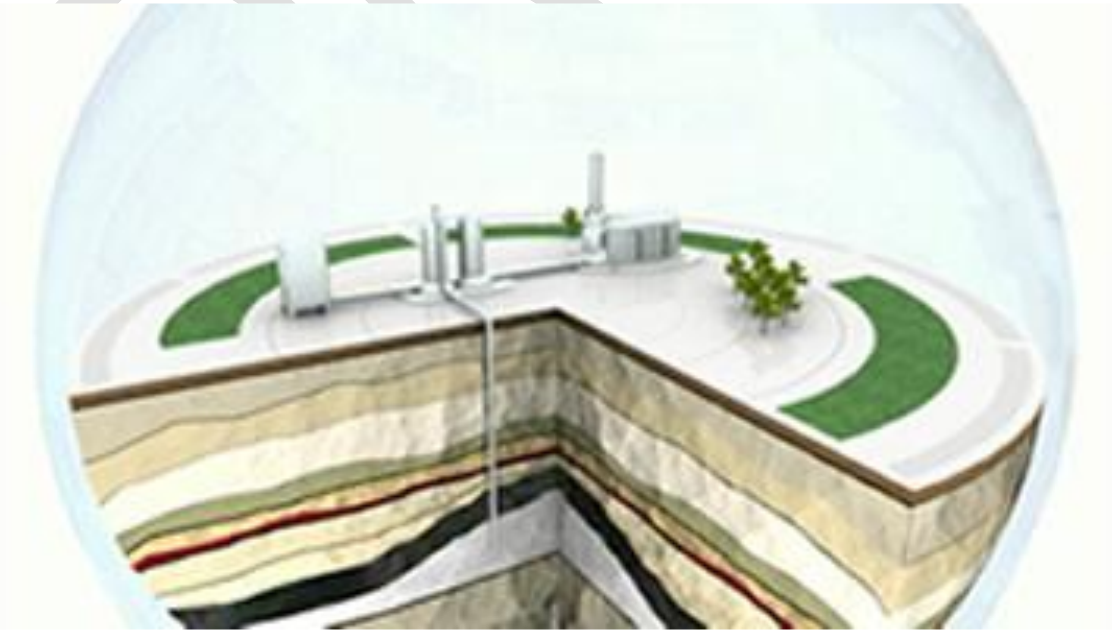

1. Executive Summary

While the worldwide demand for energy grows, so does the demand that it should be lower-carbon. The increasing concentration of CO_2 in the atmosphere exacerbates global warming. However, geologic CO_2 storage has been identified by the Intergovernmental Panel on Climate Change (IPCC) as a viable and mature technology that can reduce CO_2 emissions and limit the anticipated rise in average global temperatures to less than 2°C. CO_2 is an unavoidable by-product of natural gas-based industrial activities in Trinidad and Tobago. These activities, which account for over 35.7% of the GDP and 82.8% of the Foreign Exchange Earnings, produce 31.5 million metric tonnes or 87% of the country's annual CO_2 emissions. This sector of the market is in the spotlight not just because of increasing recognition of the need to change, but with governments, organisations and businesses setting targets and taking and encouraging action. The need to act quickly and effectively is even further underlined by the fact that, if we are actually going to mitigate the extent of climate change, the industrial processing of hydrocarbons and power generating sector will need to be decarbonised by 2050.

At a time when the world is looking for answers, the Government of Trinidad and Tobago has an opportunity to be part of the solution.

In CCS TLM's view there are a few key determinants that define a project's potential, namely:

- CO_2 storage sinks (availability, capacity, and security of storage);
- Access to indigenous fuel (and reliance on hydrocarbons), and
- Policy (and financial) support – to reflect the country's capacity to deliver it.

The Terms of Reference for this study is to "*assess the conditions necessary to facilitate the implementation of a national CCS program, including recommendations for addressing identified gaps and a cost-benefit analysis*"; the authors believe that CCS is viable for Trinidad & Tobago.

1. **Does Trinidad and Tobago have sufficient and suitable sinks for the storage of CO_2?**
   Yes, it is believed so, albeit the necessary data to assess and verify this statement has been difficult to obtain and incomplete for several reservoir targets and so a full understanding of the potential for CO_2 storage has not been substantiated during this study.

2. **Does Trinidad and Tobago have access to sufficient supplies of indigenous fuels and sufficient reliance on hydrocarbons?**
   Yes, undoubtedly, with the well-established oil and gas production and gas processing sectors (ammonia and methanol manufacturing), the region has significant access to

indigenous hydrocarbon supplies and relies heavily on those hydrocarbons for a substantial contribution to the nations GDP.

3. **Does Trinidad and Tobago have the basis upon which (and motivation) to develop robust CCS related policies and regulations?**
   Section 8 reflects on the strong interest and motivation to develop the necessary policies and regulations to support the development and deployment of a CCS programme.

In order for CCS to play its role in reducing global carbon dioxide (CO_2) emissions on a significant scale, it will need to be deployed in developed and developing countries (Non-Annex 1 countries under the UN Framework Convention on Climate Change (UNFCCC)).

In the coming decades, it is expected that all of the world's net fossil fuel growth and associated CO_2 emissions will be in developing countries. Accordingly, the International Energy Agency estimates that 50%-60% of CCS deployment will need to happen in non-OECD countries to achieve global emission reduction targets.

A major challenge facing many developing countries is how to increase access to energy in a sustainable, climate-friendly way. Numerous developing countries are also interested in continuing to utilise their local fossil fuel resources to ensure energy security and maintain the associated economic benefits. CCS enables these dual objectives to be achieved.

By actively promoting Carbon Capture and storing approximately 90% of the resulting Carbon Dioxide (CO_2) deep underground (CCS), it is possible to use fossil fuels in less polluting ways. It's a crossroads moment. What has been seen as part of the problem can now play an invaluable role as a significant part of the solution.

The possibilities this transformation opens up are global. Not least in territories where fossil fuels are still the easiest and lowest cost options for power generation. Territories with large fossil fuel consumption can access the energy it contains without contributing to damaging climate change.

Trinidad & Tobago can benefit immensely through the use of CCS as a means of CO_2 emission mitigation. There is a clear imbalance in the country's present CO_2 emission levels with respect to its population size and gross domestic product (GDP). An opportunity exists for Trinidad & Tobago to reverse this inequity with the aid of CCS technologies – this would indicate a step towards sustainable development for the country.

The assessment of CO_2 capture opportunities assessed within this report concluded that from a cost and benefit perspective, any CCS programme should target the following sectors in order:

1. Ammonia plant,
2. Power generation, and then
3. Methanol plant

For Trinidad and Tobago, it is possible that the energy sector can arrest declining oil production and reduce the country's net carbon dioxide (CO2) emissions by integrating upstream and downstream operations to accommodate the transport of waste CO2 from downstream operations for use in oil fields. By collecting and injecting waste CO2 into hydrocarbon reservoirs Trinidad and Tobago could potentially simultaneously increase oil production while sequestering CO2.[1]

It should be noted that the CO_2 capacity estimates derived in this report are based on data received from the client. Capacity is estimated using the principle that hydrocarbon production from a reservoir is a good estimate of the volume of CO_2 (at reservoir conditions) that can injected into the deplete reservoir. This means that initial oil/gas in place and ultimate recovery factor are critical to the capacity estimate. The reserves listed in the data received are small compared to the very large quantity of LNG exported from Trinidad and Tobago. In the short time available, it has not been possible to identify the source of this discrepancy. The received data is assumed to be correct.

This report has identified a real opportunity for the deployment of CCS through the development of a CCS roadmap to 2030 and ultimately to 2050 where 16million and 150million tonnes of CO2 could be abated respectively.

[1] Win-Win: Enhanced Oil Recovery and Carbon Storage in Trinidad & Tobago. Lorraine Sobers & Selwyn Lashley. 2012

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2. Introduction

The Inter-American Development Bank (IDB) has provided a grant to the Government of Trinidad and Tobago to assist with the consideration of the impact of climate change into national policies and institutions.

As part of the Program, the Government is undertaking a study to examine the feasibility of a carbon capture and storage (CCS) project in Trinidad and Tobago. Through this study, it is hoped that the Government and other stakeholders will better understand the potential role CCS could play in Trinidad and Tobago.

The Global CCS Institute is supportive of the initiative and has contributed to the Program through the Carbon Capture and Storage Regulatory Review for Trinidad and Tobago[2]. This Review considered the existing legal and regulatory framework as it might be applied to CCS in Trinidad and Tobago.

The major sources of carbon dioxide (CO2) emissions in Trinidad and Tobago are the energy and manufacturing sectors (see Figure 2.1). The National Climate Change Policy 2011 indicates that the CO2 emission levels for Trinidad and Tobago for 2008 was 28.37 tonnes of CO2 per capita, the highest in the region. Given that the country is the leading producer of oil and gas in the Caribbean as well as being the largest producer of methanol and the largest trader of ammonia[3] this figure might not be surprising.

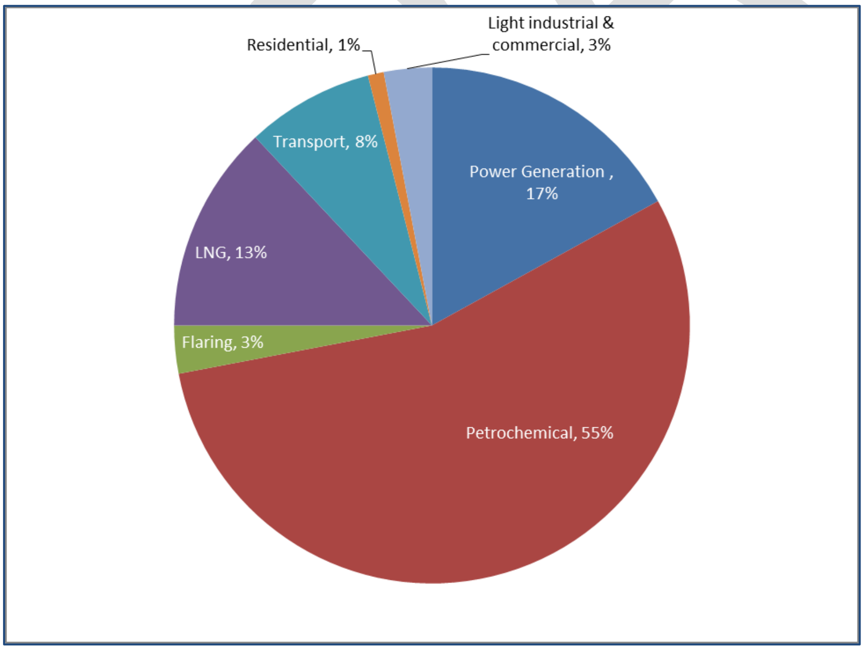


Figure 2.1: Trinidad & Tobago CO2 emissions, by sector[3]

[2] http://cdn.globalccsinstitute.com/sites/default/files/publications/54126/ccs-regulatory-review-trinidad-tobago.pdf
[3] Boodlal and Furlonge, 2008

As can be seen from Figure 2.1 above, Trinidad and Tobago CO2 emissions are produced mainly from the industrial sector as a result of natural gas combustion and petrochemical manufacture. These activities, which account for over 37.5% of the GDP and 82.8% of the Foreign Exchange Earnings, produce 31.5 million metric tonnes (or 87%) of the country's annual CO2 emissions.

As a result, the Government of Trinidad and Tobago has initiated and developed multiple policies that look toward taking action on reducing the country's greenhouse gas (GHG) emissions and CCS is a potential mitigation option. In Trinidad and Tobago there is evidence to suggest that there is opportunity to be an early adopter of CCS[4]. For instance, CO2 could be captured from industrial plants (e.g. ammonia and/or methanol manufacturing plant) and then injected into depleting oil or depleted gas fields to be sequestered. Economic benefit being obtained from utilising the CO2 to increase the oil recovery from depleting oil fields is a further benefit that could be explored. Trinidad tested the first CO2 enhanced oil recovery (CO2-EOR) project in either Central or South America in 1973. Four immiscible CO2 pilot floods were implemented between 1973 and 1990 in what is now the Petroleum Company of Trinidad and Tobago Limited's (Petrotrin) reservoirs at its Forest Reserve and Oropouche fields[5]. CO2 for these pilots was supplied from an ammonia plant in Point Lisas.

Trinidad and Tobago had proven oil reserves of 0.83 billion barrels at the end of 2011 and produced an average of 136 thousand barrels of crude oil per day[6]. Most oil production in Trinidad and Tobago occurs offshore. The two largest crude oil producers in Trinidad and Tobago are BHP Billiton and the state-owned Petrotrin, who each control around 25 per cent of the country's crude oil production. In addition there are perhaps a further 3 bn bbl which is potentially recoverable using enhanced recovery methods like carbon dioxide. CO2 is in fact a resource Trinidad and Tobago has in abundance as a by-product of petro-manufacture of products like ammonia at Point Lisas.

Trinidad and Tobago has proven natural gas reserves of 0.40 trillion cubic metres and natural gas production of 40.7 billion cubic metres in 2011[6].

This report addresses all the key issues identified by the Trinidad and Tobago authorities.

- What sources of CO2 exist to support a CCS deployment programme?
- Where are these sources located:
    - are there opportunities for aggregation,
    - are there opportunities to optimise economies of scale?
- Where are the deep geological formations (hydrocarbon reservoirs) for use as long term CO2 stores?

[4] Boodlal and Smith, 2008 and Sobers and Lashley, 2012
[5] Mohammed-Singh and Singhal 2005
[6] BP Statistical Review of World Energy 2012

The report reflects on the GCCSI review of the regulation and policies necessary to support commercial deployment of CCS as well as identification of possible funding mechanisms to support early demonstration programmes.

The report then assesses the conceptual costs and benefits of a CCS deployment programme and provides a "road-map" for potential CCS project developments over time, before identifying areas of further work necessary to deliver the optimum programme and likely participants in CCS projects in the region.

3. CCS Project Fundamentals

CCS TLM has an unparalleled expertise in CCS project economic and technical evaluation. While CCS projects are exceedingly complex, in CCS TLM's view there are a few key determinants that define a project's potential. CCS TLM has defined the following as critical elements:

- **Sinks** (availability, capacity, and security of storage);
- **Access to (indigenous) fuel** (and reliance on hydrocarbons);
- **Policy (and Fiscal) support** (the country's capacity to deliver it); and
- **Feedstocks** (indigenous reserves and import capacities).

Second tier factors include a country's proven commitment to reduce emissions or demonstrate "sustainable development"[7], or the ability of a project to provide synergies for integration with industrial counterparties etc.

3.1. CO2 storage in deep geological formations

Fundamental to the success of a CCS project is access to a quality geological formation for securely storing the captured CO2.

Pipeline transportation of CO2 is a well-established technology and has been carried out for many years. Following transportation, the CO2 is stored securely and permanently in the formation. Geologists recognize that a number of geological formations can be used:

- mature or depleted oil and gas fields (hydrocarbon reservoirs);
- saline formations; or
- deep (unmineable) coal seams.[8]

Research indicates that deep geological storage of CO2 could accommodate 1,000Gt of carbon capture worldwide.[8] CCS TLM estimates that the storage capacity of an individual formation should typically be greater than 0.1 Gt CO2 to enable the storage of the CO2 captured from a 500MW gas-fired CCS power station over its operating life. Larger formations (greater than 0.25 Gt) provide the opportunity for aggregation - adding CO2 captured from several power generation projects or other (and several) industrial CO2 sources.

7 Sustainable development refers to a mode of human development in which resource use aims to meet human needs while preserving the environment so that these needs can be met not only in the present, but also for generations to come.

8 IPCC Special Report on Carbon Dioxide Capture and Storage

3.1.1. Storage in oil and gas fields

CO_2 storage in mature oil and gas fields offers the potential for enhanced oil recovery (EOR). The CO_2 mobilises some of the oil that would not be recovered by other means and therefore extends the life of the oil field. EOR can have a dramatic effect on project economics; the value of EOR depends on the characteristics of the field:

- Productivity – choose fields with high EOR response. Some fields may yield up to 2 barrels of oil per tonne of CO_2 stored while others may yield up to 6 barrels for the same tonne.[9]
- Location – best if onshore oil fields can be accessed. It is widely recognised that the cost of setting up the equipment and operating it is much lower if the field is onshore.
- Capacity - choose fields large enough to sustain EOR production over the life of the project – which maximises revenue either through direct payment per tonne of CO_2 supplied, or via recycling of government oil royalties into subsidy for the plant.

The compelling support provided by EOR revenue to project economics means that CCS projects should, wherever possible, combine capture plants into large, onshore fields with the best EOR response.

Even when an oil or gas field does not offer the opportunity for EOR, it can be a good location for CO_2 storage. For oil or gas to be produced, the geological properties of the field must be well known, so using such a field cuts down on the level of costly (up front) analysis required to confirm its use for CO_2 storage.

3.1.2. Storage in Saline Formations

Saline formations are large naturally occurring geological structures and sometimes offer an advantage over oil and gas fields in terms of capacity, due to the physical size and properties of the structure.[10] The distribution and size of saline formations are generally less well understood than oil and gas fields, but nearly all regions of the world appear to have significant potential saline formation storage capacity.[10] However, the cost of assessing the suitability of saline formations for storage can be high and carries the risk of being of no value if the formation is subsequently proved to be unsuitable. Such a situation occurred in Kwinana, Western Australia, where significant effort and cost to assess a saline formation resulted in the determination that it could not be used for CO_2 storage.

[9] Petroleum Technology Research Centre, Weyburn-Midale CO_2 project statistics show 5.5 – 6.7 barrels oil recovery for each tonne CO_2 injected: http://www.ptrc.ca/weyburn_statistics.php

[10] IPCC Special Report on Carbon Dioxide Capture and Storage

3.1.3. Deep (Unmineable) Coal seams

Scientific understanding of the use of coal seams for CO_2 storage is in its infancy. CCS TLM do not advocate for coal seam storage until it is better understood.

If the geological formations for CO_2 storage are available, then capturing the CO_2 from the manufacturing and industrial processing of hydrocarbons as well as the power generation sector are the next critical success element.

3.2. Access to (indigenous) and reliance on hydrocarbons

For countries to consider CCS and thus invest material funds in supporting either an individual project or a programme of deployment, there needs to be a compelling enough motivation behind it. The following issues may support such a motivation:

- Countries with very large hydrocarbon production/reserves volumes,
    - This may result in access to readily available opportunities to pursue Enhanced Oil Recovery to further support (fund) higher cost CCS projects;
- Very high per capita (or overall) emissions;
- Gas is a major energy source for the country's economy/population;
- Need to reduce CO_2 emissions to meet Kyoto targets;
- Need new, updated 'base-load' low carbon energy solutions (as opposed to intermittent renewables);
- Countries where important local corporations are heavily involved in sustainable developments globally, e.g. BP, BHP Billiton.
- Countries which may desire to be a leader in CCS deployment for CDM credits or other reasons.

Projects benefit the most from proximity to other industries to make use of potential synergies and/or additional sources of CO_2. In particular, jurisdictions with high concentrations of neighbouring ammonia and methanol plants are advantaged.

3.3. Regulatory and Political support

Favourable policy and regulations are key requirements for any CCS project - projects will not develop without regulatory and financial support.

Policy and regulatory support from governments is a prerequisite for CCS to be applied to either power generation or industrial plant, to enable them to compete in their respective markets. This is particularly the case where no EOR is available for CO_2 utilisation - absent EOR Revenues from successful EOR operations, support from government is very likely required.

Power generation and industrial processes fitted with CCS are more expensive than traditional fossil-fuel based technologies, although enhanced oil recovery can offset some of these costs. The capital and operating costs for power stations and industrial plant fitted with CCS are higher than for conventional plant. They require additional equipment, processing and energy for capture, transport and storage of CO_2. The costs of CO_2 handling are also incremental to a conventional plant.

The following policy characteristics make a country more attractive for CCS opportunities:

- Existing (or planned) low carbon power funding/support (e.g. feed in tariffs).
- National or International funding availability for new clean energy projects
- Future Emissions Trading/Emissions Reduction plans.
- The Kyoto Protocol Clean Development Mechanism (CDM) validity.
- Stable macro political and regulatory environment.

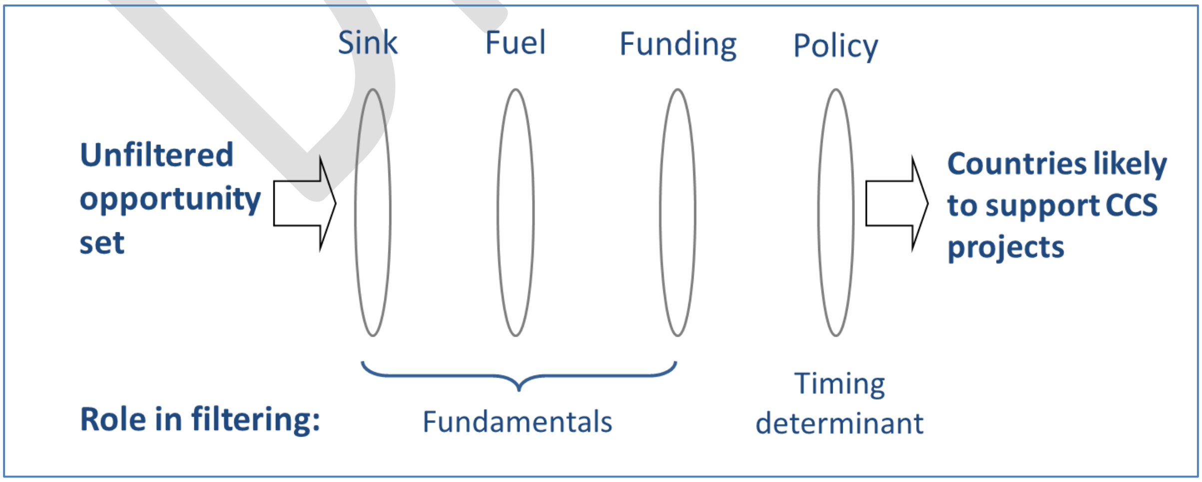
3.4. Fossil Fuel Feedstock

Access to an advantaged feedstock also helps project economics. Access to a local fuel source that enables cost-effective manufacture of products and/or generation of power provides an important source of value creation for a CCS project.

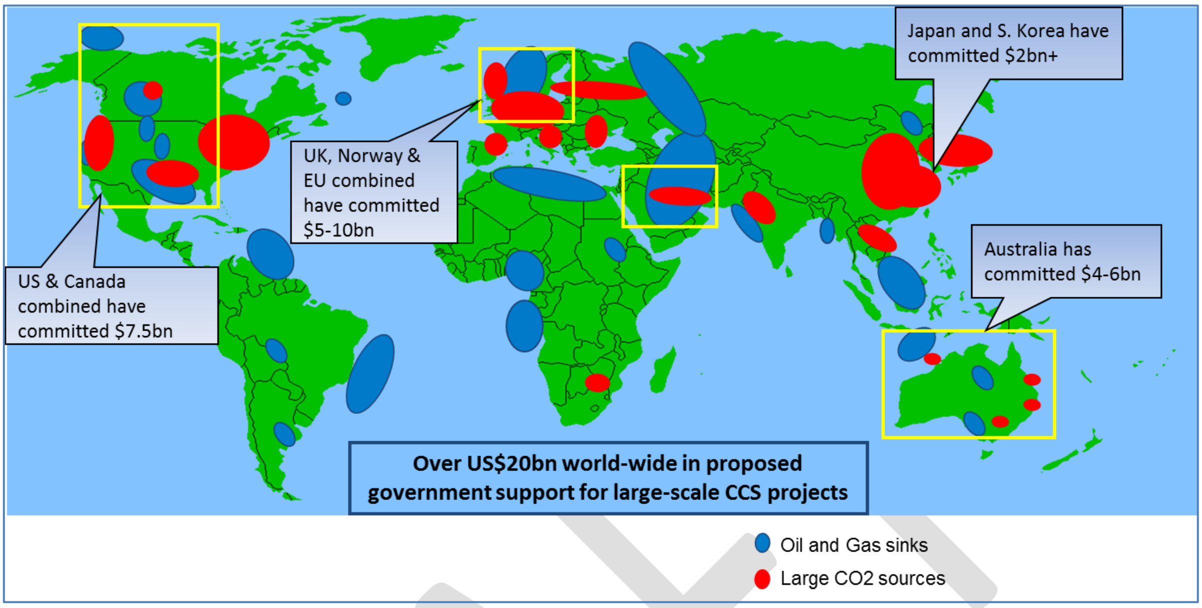
The vast supply and relatively high carbon content of natural gas makes its continued use difficult in a carbon constrained world. However CCS provides an opportunity to enable cleaner hydrocarbon developments.

3.5. Which geographies support CCS project fundamentals?

In summary, the key criteria for CCS project success can be illustrated as follows:



Combining these criteria then yields the following geographies as "hot-spots" for CCS deployment over the next 10-20 years:



4. CO2 Point Sources

In Trinidad and Tobago carbon dioxide (CO2) is produced mainly from the industrial sector as a result of natural gas combustion and petrochemical manufacture (see Figure 2.1).

Since 1958, natural gas has been used as a raw material for the production of ammonia by WR Grace at Federation Chemicals Limited at Savonetta. The use of natural gas in these initial applications was the forerunner to the much more significant intervention of the conceptualisation and development of the Point Lisas Industrial Estate on the Western Coast of Trinidad island.

The Point Lisas Industrial Estate was born out of the desire of the South Chamber of Commerce to develop port facilities in the southern portion of Trinidad and, to use associated and non-associated natural gas to fuel heavy industries. Led, in large measure, by a policy of direct investment and participation by the State, the estate became the site for the construction and operation of several large scale facilities including ammonia, urea, methanol and steel manufacture. During this period of development, Trinidad was again the arena for the implementation of new technology and innovation, this time in respect of natural gas conversion along with the introduction of new concepts in reformer design and improvements in ammonia and methanol plant conversion and energy efficiencies.

The nation's downstream gas market is now a diverse mix of export opportunities for gas-based petrochemicals, metals and LNG. Natural gas is transported at a rate of 68 million m^3 (2.4 billion cubic feet) per day by pipeline from gas fields off the north and east coasts mainly to the Point Lisas Industrial Estate for feedstock in downstream industries, such as ammonia and methanol production and fuel for power generation, and to Point Fortin for LNG production. This approach to natural gas development has been recognized internationally as a unique model of development called the "Trinidad Model". Several countries such as Ghana, Tanzania and Mozambique, with recently discovered significant quantities of hydrocarbon resources, have turned to Trinidad and Tobago for support and advice on the formulation of plans and the establishment of a policy framework for future development based on this "Trinidad Model".

One of the downsides of the nation's aggressive natural gas development however is the consequently high level of emissions of CO2 on a per capita basis. In 2007, Trinidad and Tobago, with a population of approximately 1.3 million, was ranked 6th in the world in carbon emissions per capita producing on average 27 metric tonnes per person (The World Bank). The majority of CO2 emissions come from industrial plants, whose production is almost exclusively for export, with overall country emissions accounting for less than 1% of worldwide emissions.

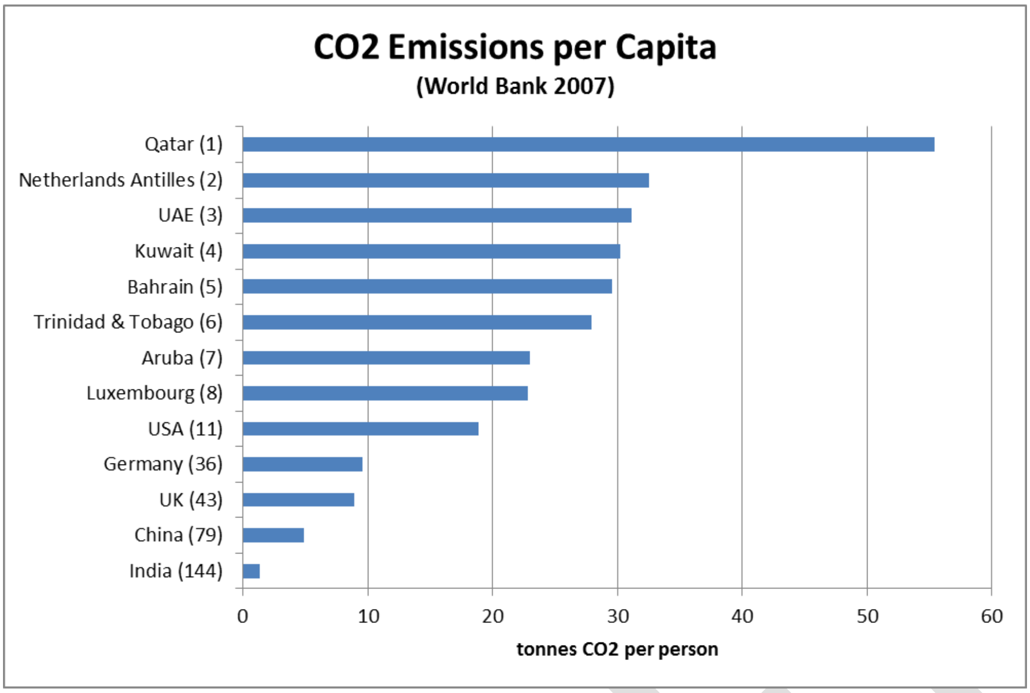


Figure 4: CO_2 emissions per capita

Trinidad has a large petrochemical industry with nine ammonia complexes, six methanol units, a urea plant, and an iron and steel production plant.

4.1. Ammonia Plant

Owner	Plant	Start-up year	Capacity NH3 (tonnes per annum)
PCS Nitrogen Trinidad	PCS Nitrogen I	1981	445,000
	PCS Nitrogen II	1981	495,000
	PCS Nitrogen III	1996	250,000
	PCS Nitrogen IV	1998	610,000
Yara Trinidad Ltd	Yara Trinidad Ltd	1959	285,000
	Trinidad Nitrogen Co Ltd I	1977	500,000
	Trinidad Nitrogen Co Ltd II	1988	495,000
Koch Fertilizer Affiliates	Caribbean Nitrogen Co	2002	660,000
	Nitrogen 2000 Unlimited	2004	660,000
	Point Lisas Nitrogen Ltd	1998	610,000

Figure 4.1: Summary of existing ammonia plant

4.1.1. PCS Trinidad

A subsidiary of Potash Corp, is strategically located to serve the US Gulf Coast, the Caribbean and Latin American markets. It is one of the world's largest nitrogen complexes, with four ammonia plants and one urea plant on 165 acres of Trinidad's sheltered west coast. It benefits from the country's plentiful and favourably-priced natural gas.

Production: Annual capacity – 2.19 million tonnes ammonia from four plants, 0.71 million tonnes urea solids from one plant.

Products: Anhydrous Ammonia and Granular Urea

Uses: Solid and liquid fertilizers are used in agriculture and, to a lesser extent, to manufacture downstream industrial products.

4.1.2. Yara Trinidad Limited

Yara has a large production site in Trinidad and Tobago and ranks as one of the country's top exporters. Nearly all the production from Yara's production plants in Trinidad and Tobago is exported. Yara Trinidad Ltd currently manages and operates a three-plant ammonia production facility located at Savonetta in central Trinidad.

The strong and successful joint venture ownership of the Trinidad Nitrogen Co Limited (Tringen) is being maintained by Yara International ASA, which owns 100% of the Yara Plant and 49% of the Tringen I and II Plants through the share structure of Tringen. Nearly all of the sites annual production of 1.3 million metric tons (99%) is exported.

Production volumes

Ammonia: 800,000 tons per annum

4.1.3. Koch Fertiliser Affiliates

Point Lisas Nitrogen Limited – Affiliates of Koch Fertilizer own 50% of PLN, which owns an ammonia plant in the country, along with the rights to market 50% of PLN's ammonia production.

Caribbean Nitrogen Company Limited – Affiliates of Koch Nitrogen own a minority equity interest in CNC and has the rights to market 100% of CNC's ammonia production.

Nitrogen (2000) Unlimited – Affiliates of Koch Nitrogen own a minority equity interest in N2000, which owns an ammonia plant in the country, along with the rights to market 100% of N2000's production.

4.2. Methanol Plant

Owner	Plant	Start-up year	Capacity Methanol (tonnes per annum)
Methanol Holdings Trinidad Ltd	Trinidad and Tobago Methanol Company (TTMC) I	1984	460,000
	Trinidad and Tobago Methanol Company (TTMC) II	1996	550,000
	Caribbean Methanol Company Limited (CMC)	1998	550,000
	Methanol IV Company Limited	1993	550,000
	Methanol 5000	2005	1,890,000
Methanex	Titan Methanol	1999	860,000
	Atlas Methanol	2004	1,890,000

Figure 4.2: Summary of existing methanol plant

4.2.1. Methanol Holdings (Trinidad) Limited (MHTL)

Methanol Holdings (Trinidad) Limited (MHTL) is one of the largest methanol producers in the world with a total capacity of over 4 million metric tonnes annually from its five (5) methanol plants located at the Point Lisas Industrial Estate. The company is the largest supplier of methanol to North America and is also a significant supplier to the European market.

Methanol Holdings (Trinidad) Limited (MHTL), incorporated in 1999, is the amalgamated entity of its former subsidiary companies, Trinidad and Tobago Methanol Company (TTMC), Caribbean Methanol Company Limited (CMC) and Methanol IV Company Limited (MIV). In 2003, following a group restructuring, MHTL became the parent company of the operating methanol companies, which was continued in 2004 by way of a group amalgamation and dissolution of the subsidiaries. By virtue of this reorganization and amalgamation, MHTL has acquired over 25 years' experience in the methanol business.

The company is headquartered in the Point Lisas Industrial Estate in Trinidad, at the site of its methanol complex. The company's most recent plant, the M5000 plant, is rated as the largest methanol plant in the world with a designed capacity of 5,400 metric tonnes per day.

The company's management and operations are entirely managed and operated by nationals of Trinidad and Tobago. Its marketing and shipping operations are housed at its corporate office in Point Lisas. The operations of MHTL's methanol plants have been outsourced to Industrial Plant Services Limited (IPSL) a local plant operation and Management Company. This company will also operate and manage MHTL's new AUM Complex.

MHTL has successfully diversified its business operations with the construction of its first downstream Ammonia-Urea Ammonium Nitrate-Melamine (AUM1) Complex which commenced commercial operations in 2010 with product sales to both North America and Europe.

4.2.2. Methanex in Trinidad and Tobago

Methanex's operation in Trinidad and Tobago represents 2.7 million tonnes of methanol per year, making this an important production centre in the organization's network. Methanex Trinidad Limited has been managing and operating the 2-plant facility situated on the Point Lisas Industrial Estate since May 2006. 100% of its methanol production is exported, contributing to Trinidad and Tobago's position as the world's leading exporter of methanol.

The Methanex-owned Titan Plant has an annual production capacity of 900,000 tonnes. Commercial production began in June 2000.

The Atlas Plant is a joint venture between Methanex Corporation (63.1%) and BP Trinidad and Tobago LLC (36.9%). Commercial production began in July 2004. The Atlas facility features one of the largest single train methanol plants in the world, with an annual production capacity of 1.8 million tonnes per year.

4.3. Power Generation

Energy security in Trinidad and Tobago is currently not a significant concern as oil and gas is abundant and electricity prices are the lowest in the Caribbean. There are currently three power companies operating in Trinidad and Tobago:

- Trinidad and Tobago Electricity Commission (T&TEC),
- Trinity Power and
- PowerGen.

There is a fourth power utility company in the country, the Trinidad Generation Unlimited, with a Power Purchase Agreement between it and T&TEC which sets out the terms and conditions of its supply obligations.

Owner	Plant	Start-up Year	Capacity MW
Amoco Trinidad Power Resources Corporation, MaruEnergy Trinidad LLC and T&TEC	Powergen Port of Spain Powergen Point Lisas Powergen Penal	1965-1984 1976-2007 1976-1985	304 852 236
US consortium	Trinity Power Point Lisa	1999	225
Trinidad Generation Unlimited (TGU) subsidiary of AES Global	Union Estate Power Station	2011-2012	720

Figure 4.3: Summary of Power generation plant

4.3.1. Trinidad and Tobago Electricity Commission (T&TEC)

Ownership: Goverment of Trinidad and Tobago (GOTT) - 100%

The Trinidad and Tobago Electricity Commission (T&TEC) came into being by virtue of the Trinidad and Tobago Electricity Commission Ordinance No. 42 of 1945. It was formed to generate electricity and to distribute it outside the city of Port of Spain and the town of San Fernando. T&TEC was responsible for the generation, transmission and distribution of electricity throughout Trinidad and Tobago.

The Point Lisas Power Station was formally opened in 1977, to maintain supply to the emerging industries at the Point Lisas Industrial Estate.

Over the years T&TEC has moved from an integrated power company (power generation, transmission and distribution) to an organisation where focus is on design, construction operation and maintenance of the country's electrical transmission and distribution network, with generation being done by Independent Power Producers (IPPs) - Powergen and Trinity Power.

4.3.2. Cove Power Station, Cove Eco-Industrial and Business Park at Lowlands, Tobago

Ownership: T&TEC

Capacity: This power station will be able to produce 64 megawatts (MW) and can operate on natural gas, with diesel as a back-up. Prior to the addition of this new facility, the electrical power needs of Tobago were met by the T&TEC Scarborough Power Station (with a generating capacity of 21 MW, although uses only diesel fuel).

Start of commercial operations: The plant was commissioned in October 2009.

The new power station will reduce present transmission losses and reduce dependence on diesel fuel when it begins to operate on natural gas. The new station will receive the natural gas for its operations from the east coast of Trinidad, in a phased development.

Neither of the power plant located on the island of Tobago have been considered for this study of CCS deployment at this stage.

4.3.3. Independent Power Producers

Power Generation Company of Trinidad and Tobago (POWERGEN)

The Power Generation Company of Trinidad and Tobago was established in December 1994 and is a joint venture company created out of the partial divestment of T&TEC. Powergen was formed to purchase the generation assets of T&TEC. Majority shareholding in Powergen has however been retained by T&TEC.

Ownership: Amoco Trinidad Power Resources Corporation, MaruEnergy Trinidad LLC and T&TEC

Capacity: 1,344 Megawatts (MW)

Powergen operates three major power generation plants at Point Lisas, Port of Spain and Penal. The largest plant is located at Point Lisas.

Trinity Power Ltd, Point Lisas

Ownership: Trinity Power Limited is owned by a US consortium, with the controlling interest being an independent power and infrastructure company with expertise in the development, acquisition and long-term operation of power generation plants.

Capacity: 225MW

Start of commercial operations: September 1999.

Union Estate Power Station

Ownership: Trinidad Generation Unlimited (TGU), a locally registered subsidiary of AES Global Inc.

Capacity: 720MW combined cycle power generation (Union Industrial Estate in La Brea).

The Union Estate Power Station (UEPS) will generate electricity to supply 240 MW to the Alutrint Aluminium Complex (AAC) through two dedicated transmission lines and a sub-station to be owned and operated by T&TEC, with the extra 480MW going into the national grid.

5. CO2 Capture Opportunities

Three main sources of CO2 emissions from Trinidad and Tobago have been identified:

1. **CO2 emissions from Ammonia manufacture:** For the ammonia industry there are two sources of CO2 emissions generated. The first source (an external source) is derived from natural gas combustion which provides the heat necessary to drive the steam methane reformer (SMR). The second source (an internal source) of CO2 is generated from within the Ammonia production process following the carbon monoxide conversion step which generates additional H2 and CO2. The CO2 is then removed prior to the methanation and Ammonia synthesis steps as CO2 is considered a "poison" to the methanation and ammonia manufacturing processes.
2. **CO2 emissions from Methanol manufacture:** The source of CO2 from the Methanol industry is derived as discussed previously for the "syn-gas" production from natural gas combustion which provides the heat necessary to drive the steam methane reformer (SMR) process to synthesize "Syn-gas" which is subsequently used in the production of Methanol.
3. **CO2 emissions from power generation:** For the power generation industry, the source of CO2 is derived predominantly from the combustion of natural gas in a portfolio of open cycle gas turbines (OCGTs) and combined cycle gas turbines (CCGTs).

Using both public domain and in-house simulation modelling CCS TLM have calculated CO2 emissions for each of the above (large) point sources: ammonia, methanol and power generation.

5.1. Ammonia Production

For the simulation model the end product, ammonia, is basically produced from water, air, and energy. The energy source in the simulations is natural gas which not only provides the thermal energy but also provides the hydrogen feedstock. Steam reforming of Natural Gas is the most efficient route, with a large percentage of world ammonia production being based on natural gas steam reforming (Steam Methane Reforming (SMR)). As discussed above, in the production of Ammonia there are two sources of CO2 emissions available for capture. The first source is from the generation of heat via the combustion of natural gas in the reformer furnace which is termed the "external" CO2 emission source[11]. The second source of

[11] CO2 from the combustion of natural gas to generate heat in the ammonia production process is referred to as "external" CO2 emissions

CO_2 emissions is from the removal of CO_2 from the syngas as this is internal to the process it is termed "internal"[12] CO_2 emission source.

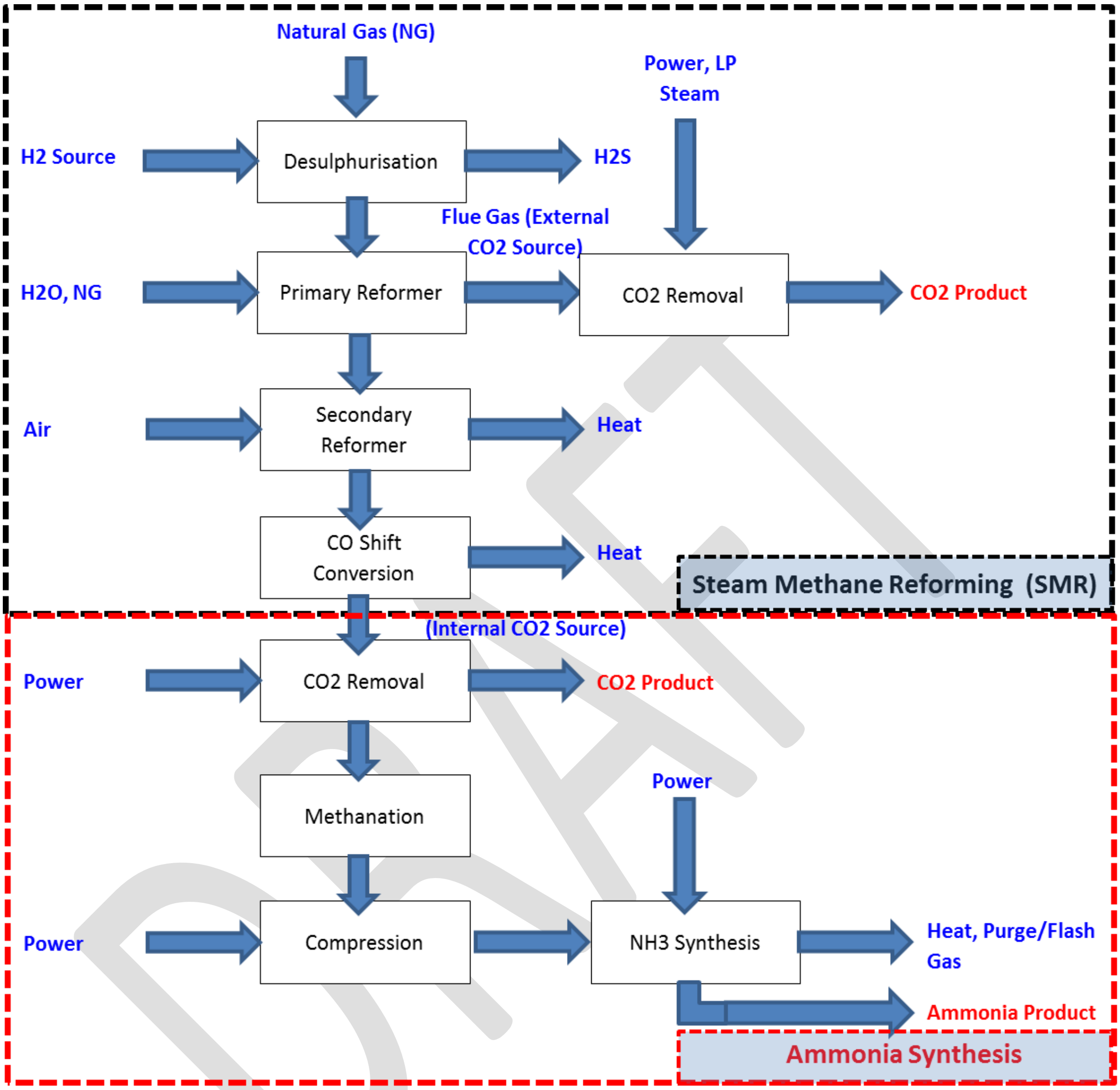


Figure 5.1.1: Block diagram of the Steam Methane Reforming process plus Ammonia Production.

5.1.1. Description of SMR/Ammonia Manufacture

The simulation of manufacturing ammonia (NH_3) based on steam reforming of the natural gas feedstock is briefly described as follows:

[12] CO_2 sourced from its removal from the syngas feedstock is referred to as "internal" CO_2 emissions

5.1.1.1. Natural Gas Desulphurisation

Natural gas feed stock is delivered as dry gas containing sulphur. This sulphur requires removal as it is a poison for the reformer catalyst in the downstream processes. In the simulation it is assumed the desulphurisation unit removes all the sulphur by reacting it with hydrogen to form H_2S. No further treatment of H_2S has been simulated in the current model.

5.1.1.2. Reforming Unit

The steam methane reforming reaction is basically: $H_2O + CH_4 \rightarrow CO + 3H_2$. This is a highly endothermic reaction which is supported by heat from the reformer furnace. The reformer unit is simulated as two sections:

1. Primary Reforming

Steam is mixed with natural gas, then heated and passed over a catalyst to form hydrogen, carbon monoxide and carbon dioxide. The catalyst promotes a reforming reaction through which the natural gas is converted into these components.

2. Secondary Reforming

Preheated hot air is added to the secondary reformer in the necessary proportion to create a ratio of three parts hydrogen to one part nitrogen. The oxygen that is present in the air reacts with un-reacted methane to form carbon dioxide and water. In addition to this the reactions that occur in the primary reforming step continue in the secondary reformer.

5.1.1.3. Carbon Monoxide Shift Conversion

Carbon monoxide formed in the primary and secondary reforming steps is further reacted with steam to produce hydrogen and carbon dioxide in two catalytic stages, the first at high temperature shift and the second at low temperature shift.

5.1.1.4. Internal Carbon Dioxide Removal

Carbon dioxide can be removed internally from the synthesis gas stream by a variety of absorption processes such as monoethanolamine (MDEA) or Benfield process (a potassium carbonate solution). The CO_2 is then stripped from the absorbing solution to form a high purity stream of CO2 which has a variety of end uses (in the current work it will be used for CCS project developments). The stripped MDEA/Benfield solution is then recycled back to the absorber and the cycle repeats.

5.1.1.5. Methanation Unit

The gas stream now consists primarily of hydrogen and nitrogen, plus small quantities of carbon oxides not removed in the preceding steps. Since carbon oxides would poison the ammonia synthesis catalyst, it is necessary to adjust the concentration to lower than 10 ppm. This is achieved by reacting over a nickel catalyst the carbon oxides to methane.

5.1.1.6. Compression/Ammonia Synthesis

The synthesis gas contains an approximate 3:1 mole ratio of hydrogen to nitrogen. This gas is pressurized by a centrifugal compressor to approximately 290 bar. The compressed gas enters the synthesis reactor where the ammonia synthesis reaction occurs. The gas leaving the synthesis reactor contains approximately 23 mole percent of ammonia which is condensed to liquid ammonia in a refrigeration step unreacted gases are recycled to the synthesis reactor.

5.1.1.7. External Carbon Dioxide Removal

The Carbon dioxide contained in the flue gases exiting the reformer furnace ("external CO2"[12]) are removed in the current simulation model via a Monoethanolamine (MEA) solution operating at atmospheric pressure. The CO2 contained in the rich MEA solution is then stripped to form a high purity stream of CO2. The stripped lean MEA solution is then recycled back to the absorber and the cycle repeats. This External MEA CO2 removal process is described in further detail below.

5.1.2. Monoethanolamine (MEA) based CO2 capture

The reactive absorption of CO2-MEA-H2O system has been modelled using an equilibrium based simulation approach. Here the vapour-liquid mass transfer is modelled creating a section of packing where it is assumed that the vapour and liquid phases are perfectly mixed and in thermal equilibrium. This means that the streams leaving any particular tray or packing section are in equilibrium with each other. In actual operations packing and trays are rarely, if ever, operated at equilibrium. Based on this approach a minimum number of theoretical separation stages are obtained to achieve a given separation. The usual approach to deal with departures from equilibrium is to use the concept of efficiency. In the current simulations Murphree efficiency is used to describe the departure from equilibrium. The Murphree efficiency for stage number "n" is defined by equation 1 below:

$$E_M = \frac{y - y_{n-1}}{y^* - y_{n-1}} \text{ .... Equation 1}$$

Where y is the mole fraction of CO2 in the gas leaving the stage in question, Yn-1 is the mole fraction of CO2 leaving the stage below, and y* is the mole fraction of CO2 in equilibrium with the liquid leaving the stage. This combined with the theoretical number of stages determines the actual number of stages required for a given separation.

In the current series of work the CO2 contained in the flue gases exiting either the reformer furnace of the SMR or from the exhaust gases of the gas turbines are captured and separated via a monoethanolamine (MEA) absorption process. The main impurities such as sulphur dioxide and oxides of nitrogen are initially removed in the direct contact cooler (DCC) section (See Figure 5.1.2). The CO2 is then separated from other non-condensable gases (nitrogen, oxygen and argon) and from any moisture, prior to being transported via pipeline to a given storage site.

The MEA CO2 capture and compression process is designed to capture and to recover 90+% of the total carbon dioxide contained in the flue gas (in the current simulations a figure of 94% capture has been used). In the current simulation modelling, the process has been broken down into three main sections:

5.1.2.1. Flue gas scrubbing section:

The Direct Contact Cooler (DCC) consists of two packed sections, which for efficient simulation modelling, are represented by two separate equilibrium Radfrac blocks. The Radfrac block is capable of simulating: absorption, stripping, extractive distillation, azeotropic distillation, and ordinary distillation. It can also handle any number of feeds and side product streams. For these reason the Radfrac block has been employed in the current simulations.

5.1.2.2. CO2 recovery and purification section:

The flue gas stream exiting the DCC has a small positive pressure that is not high enough to pass through the absorber column hence, compression of the flue gas is required. The flue gas pressure is boosted to approximately 1.04 bar so that it will pass through the system. The blower is modelled using the isentropic efficiency method with isentropic and mechanical efficiencies of 0.85 and 0.95 respectively. This flue gas stream then enters the CO2 absorber. The flue gas enters the bottom of the Absorber and flows upward through the packed column where it reacts with a lean MEA solvent solution. Approximately 94% of the carbon dioxide contained in the flue gas is recovered. The CO2-rich MEA solvent leaves the bottom of the Absorber and is counter heated in the Lean/Rich solvent cross heat exchanger (LRHEX) against the hot lean MEA solution exiting the bottom of the stripper column. The stripper reboiler is modelled using a kettle type reboiler located in the sump of the stripper column. The condenser is modelled separately outside of the stripper column and consists of a cooler with an equilibrium flash drum. The resulting vapour from the top of the Stripper contains CO2 saturated with water. The vapour is cooled and the CO2 and condensed water are separated. The condensate is returned to the Stripper as reflux while the CO2 rich vapour is sent to the CO2 Product Compressor train.

5.1.2.3. CO2 product compression section:

For this section, an electrolyte-based physical property model as used in the previous sections is not justified as there is no need to simulate ions in the compression train. Rather, the base physical property model selected was the Peng-Robinson equation of state. This property method is recommended for gas-processing applications. The CO2 product is compressed and dried in an eight stage integrally geared centrifugal compressor and leaves the compression train at 129 bar and 60^{o}C (i.e. in dense phase).

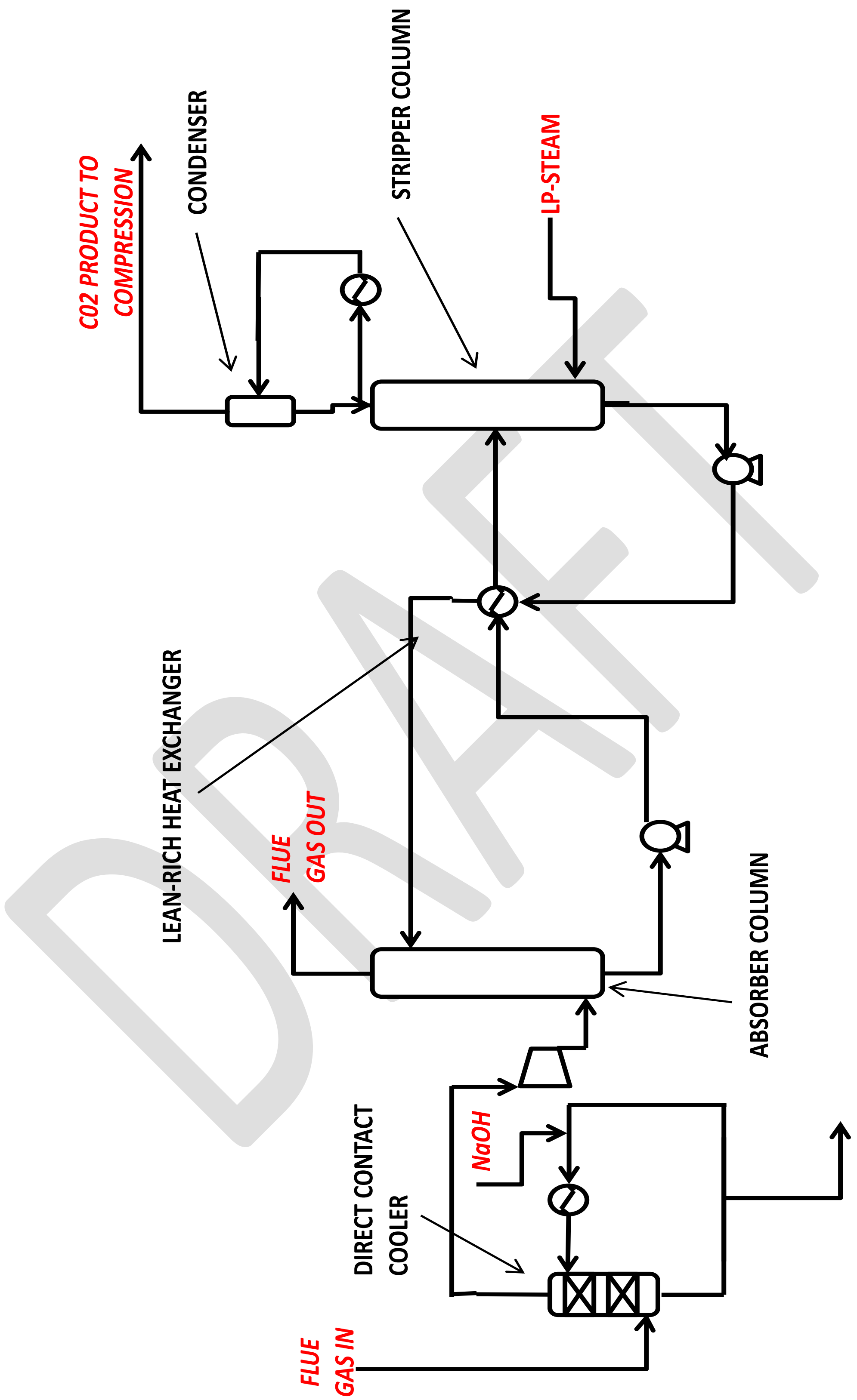


Figure 5.1.2: Process Flow Diagram of MEA CO2 Capture Plant

5.2. Methanol Production

Methanol is commonly produced by steam reforming natural gas to produce a synthesis gas that is further converted to methanol. Other option are available for syngas production such as auto thermal reforming (ATR) or hybrid SMR with ATR. Unlike ammonia production, it has been assumed that in the production of methanol there is only one CO2 emissions source available for capture which is from the generation of heat via the combustion of natural gas in the reformer furnace (i.e. the "external" source of CO2 in ammonia).

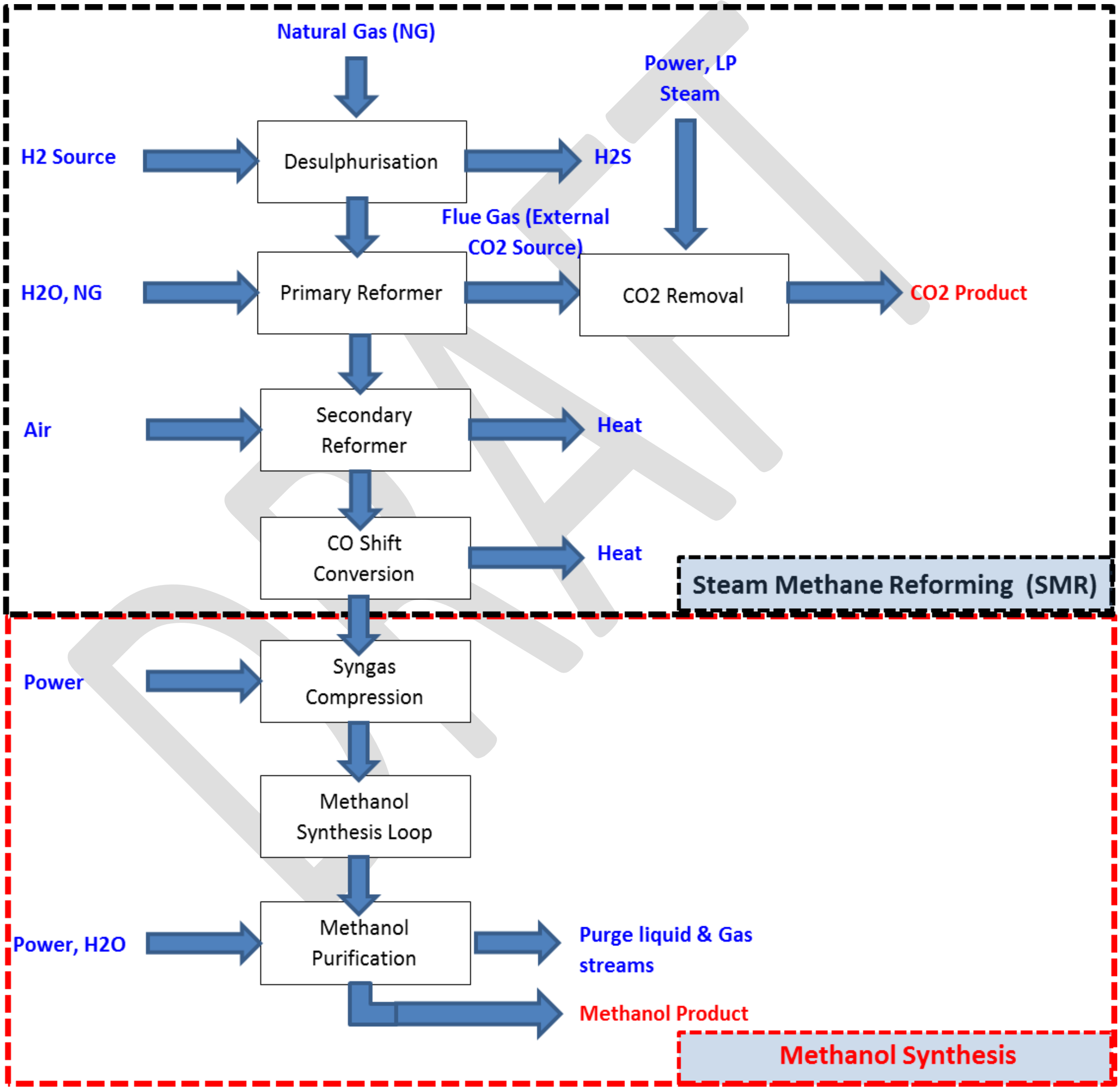


Figure 5.2: Block diagram of the Steam Methane Reforming process Plus Methanol Production.

5.2.1. Description of SMR/Methanol Model

In the current methanol production simulation the process consists of three main steps as listed below:

5.2.1.1. Synthesis gas production (via Steam Methane Reforming)

A detailed description of the steam methane reforming process can be found in section 5.1.1.2

5.2.1.2. Methanol synthesis

The syngas exiting the SMR process is further compressed in the syngas compressor to approximately 80 bar. Following this the synthesis gas enters the methanol synthesis loop which basically consists of a methanol synthesis reactor, a series of heat exchangers (including a main cross heat exchanger), two knock out vessels (flash vessels) and a recycle gas compressor. The 80 bar Syngas stream is mixed with a recycled synthesis reactor gas stream and enters the synthesis reactor. The syngas reacts to produce crude methanol, a series of two flash vessels are used to separate the uncondensed gases which are recycled back to the synthesis reactor. The impure methanol stream is then passed onto the purification stage.

5.2.1.3. Methanol purification

The crude methanol product from the methanol synthesis reactor is concentrated and purified in a two-step distillation train. The first tower, commonly called the topping column, removes light ends. The second tower, the refining column, removes intermediate components and water. Both of these columns are modelled using the equilibrium approach.

5.3. Calculation of CO2 Emissions from point sources

5.3.1. CO2 Emissions from Methanol and Ammonia Industry

The developed simulation model of the Methanol production via SMR syngas production is used as the basis for calculating the CO2 emissions for the methanol industry. For each methanol production site the production of methanol in tonnes per day is either scaled up or down to match the methanol output for a given site. From this model the necessary natural gas required for the SMR reformer furnace is obtained and thus the quantity of CO2 emitted from each point source is obtained. For the Ammonia industry a similar approach is used, the only difference is as discussed previously there are two CO2 emission sources ("internal" and "external" sources).

5.3.2. CO2 emissions – Methanol Industry

The heart of the Methanol industry in Trinidad and Tobago is located in Point Lisas industrial estate. Point Lisas, which contains both the port and industrial estate, is located in the Gulf of Paria halfway down the west coast of Trinidad, approximately 32 km south of Port of Spain, in position 10°24.2'N, 61°29.6'W. The largest Methanol producer in Trinidad and Tobago, Methanol holdings Trinidad Ltd (MHTL), who operates five production facilities, is located in the north of Point Lisas while Methanex which operates two production facilities is located in the south of Point Lisas The point source CO2 emissions from each production facility can be seen in Table 5.3.1 and their locations are illustrated in Figure 5.3.3. The potential for total captured CO2 from the methanol industry (at a 94% capture rate) in Trinidad and Tobago is approximately 2 million tonnes per annum.

				Simulation Results	
Owner	**Plant**	**Start-up Year**	**Capacity tpa Methanol**	**Captured CO2 emissions (External) kg/s**	**Total Captured CO2 emissions tpa**
Methanol Holdings Trinidad Ltd	**Trinidad and Tobago Methanol Company (TTMC) I**	1984	**460,000**	**3.686**	116,256
	Trinidad and Tobago Methanol Company (TTMC) II	1996	**550,000**	**5.205**	164,142
	Caribbean Methanol Company Limited (CMC)	1998	**550,000**	**5.205**	164,142
	Methanol IV Company Limited	1993	**550,000**	**5.205**	164,142
	Methanol 5000	2005	**1,890,000**	**17.924**	565,253
Methanex	**Titan Methanol**	1999	**860,000**	**8.145**	256,855
	Atlas Methanol	2004	**1,890,000**	**17.924**	565,253

Table 5.3.1: Point source CO2 emissions from Methanol industry, Trinidad and Tobago
(Note: Emissions values shown equate to a 94% CO2 capture rate)

5.3.3. CO2 emissions – Ammonia Industry

Like the methanol industry the Ammonia industry is also located in Point Lisas industrial estate and is operated by three key players: PCS Nitrogen Trinidad, Yara Trinidad and Koch Fertilizer Affiliates who in total operate 10 ammonia production plants (see section 4.3).

The point source CO2 emissions from each Ammonia production facility can be seen in Table 5.3.2 and their locations and relative CO2 volumes are illustrated in Figure 5.3.3. The potential for total captured CO2 from the Ammonia industry based on both the external and internal CO2 emissions sources totals 9 million tonnes per annum while the sum of external CO2 emissions alone provides 2 million tonnes per annum.

				Simulation Results		
Owner	**Plant**	**Start-up year**	**Capacity tpa NH3**	**Captured CO2 emissions (External) kg/s**	**CO2 emissions (Internal) kg/s**	**Total Captured CO2 emissions tonnes pa**
PCS Nitrogen Trinidad	**PCS Nitrogen I**	1981	**445,000**	**6.529**	19.076	807,483
	PCS Nitrogen II	1981	**495,000**	**7.266**	21.220	898,336
	PCS Nitrogen III	1996	**250,000**	**3.664**	10.717	453,505
	PCS Nitrogen IV	1998	**610,000**	**8.956**	26.149	1,107,059
Yara Trinidad Ltd	**Yara Trinidad Ltd**	1959	**285,000**	**4.179**	12.215	517,002
	Trinidad Nitrogen Co Ltd I	1977	**500,000**	**7.266**	21.220	898,336
	Trinidad Nitrogen Co Ltd II	1988	**495,000**	**7.266**	21.220	898,336
Koch Fertilizer Affiliates	**Caribbean Nitrogen Co**	2002	**660,000**	**9.692**	28.293	1,197,905
	Nitrogen 2000 Unlimited	2004	**660,000**	**9.692**	28.293	1,197,905
	Point Lisas Nitrogen Ltd	1998	**610,000**	**8.956**	26.149	1,107,059
						Total: 9,082,927

Table 5.3.2: Point source CO2 emissions from Ammonia industry, Trinidad and Tobago
(Note: External emissions values shown equate to a 94% CO2 capture rate)

Figure 5.3.3. Industrial CO2 Emission sources, Point Lisas (Trinidad and Tobago) ***) (Note: Bubble size indicates comparative volume of CO2 emission)***

5.3.4. CO2 Emissions - Power generation

The procedure used here to calculate the CO2 emissions is to firstly determine the annual power output of each site and to determine the type of power generation equipment used (e.g. open cycle gas turbine, combined cycle gas turbine). From this in house data and openly available literature[13,14,15] carbon intensity data has been used to obtain CO2 emission from each site. For the majority of the power generation fleet in Trinidad and Tobago the fuel used is natural gas with the exception of Tobago where diesel is used for power generation, (hence Tobago in the current work has been omitted) this coupled with the varying ages of the power generation fleet (commissioned dates range from 1976 to 2011) result in difficulty in applying a single carbon intensity figure to each site. For this reason due to the difficulty in calculating actual CO2 emissions from each power generation site a minimum and maximum range of CO2 emissions from each point source has been determined based on open literature and/or in-house carbon intensity data.

Power Generation Type:	Carbon Intensity, kg CO2/MWh	
	Minimum	Maximum
Open Cycle Gas Turbine (OCGT)	480	575
Combined Cycle Gas Turbine (CCGT)	340	400

Table 5.3.4: Carbon Intensity, kg CO2/MWh

The above carbon intensities are dependent on the age of the power generation fleet and generally the newer the Gas Turbine technology the lower the emissions.

The majority of the power generation fleet in Trinidad is located along the west coast. The Point Lisas industrial complex is served by two power generation facilities; Powergen Point Lisas (PGPL) and Trinity Power Point Lisas (TPPL). A new build facility which came on stream in 2011 is the Union Estate Power Station (UEPS) located in La Brea. And finally Powergen Penal (PGP) which is located more inland, located to the west of Penal Village. Although the Port of Spain is home to Powergen's Port of Spain Power station, in the current study this has been excluded as a candidate site for capturing CO2 for two main reasons: firstly Powergen Port of Spain consist of very old technology commissioned back in 1965 and the most recent addition

[13] http://www.iea-etsap.org/web/E-TechDS/PDF/E02-gas_fired_power-GS-AD-gct.pdf
[14] http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/1b2.pdf
[15] http://www.gasturbine.org/images/thegasturbinesolution.pdf

being in 1974[16] due to the age of the power station it would be infeasible to retrofit CCS to this site. Secondly, unlike other point sources which are located within Industrial Parks, the facility is located in a predominantly residential area with limited space for the construction of a capture facility. Further details on each site can be found in Section 4.3.

The point source CO2 emissions from each power generation facility can be seen in Table 5.3.5 and location with comparative CO2 volume emissions depicted in given in Figure 2.3.6. The potential for total captured CO2 from the Power Generation industry based in Trinidad equates to approximately 7.5 million tonnes per annum and 9 million tonnes per annum respectively for minimum and maximum emission cases.

Owner	Plant	Start-up Year	Capacity MW	Simulation Results: Captured CO2 emissions (kg/s)		Simulation Results: Total Captured CO2 emissions Mtpa	
				MIN	MAX	MIN	MAX
Amoco Trinidad Power Resources Corporation, MaruEnergy Trinidad LLC and T&TEC	Powergen Point Lisas	1976-2007	852	107.3	128.0	3.38	4.04
	Powergen Penal	1976-1985	236	22.4	26.5	0.71	0.84
US consortium	Trinity Power Point Lisa	1999	225	28.2	33.8	0.89	1.07
Trinidad Generation Unlimited (TGU), subsidiary of AES Global Inc.	Union Estate Power Station	2011-2012	720	64.0	75.3	2.02	2.37

Table 5.3.5: Point source CO2 emissions from Power Generation, Trinidad and Tobago
(Note: Emissions values shown equate to a 94% CO2 capture rate)

[16] Powergen Port of Spain consists of: two 50MW Steam turbo generators commissioned in 1965. In 1969 and 1974 two 80MW GE Steam Turbo-Generator units were installed, and then in 1984 two 24MW Rolls Royce Gas Turbine driven Generators were installed. (http://www.powergen.co.tt/Power/HistoryofOurPowerStations/PortofSpain.aspx)

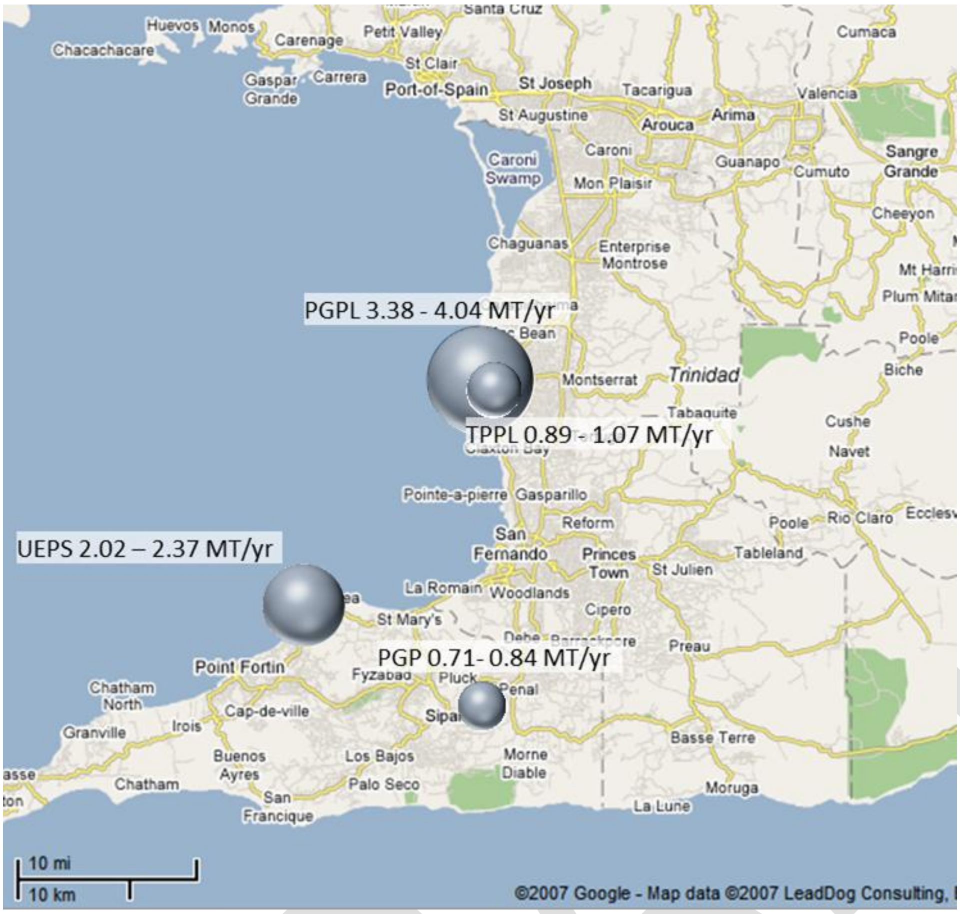


Figure 2.3.6: Power Generation CO2 emission sources, Trinidad
(Note: Bubble size indicates comparative volume of CO2 emission)

6. Hydrocarbon Reservoirs – opportunities for CO2 Storage

6.1. Background

Hydrocarbon deposits are found in the southern half of the island of Trinidad continuing from the Venezuelan Eastern Basin. While heavy oil deposits are found primarily on the south western portion of the island, producing natural gas fields are off the north and east coasts. In 1990, Petrotrin operated several immiscible CO2 floods as moderately successful pilot projects in the Forest Reserve sand found in the onshore Oropouche and Forest Reserve fields. These fields had previously undergone primary, secondary and tertiary production with water and natural gas injection. CO2 injection resulted in incremental recovery of 2 to 8% of the original oil in place. Although preliminary results were encouraging, these projects have been discontinued with no further expansion due to concerns raised over CO2 escape to surface outcrops in populated areas and other operational issues[17].

Although the technologies of CCS are not new to the industry, the integration of these technologies for the sequestration of large volumes of CO2 has not been sufficiently demonstrated internationally. The potential onshore Trinidad sites for CO2 sequestration, heavy oil fields, are scattered throughout the Southern Basin, some in and around populated areas. A comprehensive description and assessment of the geology of the field is therefore crucial to determining the risk of CO2 leakage. However, CO2 injection in heavy oil fields in the Gulf of Paria, off the western shore of Trinidad, can also be considered. The main advantages being that the oil fields are situated away from populated areas and 3D seismic has been acquired over the area to determine the locations of faults and other possible paths for leakage. An offshore pipeline route through the Gulf of Paria from Point Lisas may be developed with pipeline installations piggy-backing on any future pipeline installation activity associated with the upgrade of oil production and collection infrastructure in these areas.

For all potential CCS projects, depleted hydrocarbon reservoirs have a high probability of becoming practical sinks even though integrity risks due to existing wells are real. Hydrocarbon field operators have much of the data required for assessments of CO2 storage potential.

Timing is important in the consideration of hydrocarbon sinks. The window between the time when the reservoir is depleted and when the field is abandoned and dismantled is quite short.

17 Win-Win: Enhanced oil Recovery and Carbon Storage in Trinidad & Tobago. Lorraine Sobers & Selwyn Lashley. 2012

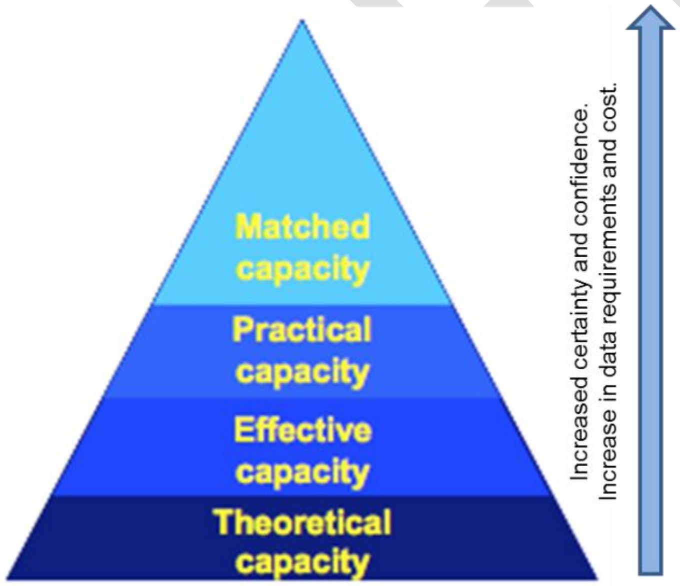
6.2. Methodology & Definitions

Estimates of carbon dioxide (CO_2) geologic storage potential are required to assess the potential contribution of carbon capture and storage (CCS) technologies towards the reduction of CO_2 emissions. Governments and industries worldwide rely on CO_2 storage estimates for broad energy-related government policy and business decisions. Reliable CO_2 storage estimates are necessary to ensure successful deployment of CCS technologies.

It is proposed that two types of CO_2 storage formations be reviewed and targeted for CCS: depleting oil reservoirs and depleted gas reservoirs. Deep saline formations have not been considered for this study.

6.2.1. Classification of CO2 Storage Capacity

An understanding of the classifications of storage capacity is required to interpret numbers published in various assessments and studies.



Source: NOGEPA Phase 1 (after CSLF 2007)

Theoretical capacity is the first estimate of storage volume and is made before detailed geological data is available. It is necessarily very high level and is based on the assumption that a certain fraction of the pore space in a reservoir is available for CO_2. This requires information on the size and thickness of the reservoir and rock porosity. Details of this calculation will be addressed in the following section. The important point to make is that the fraction available for storage generally requires a high level assumption, as the data to make a more specific estimate is not available.

Effective capacity is the estimate of capacity after various geological and engineering limits have been addressed. As sufficient information to construct hydrodynamic models becomes available, pressure profiles across the reservoir for various injection scenarios can be estimated. Reservoir pressure must be kept below:

- Fracture pressure
- Capillary entry pressure of the seal
- Fault reactivation pressure

Practical capacity further refines the capacity estimate by considering economic and legal issues. Injection rate per well can have a significant impact on ultimate capacity so an optimisation of well count and capacity is usually required. Legal considerations, such as the boundaries of the storage lease will also impact ultimate capacity.

For the development of specific commercial-scale geologic storage sites, economic and regulatory constraints must be considered to determine the portion of the CO2 storage resource estimate that is available. Examples[18] of economic considerations to determine CO2 storage capability:

- CO2 injection rate and pressure,
- the number of wells drilled into the formation,
- types of wells (horizontal versus vertical),
- operating expenses,
- management of in situ formation fluids,
- injection site proximity to a CO2 source, and
- Combination with enhanced oil recovery or enhanced gas recovery activities.

Examples of regulatory considerations include:

- protection of potable water;
- well spacing requirements,
- maximum injection rates,
- prescribed completion methods (cased vs. open-hole),
- proximity to existing wells,
- treatment of in situ fluids, and
- Surface usage considerations.

Additional regulatory considerations may exist at national Government level.

Matched capacity is the final classification and determined when the actual source, injection rates and required duration are finalised.

18 http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html

In most studies/assessments, deep saline formation data is limited to a little more than "theoretical" by applying "cut offs". These are high-level assumptions about the minimum size of sink and/or some injectivity parameter. This provides additional justification for not considering deep saline formations for CO2 storage within this report.

The reason that hydrocarbon reservoirs can be classified as something closer to "effective" is that more data is available to refine the calculations.

6.2.2. Oil and Gas Reservoir CO2 Storage Resource Estimates

The calculated estimates for hydrocarbon reservoirs within this report are based on the assumption that produced oil and gas provides volume for subsequent CO2 storage. Typically this is estimated from the Original Oil In Place (OOIP) or Original Gas In Place (OGIP) and an estimate of the ultimate recovery factor.

The general form of the volumetric equation to calculate the CO2 storage resource mass estimate (M_{CO2}) for geologic storage in gas reservoirs is as follows:

$$M_{CO2} = OGIP \times B_g \times \rho_{CO2} \times R_f \times (1\text{-}Fig) \times E$$

Where:

- M_{CO2} Mass of CO2
- OGIP Original Gas In Place (volume at standard temperature and pressure)
- B_g Factor to convert stp volume to reservoir conditions
- ρ_{CO2} Density of CO2 at reservoir conditions (kg/m^3).
- R_f Recovery factor
- Fig Fraction of gas injected
- E Efficiency factor.

The general form of the volumetric equation to calculate the CO2 storage resource mass estimate (M_{CO2}) for geologic storage in oil reservoirs is as follows:

$$M_{CO2} = (OOIP \times B_o \times R_f - V_{iw} + V_{pw}) \times \rho_{CO2} \times E$$

Where:

- M_{CO2} Mass of CO2
- OOIP Original Oil In Place (volume at standard temperature and pressure)
- B_o Factor to convert stp volume to reservoir conditions
- R_f Recovery factor
- V_{iw} Volume of injected water
- V_{pw} Volume of produced water

- ρ_{CO2} Density of CO2 (kg/m^3)
- E Efficiency factor

In the absence of any data (see Section 6.4 below), the efficiency factor could be assumed to be 1.0 in all cases. Further work and access to detailed reservoir data would be required to calculate more accurate efficiency factors (see Section 10), while estimates of OOIP/OGIP and recovery factor can be improved with access to production data.

6.3. Enhanced Oil Recovery (EOR) using CO2

EOR for depleting oil fields can be a useful "enabler" for CCS for a number of reasons. Oil (and gas) formations have held gases and liquids for millions of years before they were removed for use, signifying a geological formation that is a viable capacity to store similar substances. In some cases, where some recoverable oil or gas resource remains in the reservoir, CO2 may be useful for filling (or pressurising) the reservoirs for enhanced recovery of these resources.

Generally, the geology of hydrocarbon reservoirs is known as they have been mapped and studied through previous oil extraction endeavours. As a consequence, scientists have a thorough and extensive understanding of the available storage capacity of these fields.

6.3.1. Industrial CCS projects with EOR

Injection of gases such as CO2 can enhance the recovery of oil from more mature heavy oil reservoirs by pressurising the reservoir and thus "pushing" the oil and driving it towards production wells. Most CO2 used for CO2-EOR originates from natural underground accumulations of CO2. When this natural underground CO2 is replaced with CO2 from human activities (anthropogenic CO2), emissions can be reduced. Not all reservoirs are suitable for CO2-EOR, so detailed assessment is needed to evaluate their actual potential.

The use of CO2 in EOR is taking place in several countries, predominantly in the United States. Globally, 47 MtCO2 from natural underground reservoirs are used for EOR operations[19]. Most CO2-EOR projects have been designed to minimize the amount of CO2 injected because of the cost of CO2. If EOR is to be used for storing CO2, operators will need to inject more CO2 and change the way they recycle, store and monitor it in the reservoir in the long term.

At least half a dozen projects use anthropogenic CO2 exclusively, including Weyburn in Canada, and the Rangely, Sharon Ridge, Enid Fertilizer and Salt Creek projects in

19 http://www.unido.org/fileadmin/user_media/Services/Energy_and_Climate_Change/Energy_Efficiency/CCS/EOR.pdf

the United States. Until 2004, the supply of CO_2 in the United States exceeded demand, and CO_2 for EOR was traded at low prices. The current price paid for CO_2 used for EOR, about USD $40/tonne CO_2, could support early capture opportunities. While the storage potential for EOR in the long term is uncertain, it could help early demonstration projects to get off the ground, paving the way for large-scale CCS deployment.

EOR in combination with high-purity CO_2 sources may be particularly attractive for developing countries that produce oil. In a few cases, EOR is carried out with natural gas, but companies are increasingly aware of the opportunity of exporting natural gas instead of using it for EOR. Developing countries have few other incentives to reduce CO_2 emissions, so sustaining oil production through CO_2-EOR can not only support national energy security, but also familiarise authorities, industry and policy makers with the process of injecting CO_2 into geological formations. This would also require the development of regulatory frameworks that can accommodate both EOR and conventional CO_2 storage.

6.3.2. Regional focus and potential projects

In the short term, EOR efforts should focus on countries where all the conditions for EOR implementation are met, i.e. mature, well characterised oil fields, sufficient sources of CO_2, political will, human capacity and companies that can implement EOR.

6.4. Results

For the purposes of this study, the following hydrocarbon fields were of interest to assess their capability and capacity of CO_2 storage and their prospects for possible Enhanced Oil Recovery opportunities.

- Angostura
- Blocks 1(a) & 1(b)
- Block 22
- East Coast Marine Area
- Minor Fields
- Osprey
- Petrotrin Offshore Area
- Primera Operated Onshore Fields
- TSP Area
- BP East & West Blocks
- Block 5 (c)
- Central Block

- Galeota Block
- North Coast Marine Area
- Pelican
- Petrotrin Onshore Area
- SECC Block
- Toucan

However, the data provided by the Ministry of Energy and Energy Affairs (MEEA) did not cover all requested hydrocarbon reservoirs (as outlined in Table 6.4.1 below).

Hydrocarbon Field Name	Data Received
Angostura	Data not received
Blocks 1(a) & 1(b)	Partial Data received no data on Manicou (block 1a) or Couva Marine (block 1b)
Block 22	Data for Cassra field received
East Coast Marine Area	Data received
Minor Fields	No specific data received
Osprey	Data received
Petrotrin Offshore Area	Data received
Primera Operated Onshore Fields	No specific data received
TSP Area	No specific data received
BP East & West Blocks	Data received only for East Block
Block 5 (c)	Data not received
Central Block	Data received
Galeota Block	No specific data received
North Coast Marine Area	Data received
Pelican	Data not received
Petrotrin Onshore Area	Partial Data received
SECC Block	No specific data received
Toucan	Data not received

Table 6.4.1: Data received for hydrocarbon reservoirs

Then, for each of these fields, the data items requested were:

- Original Oil in Place (OOIP)
- Original Gas in Place (OGIP)
- Date of discovery
- Estimated end of hydrocarbon field life

- Temperature
- Pressure
- Depths (minimum, maximum)
- Permeability
- Porosity
- Production history
- Location (GIS – longitude and latitude dimensions)
- What pipelines exist – length & diameter

Capacity is estimated using the principle that hydrocarbon production from a reservoir is a good estimate of the volume of CO_2 (at reservoir conditions) that can injected into the deplete reservoir. This means that initial oil/gas in place and ultimate recovery factor are critical to the capacity estimate. The reserves listed in the data received are small compared to the very large quantity of LNG exported from Trinidad and Tobago. In the short time available, it has not been possible to identify the source of this discrepancy. The received data is assumed to be correct.

It is understood that the collation of this data for all of these fields requires substantial cooperation. It will be necessary to collate detailed data for all hydrocarbon reservoirs as well as their production history to understand their capacities as well as their availabilities for CO2 injection and storage.

6.4.1. Screening of Hydrocarbon Reservoirs for CO2 Storage

The following procedure was applied to the data received from MEEA, to identify those hydrocarbon reservoirs that have potential for CO2 storage, albeit that all fields qualifying these screening criteria will need further analysis.

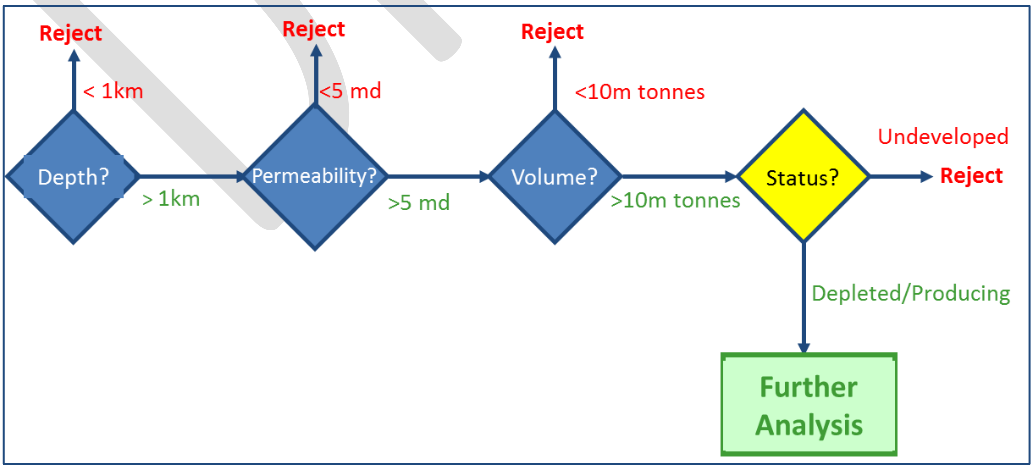


Figure 6.4.2: High-level screening of hydrocarbon reservoirs for CO2 storage

Applying this screening methodology then yielded the following observations:

- Based on the above selection criteria for the data received, only 8 suitable candidates were identified for further analysis.
- More detailed sub surface data is required for fields which have very little information such as the fields located off the East Coast of Trinidad.
- Some fields had very little useful data and some fields of interest were not included in the received data (as outlined in Table 6.4.3 below). As such no analysis on the CO2 storage potential of these fields has been possible due to the lack of available subsurface data.

6.4.2. Results of Screening of Hydrocarbon Reservoirs for CO2 Storage

The results of the screening of the data received were thus:

Field name	Depth (metres)	Permeability (mD)	CO2 Capacity (mtonnes)
Amherstia	1591 - Ok	No Data	16.2
Anolie	1265 - Ok	No Data	1.3
Begonia	2492 - Ok	No Data	0.0
Bougainvillea	2476 - Ok	No Data	1.9
Cassia	3298 - Ok	No Data	4.7
Cassra -1	1554 - Ok	No Data	62.6
Cassra -2	1530 - Ok	No Data	15.0
Celosia	2947 - Ok	No Data	2.5
Central Block - Baraka	2242 - Ok	No Data	3.6
Central Block-Carapal Ridge 1	2107 - Ok	No Data	6.6
Central Block-Carapal Ridge 2	2117 - Ok	No Data	9.2
Chaconia	2384 - Ok	No Data	20.7
Chaconia	2384 - Ok	No Data	20.7
Dolphin	2395 - Ok	No Data	66.8
Dolphin Deep	3077 - Ok	No Data	0.8
Gloxinia	2800 - Ok	No Data	1.1
Heliconia	2499 - Ok	No Data	1.7
Hibiscus	2536 - Ok	No Data	2.9
Hibiscus	2555 - Ok	No Data	73.5
Iguana 2	1184 - Ok	No Data	2.8
Iguana 1	1725 - Ok	No Data	36.5
Iris	1087 - Ok	No Data	10.2
Ixora	2592 - Ok	No Data	2.0
Kapok	1980 - Ok	No Data	5.6
Kiskadee	2566 - Ok	No Data	0.8
Mahogany	2519 - Ok	No Data	10.2

Oilbird	4432 - Ok	No Data	3.7
Orchid (KK6-1)	1858 - Ok	No Data	1.7
Orchid (KK6-2)	2344 - Ok	No Data	3.1
Osprey	3800 - Ok	No Data	26.9
Parula	4694 - Ok	No Data	7.6
Poinsettia	2332 - Ok	No Data	41.3
Poinsettia SW	2363 - Ok	No Data	2.7
Sancoche	1848 - Ok	No Data	20.5
Zandolie West-1	1151 - Ok	4000-5000	2.8
Zandolie East	1118 - Ok	No Data	2.2
Fortin Territorial	853 to 2377 (No individual data except for min and max depth value)	300 to 800 mD (No individual data except for min and max Permeability)	N/A
North Marine			N/A
Point Fortin			N/A
Point Ligoure			N/A
San Fernando Basin			N/A
East Solodado			N/A
Main Soldado			N/A
North Soldado			N/A
Southwest Soldado			N/A
West Soldado			N/A
Balata East	305 to 610 (No individual data except for min and max depth value)	265 - 500 (No individual data except for min and max Permeability)	N/A
Barrackpore			N/A
Catshill			N/A
Central los Bajos			N/A
Cruse E expansion			N/A
Forest Reserve			N/A
Fortin Central			N/A
Guapo thermal			N/A
North Palo seco			N/A
Moruga East& West			N/A
Parrylands E			N/A

Table 6.4.3: Elimination of fields through Screening

As a consequence of this screening, the most prospective CO_2 storage opportunities (at this stage) have been identified as:

	FIELD NAME	CO2 Storage Capacity (Mtonnes)	Reservoir Type (Gas/Oil?)
East Coast (developed)	Osprey	26.9	Gas
	Amherstia	16.2	Gas
	Mahogany	10.2	Gas
	Dolphin	66.8	Gas
	Total Capacity	**120.1**	
North Coast (developed)	Chaconia	20.7	Gas
	Hibiscus	73.5	Gas
	Poinsettia	41.3	Gas
	Total Capacity	**135.5**	
On Shore (developed)	Central Block - Carapal Ridge	9.2	Oil
	Total Capacity	**9.2**	

Table 6.4.4: Prospective hydrocarbon reservoirs for CO2 storage

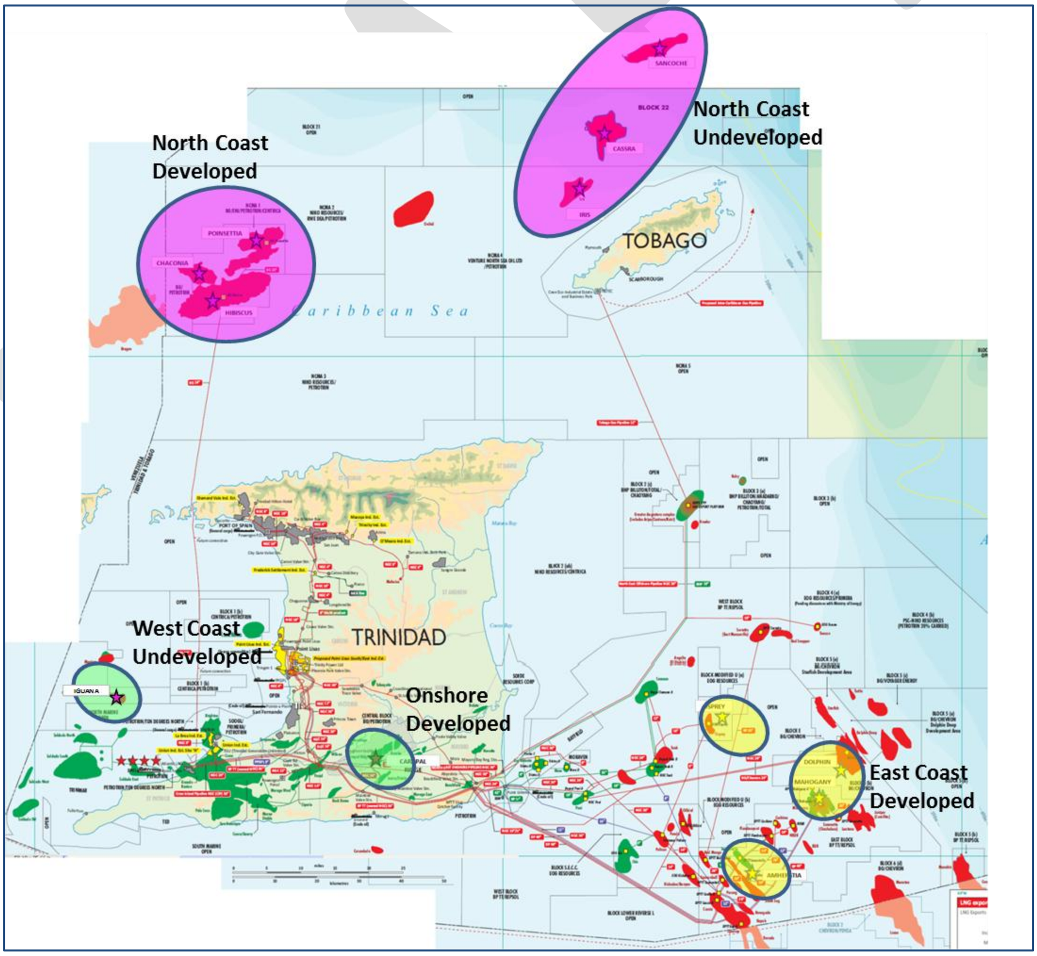


Figure 6.4.5: Location of Prospective hydrocarbon reservoirs for CO2 storage

Despite the lack of complete data for Block 1a and Block 1b, it has been assumed that for the purposes of this report and study that these oil field offshore to the west of Point Lisas (circled in the following map) are of sufficient capacity and suitability for CO2 storage to support a CCS deployment programme. It is acknowledged that this is a very substantial assumption but it is made to give some impression of the costs, benefits and issues that might be encountered in such a project. Clearly this assumption will need to be verified during Phase 2 of this study.

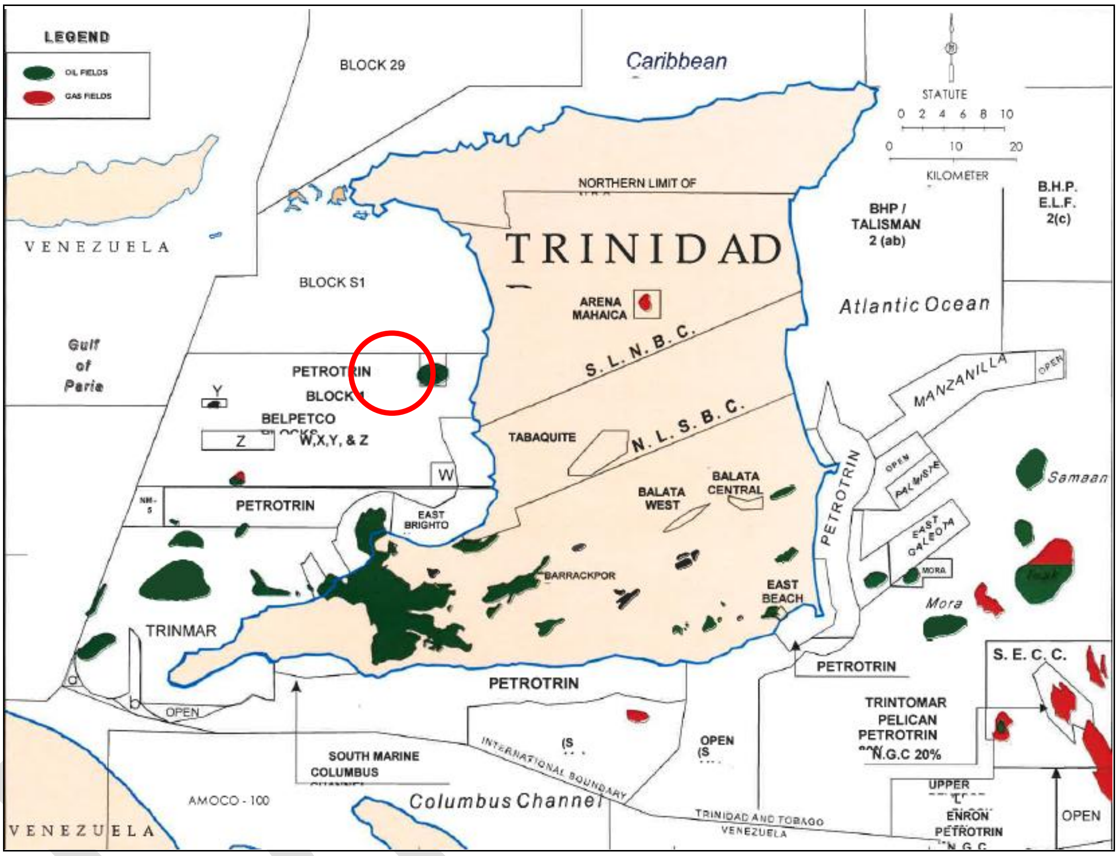


Figure 6.4.6: Map of oil & gas reservoirs within Trinidad & Tobago international boundaries[20]. (Reservoirs of interest (Block 1a & Block 1b), offshore to the west of Point Lisas, circled)

[20] SPE 157136: Evaluating a Depleted Oil and Gas Field in the East Cost of Trinidad for Disposal of CO2 (DJ Jaggernauth, SPE, Petrotrin)

7. Indicative Costs of CO2 Capture Opportunities

For each point source identified and assessed in Sections 4 and 5 respectively, in addition to the CO2 emissions calculated the capture plant and CO2 product compression train CAPEX costs have also been estimated. These cost estimates are for retrofit of a post combustion amine (MEA) capture plant and compression train which is ready to operate. The CAPEX cost estimate includes the following items:

- Auxiliary boiler;
- CO2 Capture and Separation plant, and
- CO2 product compression train.

The CAPEX costs are based on CCS TLM in-house costing models which have been calibrated with in-house data on similar scale global projects. The CAPEX costs have an accuracy of +/- 30% and are all quoted real 2012.

Excluded from the CAPEX cost estimates are all outside battery limit scope of works including but not limited to:

- Power supply & distribution to capture plant/compression train battery limit;
- Water systems and cooling towers;
- Air & Nitrogen systems, and
- Control room.

Owner	Plant	Start-up Year	Capacity tpa Methanol	Total Captured CO2 emissions tpa	Capital Cost for Capture Plant (US $ M)*
Methanol Holdings Trinidad Ltd	Trinidad and Tobago Methanol Company (TTMC) I	1984	460,000	116,256	$ 95
	Trinidad and Tobago Methanol Company (TTMC) II	1996	550,000	164,142	$ 115
	Caribbean Methanol Company Limited (CMC)	1998	550,000	164,142	$ 115
	Methanol IV Company Limited	1993	550,000	164,142	$ 115
	Methanol 5000	2005	1,890,000	565,253	$ 260
Methanex	Titan Methanol	1999	860,000	256,855	$ 150
	Atlas Methanol	2004	1,890,000	565,253	$ 260

(*) -30%/+30%

Table 7.0.1: CAPEX cost estimates for MEA CO2 capture plant and compression train - Methanol Production

Owner	Plant	Start-up year	Capacity NH3 tonnes pa	Total Captured CO2 emissions tonnes pa	Capital Cost External Capture Plant (US $M)*
PCS Nitrogen Trinidad	PCS Nitrogen I	1981	445,000	807,483	$ 130
	PCS Nitrogen II	1981	495,000	898,336	$ 140
	PCS Nitrogen III	1996	250,000	453,505	$ 95
	PCS Nitrogen IV	1998	610,000	1,107,059	$ 155
Yara Trinidad Ltd	Yara Trinidad Ltd	1959	285,000	517,002	$ 97
	Trinidad Nitrogen Co Ltd I	1977	500,000	898,336	$ 140
	Trinidad Nitrogen Co Ltd II	1988	495,000	898,336	$ 140
Koch Fertilizer Affiliates	Caribbean Nitrogen Co	2002	660,000	1,197,905	$ 165
	Nitrogen 2000 Unlimited	2004	660,000	1,197,905	$ 165
	Point Lisas Nitrogen Ltd	1998	610,000	1,107,059	$ 155

(*) -30%/+30%

Table 7.0.2: CAPEX cost estimates for MEA CO2 capture plant and compression train - Ammonia Production

Owner	Plant	Start-up Year	Capacity MW	Captured CO2 emissions (million tonnes pa)		Capital Cost for Capture Plant (US $M)*	
				MIN	MAX	MIN	MAX
Amoco Trinidad Power Resources Corporation	Powergen Point Lisas	1976-2007	852	3.38	4.04	$1,040	$1,300
MaruEnergy Trinidad LLC and T&TEC	Powergen Penal	1976-1985	236	0.71	0.84	$245	$290
US Consortium	Trinity Power Point Lisas	1999	225	0.89	1.07	$300	$330
Trinidad Generation Unlimited (TGU)	Union Estate Power Station	2011-12	720	2.02	2.37	$650	$720

(*) -30%/+30%

Table 7.0.3: CAPEX cost estimates for MEA CO2 capture plant and compression train - Power Generation

7.1. Comparison of CO2 capture costs and volumes of CO2 abated ("Piano Curve")

The chart, "Piano Curve" in Figure 7.1.1 (below) illustrates a ranking of each plant – from Ammonia to Power Generating to Methanol plant and ranks their CCS attractiveness in terms of cost per tonne of CO2 captured. This analysis assumes a 20 year operating life for each plant and merely provides an indication of which plant to "convert" and when.

From this chart it follows that from a cost and benefit perspective, it is prudent to target CCS on ammonia plant first. Whilst the captured volumes are moderate, the abatement costs (capital expenditure for CO2 capture, see Section 5) are lowest and are supportive of an introductory and phased approach to the deployment of CCS.

Power generators are the next best target which then provides greater volumes of abated CO2.

The Methanol plant are disadvantaged due to their lower volumes of CO2 availabilities and the costs of capturing them. In summary therefore, any CCS programme should target the following sectors in order:

1. Ammonia plant, followed by
2. Power generation, and then
3. Methanol plant

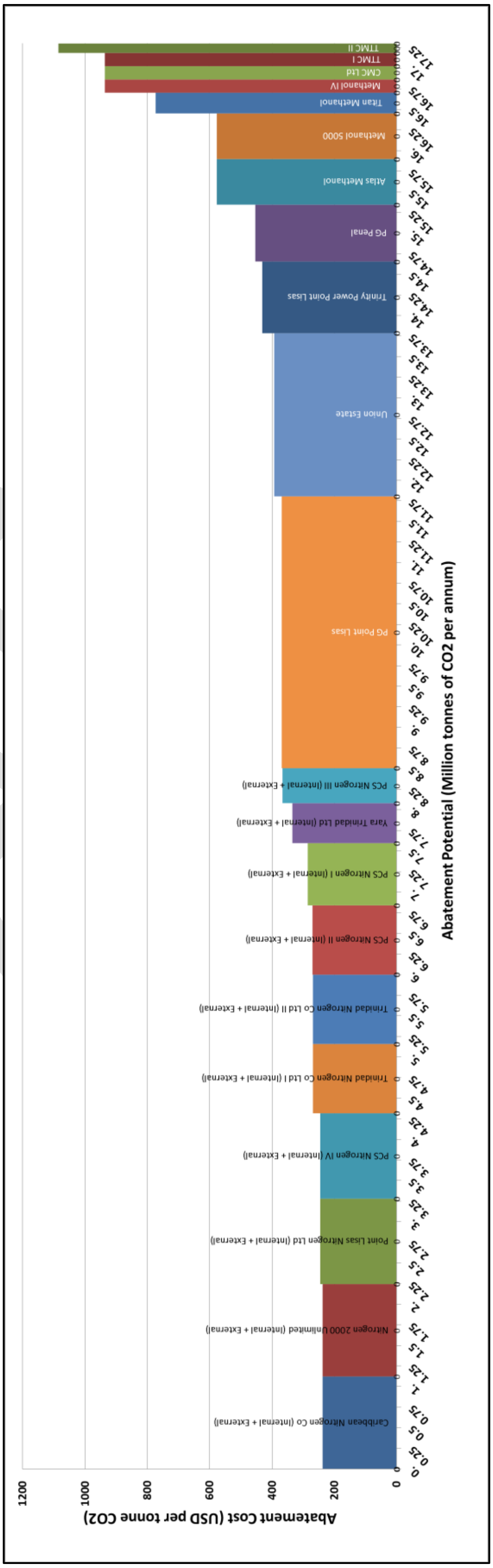


Figure 7.1.1: Piano curve of cost of CO2 abatement for each industrial plant in Trinidad & Tobago (more detailed version available in Appendix 2)

8. Policy strategy for CCS in industry

8.1. Background

Unless governments and relevant authorities analyse the potential of CCS and provide explicit recognition of the role it can play in a country's energy future, CCS projects are unlikely to be developed. Governments should establish an overall policy strategy and pathway for CCS in industry, incorporating the necessary commercial deployment priorities, incentive policy mechanisms and enabling legal frameworks. Governments should also play a role in raising awareness of CCS as a whole. This is particularly the case for industrial applications of CCS, as the awareness of these opportunities is in general lower than for power generation-related CCS. Governments and industry should together pursue large-scale demonstration for CCS in industry in national or regional demonstration programmes[21].

There is a growing awareness of CCS as a potential mitigation technology within developing countries, especially by those relying heavily on fossil fuel-based energy and industries. It is clear that the Government of Trinidad and Tobago are very aware of the opportunities that CCS enables for their fossil fuel rich economy. This growing awareness can also be attributed in part to the inclusion of CCS in the UNFCCC's Clean Development Mechanism.

8.2. Incentive mechanisms for CCS in industry

Industry is unlikely to adopt CCS without incentives and regulatory mechanisms, which governments should tailor to the maturity of the technology and its development over time. Governments should clearly state what incentive policies are intended to achieve, and when. For mature technologies incentives can be more generic and should aim to achieve CO2 emission cuts. Good government policy would outline a pathway for policy evolution and CCS project deployment over time. The IEA[21] has recently provided a comprehensive analysis of incentives policies and outlined an overarching policy architecture to deliver CCS.

8.3. Financial support mechanisms and tax credits

Several countries have announced or are implementing measures to fund CCS demonstration in industrial applications. Such mechanisms include direct financial support to cover additional upfront investment costs, tax credits, CO2 price guarantees and government loan guarantees. One estimate shows that around USD $26 billion has been committed by developed countries to subsidise a first group of CCS projects (IEA/CSLF, 2010), see also Section 3.5.

[21] http://cdn.globalccsinstitute.com/sites/default/files/publications/22002/ccs-industry-roadmap-web.pdf

8.3.1. Carbon prices or taxes

The most commonly considered policy incentive for CCS is a sufficiently high and stable global price for carbon emissions. Carbon prices can be created through emissions trading schemes, which involve setting a cap on CO2 emissions, or by imposing carbon taxes. In the long term, carbon markets are expected to deliver the required reductions at lowest cost to society, but it has not been demonstrated that they will provide enough incentives to encourage the deployment of new, more expensive technology in the short term. Other support mechanisms will therefore be needed in the medium term.

Norway's carbon tax is one of the few successful examples. In 1991, the Norwegian government decided to tax CO2 emissions from its offshore oil and gas industry at a rate of around USD $35/tCO2 emitted. The tax is now around USD $70/tCO2[22]. The Norwegian petroleum sector is also included in the European Union Emission Trading Scheme (EU ETS). Both the Sleipner and Snøhvit industrial CCS projects (gas processing) have been strongly incentivised by this CO2 taxation.

Another example of a support mechanism has recently been proposed by the UK government. A proposal to introduce a "carbon price floor" has been put forward, by which a price differential will be added to the EU Emission Allowances (EUA)[23] value to ensure a minimum price for traded emissions in the EU ETS. The price differential aims to reach GBP £30/tonne CO2 by 2020 with a straight line trajectory to GBP £50/tonne by 2030 and GBP £70/tonne by 2050.

8.4. Mandates and standards

Regulatory instruments such as technology mandates and standards could also be used to provide incentives for CCS in industrial applications. Governments could, for example, require CCS in certain installations or industries as a condition for granting an operating license. Governments could also consider prohibiting CO2 venting from natural gas processing plants or from large, high-purity point sources of CO2 (such as ammonia or methanol plant). Sectoral GHG emission intensity standards or GHG emissions limits are further options. But a balance will have to be struck between mechanisms that are specific to technologies or facilities, and more general market-based mechanisms, which provide more flexibility to the operator and result in lower costs of GHG mitigation to society. There is likely to be a need to consider the

[22] http://www.guardian.co.uk/environment/2012/oct/11/norway-carbon-tax-oil

[23] Credits that are allocated to the companies covered by the EU ETS. Each one represents the right to emit one tonne of carbon dioxide.

impact on economics of a CCS programme compared with the economics of shale gas developments in the US.

Mandates and standards are also unlikely to provide a practical option before technologies are commercially available and could therefore be counter-productive if not implemented carefully.

8.5. Carbon financing in developing countries

The CDM (Clean Development Mechanism) of the Kyoto Protocol is currently the only financial incentive to attract investment in projects that reduce CO2 emissions in developing countries. Trinidad & Tobago have recently announced the first carbon offset programme in the Caribbean under the Kyoto Protocol[24].

After a prolonged debate on the suitability of CCS for the CDM, it was recognised by the UNFCCC as a CDM project activity in late 2010. However, a set of modalities and procedures must be established before the first CCS projects under the CDM can be implemented. However, at present, CCS projects involving Enhanced Oil Recovery (EOR) do not qualify for CDM credits.

Other international mechanisms that may attract funding for CCS include the Green Climate Fund and the Nationally Appropriate Mitigation Action (NAMA) architecture, both agreed at the United Nations (UN) climate change conference in Copenhagen in 2009.

8.6. Actions for policy

When developing regulations, policies and relevant incentives to support CCS deployment, governments should:

- Review opportunities for industrial CCS, or encourage industry to undertake such a review, and ensure that CCS in industrial applications is given the required attention in government scenarios and policy. This study, the GCCSI policy review and IDB program is an encouraging first step.
- Establish and promote programmes to raise public awareness and understanding of the need for CCS, so that it can become part of a low-carbon industrial development strategy.
- Implement demonstration programmes that include industrial CCS and ensure that funding for CCS demonstration is distributed efficiently between relevant stakeholders, given that the potential for reducing CO2 emissions in industry is large, and that there are few alternatives to CCS for making significant reductions.

[24] http://www.guardian.co.tt/business-guardian/2013-01-24/tosl-petrotrin-partner-25m-carbon-credit-project

- Design policy frameworks and provide incentives that accelerate commercial-scale CCS deployment in industry beyond the demonstration phase. Incentive policies should be analysed and then adapted to meet the specific needs of different industry sectors, and economy-wide policies and technology-specific policies should be compatible with each other. Without such incentive policies, CCS projects will not be able to attract financing from capital markets.
- Explore sector-based approaches, including technology transfer and mandates, for CCS policies in appropriate specific sectors, e.g. ammonia and methanol.
- Consider requiring CCS readiness when providing finance to new conventional industry projects.
- Investigate the viability of an international financial mechanism for demonstrating industrial CCS in developing countries.

8.7. CCS Regulatory Review for Trinidad & Tobago

The GCCSI analysis of existing Trinidad and Tobago legal and regulatory framework[25] demonstrates that, as a result of this thriving oil and gas industry, the country is well placed to accommodate a CCS project. The Environmental Management Act 2000, The Petroleum Act 1969 and The Pipelines Act 1933 are key pieces of legislation that will impact on any CCS law, whether it be built into existing legislation, or if new legislation is created. The GCCSI analysis demonstrates that under the existing model, primarily through the MEEA (Ministry of Energy & Energy Affairs) and the EMA (Environmental Management Authority) processes, a project could be legally permitted and regulated throughout its lifecycle. Essentially, this could be achieved by utilising a CEC (Certificate of Environmental Clearance) approval process to outline and determine the various obligations deemed necessary by relevant authorities. However, if these existing regulatory mechanisms were to be utilised, Trinidad and Tobago would have to develop or adopt specific site selection, MMV, and decommissioning criteria that could be incorporated within the CEC approval process.[25]

It is clear that much of the technical, policy and regulatory expertise to legislate a CCS project already exists in Trinidad and Tobago, and there is capacity for further legislative developments to be undertaken in the near future.

There are many CCS regulatory issues to be considered in the development of a robust CCS regulatory regime. However, the GCCSI in their Regulatory Review recommend that the Trinidad and Tobago Government give further consideration to the following policy and related issues pertaining to the regulation of a CCS project in Trinidad and Tobago[25]:

[25] http://cdn.globalccsinstitute.com/sites/default/files/publications/54126/ccs-regulatory-review-trinidad-tobago.pdf

1. management of long term liability of stored CO_2, including ultimate transfer back to the Government;
2. potential inclusion of CCS as a specific Designated Activity under the Certificate of Environmental Clearance (Designated Activities) Order 2001;
3. specific inclusion of CO_2 pipelines under the Pipelines Act 1933;
4. mechanisms for greater coordination in the permitting of a CCS project;
5. benefits of project specific Act or stand-alone legislation as an efficient and effective way to coordinate the permitting of a CCS project, compared to integration of requirements into existing framework;
6. development of site selection, MMV and decommissioning criteria for a CCS project; and
7. Development of CCS expertise in relevant regulatory authorities.

The existing regulatory framework within Trinidad and Tobago is well placed to accommodate a CCS project. This is particularly true if the proposed project was to capture CO_2 from an industrial facility (such as an ammonia plant) and transported via pipeline to either an existing offshore or onshore oil or gas reservoir.

This provides another opportunity for Trinidad and Tobago to enhance the "Trinidad model" and export advisory services to other nations who are looking to developing similar energy market structures (as discussed in Section 4).

9. Conclusions

Although Trinidad and Tobago has earned international acclaim in its model for natural gas development, the level of integration of downstream industries needs an in-depth review[26]. The next stage in development should therefore be to identify and leverage on possibilities for operational integration to realize the reduction of CO2 emissions and the optimal use of by-product streams. Carbon Capture and Storage (CCS) are a set of technologies to reduce carbon emissions which include:

1. Capture of CO2 from industrial sources
2. Handling and Transporting of CO2
3. Injection and storage of CO2 in deep geological formations

CCS is a proposed technical solution to reducing the concentration of CO2 in the atmosphere by collecting CO2 generated at industrial sites or fossil-fuel burning power stations and injecting it deep underground, rather than allowing its release to the atmosphere.

The capture of CO2 represents the major limiting cost factor in the implementation of CCS. In most countries CO2 is emitted in flue gas streams and capture involves removing CO2 at significant capital expenditure and typically increases energy consumption by about 20%. Fortunately, for Trinidad and Tobago one-fifth of the CO2 is produced at high purity (90-96%) from eleven ammonia plants. Only a limited quantity of this CO2 is currently being used for methanol, urea and downstream petrochemical manufacture.

Within the Point Lisas Industrial Estate there is currently an existing network of CO2 pipelines connecting several ammonia plants to methanol production facilities. This network of pipelines can form the core of the basic infrastructure required for the collection, transportation and optimal distribution of CO2 within the Point Lisas area and can be used as a platform for the development of a robust and reliable integrated CCS system. It is possible to expand and integrate this network to include a centralised CO2 compression and treatment facility before connecting to a dedicated trunk pipeline to transport CO2 to storage sites in the producing oil fields.

Trinidad and Tobago has the unique opportunity to leverage on the significant cost and logistical advantages arising out of the relative proximity of CO2 sources and potential CO2 sinks. For the CO2EOR Weyburn Project in North America the distance between the CO2 source and the oil fields was bridged by a 325 km pipeline, which needed an investment of

[26] Win-Win: Enhanced Oil Recovery and Carbon Storage in Trinidad & Tobago. Sobers & Lashley. 2012

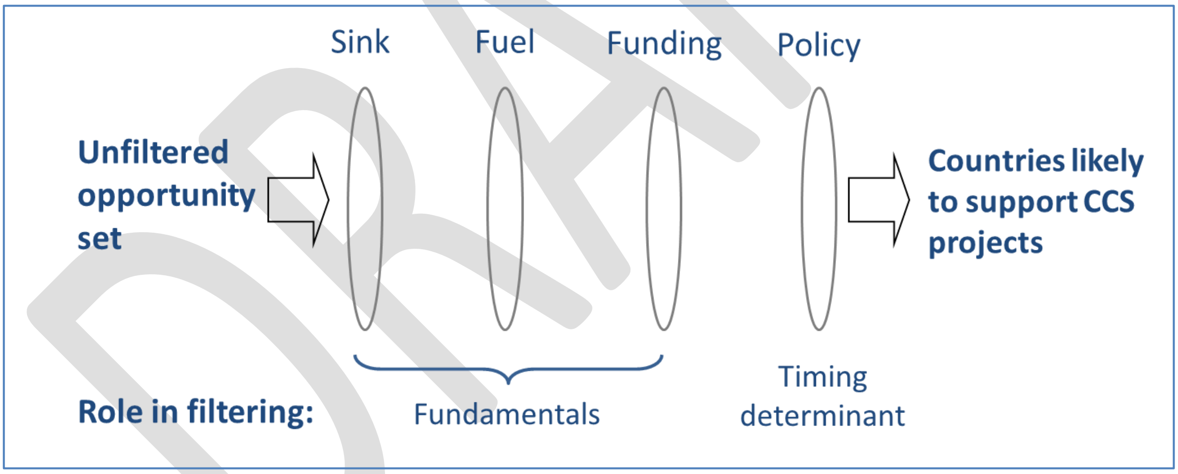
US$100 million[27] By comparison, the distance between major CO2 sources and potential oil field sinks in Trinidad range between 30 and 50 km.

Even with new oil reserves, enhanced oil recovery is needed to boost declining oil production in Trinidad which has been on a steady decline since peaking in 1978. In the last 5 years, annual oil production has declined at a rate of 9% per year[28]. At the same time CO2 emissions continue unchecked and largely unused. Geological CO2 storage coupled with CO2 EOR is a 'win-win' scenario for Trinidad and Tobago. The three main opportunities are:

1. Reduction of CO2 emissions, thus reducing the nation's carbon intensity of growth and carbon footprint (see Section 4),
2. Increased oil recovery in nearby oil fields and arrest declining oil production and,
3. Demonstration of the integration of CCS technology within the framework of gas-based industrialisation to the international energy industry.

9.1. Is a Carbon Capture & Storage project feasible in Trinidad and Tobago?

As we learnt in section 3.5, the key criteria for CCS project success can be illustrated as follows:



In CCS TLM's view there are a few key determinants that define a project's potential. CCS TLM identifies the following as critical elements:

- Sinks (availability, capacity, and security of storage);
- Access to indigenous fuel (and reliance on hydrocarbons), and
- Policy (and financial) support – to reflect the country's capacity to deliver it.

The Terms of Reference for this study was to "*assess the conditions necessary to facilitate the implementation of a national CCS program, including recommendations*

[27] http://www.ieaghg.org/docs/general_publications/weyburn.pdf
[28] Ministry of Energy and Energy Industries

for addressing identified gaps and a cost-benefit analysis", the authors believe that CCS is viable for Trinidad & Tobago.

1. **Does Trinidad and Tobago have sufficient and suitable sinks for the storage of CO2?**
   Yes, we believe so, see Section 6.4 above and 9.1.1 below.

2. **Does Trinidad and Tobago have access to sufficient supplies of indigenous fuels and sufficient reliance on hydrocarbons?**
   Yes, undoubtedly, with the well-established oil and gas production and gas processing sectors (ammonia and methanol manufacturing), the region has significant access to indigenous hydrocarbon supplies and relies heavily on those hydrocarbons for a substantial contribution to the nations GDP.

3. **Does Trinidad and Tobago have the basis upon which (and motivation) to develop robust CCS related policies and regulations?**
   From Section 8 it is clear that there is strong interest and motivation to develop the necessary policies and regulations to support the development and deployment of a CCS programme. From the GCCSI sponsored workshop in 2012, there was evidence of strong cooperation and understanding across all the necessary stakeholders and different government departments.

9.1.1. Necessary Conditions and Identified Gaps

Over the last 50 years Trinidad and Tobago has transformed its first fledgling steps into the realm of petroleum production into a bold march into the international energy industry.

This 'Trinidad model' should now be reviewed and, where appropriate, modified to include CCS as a valuable new dimension. Today's vented CO2 from natural gas-based operations can be monetized in much the same way as was done in the case of natural gas, with the main differences being the nature and composition of the gas used and the direction of flow[29].

To enable this and as discussed in Section 6.4 above, the "conditions necessary" to verify that CCS is viable in Trinidad and Tobago would require access to the geological data relating to the oil and gas reservoirs on- and off-shore Trinidad. The assessment and understanding of these reservoirs' suitability and capacity for CO2 storage is a "challenge" to the completeness of this study which is addressed in Section 10 (further work), below.

[29] Win-Win: Enhanced Oil Recovery and Carbon Storage in Trinidad & Tobago. Sobers & Lashley. 2012.

Nonetheless, the authors are confident that CCS is viable and have consequently devised an illustrative Roadmap for the deployment of CCS in Trinidad and Tobago to the year 2050 in which over 150 million tonnes of CO2 can be captured and stored and/or utilised for enhanced oil recovery to ensure that the "Trinidad model" continues to be studied and replicated by countries new to the energy industry.

9.2. Indicative Roadmap for CCS deployment in Trinidad & Tobago to 2030 & 2050

It is clear that from assessing:

a) the sources and quantities of CO2 available across the primary industrial sectors of Trinidad, i.e. Ammonia production, methanol production and power generation,
b) public domain literature regarding CCS opportunities in the region, and combining this with,
c) our understanding of the fundamentals for CCS developments,

that Trinidad and Tobago have an ideal platform to pursue a programme of CCS deployment from pilot/demonstration scale projects through to commercial scale fully integrated power generation projects with CCS.

Section 5.3 has already identified the Point Lisas industrial estate as a prime location to "anchor" such a deployment programme.

It is our opinion that the first phase of CCS deployment should focus on the "Point Lisas North Cluster" to provide anchor project(s) with a small-scale demonstration then growing to first network for all PCS, MHTL and Point Lisas PowerGen plant. The "South Cluster" can form a later development and/or when CCS becomes economic and/or sustainable.

However, it must be noted that at this time, the absence of current production rates creates a challenge for making any sort of a guess at end of field life. Indeed, it is difficult to make any sort of a development plan without this. As a consequence, the following proposed storage clusters can only be conceptual absent this data.

9.2.1. CCS Deployment Phase 1: 2018 to 2030

It is proposed that the demonstration phase be focused on the PCS Nitrogen III ammonia manufacturing plant for the simplistic reasons that for an estimated capital expenditure of approximately $190m a full chain of capture, transportation and storage of high purity CO2 can be sequestered and used to illustrate to all stakeholders (locally, nationally and internationally) that CCS can be successfully developed.

This demonstration project would include an oversized pipeline to the Petrotrin oil field that will allow for additional CO2 supplies, namely from the remaining PCS Nitrogen plant (units I, II and IV) to be added during the development programme.

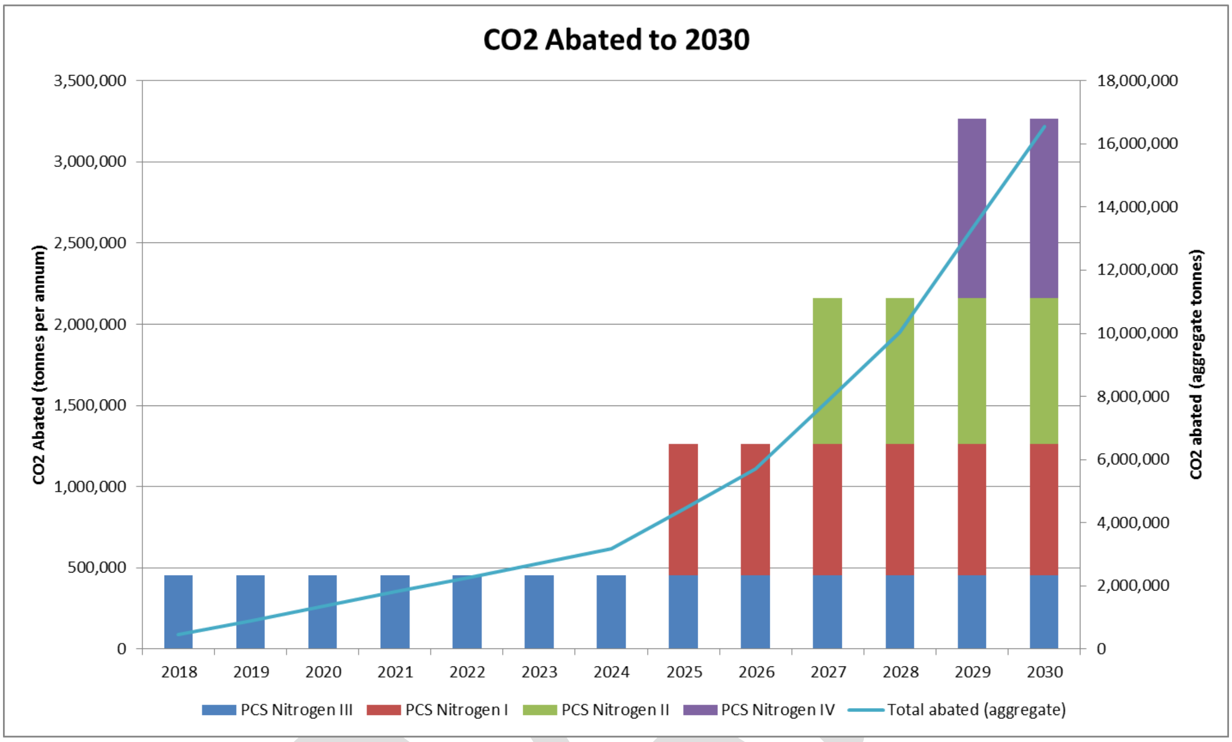


Figure 9.2.1: CCS Project deployment to 2030

After allowing for 5 years of "proving", it is then proposed to add the remaining PCS Nitrogen plant to the network, utilising the same pipeline.

As can be seen from the chart above, the aggregate CO2 abated during this phase exceeds 16 million tonnes.

9.2.2. CCS Deployment Phase 2: 2030 to 2050

Phase 2 would introduce the Point Lisas Powergen power plant to the CCS network in 2030.

This alone would yield an aggregate abatement of 90 million tonnes of CO2 by the year 2050.

This does not include any of the Methanol plant adjacent to the PCS plant, or any of the ammonia or methanol manufacturing plant of the "South Cluster" which are likely to be viable for CCS development by 2030.

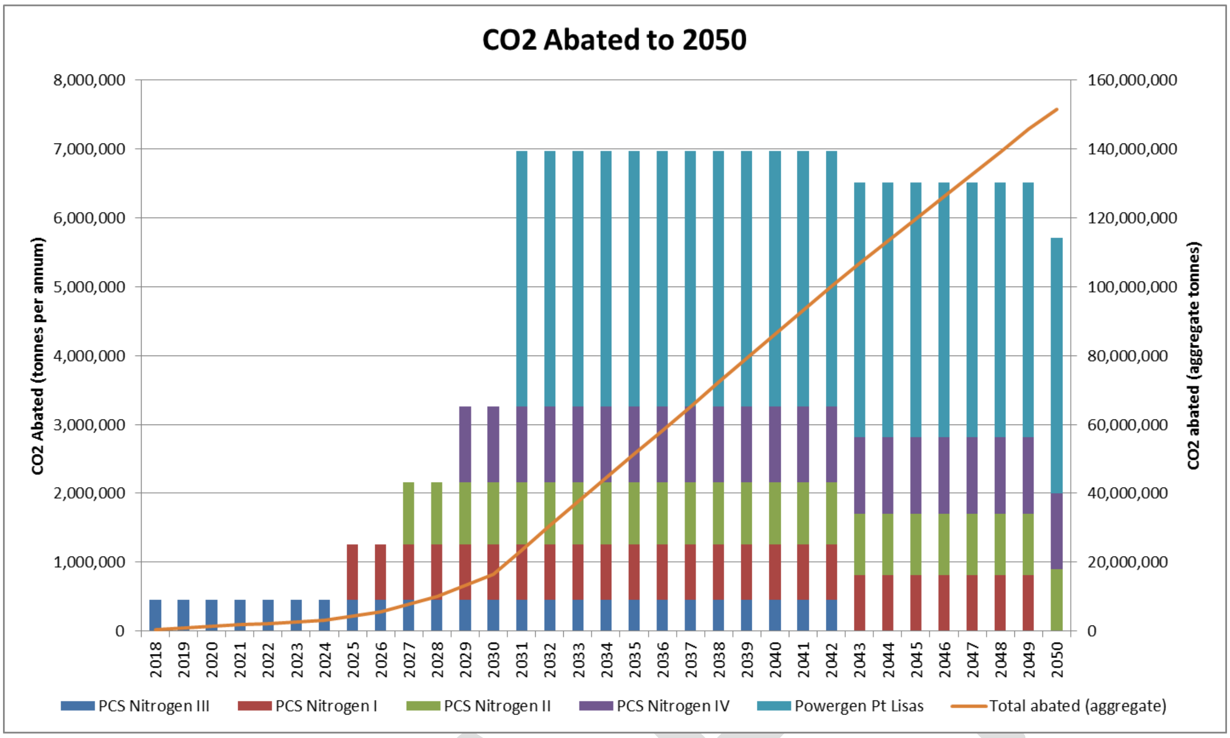


Figure 9.2.2: CCS Project deployment post 2030

9.2.3. Discounted Cash Flow Analysis

For each of the above "low lying fruit" opportunities for deployment of CCS, a discounted cash flow (DCF) analysis has been performed for each identified site. The DCF analysis takes into account the capture plant and compression train CAPEX cost and also in addition to this includes pipe line (transport) and storage costs. This DCF analysis encompasses the full "End to End" chain from capture of CO2 to long-term storage of CO2 volumes.

For the ammonia plant, it has been assumed that both internal and external CO2 emission streams are utilised for CCS, i.e. it is assumed that the internal CO2 stream is currently vented and not sold and has no current economic benefit to the ammonia process operators in Trinidad.

9.2.4. Common Assumptions: Economic Modelling DCF Analysis

- Capture plant operations have an assumed 80% availability for the purposes of this Feasibility Study
- Inflation throughout is fixed at 3% per annum.
- Straight line depreciation on fixed assets has been assumed
- Tax rate of 29.1%[30]
- Capture plant life of 20 years has been used.

[30] http://www.doingbusiness.org/data/exploreeconomies/trinidad-and-tobago/paying-taxes

- Capital investment costs are based on current in-house benchmarks.
- Total operating expenses (OPEX), fixed and variable, have been assumed to amount to 10%[31] of capture plant CAPEX investment per annum.
- As with the current situation, no cost (penalty) is associated with any CO2 emissions not captured.
- Pipe line costs are based on 15 km of pipeline[32] for the Demonstration project at PCS Nitrogen III.
- Pipe line costs are based on 2.5 km of pipeline for the incremental projects at PCS Nitrogen I, II and IV
- The Demonstration project at PCS Nitrogen III also incurs the (significant) upfront appraisal costs of the storage reservoir as well as the above (higher) costs of the anchor pipeline from Point Lisas to the storage site.
- An IRR of 10% is assumed throughout unless otherwise stated.
- No penalty consideration is given to CO2 emissions/escape from injection and/or production wells during CO2 storage and/or EOR operations.
- For the ammonia industry it is assumed that the internal CO2 emission source is combined with the external CO2 emissions source and that the current capture infrastructure requires an additional 6% to incorporate the "internal" CO2 sources with the captured external sources.
    - At this stage, it is assumed that the internal source of CO2 within the Ammonia manufacturing plant does not require processing to CCS quality
- The CO2 price to repay the necessary investment and yield an IRR of 10% is then calculated, i.e. goal-seek CO2 price to deliver £0 NPV at 10% discount rate.

9.2.5. Economic Analysis of CCS Deployment to 2030

The economics of this proposed Roadmap as outlined in Section 9.2 above, can be summarised as follows:

[31] Internal CCS TLM estimates
[32] CCS TLM estimate of distance from Point Lisas to Petrotrin oil field offshore to the west of Point Lisas

Plant	CCS on-stream	CO2 captured (million tonnes pa)	Capture Cost (incl. compression)	Transport & Storage Costs	CO2 price to deliver IRR 10%
PCS Nitrogen III	2018	0.4	$95m	$85m	$90/tonne
PCS Nitrogen I	2025	0.8	$133m	$15m	$50/tonne
PCS Nitrogen II	2027	0.8	$140m	$20m	$48/tonne
PCS Nitrogen IV	2029	1.0	$157m	$20m	$44/tonne

Table 9.2.5: Economic Analysis of CCS deployment to 2030

While the above analysis indicates a very high cost for the demonstration project at PCS Nitrogen III of $90/tonne of CO2 stored, it must be remembered that, as with all demonstration projects, all the costs associated with the new infrastructure are "loaded" into this phase, i.e. the demonstration and anchor project at PCS Nitrogen III incurs a disproportionate share ($86m) of the infrastructure costs which includes:

- an over-sized pipeline from Point Lisas to the CO2 storage site
  - this is assumed to be >90% offshore which is higher cost than onshore pipelines,
- the cost of appraising the detailed geological data of the CO2 storage site, and
- the cost of well appraisal and refurbishing and/or drilling of new wells if necessary.

Once the CCS solution is proven, then the "growth" projects at PCS Nitrogen I, II and IV respectively only incur a cost of a short pipeline of 2-3km (onshore) to a previously appraised and refurbished CO2 storage site and platform. These sites therefore benefit from this and so the incremental cost of CCS projects drops dramatically to below $50/tonne.

It must also be remembered, that the above economics assume no EOR, which could yield much improved economics. The total capital cost of applying EOR to the demonstration of CCS at PCS Nitrogen III would be in the region of $250m, but with possible oil sales at $100/bbl, EOR projects should be given due consideration to support CCS deployment in Trinidad and Tobago. A simple economic analysis suggests that with these parameters, the cost of the demonstration project falls to $20/tonne CO2 captured when EOR is applied.

Alternatively, with regards to the high costs associated with the demonstration project (without EOR), several national and/or international agencies could be approached to explore what funding might be available for Trinidad and Tobago to support this initiative, see Section 10.3 below.

10. Recommendations & Next Steps (further work)

This report has assessed the fundamental building blocks necessary to support the development of CCS schemes in Trinidad and Tobago and has concluded that there is indeed an opportunity for the Republic to consider a programme of deployment and thus an indicative Roadmap has been proposed.

To support these conclusions and proposals, further work of studies will be necessary to confirm these early conclusions to deliver greater confidence that CCS can be efficiently deployed. The further work identified below should be considered in parallel to the development of the necessary Regulatory and Policy development activities in cooperation with the Global Institute (GCCSI).

As a follow-up to this report therefore, it is recommended that the following assessments are conducted:

- More detailed assessment of CO2 storage capacity in Trinidad and Tobago for all hydrocarbon reservoirs, including an understanding of their individual estimated end-of-life;
- Assessment of the prospects for CO2 Enhanced Oil Recovery;
- Assessment of the potential funding from national and international sources to support CCS project developments;
- A programme of engagement with the key participants in a CCS programme, e.g. the management team at PCS Nitrogen and Petrotrin, and
- Conduct a programme of CCS training for all stakeholders, including public engagement presentations to build full stakeholder support

The above programme of further work can be conducted in isolation or as a single Phase 2 to this initial Phase 1 Feasibility Study.

10.1. Assessment of CO2 storage capacity in hydrocarbon reservoirs

Estimates of carbon dioxide (CO2) geologic storage potential are required to assess the potential contribution of carbon capture and storage (CCS) technologies towards the reduction of CO2 emissions. Governments and industries worldwide rely on CO2 storage estimates for broad energy-related government policy and business decisions. Reliable CO2 storage estimates are necessary to ensure successful deployment of CCS technologies.

Unfortunately, this study has revealed that the necessary data was difficult to collect and so the calculation and verification of the CO2 storage capacities in oil or gas fields has been challenging.

Specifically, despite the lack of complete data for hydrocarbon reservoirs Block 1a and Block 1b, it has been assumed that for the purposes of this report and study that these oil field offshore to the west of Point Lisas (see Figure 6.4.6) to be of sufficient capacity and suitability for CO2 storage to support a CCS deployment programme. It is acknowledged that this is a very substantial assumption but it is made to give some impression of the costs, benefits and issues that might be encountered in such a project. Clearly this assumption will need to be verified during Phase 2 of this study.

As a consequence, the primary follow-up work should aim to work alongside the data holders, i.e. the Ministry of Energy and/or the oil/gas reservoir owners/operators to collect the detailed data on hydrocarbon reservoirs to ascertain where CO2 "hubs" and networks might develop. This could, if necessary, be supported with an illustration of the location of saline formations for later characterisation and detailed assessment.

10.2. Assessment of the prospects for CO2 Enhanced Oil Recovery

As an extension to the study of hydrocarbon reservoirs to determine their CO2 storage capabilities and capacities, further, more detailed access to individual reservoir and geological models from the assets' owners/operators, based on seismic studies and reservoir fluid properties would enable a more detailed study into the prospectiveness of CO2 for Enhanced Oil Recovery (EOR).

The use of CO2 for EOR presents several other benefits. By increasing the ultimate oil recovery, governments increase their revenues through taxes and royalties. EOR can further reduce the need for new exploration for oil and gas. In addition it will decrease and/or delay the need to exploit unconventional hydrocarbon reserves which are likely to have significant environmental impacts, such as tar sand and shale gas (through the use of "fracking").

EOR also presents an early opportunity for CCS deployment by stimulating the entire CCS chain. The additional revenues generated from EOR could accelerate the selection of storage sites and the development of infrastructure and at the same time reduce investments by re-using the existing facilities when an EOR project is converted to a CCS project. Additional side benefits for the CCS chain include an accelerated CCS learning curve (achieving early maturing of CCS-related technologies and possibly also lowering costs), further strengthening of the CCS market and promotion of manufacturers of capture technologies etc. to step in and compete for contracts.

A prerequisite to make CCS projects viable is to create sufficient value for delivered $CO2$ to justify the costs of capture and transport and subsequently a market for $CO2$ storage. Such market is non-existent at the present time and will more likely only develop in the near term if oil companies are given sufficient incentives to initiate enhanced oil and/or gas production using CO2. This requires the support of governments in the form of incentive schemes and/or regulations.

Once again, this might provide an opportunity for Trinidad and Tobago to enhance the "Trinidad model" and export advisory services to other nations who are looking to developing similar energy market structures (as discussed in Section 4).

10.3. Assessment of the potential funding from national/international sources

Clearly, from Section 9.3 above, the costs of applying and developing CCS are not immaterial. As a Kyoto Protocol Annexe II country, Trinidad and Tobago could target the Clean Development Mechanism (CDM) as a means of earning revenues from storing CO2 in depleted hydrocarbon fields (CDM credits are unlikely for any EOR projects). The CDM could provide an enduring support and provide a $/tonne revenue for every tonne of CO2 stored paid for by the sponsoring Annexe 1 country/organisation.

However, the current value of CERs (Certified Emissions Reduction certificates) is very low and would not yield sufficient revenue to support any CCS business case.

Consequently, it is recommended to undertake further work to explore opportunities for capital or enduring support mechanisms to supplement or substitute the CDM route. Clearly, capital grants or support mechanisms would yield the greatest and most immediate assistance.

Several national and regional governments have launched several CCS programmes with capital and enduring support mechanisms. For example, the UK Government have launched their "CCS Commercialisation Programme" whereby successful bidding projects will receive up to £1bn ($1.5bn) to support the high capital expenditure of CCS projects. Also, the European Union launched the NER300 funding mechanism which offered €1.2bn ($1.5bn) as an enduring support ($/tonnes), rather than capital support for successful renewable and/or CCS projects.

Other entities, such as the World Bank may have funding opportunities to support CCS project similar to those proposed herein.

Alternatively, private organisations may be interested in sponsoring CCS projects in Trinidad to provide them with access to carbon credits to offset their high CO2 emitting costs in other jurisdictions of their operations.

To illustrate this, if the demonstration project at PCS Nitrogen III was to receive a capital grant then the following break-even prices for CO2 could be achieved:

Capital Cost	Capital Grant	Cost of CO2 avoided
$180m	none	$90/tonne
$120m	$60m (30%)	$70/tonne
$100m	$80m (45%)	$60/tonne

Table 10.3: Illustrative impacts of capital grants on CCS economics

10.4. A programme of engagement with the key participants in a CCS programme

From an understanding of the funding sources/opportunities, it will also be important to gauge and collect the interest, motivation and willingness of the key participants to undertake a CCS programme.

The Roadmap identified herein has identified PCS Nitrogen as a potential CO2 capture source and Petrotrin as a potential CO2 storage operator. An understanding of their respective interests in conducting detailed studies of CCS at their plant and willingness to participate, will be key in determining the success of this proposed programme of CCS deployment for Trinidad and Tobago.

10.5. Public Acceptance

Public acceptance is one of the most critical factors affecting CCS[33]. Since the public's environment and standard of living can be directly affected through the implementation of CCS, it is imperative that both the public and business communities feel confident in the safety and reliability of the technology. In addition, consumers may be expected to pay higher prices for electricity in order to facilitate the technology. Thus they will expect assurance that their investments are necessary and effective. Trinidad and Tobago's relatively small population places it among the world leaders with respect to CO2 emissions per capita. In addition, the small island states such as Trinidad and Tobago (and the wider Caribbean) are the most vulnerable to coastal erosion, rising sea levels and flooding due to intensive rainfall, all of which are forecast to be more severe if the climate grows warmer. The communication of these factors to the public and business community is an essential part of gaining acceptance of CCS technologies.

The public's acceptance towards adopting geological CCS has been measured and reported in a recent market research survey. The survey indicated that a greater public awareness and informative campaign is needed in Trinidad and Tobago before the population can be comfortable and confident on their position

[33] Employing CCS technologies in the Caribbean: A case study for Trinidad and Tobago. David Alexander, Donnie Boodlal, Steven Bryant. 2011.

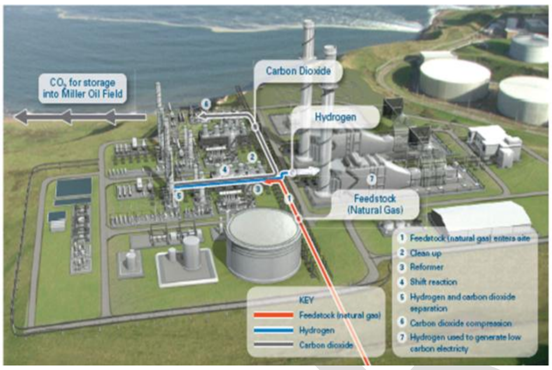
with respect to the technology. Not surprisingly, on the issue of funding a CCS project if needed most participants felt that this was the responsibility of either the government or related industries. This supports the suggested study to explore funding opportunities form national and/or international parties.

As stated earlier, the above programme of further work can be conducted as five individual studies or as a single all-encompassing exercise.

Appendix 1: Introduction to CCS TLM Limited

The emerging CCS industry is the single-most challenging and exciting aspect of today's global energy sector. CCS TLM's sole focus is to support the development of CCS projects through the provision of real experience and capability. The management team of CCS TLM are amongst the most experienced and successful developers of CCS projects anywhere, having previously been responsible for a number of landmark projects globally.

The founders of CCS TLM have a rich history of project development of de-carbonised fuel for power generation and industry with carbon capture and storage (CCS). Since 2005, they were members of BP's Hydrogen Power business committed to developing projects in all the key geographies of the world where fossil-fuelled power generation is a necessity and cleaner, more sustainable energy forms are an increasing requirement, e.g. Peterhead (Scotland), California (USA), Kwinana (Australia) and Abu Dhabi (UAE) for BP and then Hydrogen Energy International Limited.



DF1 Project at Peterhead, Scotland (left):
Technically sound – 200,000 man-hours and first fully permitted site in the world with a robust sink available and ready for CO2 storage.

(Image courtesy of BP Alternative Energy)

HPAD, Abu Dhabi, UAE (right):
Potentially the world's first natural gas fired, low-carbon hydrogen power plant. 1.7 million tonnes per annum CO2 captured and injected for Enhanced Oil Recovery while providing approximately 400MW low carbon power.

(Image courtesy of BP Alternative Energy)

CCS TLM offers advisory services based on real project experiences and, we believe, is the only consultancy that can credibly do this. Advisory services include; technical & engineering, commercial structuring & finance, value chain analysis & integration, storage site selection and development, EOR. Currently CCS TLM is collaborating with the Australian Coal Association, the ROAD project in Rotterdam and the Global CCS Institute (GCCSI) among others. Since April 2012, Belgium's Tractebel Engineering International, a subsidiary of GDF SUEZ have been a joint venture partner in the company, building on the strong synergies between the two organisations. CCS TLM now combines Tractebel Engineering's global reach and credentials for engineering expertise together with a team with unmatchable CCS experience in one, independent company, applying our expertise across the entire value chain.

At CCS TLM, the combination of Tractebel Engineering with our in-house resources, brings specialist expertise to all aspects of the Carbon Capture and Storage value chain. Our goal is to provide reliable and dependable expert consultancy and advisory services throughout the life-of-asset, from project identification to feasibility studies through to deployment of commercial scale solutions.

Whilst every project is different and has unique attributes, there are underlying common factors that make for a successful CCS project, for example:

- Political (& fiscal) support is vital to ensure successful project completion through the alignment of commercial and political aspirations;
- Robust and global solutions to knowledge sharing is key to ensuring the successful development of CCS as an emerging technology/industry; and
- A robust sink is also key to ensure that the long-term storage of CO2 can be confidently assured to support the development of the CCS industry.

CCS TLM are delighted to utilise these capabilities and to work in partnership with the Government of Trinidad and Tobago to identify and assess projects with high potential for success.

Appendix 2: Piano Curve of CO2 abatement costs in Trinidad & Tobago