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CCS Roadmap for Industry: *High-purity CO$_2$ sources*

Sectoral Assessment – Final Draft Report

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Our Ref: 025 CCS Roadmap for Industry

CARBON COUNTS

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CONTENTS

1 INTRODUCTION

Implementation of carbon dioxide (CO_2) capture and storage (CCS) technologies for most industrial activities – for example boilers, turbines, iron & steel furnaces and cement kilns - requires a capture step to convert a relatively dilute stream of CO_2 to a higher concentration so as to allow economic transportation and storage. In these applications, concentrations of CO_2 in exhaust gas streams range from approximately 3-20% CO_2 (Metz *et al*, 2005), which typically need to be concentrated to >85% prior to compression, transport and storage. CO_2 capture processes thus entails the stripping of the CO_2 from other gases present in the exhaust gas stream, in particular nitrogen (N_2), carbon monoxide (CO) and elemental oxygen (O_2). Alternatively, introduction of alternative combustion methods can limit the amount of other gases present in exhaust streams, for example combusting fuels in nearly pure oxygen.

In these contexts, a range of technologies are available for capturing the CO_2, including:

> **Post combustion capture processes** – where the flue gases exiting combustion plant are treated using chemical or physical sorbents to selectively remove CO_2 from the gas mixture. The solvents are subsequently regenerated –using, for example steam – to produce a concentrated CO_2 stream from the stripping column. A range of novel solvents that reduce regeneration energy requirements are also under consideration for post-combustion capture, including chilled ammonia and hindered amines;

> **Pre-combustion capture processes** – where input fossil fuel is gasified to a synfuel mixture, which is then subject to water-gas shift reaction and subsequent gas clean up to separate the produced hydrogen from the CO_2. The gas clean up step is usually achieved using similar methods employed as described for post-combustion processes, although there are advantages to removing the CO_2 from the syngas mainly associated with the pressure of the gas which reduces compression energy requirements. The hydrogen is used as the input fuel to the combustion process, whilst the CO_2 is available in a concentrated form for compression, transport and storage; and,

> **Oxyfuel technologies** – where the combustion process takes place in a relatively pure oxygen environment, resulting in flue gases of high CO_2 concentration. In this case, the exhaust gas requires little or no treatment prior to transport and storage.

In all cases, new equipment must be applied to the standard processes, which imposes additional capital costs, whilst additional operating costs are involved with the operation of the plant, including additional fuel and chemical solvents. Such modifications also require some process integration, increasing the overall complexity of plant operation.

Notwithstanding the challenges of capturing CO_2 from gas streams, some industrial activities already employ technologies similar to those described as part of the standard industrial process. This results in the generation of high purity, high concentration CO_2 process offgas streams which are readily available for dehydration, compression, transport and storage. The types of activities this covers include natural gas processing, hydrogen production (including for the production of

ammonia and subsequent fertilisers), synthetic fuel production (e.g. coal-to liquids; gas to liquids) and certain organic chemical production processes (e.g. ethylene oxide production).

On a global scale, the CO_2 emissions from these activities are relatively modest when compared to emissions from other activities (around 400-450 million tCO_2 per year – approximately 6% of global emissions from industry; Figure 1). However, the scope for utilising these streams for 'early opportunity'[1] CCS projects is an extremely important consideration for rolling-out the demonstration of CCS technologies, in particular sub-surface storage aspects. This is because many of the challenges posed by CO_2 capture for other sectors do not apply to these activities. As such, high purity sources allow early experience with CO_2 storage to be gained in parallel with technology developments for CO_2 capture for other activities, potentially accelerating the rate at which CCS can be fully demonstrated and ultimately deployed on a large-scale.

Figure 1   Global industrial emissions and high purity emissions (2007)

Industry total = 7.6 GtCO$_2$

High purity total = 0.43 GtCO$_2$

- High purity sources
- Other industry

430 MtCO2, 6%

7,175 MtCO2, 94%

119.4 MtCO$_2$ is available for CCS (27.8%)

27.6 MtCO2, 6.4%
6.3 MtCO2, 1.5%
236.0 MtCO2, 54.9%
160.0 MtCO2, 37.2%

- Gas Processing
- Ammonia
- Ethylene oxide
- Coal-to-liquids
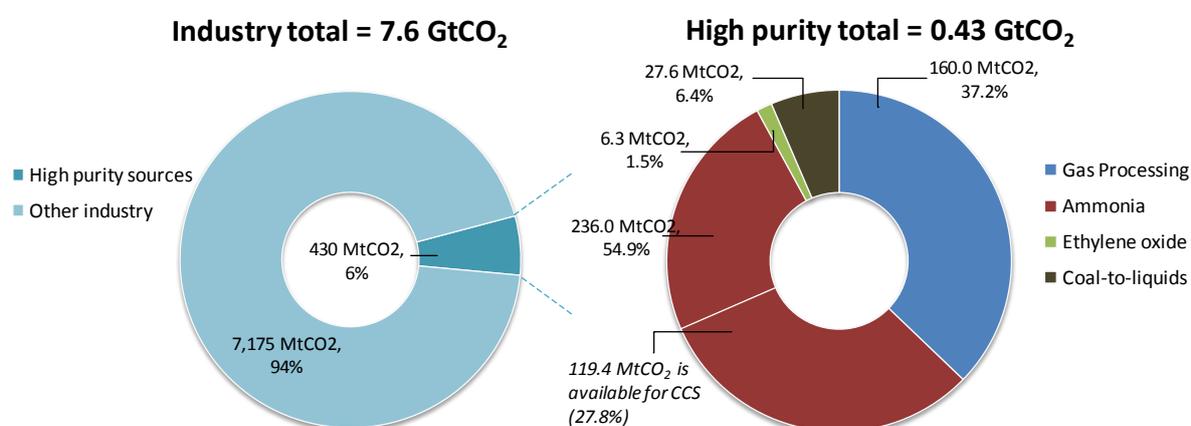
Source: global industry emissions taken from IEA (2009). See main report text for other sources.

This report focuses on the role of high purity CO_2 sources in CCS demonstration and deployment. It covers the following aspects that can illustrate a pathway to CCS demonstration and deployment for high purity sectors to 2050, covering:

- Characteristics of the sector;
- The major processes in these sectors which generate high purity CO_2;
- The outlook for CO_2 emissions and emissions abatement;
- The scope for applying CCS, including estimated costs, global capture potential and investment needs;
- Gaps and barriers that need to be overcome; and
- Actions and milestones that can support and measure deployment.

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[1] The Intergovernmental Panel on Climate Change Special Report on Carbon Dioxide Capture and Storage (Metz *et al*. 2005) defines *early opportunities* as projects that [are likely to] "involve CO_2 captured from a high-purity, low-cost source, the transport of CO_2 over distances of less than 50 km, coupled with CO_2 storage in a value-added application such as EOR."

2   BACKGROUND TO HIGH PURITY CO_2 SOURCE SECTORS

The high purity sector described in this Roadmap covers a diverse range of industrial activities, including natural gas production, synthetic fuel production, and bulk inorganic and organic chemicals production. A brief overview of the level of industrial activity in each sector is outline in the following sections, covering:

- Product uses and global market status
- Production technologies and characteristics
- Forecast production and demand growth / decline
- Regional characteristics of the industry

2.1   Natural gas production

Natural gas is a source of hydrocarbon fossil fuel consisting primarily of methane (CH_4), with trace levels of other longer-chain hydrocarbon gases including ethane, butane and propane. It is produced from geological reservoirs both in free gas phase (non-associated gas), in association with natural gas liquids (condensates) and in association with oil (associated gas). Following processing to remove any impurities, water and heavier hydrocarbon fractions including gases and liquids, it is delivered to markets for end use via three main routes: pipelines, liquefaction and transport by ships for re-gassing at the consumer market, or converted to synthetic gasoline, diesel or aviation fuel (see Section 2.2.3 for discussion of the latter).

The principal market uses for pipeline and liquefied natural gas are power generation, feedstock in industrial processes (e.g. fertilizer and petrochemicals production) and in commercial and domestic heating and hot water use.

The natural gas production industry is characterised by two sets of producers, the international oil companies (IOCs) and state owned oil companies (Table 1).

The six global major IOCs are widely considered to be ExxonMobil, BP, Royal Dutch Shell, Total, Chevron and ConocoPhilips (the "supermajors"). In addition, a wide range of smaller but significant "tier-two" IOCs (e.g. ENI, Repsol YPF, Marathon, Anadarko, Occidental, BG Group) also operate on an increasingly global scale, whilst a range of other smaller exploration and production (E&P) companies, largely prospecting in frontier provinces, are also a feature of the privately held oil and gas sector.

In most oil and gas producing regions outside of the OECD, state owned national oil companies (NOCs) dominate production, although they often operate under production sharing agreements with super-majors and IOCs. Cooperation between NOCs is also becoming a feature of new investment developments in the sector. The major NOCs include: Saudi Aramco (Saudi Arabia), JSC Gazprom (Russia), CNPC (PetroChina), PDVSA (Venezuela), Petrobras (Brazil), Petronas (Malaysia), and PEMEX (Mexico). Other large producers, in particular for gas production, include Qatar Petroleum (Qatar), Sonatrach (Algeria), KPC (Kuwait), NOC (Libya), ADNOC (Abu Dhabi), National Iranian Oil Company (NIOC), NNPC (Nigeria), CNOOC (China), Sinopec (China) and PTT (Thailand). In

recent years, some of these companies have extended their areas of operation into emerging production provinces, in particular in Africa.

Table 1   Gas production by company (top 15 producers; 2007)

	Company	Type	Production (bcm, 2007)	% of global production
1	Gazprom	NOC	548.5	18.4
2	NIOC	NOC	106.7	3.6
3	ExxonMobil	Super-major	97.0	3.2
4	Sonatrach	NOC	90.0	3.0
5	Shell	Super-major	84.9	2.8
6	BP	Super-major	84.2	2.8
7	SaudiAramco	NOC	68.4	2.3
8	CNPC	NOC	57.8	1.9
9	Petronas	NOC	57.3	1.9
10	Pemex	NOC	56.0	1.9
11	ConocoPhillips	Super-major	52.6	1.8
12	Chevron	Super-major	51.9	1.7
13	Total	Super-major	50.0	1.7
14	Qatar Petroleum	NOC	42.9	1.4
15	ENI	IOC	42.3	1.4

Source: IEA, 2008a

In terms of global gas production by company, Russia's Gazprom dominates the global gas supply, with a market share of 18%. Other major NOCs include the NIOC, Sonatrach, Saudi Aramco, PetroChina, Petronas, PEMEX and Qatar Petroleum whom along with Gasprom account for nearly 35% of global gas supply; the super majors account for just under 15% (Table 1).

Despite a 2.1% decrease in world gas demand in 2009 – the first decline ever recorded (BP, 2010) – the longer-term supply outlook for natural gas suggest significant increases through 2030. Proven gas reserves are considered more than sufficient to meet demand over this period.

The top 15 largest gas producing countries of the world are responsible for 75% of global gas production (Table 2).

Table 2   Gas production by country (top 15 producers; 2009)

	Country	Production (bcm, 2009)	% of global production	Reserves (tcm, 2009)	R:P ratio
1	United States	593.4	19.9	6.93	12
2	Russia	527.5	17.7	44.38	84
3	Canada	161.4	5.4	1.75	11
4	Iran	131.2	4.4	29.61	226
5	Norway	103.5	3.5	2.05	20
6	Qatar	89.3	3.0	25.37	284
7	China	85.2	2.9	2.46	29
8	Algeria	81.4	2.7	4.50	55
9	Saudi Arabia	77.5	2.6	7.92	102
10	Indonesia	71.9	2.4	3.18	44
11	Uzbekistan	64.4	2.2	1.68	26
12	Netherlands	62.7	2.1	1.09	17
13	Egypt	62.7	2.1	2.19	35
14	Malaysia	62.7	2.1	2.38	38
15	United Kingdom	59.6	2.0	0.29	5
	Rest of the world	752.6	25.0	47.74	63
	World total	**2987.0**	**100**	**183.51**	**61**

Notes: R:P Ratio = Reserves to production ratio. It is an indication of the expected lifetime of the natural gas resource in years based on the current situation.
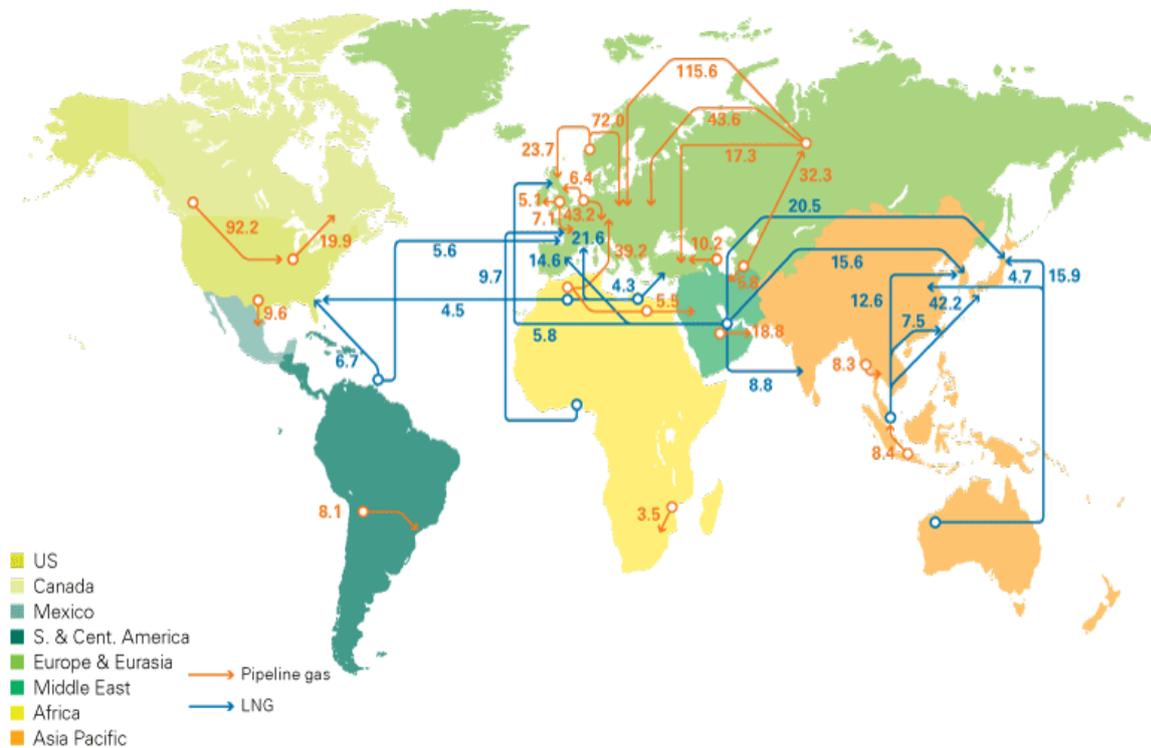
Source: BP, 2010

The precise nature of the growth in gas demand will be determined by the economics of delivering gas to markets. Increasingly there is a geographical imbalance between supply and demand which is met by increasingly more complex – and therefore costly – pipeline projects and a growing supply of liquefied natural gas (LNG; Figure 2). The result of increases in gas supply costs, along with increasing concerns over energy security and the challenges of raising debt for large projects due to the global credit crises has led to unconventional gas becoming more attractive in some regions. This is particularly the case in the United States, where production of unconventional gas (e.g. coalbed methane) increased significantly during 2009 (BP, 2010). Increasing trade in natural gas, coupled to increasing supplies of LNG will likely lead to the emergence of a single global gas price that will seemingly be determined by the marginal cost of developing the required midstream infrastructure over coming years.

Figure 2   Major trade movements in natural gas (bcm, 2009)

Major trade movements
Trade flows worldwide (billion cubic metres)

Legend:
- US
- Canada
- Mexico
- S. & Cent. America
- Europe & Eurasia
- Middle East
- Africa
- Asia Pacific
- → Pipeline gas
- → LNG

Source: BP, 2010

The IEA's Reference Scenario (IEA, 2009c) suggests that natural gas consumption will grow by about 1.6% per year from the current 3 tcm per year to 4.3 tcm in 2030; this is forecast to increase to 5.6 tcm by the year 2050 (IEA, 2010), and is expected to be dominated by supplies from the Middle East (in particular Iran and Qatar), Russia and Nigeria (Figure 3).

The IEA's 450ppm and BLUE Map Scenarios forecast a lower rate of growth in gas supply through 2030 and 2050, reflecting an alternative low carbon pathway supported by a significant shift in future climate policy and abatement incentives. Under these alternative scenarios, gas supply is estimated to reach around 3.6 tcm per year in 2030 (IEA, 2009c) and 2.7 tcm in 2050 (IEA, 2010) – a reduction of around 50% compared to the reference case by the year 2050.

Figure 3   Natural gas production forecast (IEA Reference/baseline scenario 2007-2050; bcm)
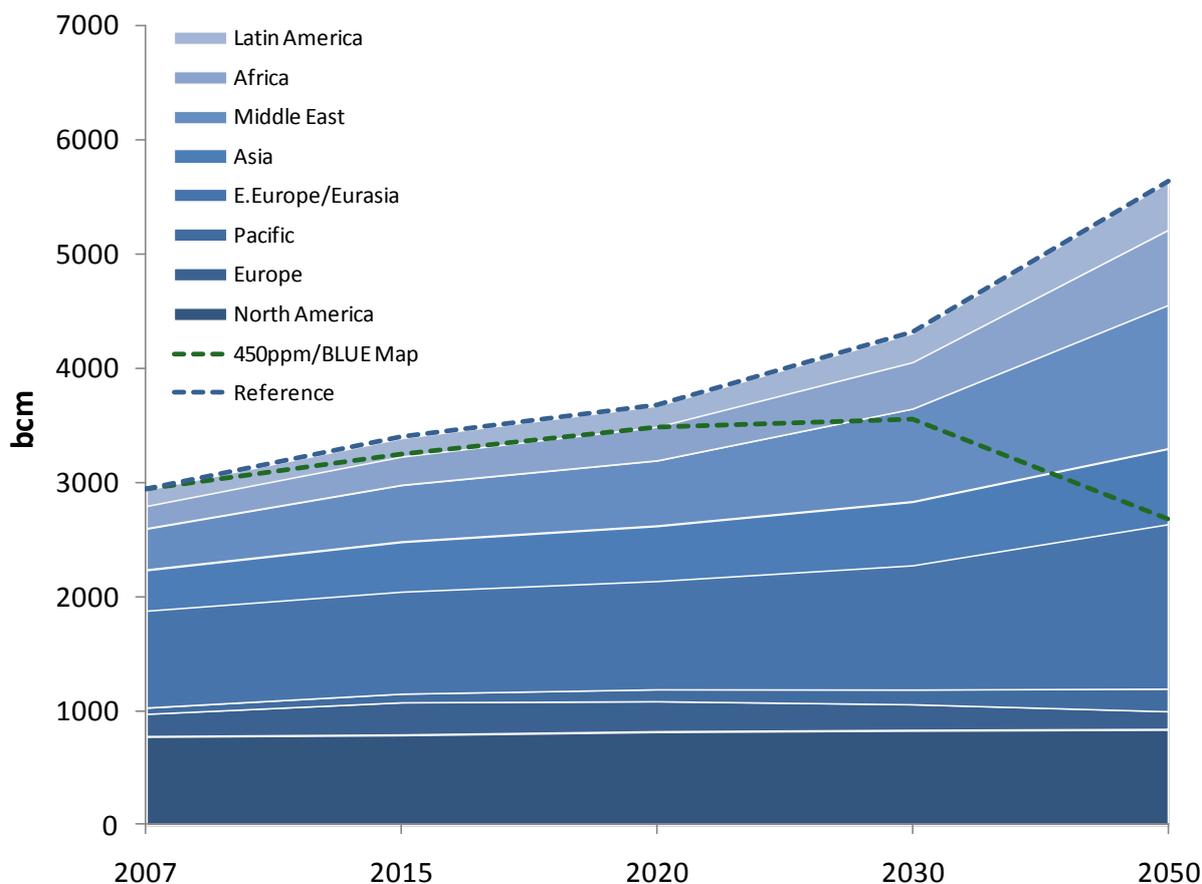
Note: the graph shows projected gas production under the WEO Reference case 2007-2030 and the ETP baseline scenario 2030-2050. An alternative low carbon pathway is indicated by the dashed green line and indicates the IEA 440ppm and BLUE Map scenario forecasts to 2050. Note that the BLUE Map scenario aims for a 50% reduction in global CO_2 emissions by 2050, while the WEO Reference case does not assume such a long term target.
Source: IEA, 2009c; IEA 2010

2.1.1 Natural gas processing

As mentioned previously, natural gas typically undergoes processing prior to export to markets. This can involve the simple 'flashing off' of lighter gaseous phases, through to more complex treatments including liquefaction and conversion to liquid fuels (gas to liquids; GTL).

Where the natural gas contains significant levels of impurities, additional treatments must be applied to remove these. Natural gas reservoirs containing significant quantities of CO_2 and hydrogen sulphide (H_2S) are typically referred to as sour gas reservoirs or acid gas reservoirs where CO_2 predominates. The IEA report that more than 40% of the world's gas reserves are sour, with the number increasing to 60% for Middle Eastern gas reserves. Where the produced natural gas is sour or acid, it must be "sweetened" before use.
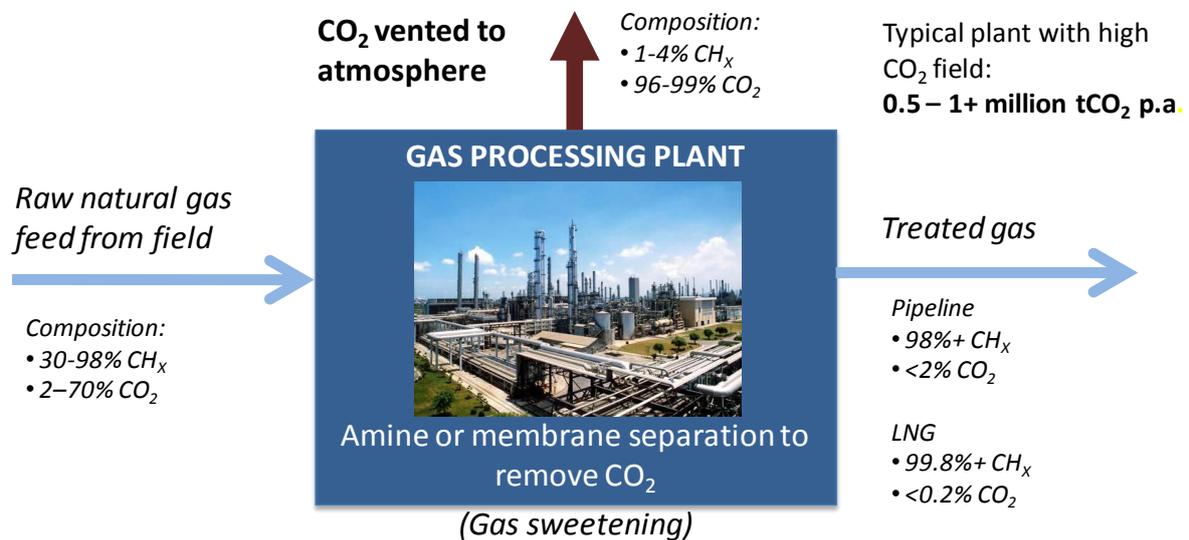
Gas sweetening

H_2S must be removed to trace levels from natural gas as it is highly corrosive when mixed with water and toxic to biological organisms. For CO_2, the level of removal will vary depending on delivery route and end use. For pipeline gas, this will be determined by the gas network operator through a

contracted delivery specification for the gas, which in turn depends on the level of blending that may be achieved. For some dedicated applications, these standards may be relaxed where low calorific value (LCV) gas can be combusted (e.g. for use in modified gas turbines). Consequently, specifications for pipeline gas will vary from 0.2% to up to 18% or 20% CO_2 by volume, however, typical specification for gas distribution grids are for less than 2% CO_2 by volume.

For LNG and GTL, CO_2 must be removed to trace levels in order to prevent CO_2 solidifying during compression (i.e. dry-ice formation), which has serious implications for process control. Typical specifications for LNG and GTL feedstock is less than 0.2% by volume. Generalised process flows for gas sweetening are highlighted below (Figure 4a and b).

Figure 4   Generalised process flow for gas sweetening

(a) Natural gas sweetening configuration

(b) Potential offshore configuration for gas sweetening
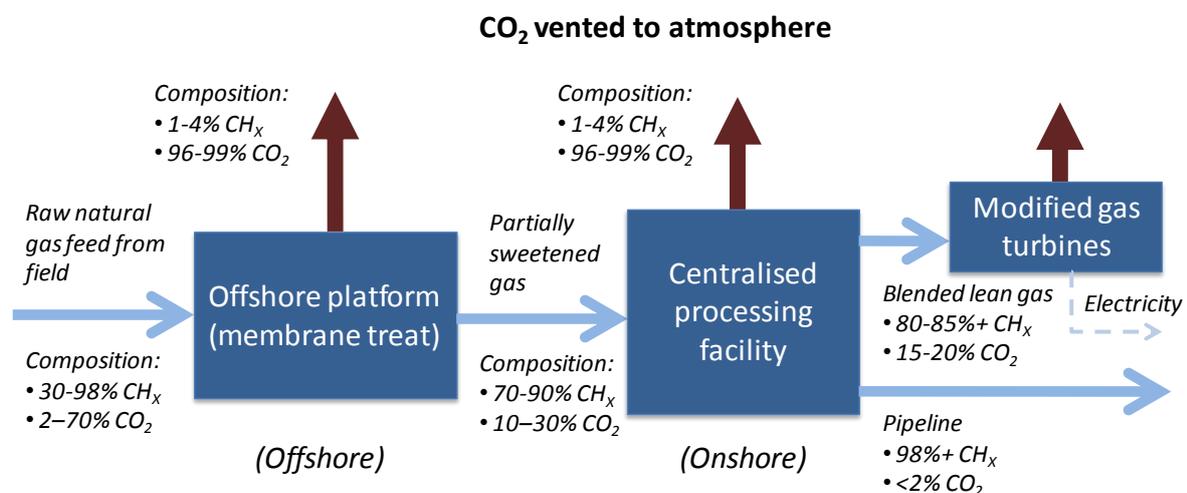
Note: Figure 4b based on configurations at Songkhla, Thailand.

Figure 4a shows a generalised process configuration for gas sweetening, where raw gas from reservoirs – either a single reservoir or multiple fields – is treated at a centralised processing facility using an amine or membrane based treatment to remove CO_2. The removed CO_2 is vented to the atmosphere and the treated gas is either exported to markets in pipelines or input to LNG or GTL production. The gas may be further blended at other processing facilities prior to delivery to end users.

Figure 4b shows an alternative treatment configuration that is sometimes employed offshore. In this configuration, some processing takes place at the wellhead at the offshore platform prior to transporting the natural gas onshore. Typically, because of weight and maintenance configurations, the offshore platform uses a membrane treatment. Constraints on available energy may also require the application of a single pass technology, which can only reduce the CO_2 content to around 20-25% (depending on initial content). The partially sweetened gas is then transported to a centralised processing facility onshore, where it is blended with gas from other sources. Typically centralised processing facilities will be co-located with a bank of gas-fired power plants to provide anchor demand for the gas. In some cases, the gas turbines may be modified to run on a low caloric mixture of natural gas and CO_2 (as much as 20% CO_2) as a means of reducing the amount of gas processing required. Treated gas will be exported to end users.

A more detailed description of the technologies employed to remove CO_2 from natural gas mixtures is presented in Section 2.4 below.

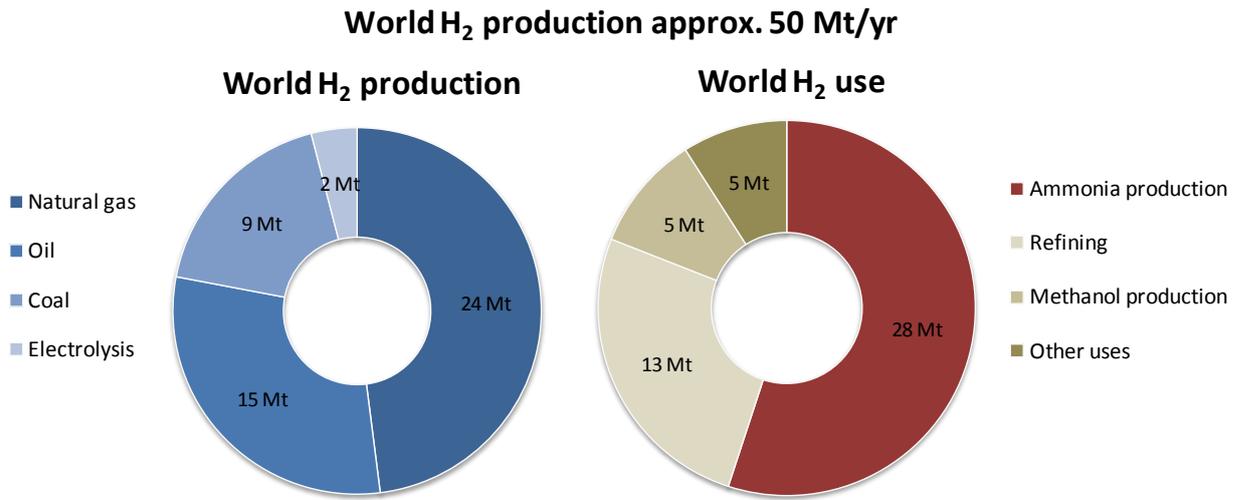## 2.2 Industrial hydrogen and synfuel production and use

In the following section, several activities that are included in the high purity CO_2 source category are considered in the same context due to the similarity of the underlying process. All involve the application of solid fuel gasification or natural gas reforming technologies to produce a syngas which is purified via a gas clean-up step to produce a reformed syngas mix or hydrogen (H_2) for use as feedstock to for the production of various final products. The water-gas shift reaction process converts syngas to a mixture of CO_2 and hydrogen in varying amounts. In the case of hydrogen production, the CO_2 must be removed to produce a purified stream, whilst for synthetic fuel production, the water-gas shift conversion and gas clean-up steps are carefully controlled to optimise the H_2/CO ratio. This type of technology covers the following sectors:

- Ammonia (and fertiliser) production, and
- Synthetic fuel production.

2.2.1 Hydrogen production

Globally, around 45-50 million tonnes of hydrogen are produced each year, the majority of which is produced using fossil fuel feedstocks (Figure 5, Figure 6; Hydrogen Association; Evers, 2008). Around half is used to produce ammonia, around a quarter is used for hydrocracking in petroleum refining, with the balance used to make methanol and other industrial applications including coal-to-liquids (Figure 5).

Figure 5   Estimated world hydrogen production and use (2008)

World H$_2$ production approx. 50 Mt/yr

World H$_2$ production

- Natural gas
- Oil
- Coal
- Electrolysis

24 Mt
15 Mt
9 Mt
2 Mt

World H$_2$ use

- Ammonia production
- Refining
- Methanol production
- Other uses

28 Mt
13 Mt
5 Mt
5 Mt

Source: various as in text

There are several processes for producing hydrogen from fossil fuel or biomass feedstocks, including: steam reforming, auto-thermal reforming (ATR), partial oxidation (POX), and gasification. Technology selection depends on economics, plant flexibility and feedstock source. A generalised schematic of the industrial hydrogen production process is shown below (Figure 6)

Figure 6   Generalised process flow for industrial hydrogen and syngas production

O$_2$ and/or Air

Feedstock in

Coal/Biomass

GASIFIER

Natural gas/fuel oil

PARTIAL OXI (POX)

Syngas (H$_2$, CO, CO$_2$, H$_2$O)

Natural gas/naptha

REFORMER (SMR/ATR)

O$_2$ and/or Air Steam

SHIFT REACTOR

(Water –gas shift H$_2$O, H$_2$, CO, CO$_2$ shift to H$_2$ & CO$_2$)

GAS CLEAN UP (H$_2$ & CO$_2$ separation) PSA, physical absorption e.g. Selexol

CO$_2$:
- **Vented**
- **To urea production**
- **Enhanced oil recovery**

H$_2$ and to ammonia and F-T processes

Note: SMR = Steam methane reforming; ATR = Auto thermal reforming; POX = Partial oxidation.

Steam reforming

Steam reforming is the most widespread process in use today for industrial hydrogen production (Metz *et al.*, 2005). It typically involves the use of natural gas, where it is referred to as steam methane reforming (SMR), but can also use other light hydrocarbons.

The first stage is the removal of sulphur, followed by the introduction of the hydrocarbon feedstock into a reformer, where synthesis gas is produced at around 800-900°C in the presence of a nickel-based catalyst. The process is endothermic, and additional heat is supplied to the reaction through the partial burning of the fuels (secondary fuels). The reformed gas is cooled in a waste heat boiler, which provides the steam for the reaction process. The reformed gas is then subject to shift reactions and gas clean-up (Figure 6). Typically, carbon monoxide (CO) in the syngas is reduced to 0.2-0.3% through the water-gas shift reactor, resulting in a mixture of mainly CO_2 and H_2, from which the CO_2 is removed to produce pure hydrogen (Metz *et al.*, 2005). Traditionally the CO_2 was removed from the syngas mixture using chemical based solvent absorption techniques, although more modern plants may use pressure swing adsorption (Metz *et al.*, 2005). The gas clean up technique used has ramifications for subsequent CO_2 compression, transport and storage, as described in Section 2.4.

Partial oxidation

Partial oxidation (POX) processes involve the reacting of fuel with oxygen at high pressures. The process is exothermic and therefore doesn't require an external heat source, typically taking place at temperatures around 1250-1400°C. The produced syngas is subject to water-gas shift and gas clean-up as described for SMR above. The heat required for the reaction is supplied by the partial combustion of the feedstock (Metz *et al.*, 2005).

Oxygen is supplied from an air separation unit (ASU), which imposes a significant energy burden on the gasification step compared to SMR. However, this is partially made up through the exothermic nature of the reaction, and because it uses oxygen instead of air in the reactor, nitrogen is excluded from the water-gas shift and gas clean up steps, reducing energy requirements in subsequent processes. Generally, the POX process is less efficient than the SMR technique, however, it has the benefit of being more widely adaptable to a range of feedstocks.

Auto-thermal reforming

Auto thermal reforming (ATR) is a combination of SMR and POX processes, with the required heat being generated by the partial oxidation reaction using air or oxygen, but because steam is also provided the endothermic reforming reaction occurs in the catalytic section of the reactor downstream of the POX burner. It has advantages over the SMR process as no direct CO_2 emissions are produced because all of the heat release is internal (Metz *et al.*, 2005). However, these benefits are offset by the investment and operating costs of the ASU plant.

Gasification of solid fuels

Gasification is similar to the POX process, although with the addition of steam. A variety of different gasifier configurations are currently in use, including fixed bed and entrained flow systems, all of which have different requirements in terms of the oxidant used, operating pressure, feed system, syngas cooling system and gas clean up steps (Metz *et al.*, 2005). Most systems installed in the last 20 years employ the entrained flow system, of which there are three alternatives available on the market (Metz *et al.*, 2005).

The gasification process results in the production of a syngas, which is then subject to water-gas shift reactions and gas clean–up as described for other processes above.

2.2.2 Ammonia production

Production of hydrogen using processes described in the previous section is the first step in the manufacture of ammonia in the Haber-Bosch process. The Haber-Bosch process involves the synthesis of hydrogen with gaseous nitrogen using an iron or ruthenium enriched catalyst at high temperature and high pressure.

Around 80% of all ammonia manufactured worldwide is used to produce inorganic nitrogen based fertilisers. Other important uses of ammonia include the manufacture of nitric acid, nylon and other polymides, refrigerants, dyes, explosives and cleaning solutions.

The challenges associated with storing and transporting hydrogen mean that ammonia and fertiliser producers manufacture hydrogen onsite. The International Fertiliser Association (IFA) reports that the predominant source of hydrogen for ammonia production is natural gas, although coal also forms a significant proportion, especially in China (Figure 7). In terms of the preferred hydrogen production method, a variety of different techniques as described in the previous section are used, with no publically available data on the different types of plant in operation today.

Presently around 150 million tonnes of ammonia are produced globally (IFA, 2010a). The main producing regions are East, Central and South Asia, where more than half of global ammonia production is located (Table 3).

Table 3   Global ammonia production by region (2008)

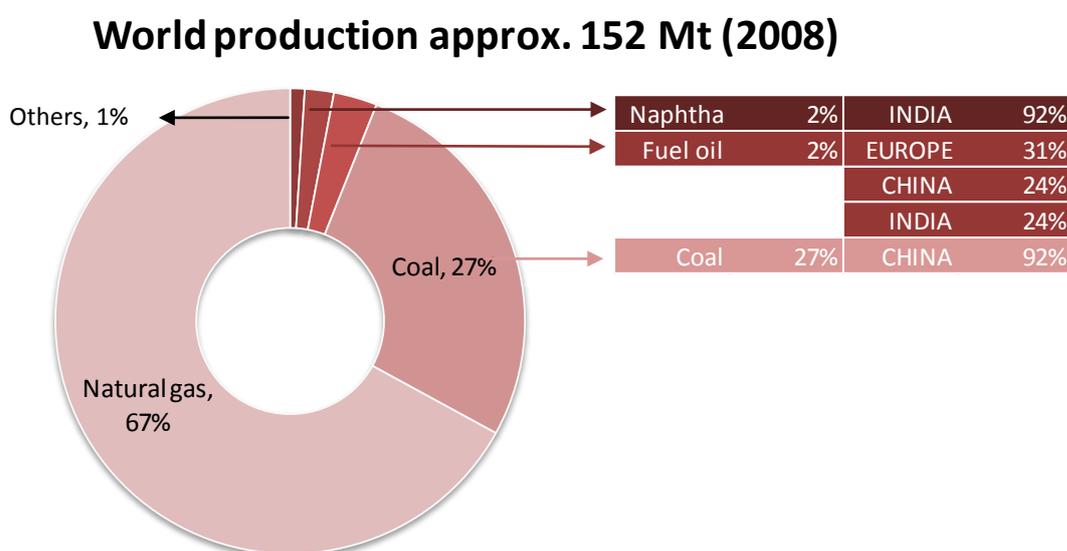| Region	Production (000's tonnes; 2008)	Seven year trend (2001-2008)	Share of production
East Asia	57,619	4.3%	37.9%
E. Europe & C. Asia	21,690	3.0%	14.3%
South Asia	16,376	-0.1%	10.8%
North America	14,432	-4.0%	9.5%
West Asia (M. East)	10,928	6.8%	7.2%
West Europe	10,315	-2.2%	6.8%
Latin America	9,202	3.6%	6.1%
Africa	5,054	2.2%	3.3%
Central Europe	4,873	1.2%	3.2%
Oceania	1,415	8.9%	0.9%
Total	**151,904**	**1.9%**	**100%**

Source: IFA, 2010a

The Middle East has increased its production of ammonia in recent years, and is likely to be a major source of ammonia in the future as production in OECD areas such as Europe and North America

continues to decline. However, this will require a marked increase in global trade, which has remained stable at around 11-13% over the period 1999-2008 (IFA, 2010b).

In terms of producers, the industry is highly diversified, with no major global companies dominating the market. For many countries, the industry is strategically important either because of the importance it plays in national food security (e.g. India) or because of its role in raising foreign direct earnings through valoration of natural gas resources (e.g. the Middle East). In some cases, the industry is largely within the control of state owned enterprises with close ties to the national oil company (e.g. Saudi Basic Industries Corporation; SABIC). This is most likely the reason for the low levels of trade in ammonia to date.

Figure 7   **World ammonia production by feedstock type**

World production approx. 152 Mt (2008)

Naphtha	2%	INDIA	92%
Fuel oil	2%	EUROPE	31%
		CHINA	24%
		INDIA	24%
Coal	27%	CHINA	92%

Source: IFA, 2010b

The International Fertiliser Association reports that the industry already utilises around 36% of the CO_2 removed from the syngas in the gas clean-up step (IFA, 2010b). Of this, around 33% is used for the synthesis of ammonia into urea, whilst the remaining 2.2% is sold on to other uses (5.2 $MtCO_2$), such as CO_2 use for enhanced oil recovery (IFA, 2010b; see Figure 13; Section 3.1.2). This suggests that 78 $MtCO_2$ produced in ammonia production is consumed in urea manufacture globally. However, these data should be modified in light of the stoichiometry of urea production using ammonia, which is 0.733 tCO_2/t NH_3. Using this approach, the IFA report that global urea production in 2008 was 146 Mt of product (IFA, 2010a), which would therefore suggest high utilisation rates of CO_2 in the fertiliser industry, at around 107 $MtCO_2$ per annum.

Therefore, adopting the stoichiometric basis for use in urea production and adding in the 2.2% of produced CO_2 sold into other value chains, around 50% of produced CO_2 is vented direct to the atmosphere (119 $MtCO_2$/yr). In addition to the high purity streams produced, ammonia plants also produce impure CO_2 streams, arising from combustion of fuels in reformers, boilers and gas turbines (where power is produced on site), which have not been considered within the scope of this study.

In a modern fertiliser plant, around 1.6-3.8 tonnes of CO_2 are produced per tonne ammonia (IFA, 2009), of which around 1.15-2.60 tCO_2 is produced from the production of hydrogen - depending on the hydrogen production process and feedstock employed (Table 4).

Table 4   Typical performance data for ammonia production plants

	Conventional reforming	Excess air reforming	Partial oxidation
Total energy (GJ/t NH_3)	32-35	32-35	39-45
Feedstock	*24.5*	*26.0*	*32.0*
Fuel	*8-10*	*6-8*	*-*
Outputs			
Ammonia (t/d)	*1000 – 1500*	*1000 – 1500*	*1000 – 1500*
CO_2 reformer (t/tNH$_3$)[a]	*1.15 – 1.30*	*1.15 – 1.30*	*2.0-2.6*
Emissions			
CO_2 in flue gas (t/t NH$_3$)[b]	*0.5*	*0.4 – 0.5*	*n.a*

[a] not including CO_2 in flue gases.   [b] Assumes CO_2 is used in plant and not vented.

Source: UNEP/UNIDO (1998)

The outlook for ammonia production is strongly driven by increasing demand for inorganic fertilisers for food and biomass production. The IEA estimates that annual ammonia production will increase by between 101 and 143 million tonnes between 2007 and 2050 (IEA, 2010) to as high as 303 million tonnes, or double the current levels production levels. The main increases are expected to occur in the Middle East (24-38 Mt,) developing Asia (24-38 Mt), Russia (11-15 Mt), Latin America (9-13 Mt) and Africa (11-14 Mt) whilst production on Western Europe and North America is likely to remain at current levels (*ibid*).

2.2.3 Synthetic fuel production

At present a small proportion of the synthesis gas produced globally is converted to synthetic fuels. Synthetic fuels production is a means to substitute conventional liquid fossil fuels through production of liquid fuels through alternative pathways, such as the conversion of coal and natural gas. Options for synthetic fuel production include production of the following:

- Synthetic diesel and jet fuel
- Synthetic gasoline, and
- Naphtha, DiMethyl Ether (DME) and methanol

Interest in the production of synthetic fuels as a substitute to oil derived products has risen in recent years in response to increasing oil prices and concerns over energy security. The production of synthetic fuels is energy intensive, and therefore it is only economic under high oil price scenarios. Moreover, CO_2 emissions from synthetic fuel production are also much higher than for conventional fuel production, in particular for coal-based processes; gas based processes, such as gas-to-liquid production, have lower emissions (Table 5; IEA, 2008c).

Table 5 CO_2 emission from various synthetic fuel production processes

	Efficiency (%)	CO_2 (kg/GJ product)	CO_2 (Mt/yr/plant)
FT natural gas	70	7	0.25 - 0.5
FT coal	40	160	10 - 15
FT biomass	40	210	0.2
Methanol/DME from coal	65	110	5-10
Methanol/DME from natural gas	70	8	0.25 - 0.5

Source: IEA, 2008c and Steynberg and Nel, 2004

There are two main methods for coal liquefaction:

Indirect methods – Indirect methods for synthetic fuel production begins with similar industrial gasification and reforming technologies as described previously (Figure 6). However, the fundamental process involves the hydrogenation of CO, and thus unlike pure H_2 production, CO is required in the syngas feedstock to the Fischer-Tropsch (F-T) reactor. In order to achieve this, the water-gas shift process is optimised to produce suitable ratios. For coal gasification, the water-gas shift reaction typically produces a syngas with a ratio of H_2/CO of around 0.7, whilst the optimised ratio is around 2. Therefore, removal of some CO in the form is CO_2 is required via a gas clean-up stage. This is the main source of pure CO_2 in a coal based synfuel plant. For gas based F-T processes, significantly lower amounts of CO_2 must be removed from the F-T reactor syngas feedstock, hence the lower emissions associated with natural gas synfuel production processes. The indirect CTL production method is the only technique in commercial operation today.

Direct methods – Direct methods of coal liquefaction, such as the NEDOL or ExxonDonor Solvent process, have also been developed by some companies as an alternative to the indirect method. The direct method involves mixing coal with a solvent and then cracking the syngas with hydrogen using a catalyst. It produces a high H_2/CO ratio, reducing CO_2 removal requirements. Therefore it has lower emissions than the indirect method. However, no commercial scale plant has ever been built. Presently, Shenhua Corporation's CTL project in the Ordos Basin, Inner Mongolia, which was recently commissioned, is an example of a plant using the direct method for coal liquefaction.

Natural gas based synfuel production processes are a less interesting candidate for CCS compared to coal-based processes, and are not considered further in this report.

Sasol's Secunda CTL plant is the largest commercial scale CTL plant in operation worldwide. It employs the indirect method of production involving coal gasification followed by F-T synthesis. Two plants at Secunda have been in operation since 1980 and 1984, consuming more than 40 million tonnes of coal per year (Sasol, undated) and producing around 130,000-160,000 barrels of product per day. More recently, a number of other CTL projects have been proposed worldwide, including in the United States, Australia and China. These include the Shenhua plant located in Ordos, Inner Mongolia which has now begun operations. However, recent declines in oil prices have seen

investment decisions deferred for most of the known proposals. It has been reported that 31 CTL projects were proposed as of 2009 (Vallentin and Fischedick, 2009), although it has not been possible to corroborate this number within this research and analysis. A summary of known current and potential CTL projects are shown below (Table 6).

A similar coal gasification project, albeit for the production of substitute natural gas (SNG) and other by-products from the gasification of brown coal (lignite), has been operated by Great Plains Synfuel plant at in Beulah, North Dakota, USA since 1984. Almost 3 million tonnes of CO_2 produced from the Great Plains Synfuel plant is captured and transported 320 km to Saskatchewan for the purpose of enhanced oil recovery, and is one of the few commercial scale of CCS projects in operation today (see Box 1). Several other smaller SNG plant have been proposed in the US, although none have yet come on stream (Table 6). China is also pursuing SNG produced from coal with an overall capacity of around 15 bcm per year at present, as well as coal-to-DME, which stood at around 4 Mt DME per year in 2008.

Table 6   Summary of CTL projects worldwide

Operator	Plant/location	Production (bbl/day)	Emissions (MtCO$_2$/yr)[a]	CO$_2$ intensity (tCO$_2$/bbl)[b]	Status
Sasol	Secunda, RSA	150,000	24.0	0.471	Operational
Shenhua/Sasol	Ordos, China	24,000	*3.6*	0.441	Operational
Shenhua	Yulin, China	80,000	*12.4*	-	Unknown
Jinmei	Jincheng, China	2,500	*0.4*	-	Operational
Lu'an	Changzhi, China	4,000	*0.6*	-	Construction
Yitai	Ordos, China	4,000	*0.6*	-	Operational
AngloAmerican	Monash, Aus	62,000	*8.3*	-	Postponed
FuturGas	Otway, Aus	100,000	*13.3*	-	Postponed
Malstrom	Montana, US	n/a		-	Cancelled
East Dubuque F-T plant	Illinois, USA	n/a		-	Unknown
Rentech Strategic Fuels	Colorado, USA	n/a		-	Unknown
Coffeyville Syngas	Kansas, USA	n/a		-	Unknown
Total		**>426,500**	**67.5**	**(0.456)**	

Notes: [a] Metz *et al* (2005) suggest that a nearly pure stream of around 20 million tCO$_2$ is released annually at Secunda. Emissions for proposed plants estimated from Secunda CO$_2$ intensity. This data has been updated to 24 MtCO$_2$ (Liebenberg,2010, *pers comm*) and data from Sun (2008). [b] Intensity for pure CO$_2$ stream only, based on an estimated production at Secunda of around 150,000 barrels of product per day and Shenhua production of 24,000 barrels of product per day and a 340 days per year operating time, divided by the total emissions.

Source: various

The future for CTL is highly uncertain, making projections of future production very unclear. The IEA (IEA, 2008a) suggests that the large uncertainty around CTL investment is a result of technical, economic and environmental considerations. It estimates that global production of CTL derived liquids could increase to around 1.1 Mbbl/d in 2030 from its current level of 0.13-0.15 Mbbl/d, a more than 7-fold increase over the next 20 years. Realising such levels of deployment will need a stable long-term outlook for oil prices, and a shift in policies to promote synfuel developments in order to secure the large amounts of investment involved in such schemes.

The main companies looking to develop CTL projects include the oil supermajors (e.g. Shell, ConocoPhilips, Chevron), integrated energy companies such as Sasol, coal producers such as Anglo Coal (Global) and Shenhua Corporation (China), and a range of independent developers such as Rentech (USA).

2.2.4 Refineries

As shown in Figure 5, around 15 million tonnes of hydrogen are produced annually for use in petroleum refining. This is not covered in this report, but is discussed in detail in the refineries Sectoral Assessment.

2.3   Ethylene oxide production

Ethylene oxide is a colourless flammable gas produced by direct oxidation of ethylene in the presence of a silver catalyst. Because of its special molecular structure, ethylene oxide easily participates in the addition reaction, allowing it to easily polymerize into larger compounds. It therefore has a range of uses in the chemical sector.

The major industrial application of ethylene oxide is as a key raw material in the production of many industrial chemicals and intermediates, including (Shell Chemicals, 2009):

- *Ethylene glycols* –used in the production of antifreeze, polyester and polyethylene terephthalate (PET, the raw material for plastic bottles), liquid coolants and solvents.
- *Polyethylene glycols* - used in perfumes, cosmetics, pharmaceuticals, lubricants, paint thinners and plasticizers
- *Ethylene glycol ethers* - used as a key component of brake fluids, detergents, solvents, lacquers and paints
- *Ethanol amines* - used in the manufacture of soap and detergents and for purification of natural gas
- *Ethoxylates* – (produced through reaction of ethylene oxide with higher alcohols, acids or amines) in the manufacture of detergents, surfactants, emulsifiers and dispersants

Figure 8   World Industrial use of ethylene oxide (2007)
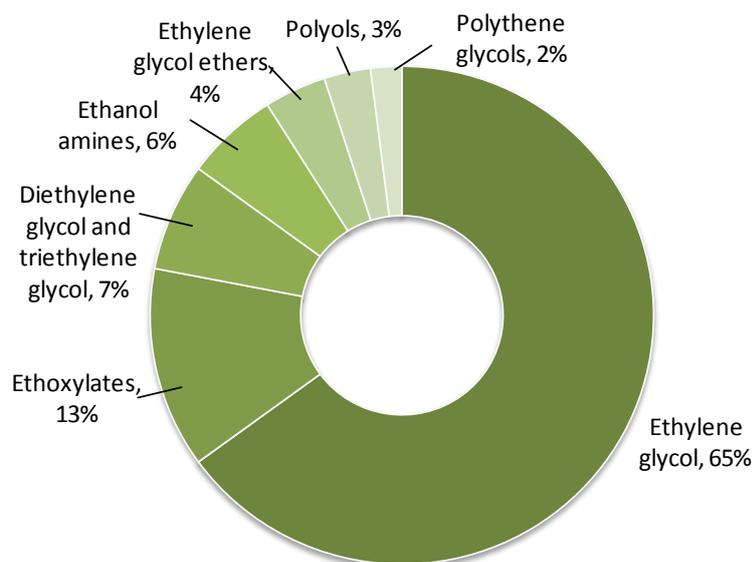
Whereas synthesis of ethylene glycols is the major application of ethylene oxide worldwide, its share of overall use varies greatly depending on the region: from 44% in Western Europe, 63% in Japan and 73% in North America to 90% in the rest of Asia and 99% in Africa (Chemical Intelligence, 2009).

Global production of ethylene oxide was around 19 million metric tons in both 2008 and 2009, having increased slightly from 18 million tonnes in 2007 (SRI Consulting, 2009). This places ethylene oxide as the 14th most produced organic chemical worldwide - the most produced organic chemical was ethylene with 113 million tonnes (SRI Consulting, 2009).

Ethylene oxide was first manufactured by BASF in 1914 using ethylene chlorohydrin (reaction of ethylene chlorohydrin with calcium hydroxide) as an intermediate, but this route has been superseded by the direct oxidation of ethylene with air or oxygen. Currently, nearly all the world's ethylene oxide production capacity is based on direct oxidation, with oxygen generally preferred over the air route in larger plants due to higher yields and less downtime (ICIS, 2010).

In direct oxidation, ethylene, compressed oxygen and recycle gas are mixed and fed to a multi-tubular catalytic reactor. The mixture is passed over a silver oxide catalyst supported on a porous carrier at 200-300°C and 10-30 bar. The reaction is highly exothermic and the heat removed can be used to generate steam. The gases from the reactor are first cooled and passed through a scrubber where the ethylene oxide is absorbed as a dilute aqueous solution. This process of reactor gas stream clean up includes the removal of the CO_2 using physical sorbents, Hot Potassium Carbonate process such as the Benfield process, or cryogenic separation techniques (see Section 2.4). The resulting high purity CO_2 stream is typically vented. The resulting ethylene oxide can then go straight to ethylene glycol manufacture or purified by fractionation for use in other ethylene oxide derivatives (Figure 9).

There is extremely limited data on the rates of CO_2 generation in the production of ethylene oxide. The stoichiometry of the process suggests it is produced at a ratio of 6/2 ethylene oxide to CO_2,

which would mean that CO_2 generation is about a third of total ethylene oxygen production. In this case, around 6.2 Mt of high purity CO_2 is produced annually from ethylene oxide production. Other literature suggests that the concentration of CO_2 in the reactor gas is around 8% (Metz *et al*. 2005; see Table 8), suggesting around 1.5 Mt high purity CO_2 production per annum (see Section 3.1.3).

Figure 9   Generalized schematic of ethylene oxide production by direct oxidation
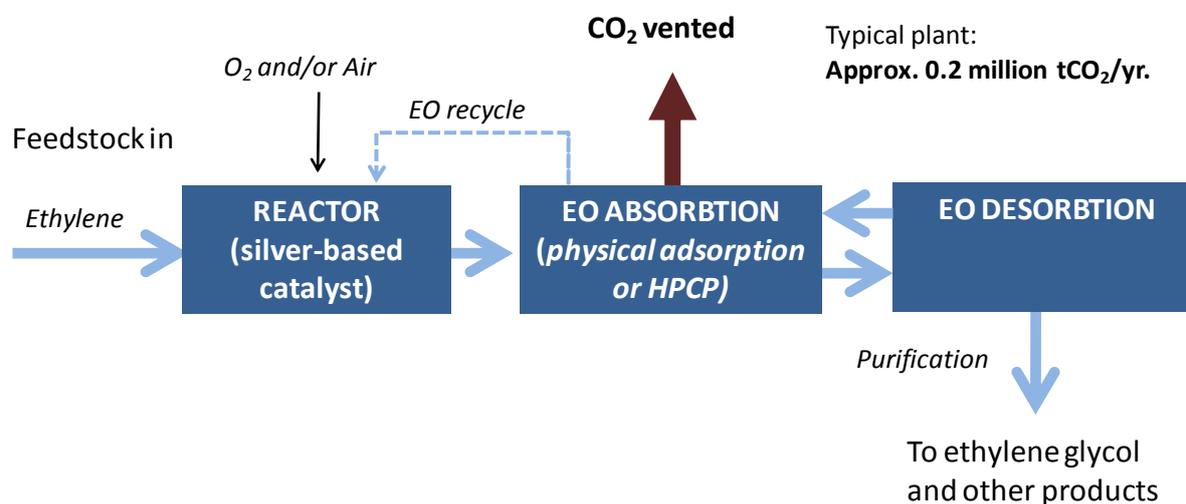


The global distribution of ethylene oxide production plants closely follows that of ethylene. As shown in Table 7the United States is the world's largest producer of ethylene oxide, accounting for over one fifth of all global production in 2004 (4 million tonnes). For the same year, the United States was followed by Venezuela (2 million tonnes) and Saudi Arabia (1.8 million tonnes).

Production is generally dominated by large multinational chemical and petrochemicals companies, often at large industrial plants combining ethylene and ethylene glycol production facilities. The world's largest producers of ethylene oxide are Dow Chemical Company, SABIC, Shell, BASF, China Petrochemicals, Formosa Plastics and Ineos, which collectively account for more than 50% of world production (Figure 10; individual company website information; SRI Consulting, 2009).

Imports and exports of ethylene oxide are negligible as it is not widely traded due to its explosive nature. However, as considerable new ethylene glycol capacity is forecast to come on stream in China and the Middle East, it is expected that exports of these products will increase, reducing domestic demand in other regions (including the United States) for ethylene oxide (ICIS, 2010).

Figure 10   World ethylene oxide production capacity by producer

World Production = 19 Mt EO (2006)
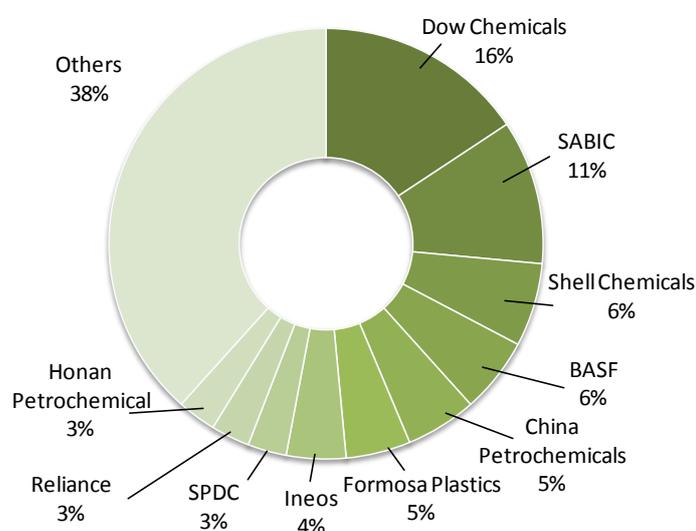
Monoethylene glycol (MEG) is the primary glycol which is used mainly to make polyester followed by automotive antifreeze. MEG demand is expected to grow at 5-6% per year globally. This is partly driven by the strong demand for polyester fibre in Asia where it is used in the production of textiles. However, this has been at the expense of the developed markets of Western Europe and North America where polyester fibre demand is stagnant. However, demand for PET bottle resin has been growing strongly in all regions of the world as it replaces glass used in water, carbonated drinks and food containers (ICIS, 2010). The second largest market for MEG is antifreeze formulations. This market is in a slight decline due to antifreeze recycling, long-life coolants and substitution by propylene-glycol based antifreeze. Alcohol ethoxylates are expected to see good demand growth, partly due to declining demand for nonyl-phenol ethoxylates, which are suffering from environmental and safety concerns (ibid).

Table 7   **World production of ethylene oxide (2004)**

Region	Number of major producers	Production (000's tonnes)
North America		
United States	10	4,009
Canada	3	1,084
Mexico	3	350
South America		
Brazil	2	312
Venezuela	1	1,982
Europe		
Belgium	2	770
France	1	215
Germany	4	995
Netherlands	2	460
Spain	1	100
Turkey	1	115
United Kingdom	1	300
Eastern Europe	no data	950
Middle East		
Iran	2	201
Kuwait	1	350
Saudi Arabia	2	1,781
Asia		
China	No data	1,354
Taiwan	4	820
India	> 2	488
Indonesia	1	175
Japan	4	949
Malaysia	1	385
South Korea	3	740
Singapore	1	80
Total	>52	18,965

Source: SRI Consulting, 2009

Global demand for ethylene oxide is forecast to grow at a rate of 5% per year from 2009 to 2014, and around 3% per year from 2014 to 2019 (SRI Consulting, 2010). Most of the forecast growth is expected to take place in non-OECD emerging economies. Production in the EU is expected to decline in the future and demand growth in the US is also expected to be much lower than the global average (ICIS, 2010).

Global capacity utilization of ethylene oxide production plant was 86% in 2009, less than that in 2008. Average global utilization rates are expected to range from the low 80s to the low 90s range throughout the next decade (SRI Consulting, 2010). There is concern that planned increases in capacity will outpace demand growth in the 2008-2011 period, leading to some overcapacity. Chemical market analysts PCI estimates that 13-14 new ethylene oxide plants will come on-stream in this period including four in Saudi Arabia, another two in the Middle East, five in China, and two or three in India (PCI Xylenes & Polyesters, 2010).

2.4 Technologies for industrial gas separation ("CO$_2$ capture")

The high purity sector covered in this Roadmap covers a diverse range of industrial activities, including natural gas production, synthetic fuel production, and bulk inorganic and organic chemicals production. The underlying production processes involved in all of these activities involves the application of a CO$_2$ removal step to purify intermediate or final products used in the production process. The application of CO$_2$ removal to these streams is more straightforward than application to flue gases because of the smaller volumes, lower temperatures and higher pressure and partial pressure of CO$_2$ in the inlet gas streams requiring separation (Table 8).

Table 8 Typical properties of gas streams that are subject to CO$_2$ separation ("capture")

Activity	Source stream	CO$_2$ conc (%; inlet)	Pressure (MPa)	Partial pressure (MPa; CO$_2$)	CO$_2$ conc (%; outlet)
Gas processing	Reservoir gas feed	2 - 65	0.9-8	0.05-4.4	95-100
Ammonia	ATR/SMR/Gasifier	15 - 20	2.8	0.5	30-100
CTL	Gasifier	10 - 15	2.8	0.5	95-100
Ethylene oxide	Reactor	8	2.5	0.2	30-100

Source: based on Metz *et al.* 2005, drawn from Chauval and Lefebre, 1989; Maddox and Morgan, 1998; IEA GHG, 2002a

Many of the processes use similar technologies to separate the CO$_2$ from the gas mixtures, including:

- Membrane separation;
- Chemical solvents, including amine-based solutions (e.g. MEA and MDEA) and hot potassium carbonate based processes (e.g. the Benfield™ process);
- Physical sorbent based process to remove CO$_2$ from gas mixtures (e.g. Selexol™, Rectisol);
- Pressure swing adsorption (PSA); and,
- Cryogenic separation processes.

Selection of the appropriate process is dependent on a number of factors including end use specification, gas inlet pressure, cost, size, weight and maintenance needs. It should be noted that whilst these are referred to as "high purity" in this sectoral assessment, some gas treatment processes may create streams that contain a number of trace contaminants – such as elemental nitrogen, water, carbon monoxide and methanol – which may need to removed to avoid corrosion during transport and injection. A brief review of each technology is provided below.

2.4.1 Membrane separation

Membranes are typically used for natural gas processing of high CO$_2$ content natural gas at the wellhead on offshore platforms where gas pressure will be higher and weight, size and maintenance considerations may be an issue. Typical applications involve the use of polymer-based membranes employing permeation processes where CO$_2$ is absorbed into the membrane, and then diffused through it (solution-diffusion process), although metallic or ceramic membranes may also be employed for CO$_2$ separation. Membrane treatment plants are available in various forms including spiral-wound systems, tubular systems, and hollow fibre, with several plant configurations possible to enhance the effectiveness of the process, including dual- and tri-pass systems. For high

concentration CO_2 streams, membrane treatment is unlikely to be able to attain high levels of CO_2 removal, and additional processing using chemical or physical adsorption processes will be required.

In all cases, the pressure of the gas – and importantly the pressure difference across the membrane - is critical to induce flow across the membrane. This makes membranes largely uneconomic for use in flue gas CO_2 capture systems.

To date, membranes have not been effective at separating hydrogen and CO_2 in syngas mixtures, and therefore have not been used in industrial hydrogen and synfuel production processes. However, several novel membrane treatment systems are under development for syngas treatment and preferential removal of hydrogen[2].
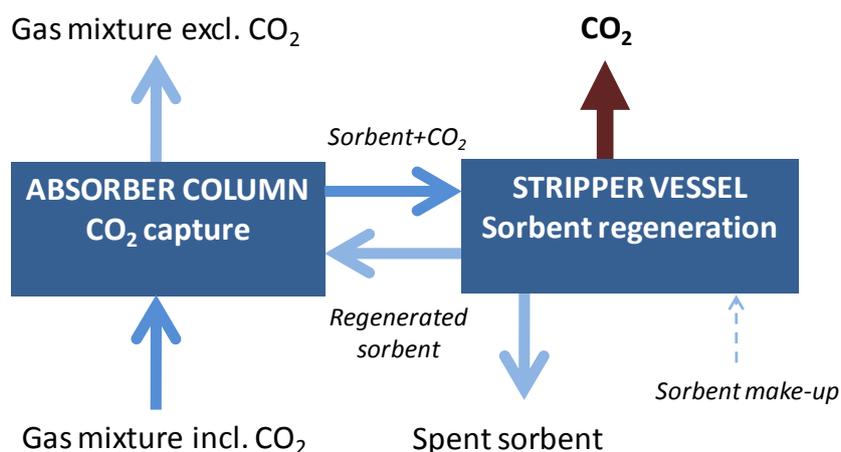
2.4.2 Chemical solvents

Chemical solvent processes are the most widely used technology for CO_2 removal in natural gas processing. They tend to be less common for syngas clean-up, where physical sorbents offer some advantages in terms of energy requirements. Compared to physical solvent processes, most chemical solvent processes, in particular those based on amines, offer faster reaction temperatures meaning smaller plant size and are able to remove CO_2 at low concentrations (and partial pressures) making them suitable for low pressure low CO_2 concentration gas streams as typically encountered in natural gas sweetening.

The basic process involves introducing the gas mixture into an absorption tower containing the chemical solvent. Typical chemical solvent used include amines and alkanoamines and variants upon these including hindered amines (as produced by KEPCO and MHI). The Benfield[TM] process and others involve the use of a hot potassium carbonate mixture as the sorbent, which is better suited to gases at partial pressures >0.70 MPa to produce a high purity CO_2 stream. Hot potassium carbonate methods have been widely employed for hydrogen purification in ammonia and ethylene oxide production. Various novel chemical solvent technologies are under research, such as the use of chilled methanol and chilled ammonia, to remove CO_2.

On entering the absorber column, CO_2 is preferentially absorbed by the solvent to form salts, while the majority of other gases present pass through the vessel. Some residual quantities of hydrocarbon gases will also be absorbed, but can be flashed off prior to solvent regeneration. The chemical sorbent is continuously cycled through a stripper vessel, where the salts formed in the absorber column are decomposed by heating, usually through the use of steam, and the CO_2 released from the aqueous phase and made available for compression, transport and storage or venting to atmosphere. The resulting regenerated solvent is recycled back to the absorber column in a continuous cycle (Figure 11).

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[2] For example, the Hysep thin-film palladium membrane system under development by the Energy research Centre of the Netherlands (ECN), described at: http://www.hysep.com/ or systems under development by the Membrane Technology and Research group, described at: http://www.mtrinc.com/hydrogen_separation_in_syngas_processes.html

Figure 11   **Generalised schematic for CO$_2$ separation using sorbents/solvents**

A range of different technologies are available on the market, employing different types of chemical solvents (Table 9). Combinations with membranes are also under development, where a membrane is included in the absorber column.

The main technical challenges posed by chemical absorption technologies are the heat requirements for solvent regeneration and the energy requirements for cycling the solvent between the two treatment stages and other auxiliary power uses such as blowers to move low pressure gas around the plant.

Table 9   **Common solvents used for natural gas sweetening and syngas clean-up**

Solvent name	Type	Chemical name	Vendors
Rectisol	Physical	Methanol	Lurgi and Linde, Germany Lotepro Corporation, USA
Purisol	Physical	N-methyl-2-pyrolidone (NMP)	Lurgi, Germany
Selexol	Physical	Dimethyl ethers of polyethylene glycol (DMPEG)	Union Carbide, USA
Benfield Giammarco-Vetrocoke Catacarb	Chemical	Potassium carbonate	UOP Giammarco-Vetrocoke Eickmeyer & Associates
MEA	Chemical	Monoethanolamine	Various
MDEA	Chemical	Methyldiethylamine	BASF and others
Sulfinol	Chemical	Tetrahydrothiophene1,1-dioxide (Sulfolane), an alkaloamine and water	Shell

Source: Metz *et al*. 2005

2.4.3 Physical sorbents

Physical solvent-based processes are better suited to gas streams which have high partial pressures (>0.35 MPa) and/or total pressure in order to ensure effective absorption of CO_2 in the gas mixture to the physical sorption chemicals (see Table 8). They are widely used to separate CO_2 and H_2 from syngas mixtures in industrial hydrogen production and synthetic fuel production, but less common in natural gas sweetening operations. The latter is a result of the generally lower CO_2 partial pressures in natural gas sweetening and the propensity of heavier hydrocarbon fractions (C_3+) to also be absorbed, leading to hydrocarbon losses.

The basic process is similar to that employed for chemical sorbents (Figure 11), with the main difference being (a) the way in which the CO_2 is absorbed, which utilises weak physical bonds as opposed to chemical bonds used for chemical solvents; and (b) as a consequence, the way in which the physical sorbent releases the CO_2 and is regenerated, usually involving pressure release and less commonly temperature swing. The alternative absorption and regeneration route offered by physical solvent-based processes offers reductions in energy requirements compared to chemical processes.

The range of solvents and processes available are highlighted in Table 9.

2.4.4 Pressure swing adsorption

Pressure swing adsorption (PSA) is commonly used for treatment of syngas to produce high purity H_2 in ammonia plants and refineries. However, it is not able to selectively separate CO_2 from gas mixtures meaning that the tail gas stream may only consist 30-40% CO_2, and additional treatments must be applied to deliver a high purity CO_2 stream. In most systems, the tail gases exiting the final stage is a lean mixture of H_2 and CO_2, which can be used in a waste heat recovery boiler to raise steam on-site. This makes recovery of all of the CO_2 produced more complex.

The PSA process works on the basis that gases absorb to solid surfaces when under pressure; the higher the pressure, the more gas that is adsorbed, and when the pressure is reduced, the gas desorbs. A generalised configuration for a PSA plant involves a 4-step cycled process of (a) a pressurisation step, where syngas feed is pressurised, (b) an adsorption step, where CO_2 is adsorbed to the packing media whilst the product gas is released from the vessel in gas phase (c) depressurisation, which releases the CO_2 from the adsorption media and (d) further purging of the vessel to regenerate the adsorption media (Figure 12). Typical adsorbents used in PSA plants include alumina, zeolites and activated carbon.

Figure 12   Generalised schematic for pressure swing adsorption processes
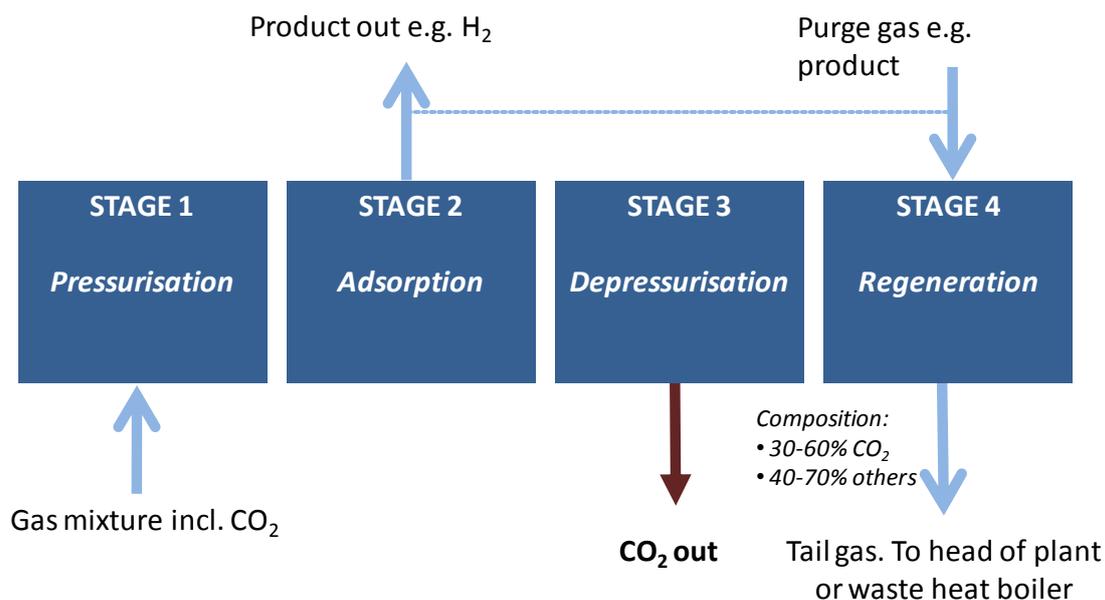
A range of vendors offer PSA plant for syngas treatment and H_2 separation. A number of PSA plants are reported to be in operation in the ammonia industry[3], although precise numbers are not currently available. The lower concentration of CO_2 in the tail gas from PSA plants could have implications on the overall efficacy and cost of applying CCS at this type of plant, as they would likely require an additional CO_2 separation step to produce CO_2 suitable for compression transport and storage.

2.4.5 Cryogenic separation processes

Cryogenic CO_2 separation is a possible means of removing CO_2 from gas mixtures, as typically applied for separating oxygen from air (cryogenic air separation). In terms of CO_2 removal, the Ryan/Holmes process has received most commercial interest, and is currently in use in several commercial operations, including for the separation of "breakthrough"[4] CO_2 from gas mixtures in enhanced oil recovery operations (EOR; Garner, 2008). It involves the use of a distillation column into which the gas mixture is introduced at the base; as it migrates up through the column it is progressively cooled and various fractions are separated out at different heights and dew points. A fairly high purity CO_2 stream can be achieved using this technique.

ExxonMobil has also been developing a technique for cryogenic gas separation since the 1980's, termed Controlled Freeze Zone (CFZ), and has recently piloted it at its LaBarge gas processing plant in Wyoming, USA. It expects CFZ to offer a low cost alternative method to develop gas which is high in impurities (ExxonMobil, undated).

To date, cryogenic separation techniques for CO_2 removal from gas mixtures have not achieved widespread commercial deployment.

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[3] For example, the Linde Ammonia Concept (LAC) plant, which utilises PSA to separate H_2 from syngas.
[4] Breakthrough CO_2 is injected CO_2 that re-emerges with produced hydrocarbons in CO_2-EOR operations.

3   EMISSIONS SOURCES, BASELINE AND FUTURE EMISSIONS

Estimates of the current level of worldwide CO_2 emissions for the high purity CO_2 sectors falling within the scope of this study have been presented previously (Figure 1). The sector and source streams under study, however, suffer from extremely limited data availability, making precise estimates of current emissions extremely challenging. Therefore, the data presented in Figure 1 is subject to significant uncertainty, as outlined in the following section.

It is also important to note that the scope of this assessment is focussed on only the high purity source streams that are associated with the process emissions from the activities described in Section 2. Combustion emission sources or other types of CO_2 emissions are not reviewed in this Section and are excluded from the emissions estimates provided.

As the focus is on process source streams, the potential abatement measures available to reduce emissions across the sector have not been considered in depth because the range of potential abatement measures will be limited. Whilst there may be scope to optimise certain techniques such as industrial hydrogen production within certain industrial activities, in general, the only way to reduce emissions from process sources streams is to move to alternative production methods (e.g. feedstock switching in ammonia production) or substitute product demand to less carbon intensive product sources (e.g. greater use of organic fertilisers to replace mineral derived products). These alternatives have not been considered here as significantly greater research is required to develop a scenario under which reasoned assessment of the likelihood of such changes occurring can be made, a task which is beyond the scope of this assessment.

3.1   Current emissions from high purity sources

Based on the estimates described below, the high purity CO_2 sector currently generates around 430 $MtCO_2$ per year, which is equal to around 6% of global industrial CO_2 emissions (IEA, 2009, which excludes emissions from fuel transformation). This represents an approximate central estimate developed using various assumptions about current production activities in the sectors, as described in Section 2.

Not all of this CO_2 is available for CCS today. Around 117 $MtCO_2$ generated during ammonia production is utilised in other ways, principally for urea production and in CO_2-EOR operations (Section 2.2.2). Similarly, some 3-4 $MtCO_2$ from coal gasification and natural gas processing is also used in CO_2-EOR operations, whilst some natural gas processors are already injecting and storing around 2-3 $MtCO_2$ per year at three sites in the world (Box 1). Consequently, around 124 $MtCO_2$ currently produced from high purity sources is already utilised, whilst around 306 $MtCO_2$ is available for application of CCS today (Figure 13).

Figure 13   Current emissions and CO₂ utilisation in high purity sectors
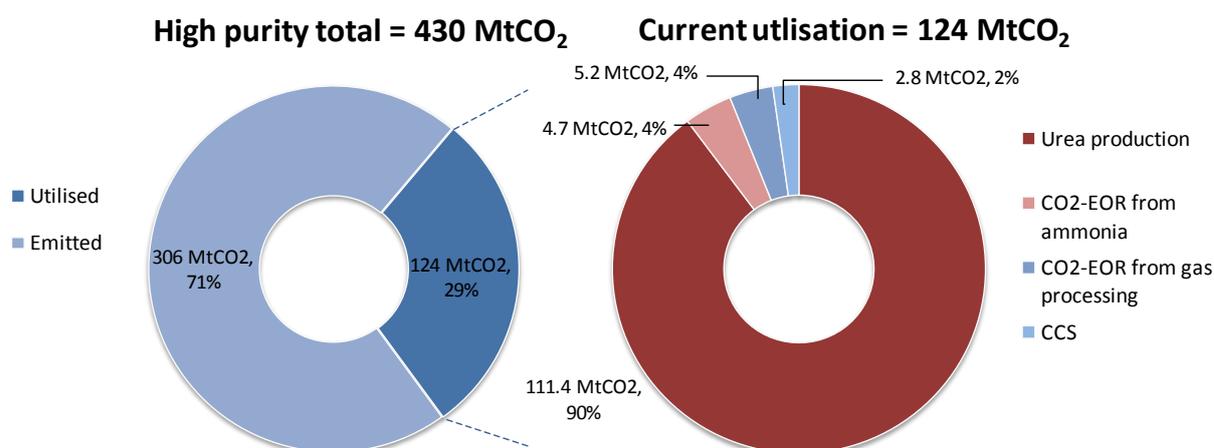
The following sections describe current emissions in each sector in more detail.

3.1.1 Natural gas processing

There are presently no publicly available data sources which provide information on the levels of CO_2 vented from natural gas processing operations. Privately held data on estimated CO_2 concentrations in gas reservoirs around the world do exist (e.g. IHS database, see Bakker *et al.* 2010). However, much of the information is proprietary and commercially sensitive. Further, no gas producers provide detailed reporting of vented emissions from gas production, making it extremely difficult to gain an insight into the level of emissions from these activities. In addition, the picture is further complicated by the production profiles for gas reservoirs, which may produce varying levels of CO_2 across their operational life, whilst the distribution of fields with CO_2 contamination is highly heterogeneous making generalised estimates difficult and subject to large uncertainty.

Consequently, and recognising these factors, a range of estimates have been developed adopting both bottom-up (e.g. IEA GHG, 2008) and top-down estimates of emissions from gas processing/sweetening operations (e.g. Metz *et al*. 2005; Philibert *et al.*, 2007). Drawing on these, a summary of estimates of current and future emissions from venting CO_2 in natural gas processing is presented below (Table 10).

Table 10   Estimates of vented CO$_2$ emission from natural gas processing

Source of estimate	MtCO$_2$/yr	Year	Assumptions
IPCC (Metz *et al*, 2005)	50	2005	2600 bcm/y gas production worldwide; ½ containing 4% CO2 that needs to be sweetened to 2%.
IEA (Philibert *et al*, 2007)[a]	167 / 324	2007 / 2020	98 bcm/y in developing countries; various new fields means increase to 324 MtCO$_2$/yr by 2020
IEA GHG (IEA GHG, 2008)[a]	219 / 313	2010 / 2020	Bottom-up estimate based on published field data and extrapolation
ECN (Bakker *et al*. 2010)[a]	174 (146-222)	2020 (range)	Bottom-up, IHS database
Average (excl IPCC)	*193 / 270*	*2010 / 2020*	-

Notes: [a] Analysis covered developing countries only

Building on these analyses, databases of high CO$_2$ fields (IEA GHG, 2008 and IHS database, *op cit.*) have been reviewed to arrive at revised estimates. The data used in the IEA GHG (2008) study has been used to generate a new upper and lower estimates of emission of 156-225 MtCO$_2$ per year vented from gas processing operations at high CO$_2$ gas fields[5]. Combining that with the current estimate extracted from the IHS database of around 94 MtCO$_2$ per year, the average of the three sets of data is 158 MtCO$_2$ per year. This has been rounded to 160 MtCO$_2$ per year for the purpose of this study (Figure 1). However, this figure still remains subject to significant uncertainty, and should be used in conjunction with the ranges cited previously (Table 10).

It is difficult to ascertain the number of points sources to which CCS could be applied in the natural gas processing sector as gas processing operations vary significantly in size. Assuming average emissions of a single operation of around 2-3 MtCO$_2$ per year, these data suggest that around 50-80 locations worldwide could potentially utilise CCS at present.

3.1.2 Industrial hydrogen production and use

The IEA Greenhouse Gas R&D Programme has developed one of the largest databases of point source CO$_2$ emissions available today (IEA GHG, 2006). However, the database is not comprehensive, and includes numerous gaps and uncertainties. These data were reviewed in establishing the current level of emissions from industrial hydrogen production, and additional analysis was undertaken to corroborate these estimates, as described below.

Ammonia production

According to IEA GHG database, annual global emissions from ammonia production in the period 1997-2002 were around 165 MtCO$_2$[6] from 264 sites, although it is unclear whether these data exclude CO$_2$ used for urea production and other uses. This estimate has been cross-checked with an estimate based on current production practices, which suggest that it is a reasonable match with the estimated emissions excluding CO$_2$ utilisation.

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[5] The upper limit is based on extrapolating data for known fields across to know high CO2 fields to other in the region. The lower limit constrains the estimate to production from known high CO$_2$ fields.
[6] Based on data on ammonia and fertiliser plants in the database.

Building on the global ammonia production data (Table 3), the sources of ammonia production (Figure 7), and the typical performance data for different types of ammonia plant (Table 4; Section 2.2.2), it is possible to estimate current emissions from ammonia production (Table 11). These analysis suggest that total amount of CO_2 generated in ammonia production globally is around 236 $MtCO_2$ per year.

Table 11   Estimated emissions from worldwide ammonia production

Source of ammonia	Production (Mt NH_3/yr)	Emission factor (tCO_2/tNH_3; Table 4)	CO_2 emissions (H_2 production) (MtCO_2/yr)
Naphtha	3.0	1.60	4.9
Fuel Oil	4.6	2.30	10.5
Coal	41.0	2.30	94.4
Natural Gas	101.8	1.22	126.7
Others	1.5	1.30	2.0
Total	**152**	-	**236.0**
Available for capture			*119.4*
IEA GHG (2006)			*164.7*

Based on the stoichiometry of urea production and IFA reported utilisation rates of CO_2 from ammonia production, almost 50% of current CO_2 production is utilised for other purposes (approximately 117 $MtCO_2$) meaning that the estimate of 236 $MtCO_2$ is revised downwards to 119 $MtCO_2$ per year in terms of the amounts available for the potential application of CCS.

Assuming an average plants size of 1,500 tNH_3/d and a 340 d/yr operating time (UNEP/UNIDO, 1998), this would equate to around 300 point sources around the world, with average emissions of 0.8 $MtCO_2$ per year. Assuming that 50% of these are unavailable due to CO_2 utilisation, around 150 ammonia plants could potentially apply CCS today.

Coal-to-liquids

As described previously, there are presently only a few CTL plants in operation in the world, the most well known ones being at Secunda, South Africa and Ordos Basin, China (Table 6). Emissions from the coal gasification process at these plant are estimated to be around 27.6 $MtCO_2$ per year (Metz *et al.*, 2005; Sun, 2008; Table 6). All of this CO_2 is available for CCS as it is presently vented to the atmosphere.
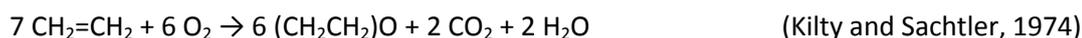
3.1.3 Ethylene oxide production

Presently no disaggregated data is available from ethylene oxide producers on levels of CO_2 emissions from ethylene oxide production. Therefore, estimates have been made using various sources.

The IEA GHG database contains emissions data for 16 ethylene oxide plants around the world, which are reported to generate 2.4 $MtCO_2$ per year. Metz *et al.* (2005), using a previous version of the

same database, provide figures of 17 plants emitting a total 3 $MtCO_2$ per year. Neither of these estimates appears consistent with the estimated number of producers worldwide, which is estimated to exceed 52 worldwide (Table 7). This may be due to some ethylene oxide plants being integrated with ethylene plants and ethylene glycol plants, and thus captured elsewhere in the IEA GHG database.
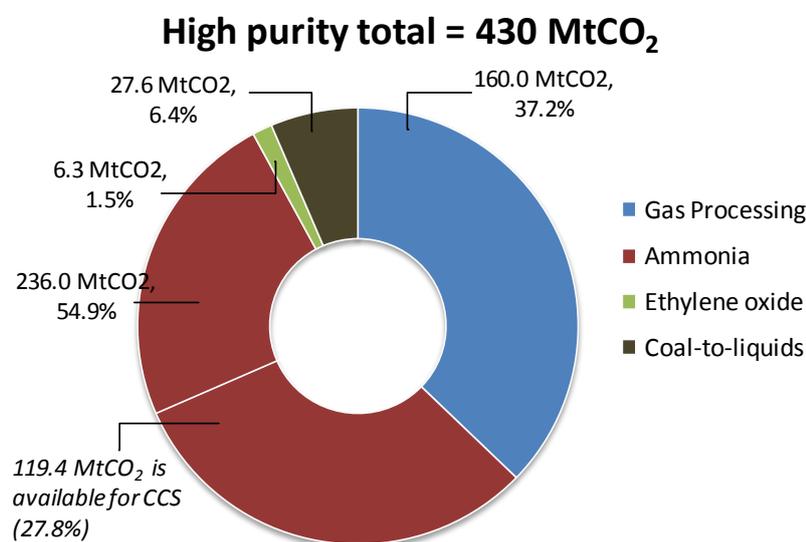
Given the uncertainty over these estimates, as an alternative it is possible to estimate emissions based on the chemistry of the underlying production process. In this context, the stiochiometry of ethylene oxide production using the direct oxidation method is given as:

$$7\ CH_2=CH_2 + 6\ O_2 \rightarrow 6\ (CH_2CH_2)O + 2\ CO_2 + 2\ H_2O \qquad \text{(Kilty and Sachtler, 1974)}$$

This suggests that the ratio of ethylene oxide to CO_2 generation is 6/2[7], meaning that for every tonne of ethylene oxide produced, 0.33 tCO_2 are generated. Therefore, for an annual production of 19 million tonnes (Table 7), 6.3 $MtCO_2$ would be generated. This data would mean that for 52 production sites worldwide, average emissions would be 0.12 $MtCO_2$ per year, which is in line with estimates of typical emissions from ethylene oxide plant, and consistent with those included in the IEA GHG database, which has an average emissions per plant of 150,000 tonnes CO_2 per year.

Based on the analysis described in the previous sections, current emissions from the high purity CO_2 sector are summarised below (Figure 14).

Figure 14   Summary of estimated current CO$_2$ emission from high purity sources

High purity total = 430 MtCO$_2$

27.6 MtCO2, 6.4%
6.3 MtCO2, 1.5%
236.0 MtCO2, 54.9%
119.4 MtCO$_2$ is available for CCS (27.8%)
160.0 MtCO2, 37.2%

■ Gas Processing
■ Ammonia
■ Ethylene oxide
■ Coal-to-liquids

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[7] Note: the molar weight of ethylene oxide is 44.05 g mol^{-1}, almost identical to carbon dioxide at 44.01 g mol^{-1}.

3.2 Future emissions from high purity sectors

The previous section highlighted the uncertainties in estimating current emissions from high purity CO_2 sources. Making projections for emissions from these sectors is even more challenging given the uncertainty over a number of factors.

The major sources of uncertainty relate to the following factors:

- *Changes in demand for products* – for example reduce demand for ethylene oxide in the global chemicals industry;
- *The scope for product substitution* – for example substitution of natural gas by SNG or other forms of energy;
- *Changes in product delivery methods* - for example, a shift to more LNG and GTL in natural gas supply chains, which could result in higher emissions at gas processing plant (Figure 4);
- *Changes in input quality for some processes* – in particular, in relation to changes in the quality of natural gas and the effects that this may have on levels of CO_2 removal in natural gas processing;
- *Changes in production processes* – for example, changes in the way hydrogen is synthesized, including shifting towards greater use of electrolysis, especially from renewable energy sources, and
- *Stock turnover in production plant* - which should deliver improved efficiency of production processes.

It has not been possible to undertake a full assessment of all of these factors for each sector within this study. That would involve development of a more detailed scenario based analysis than has been possible.

However, it has been possible to make an extrapolation of CO_2 emissions for the sectors drawing on estimated production forecasts as described in Section 2, and the emissions intensity of production derived from Section 3. The results of this analysis and the supporting assumptions are shown below (Figure 15).

Figure 15   Estimated growth in CO₂ emissions for high purity sectors, 2010 to 2050
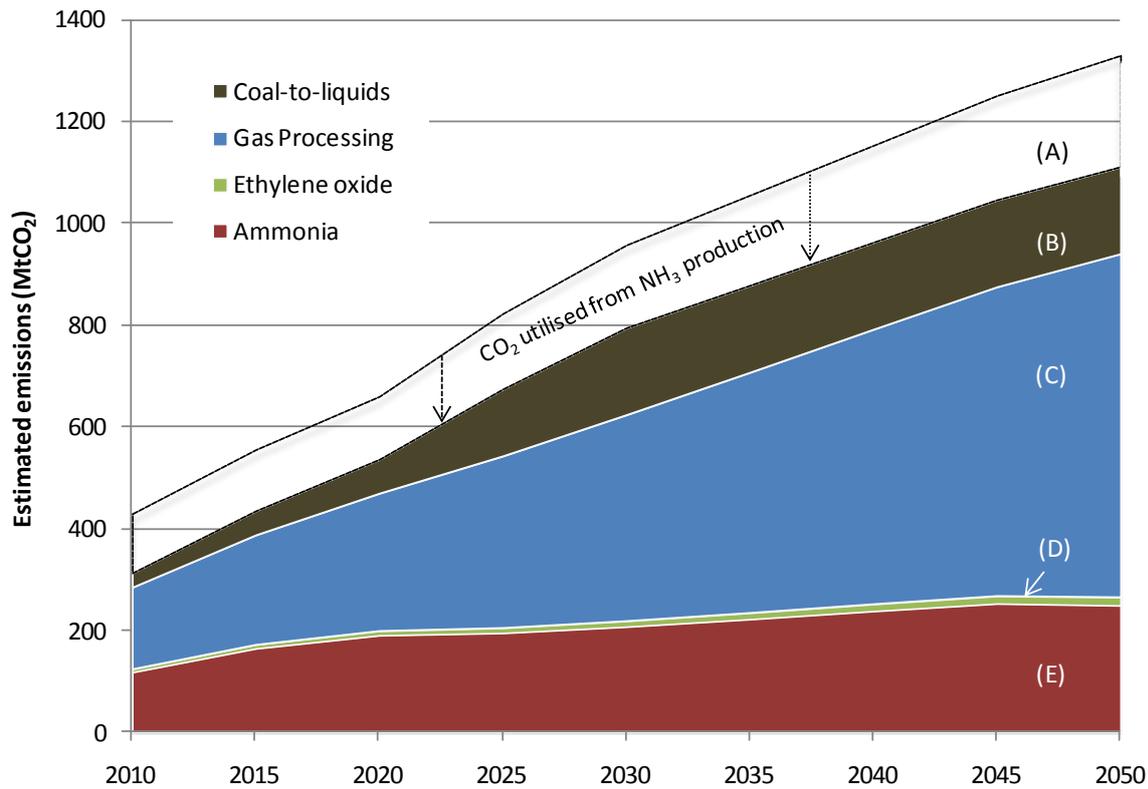

Notes:

(A) Assumes that CO_2 utilisation in ammonia production remains constant to 2050 at 49%.

(B) Based on forecast projects that could come on stream in 2020 (see Table 6), and IEA (2008a) estimates of forecast CTL production in 2030 (see Section 2.2.3). Assumes that emissions from coal gasification in CTL would remain similar to the levels at Secunda and Ordos plants at 0.456 tCO_2/bbl (see Table 6). After 2030, CTL production is assumed to remain static.

(C) Based on potential growth in CO_2 venting of 7% per year between 2010 and 2020 (see Table 10), and an assumed annual growth rate in emissions of 5% per year over the period 2020 to 2050. This is an estimate drawing on the view that 40% of the worlds gas reserves are currently sour (IEA, 2008a), and that increasingly these reserves will be valorised as sweet gas reserves become increasingly depleted. These estimated changes over time lead to changes in the emissions intensity of natural gas sweetening from around 0.05 tCO_2/bcm to 0.12 tCO_2/bcm in 2050.

(D) Based on forecast growth of 4% per year between 2010 and 2050 (see Section 2.3) and an emissions factor of 0.33 tCO_2/t EO (see Section 3.1.3)

(E) Based on the current ratio of CO_2 utilisation to CO_2 venting. Forecast growth of 100% to 2050, meaning annual growth of 3% per year from 2010-2050, based on IEA forecasts for NH_3 production increases of 151 Mt/yr by 2050 (IEA, 2010; see Section 2.2.2). Assumes that the current mix of feedstocks remains constant to 2050 (see Table 11), which gives an average emissions factor for hydrogen production in the sector of 1.55 tCO_2/tNH_3.

The estimates of future emissions of the various sectors suggest emissions of high purity CO_2 could increase to 537 $MtCO_2$ in 2020 (71% increase on current levels), and potentially reach 1,113 $MtCO_2$ in 2050, more that a three-fold increase on current levels (Figure 16).

Figure 16   Summary of high purity sector emissions in 2020 and 2050
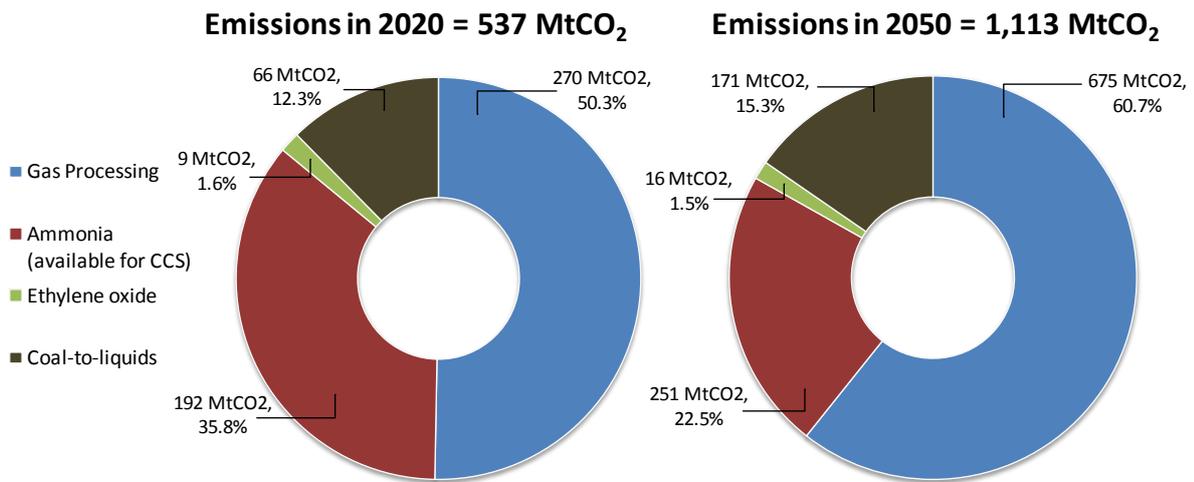
The scope for applying CCS to reduce these emissions is discussed in the following section.

4 CO$_2$ CAPTURE AND STORAGE

4.1 Current activities

4.1.1 Natural gas processing

Capturing and storing CO$_2$ from high-CO$_2$ content natural gas field presents some of the least cost 'earliest opportunities' for large-scale deployment of integrated CCS projects across a number of world regions. Gas processing facilities typically have access to *in situ* or close proximity storage sites of known geological characteristics and there is a considerable skills and knowledge base within the oil and gas industry required to undertake large commercial-scale projects. There are currently five fully integrated, commercial-scale CCS projects in operation worldwide, of which four are associated with the separation of CO$_2$ from natural gas and one from coal-based SNG production (Box 1).

The Sleipner and Snøhvit (Norway) and In Salah (Algeria) projects involve the stripping of CO$_2$ from high-CO$_2$ content natural gas to achieve sales-grade quality natural gas. The CO$_2$ is stripped, collected and stored securely in underground geological formations. The Rangely project (United States) also uses CO$_2$ captured from natural gas processing at the ExxonMobil LaBarge gas plant in Wyoming, but uses the CO$_2$ for enhanced oil recovery (EOR) and storage at the Rangely field in Colorado.

ChevronTexaco is currently in the final planning phases for one of the largest CCS projects in the world involving capturing CO$_2$ from the Gorgon natural gas field located 130km off the north-west coast of Western Australia. The project comprises the establishment of a gas processing and LNG facility on Barrow Island, which lies directly between the gas fields and the Australian mainland. The Gorgon natural gas reservoirs contain naturally occurring CO$_2$ levels of approximately 14%, which requires removal before the gas can be liquefied. The removal is necessary as CO$_2$ would freeze in the LNG process, potentially damaging the equipment. Current standard practice by all operating LNG facilities worldwide is to vent this CO$_2$ to the atmosphere. Chevron have proposed that over 3.4 million tonnes of CO$_2$ per year will be injected into the Dupuy saline reservoir beneath the north end of Barrow Island. A re-injection facility to store CO$_2$ beneath Barrow Island would be sized to accommodate the full stream of separated reservoir CO$_2$. Re-injection would commence as soon as practicable after the gas processing facilities commissioning and start-up process. All studies undertaken to date by the Gorgon joint venture indicate that re-injection is technically feasible and the joint venture is committed to re-inject reservoir CO$_2$ unless it is proven to be technically infeasible or cost-prohibitive. Final approval for the development was granted in August 2009, and it is predicted that customers in Western Australia will begin to be supplied from 2015 (IEA GHG, 2006).

Box 1.   Summary of existing CCS projects worldwide

Five fully-integrated, large scale CCS projects are in commercial operation today. Four projects – Sleipner, In Salah, Snøhvit and Rangeley – inject CO_2 from a natural gas production facility where it is separated from the natural gas and sent to market. In the first three cases, the CO_2 is injected into saline aquifers, while in the fourth it is used for enhance oil recovery (EOR). A fifth project captures CO_2 at the Great Plains Synfuels plant and transports it for EOR to the Weyburn-Midale Project. All five are contributing to the knowledge base needed for widespread CCS use.

Sleipner. The Sleipner project began in 1996 when Norway's Statoil began injecting more than 1 million tonnes a year of CO_2 under the North Sea. This CO_2 was extracted with natural gas from the offshore Sleipner gas field. In order to avoid a government-imposed carbon tax equivalent to about USD 55/tonne, Statoil built a special offshore platform to separate CO_2 from other gases. The CO_2 is re-injected about 1km below the sea floor into the Utsira saline formation located near the natural gas field. The formation is estimated to have a capacity of about 600 billion tonnes of CO_2, and is expected to continue receiving CO_2 long after natural gas extraction at Sleipner has ended.

In Salah. In August 2004, Sonatrach, the Algerian national oil and gas company, with partners BP and Statoil, began injecting about 1 million tonnes per year of CO_2 into the Krechba geologic formation near their natural gas extraction site in the Sahara Desert. The Krechba formation lies 1, 800 metres below ground and is expected to receive 17 million tonnes of CO_2 over the life of the project.

Snøhvit. Europe's first liquefied natural gas (LNG) plant also captures CO_2 for injection and storage. Statoil extracts natural gas and CO_2 from the offshore Snøhvit gas field in the Barents Sea. It pipes the mixture 160 kilometres to shore for processing at its LNG plant near Hammerfest, Europe's northernmost town. Separating the CO_2 is necessary to produce LNG and the Snøhvit project captures about 700,000 tonnes a year of CO_2. Starting in 2008, the captured CO_2 is piped back to the offshore platform and injected in the Tubåsen sandstone formation 2,600 metres under the seabed and below the geologic formation from which natural gas is produced.

Rangely. The Rangely CO_2 Project has been using CO_2 for enhanced oil recovery since 1986. The Rangely Weber Sand Unit is the largest oilfield in the Rocky Mountain region and was discovered in 1933. Gas is separated and re-injected with CO_2 from the LaBarge field in Wyoming. Since 1986, approximately 23-25 million tonnes of CO_2 have been stored in the reservoir. Computer modelling suggests nearly all of it is dissolved in the formation water as aqueous CO_2 and bicarbonate.

Weyburn-Midale. About 2.8 million tonnes per year of CO_2 are captured at the Great Plains Synfuels Plant in the US State of North Dakota, a coal gasification plant that produces synthetic natural gas and various chemicals. The CO_2 is transported by pipeline 320 kilometres (200 miles) across the international border into Saskatchewan, Canada and injected into depleting oil fields where it is used for EOR. Although it is a commercial project, researchers from around the world have been monitoring the injected CO_2. The IEA Greenhouse Gas R&D Programme's Weyburn-Midale CO_2 Monitoring and Storage Project was the first project to scientifically study and monitor the underground behaviour of CO_2. Canada's Petroleum Technologies Research Centre manages the monitoring effort. This effort is now in the second and final phase (2007-2011), of building the necessary framework to encourage global implementation of CO_2 geological storage. The project will produce a best-practices manual for carbon injection and storage.

Source: (IEA/CSLF, 2010)

In addition to the projects described previously, there are several proposed projects at different stages of development involving the capture and storage of CO_2 from natural gas facilities. Other proposed CCS projects at less advanced stages of development include (IEA/CSLF, 2010):

Browse LNG Development (Western Australia). The proposed CCS project would process gas from three natural gas fields over 400 km offshore from Broome in Western Australia. The Browse Joint Venture comprises Woodside Energy, BHP Billiton, BP, Chevron and Shell. Front End Engineering and Design (FEED) studies are expected to be undertaken in 2011 to enable a Final Investment Decision by mid-2012. The project is expected to capture up to 3 $MtCO_2$ per year and commence operation in 2017.

Fort Nelson CCS Project (British Columbia, Canada). The project proposes to capture CO_2 from Spectra's Fort Nelson natural gas processing plant and store it in the deep saline formations of the Western Canadian Sedimentary Basin. The Fort Nelson CCS Project is a partnership initiative of Spectra Energy Transmission, the Energy & Environmental Research Center Plains CO_2 Reduction Partnership, the Province of British Columbia, and the Government of Canada. The project is expected to initially capture 1.2 $MtCO_2$ from a demonstration plant in operation from 2010 to 2017 followed by an increased annual capture of 2.2 $MtCO_2$.

Occidental CCS Plant (Texas, United States). In June 2008 Occidental Petroleum and SandRidge Energy announced plans to build a $1.1 billion natural gas processing and carbon capture plant in west Texas. The CO_2 is planned to be used in an EOR project. The gas processing plant combined with the existing SandRidge gas processing plants could provide over 8 $MtCO_2$ per year for capture. A new 160-mile long pipeline will be constructed from the plant, through McCamey, Texas, to the industry CO_2 hub in Denver City, Texas.

4.1.2 Industrial hydrogen production and use

Ammonia & fertiliser production

CO_2 is routinely captured from ammonia plants for use in the production of urea and nitro-phosphates, often within the same integrated plant. Where demand for the CO_2 stream does not exist - either from urea or other nearby industrial production activities - the emissions are routinely vented to atmosphere. The Enid Fertilizer plant in Oklahoma, United States, operated by the Koch Nitrogen Company has captured over 600,000 tCO_2 per year since 2003 for use in EOR and a CCS project is being proposed at the Coffeyville Resources petroleum coke gasification-based ammonia and urea ammonium nitrate production facility in Kansas. The project will also capture around 600,000 tCO_2 per year for use in domestic EOR and/or geological storage (Blue Source media release, 21 August 2007).

In addition, the Indian fertilizer industry has begun capturing CO_2 from flue gases to meet CO_2 demand at natural gas-based ammonia-urea production plants. This is because the use of natural gas as feedstock does not provide sufficient amounts of CO_2 as required for urea production. Consequently, the use of a Carbon Dioxide Recovery Plant (CDR) for the capture of CO_2 from flue gases emitted from existing fossil fuel combustion sources has been employed. Several of these

projects have been recognised as eligible United Nations Clean Development Mechanism project activities, based on Approved Methodology AM0050. This methodology was developed on the basis of a proposed CDR project by the Indian Farmers Fertilizer Cooperative Ltd. The use of CDR to supplement the CO_2 balance for urea production represents an alternative to supplementing natural gas with naphtha feedstock, which has higher carbon content and thus results in greater process CO_2 emissions per unit of ammonia production.

Notwithstanding the use of ammonia derived EOR at two sites in the United States and the emergence of CDR in the Indian fertiliser industry, there are presently no other proposals for CCS projects in the ammonia production industry.

Coal-to-liquids production

Although no CCS projects are currently operational, several major plans to integrate CCS with CTL production plants are under development in Australia and China. The Monash Energy CTL Project in Victoria, Australia is a proposed project that will involve the drying and gasification of brown coal for conversion to synthetic diesel, followed by the separation of the produced CO_2 (up to 13 Mt per year), with transport and injection into a suitable storage site. This project was originally planned to commence in 2015 and was estimated to cost USD 6 billion to USD 7 billion. Partners involved in this project include Monash Energy, Anglo American and Shell (IEA, 2008; CO2CRC, 2009). However, the project has currently been postponed.

The FuturGas Project in South Australia is a joint venture between Hybrid Energy Australia and Strike Oil to research and develop the CO_2 storage component of another project which involves the gasification of lignite for the production of synfuels. It is proposed that the CO_2 (captured post-gasification) will be stored in the Otway Basin to the south of the lignite resources. The project is expected to begin by 2016 (Hybrid Energy, 2010).

China National Petroleum Corporation has begun construction of the nation's first potential integrated CCS project, involving capture from the Shenhua Group's coal-to-liquid project in Ordos, Inner Mongolia. The facility will initially be able to capture and store 100,000 tCO_2 per year, with annual capacity to be subsequently increased to 1-3 $MtCO_2$ in two phases (China CSR, 2010). In addition, in May 2007 Dow and Shenhua announced plans for coal-to-chemicals complex at the Yulin chemical plant in Shaanxi Province, China. The project aims to convert coal to methanol to produce ethylene and propylene, and could capture 5-10 $MtCO_2$ per year by 2015 (IEA/CSLF, 2010).

Although not a CTL project, the Weyburn-Midale project in North America involves the capture of CO_2 from the Great Plains Synfuels coal-based SNG plant in North Dakota. The captured CO_2 is compressed and sent via pipeline to the Weyburn and Midale oil fields in Canada, where it is also used for EOR as well as storage. Currently, over 5 Mt CO_2/year is stored from these plants (Box 1; IEA, 2009b).

4.1.3 Ethylene oxide production

There are no known plans to undertake capture and storage from ethylene oxide production at present. As CO_2 emissions from most existing plants are typically small (around 150-250 $ktCO_2$ per year) it is likely that economies of scale would preclude cost-effective capture unless emissions could be captured as part of an integrated multi-source CCS network. Early opportunities may exist for

integrated chemical complexes and larger facilities combined with ethylene and/or ethylene glycol production.

4.2 Costs of CCS deployment

4.2.1 Costs

High purity CO_2 sources represent relatively low cost CCS project opportunities because the costly step of separating and capturing CO_2 from the flue gas stream is avoided. The additional equipment needed is likely to be limited to compressors, dryers, pumps and coolers, and depending on the details of the project, on-site power generation to meet compressor power requirements. The cost of transporting and storing CO_2 from such sources may also be relatively low, given that candidate plants are typically located at industrial complexes located at, or close to, coastal locations with access to potential offshore storage sites. Ammonia and SMR hydrogen production facilities may in some circumstances be situated in close proximity to natural gas reservoirs (for close proximity to feedstock), whilst capture from some gas processing facilities may offer the potential for *in situ* CO_2 injection.

Table 12 shows cost estimates of capture, transport and storage from a range of high purity industrial CO_2 sources.

Table 12 CCS costs from high purity CO_2 sources

Source	Cost estimate (USD/tCO_2)	Notes	Notes
LNG plant	9	(A)	Retrofit to existing LNG plant; compressed gas injected into a depleted gas field.
Offshore NGP (deep water)	31	(A)	Retrofit to existing deep water NGP facility; compressed gas injected into a depleted gas field.
Offshore NGP (shallow water)	18-21	(A)	Range indicates difference in capital cost between retrofit and new-build NG plant (retrofit higher); compressed gas injected into a depleted gas field.
Onshore NGP	16-19	(A)	Range indicates difference in capital cost between retrofit and new-build NG plant (retrofit higher); compressed gas injected into a depleted gas field.
Ammonia	4; 47	(B)	Capture costs only; different figures indicates capture from pure CO_2 stream and flue gas (8% CO_2 content) respectively; data excludes cost of compression, which would add c. USD 10-15/tCO_2
Hydrogen	15	(C)	Capture costs only
Ethylene oxide	-	-	No known cost studies
Coal-to-Liquids	< 25	(D)	Cost analysis covering liquid-only and poly-generation CTL production using Selexol^{TM} and MEA capture indicates CCS is cost effective under carbon tax of USD 25/tCO_2 at oil price of USD 100/bbl

Notes:

(A) IEA GHG (2008) Note: NGP = natural gas processing; all capital costs based on 2012 prices and discounted at 12.5% over 21 years; T&S cost of service paid as gate fee by capture plant operator and reflects average cost across a range of developing country gas fields and pipeline transport distances including *in situ* injection.

(B) Hendriks, C. *et al* (2004) Note: capital costs discounted at 10% over 25 years; EUR/tCO_2 figures converted to USD/tCO_2 on basis of 1 EUR: 1.3 USD

(C) Metz *et al.*, (2005)

(D) Matripraganda, H.C. and Rubin, E. (2009)

The cost estimates for high purity CO_2 sources are considerably lower than capture cost estimated produced from studies of capture from power generation and other industrial sources (e.g. cement kilns, refineries and iron and steel works). Previous work by the IEA GHG R&D Programme (IEA GHG, 2008) included analysis of the technical and economic potential for CCS deployment in natural gas processing. That research suggested specific opportunities with total abatement potential in the region 40-50 MtCO_2 are present in the sector for less than USD 10 per tCO_2, based on the potential for onshore capture and *in situ* injection to be achievable for as low as USD5-10/tCO_2. The same study considers that abatement of around 150 MtCO_2 may be available at costs of less than USD 20/tCO_2, which is broadly in agreement with other studies of CCS potential in the natural gas processing sector (e.g. IEEP, 2007; Metz *et al.*, 2005).

Other studies of full chain CCS applied to ammonia and hydrogen production (McKinsey & Company, 2009) lie in the range of EUR 30-40/tCO_2 depending on retrofit or new build capture plant and assuming a transport and storage cost of EUR 18/tCO_2 abated.

Because the capture costs associated with high purity CO_2 sources are typically low, the cost of transport and storage dominate the total CCS abatement cost. <REFERENCE TO CROSS-CUTTING TEXT ON TRANSPORT AND STORAGE COSTS>.

4.2.2 Factors influencing costs

A wide range of factors influence the cost of CCS across each component of the chain (capture, transport and storage). Capture cost elements comprise capital investment costs and annual operating costs, and include the following key cost variables:

Capital cost factors:

- *Scope of capture plant requirement* - including whether additional compression is required at the source site to enter pipeline and whether additional on-site power generation is required.

- *Size of plant* - with potential for economies of scale when capture is from large installations and/or capture and compression equipment can be shared with adjacent capture sites

- *Retrofit vs. new build* - in which the cost of integrating additional compression into a new build plant design may result in significantly lower investment cost.

- *Cost of capital* - which will vary by region and investment source based on required rate of return reflected in different capital discount rates and debt repayment periods.

- *Reduction in equipment costs over time* - as a function of technology learning over time (likely to be limited for standard compression and dehydration units)

- *Project location and environment* - as well as capital cost variations across world regions (where some equipment may be procured from regional suppliers) higher engineering costs may result in increased capital costs for offshore and remote plant locations as shown in Table 12.

Operating cost factors:

- *Energy costs* - which may dominate the cost of capture for high purity CO_2 projects. Depending on the size and location of the project, load requirements for compression may be provided by electricity (from on- or off-site generation) or new build power plant. Energy costs (electricity, fossil fuels, biomass) may vary considerably by region due to market factors and/or energy price subsidies and may increase over the lifetime of the project.

- *Operation and maintenance costs (O&M)* - which may vary significantly by region and project technical details

In common with other CCS projects, the capture costs associated with high purity sources are highly-specific to each case and are highly sensitive to a range of site, technology and regional factors influencing the project economics.

A wide range of factors will also influence the cost of transport and storage elements of an integrated CCS project <REFERENCE TO CROSS-CUTTING TEXT ON TRANSPORT AND STORAGE COSTS>.

A key additional factor influencing the economics of CCS projects is whether the captured CO_2 can be used for EOR purposes (see Box 2). The IPCC Special Report (Metz *et al.*, 2005) notes that when storage is combined with EOR, enhanced gas recovery (EGR) or enhanced coal bed methane recovery (ECBM), the benefits of enhanced production can offset some of the capture and storage costs. The economic benefit of enhanced production depends very much on oil and gas prices with oil prices of USD 50 per barrel potentially able to justify a credit of up to USD 30/tCO_2 (Metz *et al.*, 2005). The economic benefits from enhanced production make EOR and ECBM potential early cost-effective options for geological storage. Their likely proximity to suitable depleted oil and gas fields make CCS projects from natural gas processing facilities suitable candidates for such early opportunities across several world regions.

Box 2:   Early opportunities for CCS projects with enhanced oil and gas recovery

"Early opportunity" CCS projects involve capture from high-purity, low-cost sources such as natural gas processing, ammonia production or synthetic fuel production; transportation of less than 50 km; and storage with a value-added application, such as enhanced oil recovery. The IPCC's 2005 Special Report concluded that up to 360 MtCO_2/year could be captured and stored from such projects under circumstances of low or no incentives. Another analysis by the IEA Greenhouse Gas R&D Programme concluded that 420 early opportunity projects and 500 Mt of annual CO_2 reductions could be achieved by transporting CO_2 less than 100 km with use in enhanced oil recovery (IEA GHG, 2002). These opportunities are particularly important for engaging developing countries, who have limited funds or incentive to invest in the higher cost of CCS.

Supporting economically attractive, early opportunity projects paves the way for large-scale CCS deployment, by providing early learning on CO_2 capture, creating parts of the infrastructure, building experience in storage site characterisation and selection, and enhancing public confidence. There is a large potential for early opportunities in developing countries; another IEA GHG study concluded that by 2020, 117 MtCO_2 to 312 MtCO_2 could be captured in developing countries through the Clean Development Mechanism. Therefore, a critical next step will be ensuring that the emissions benefits offered by early opportunity applications are recognized under global climate policies.
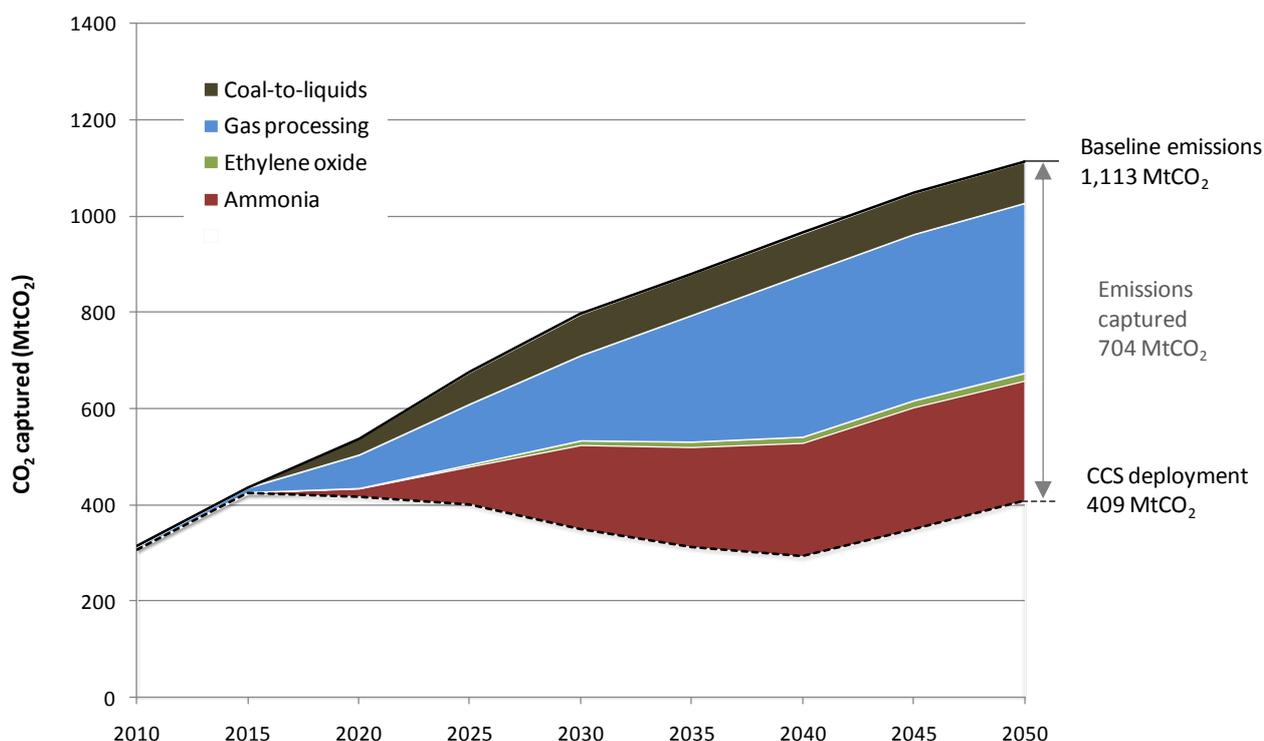
Source: IEA (2009b)

4.3   Potential for CCS deployment to 2050

A high deployment scenario for global capture from high purity CO_2 sources through 2050 is shown in Figure 17. The projected capture volumes from chemicals (ammonia and ethylene oxide) and natural gas processing are based on the IEA BLUE Map scenario data as used in the IEA CCS Technology Roadmap (IEA, 2009b). The projection of capture from CTL plant is based on the author's own analysis, assuming that from 2020 onwards 50% of new-build CTL plant deploys CCS.

Figure 17 shows that significant CCS deployment from around 2015 onwards could achieve substantial emissions reductions by 2050 compared to the baseline projection – reducing annual

emissions by around more than 60% in that year to just over 400 $MtCO_2$ compared to 1,113 $MtCO_2$ without CCS (Figure 15; Figure 16). This level of CCS deployment potential compares to an estimated CCS contribution to CO_2 abatement in industry as a whole of 30% in 2050 under the IEA Blue Map scenario (IEA, 2009b). The higher estimate for high purity sources as a group within industry reflects their relatively greater potential for lower cost CCS project opportunities through the forecast period.
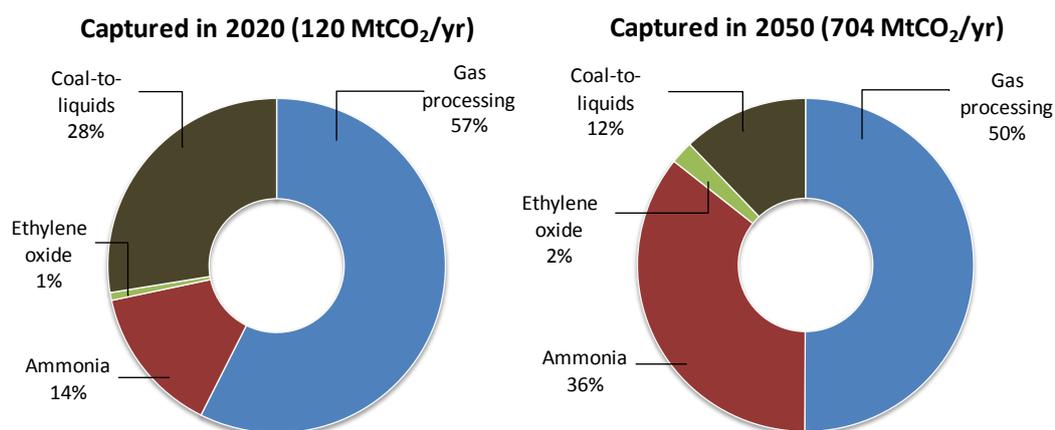
Figure 17   **Global deployment of CCS from high purity CO_2 sources 2010-2050**

Source: based on IEA (2009b) and additional analysis by the authors

The investment needs for capture plant across high purity sources will be considerable through 2050 (Figure 18). Investment of over 11 USD billion will be required in the next ten years to achieve CO_2 capture of around 120 $MtCO_2$ /year and around 53 USD billion over the period 2010-2050 to capture over 700 $MtCO_2$ /year. This figure excludes investment in transport and storage. Based on IEA estimates of transport and storage investment needs for industry as a whole (IEA, 2009b), the additional requirement for transport could be in the region of 75-150 USD billion through 2050 - at least as great as the estimated level of investment needs for capture plant from these sources. However, transport costs are likely to be relatively lower for upstream projects such as capture from natural gas processing sites where *in situ* (or close proximity) injection is possible (IEA, 2009b), and so this range may be a significantly overestimated.

Figure 18   Global deployment of CCS from high purity CO_2 sources

Captured in 2020 (120 MtCO$_2$/yr)

Coal-to-liquids 28%
Ethylene oxide 1%
Ammonia 14%
Gas processing 57%

Captured in 2050 (704 MtCO$_2$/yr)

Coal-to-liquids 12%
Ethylene oxide 2%
Ammonia 36%
Gas processing 50%

	Number of projects in 2020	Captured 2020 (MtCO$_2$/year)	Additional invest. 2010-2020 (USD bn)*	Number of projects in 2050	Captured 2050 (MtCO$_2$/year)	Additional invest. 2010-2050 (USD bn)*
Gas processing	18	69	6.4	90	353	32.7
Ammonia	10	17	0.6	181	251	8.6
Ethylene oxide	1	1	0.03	9	16	0.53
Coal-to-liquids	3	33	4.4	7	85	11.0
Total	**32**	**120**	**11.4**	**287**	**704**	**52.8**

Source: based on IEA (2009b) and additional analysis by the author

The figure indicates that in the near term, over 50% of high purity CCS projects could be deployed from capturing natural gas processing emissions. Again, their close proximity to suitable storage sites combined with the potential for EOR activities suggests their importance as near term low cost 'early opportunity' for CCS demonstration and deployment. With the evolution of transport and storage infrastructure, including optimised pipeline networks, and capture and storage hubs, an increasing share of capture from typically smaller sources including ammonia and ethylene plants could be possible.

The projections shown, largely based on the IEA Blue Map scenario (IEA, 2008b), are inherently uncertain and achieving the levels of CCS deployment shown will require a wide range of financial, regulatory and technical obstacles to be overcome - both in the next ten years when successful demonstration of CCS across different regions and sectors is crucial, and in the longer term for widespread commercial deployment. In addition to these uncertainties and the costs of CCS, the sector-specific production pathways used in the analysis of capture potential must be treated with some caution. The future production of chemicals and natural gas through 2050 will be subject to a number of highly uncertain economic, policy and technical factors, including shifting trends in patterns of energy use and production, as described previously (Section 3.2). For example, increased investment in CTL plants and demand for synfuels through 2050 - being largely linked to national energy policy objectives and expectations of future oil prices - is inherently uncertain and could

result in the CCS potential from these sources being significantly lower or higher than the projections presented here.

5 GAPS, BARRIERS, ACTIONS AND MILESTONES

5.1 Gaps and Barriers

Based on the previous section of the report and the inputs from sector experts at a workshop held in Abu Dhabi on 30th June to 1st July 2010, this section highlights some of the current gaps and barriers to CCS demonstration and deployment in high purity CO_2 sectors. In the following sections, the gaps and barriers are discussed together, clustered around four main themes:

1. *Data gaps* – where missing information inhibits understanding of the sector potential to apply CCS;
2. *Information gaps* – where additional analysis of the sector characteristics may be warranted to better understand the scope for CCS application in the sector; and
3. *Knowledge gaps* – where additional experience and knowledge-sharing, including potential pilot and demonstration projects, is required to enhance understanding.
4. *Policy gaps* – where additional awareness, policy and regulatory developments by governments may improve the prospects for deployment of CCS in high purity CO_2 sectors. Some of these are cross-cutting factors which are not specific to high purity CO_2 sources.

These are summarised below (Table 13) and reviewed in more detail in subsequent sections.

Table 13   Summary of gaps, barriers, actions and milestones identified in high purity sectoral assessment and workshop

GAPS	BARRIERS	ACTIONS	MILESTONES
Data gaps − **Technology use data** (gas treatment technologies, gasifier technologies) − **Emissions data** (venting, EO production) − **Cost data** (for CO_2 treatment, compression etc.)	→ Commercially sensitive nature of sales data for industrial equipment → Sensitivity of natural gas industry in publishing venting data → Lack of information and knowledge on costs of CCS application to high purity CO_2 sector	→ Engage to industry to assess limits of disclosure. → Establish working groups within sectors: − Natural gas processing - like World Bank Gas Flaring Partnership (GGFR) − Ammonia/fertiliser - through IFA Climate Change Task Force − EO/Ammonia – through ICCA, CEFIC, UNIDO → Review monitoring and reporting protocols to identify scope for improved reporting of CO_2 venting → Update IEA GHG CO_2 source database	→ Set up meetings with established WGs within next 6-12 months → Set up CCS early opportunities conference – next 6-12 months → Review within 12-18 months → Within 24-48 months
Information gaps − **Technical information** (co-disposal of acid/sour gas, fertiliser delivery pathways − **Economic issues** (greenfield investment, high CO_2 gas field development, risk of perverse outcomes; oil production economics and EOR)	→ Information on CO_2/H_2S co-disposal resides in industry → Unclear whether feasible to shift to alternative fertiliser delivery systems → Low greenfield oil production costs in Middle East mean little incentive for CO_2-EOR → Commercially sensitive nature of gas reserves data and investment decision-making in O&G industry → Analysis of economic issues dependent on economics of CCS deployment, and in particular the level of incentives	→ Engage with industry to identify expertise and experience → Gain expert view on the factors affecting potential switch fertiliser production routes → Work with governments and industry to better understand the role CO_2-EOR could play in oil-rich regions → Undertake scenario based analysis to evaluate CO_2 price point that could trigger changes in fertiliser production and gas field development. → Assess the scope for perverse incentives to arise (linked to previous)	→ Within next 6-12 months → Within 12-24 months → Within 24-48 months
Knowledge gaps − **Source-sink matching** (focused **on** early opportunities projects, unclear if size of high purity soruces make it economically unattractive, esp for EOR) − **Offshore EOR** (lack of knowledge on the limitations, risks etc.)	→ Lack of source data. Lack of sink data. Resource intensive → Limited R&D and pilot efforts.	→ Revisit IEA GHG (2002) study on Early Opportunities, and update with new info → Role of EOR in supporting early opportunity projects using high-purity CO_2 needs further analysis. → Review and document experience to date (e.g. BP/Miller, Statoil & Shell/Draugen field).	→ Within 12-24 months → Within 12-24 months → Within 12-24 months
Policy & cross cutting gaps − **Lack of carbon price incentive** (especially developing countries) − **Lack of regulatory framework** − **Limited policy-maker focus on early opportunities**	→ UNFCCC challenge for CDM and post-2012 → EOR role in climate mitigation unclear → Unable to permit CCS projects in most regions → Focus tends to be on power setor. CSLF/IEA work for G8 didn't move the topic forward → Limted attention to CCS in developing countries	→ Develop clearer position on the types of support mechanisms suitable for CCS & EOR deployment, especially in developing economies → Expedite regulatory developments → Develop more coherent industrial policies & strategy, and cooperation in key regions (e.g. ME) → IEA/CSLF develop revised early opportunity effort, building on information gaps highlighted above → More CCS capacity building in developing countries Gain insight into views and perspectives on CCS in key regions.	→ Within next 6-12 months → Roll out IEA Legal & Regulatory Guidelines. Next 12-24 months → Establish GCC task force on CCS. Next 12 months → Next 12 months → Continue capacity building efforts. Next 6-48 months

5.1.1 Data gaps

The analysis presented highlights several existing data gaps. These include gaps relating to the following key areas:

- Current distribution of technology employed within sectors
- Current levels of emissions
- Costs associated with CO_2 capture

Technology use

There is little data on the current distribution of different types of gasifiers, reformers and gas treatment technologies employed in ammonia, natural gas processing, and ethylene oxide production. It would be useful to have a better understanding of the distribution of different treatment systems currently in use in order to understand whether there are any issues presented within by current arrangements. The analysis outlined in this report has assumed that there are no technical barriers to compressing, transporting and storing the CO_2 offgas streams from the high purity sectors analysed. However, the use of pressure swing adsorption (PSA) in ammonia production could have impacts on the availability of high purity CO_2 where the tail gas is used for low grade heat production. The main barrier to accessing this type of information is likely to be technology vendors; this type of information will usually be commercially sensitive and is therefore unlikely to be placed in the public domain.

Emissions data

The analysis presented clearly highlights the paucity of data on levels of CO_2 venting currently carried out in natural gas processing. Although additional analysis may be possible to help refine the projections presented, such an exercise would need to be facilitated by industry engagement. The greatest barriers are likely to be the perceived sensitivity of the information, which will make producers unwilling to disclose the extent of current venting activities. In particular, such an exercise is likely to highlight a large degree of variability between producers, as the distribution of the issue is heterogeneous i.e. producers in regions characterised by high levels of CO_2 contamination will be more exposed than producers in other regions.

Additional analysis concerning CO_2 emissions from ethylene oxide production may also be warranted to attain improved certainty regarding the estimates provided in this report.

Cost data

There is significant uncertainty concerning the estimates of capture costs from high purity sources in the existing literature. Although an in-depth study of CCS costs from different natural gas processing facilities exists (IEA GHG, 2008), published costs data from other sources is less extensive, including descriptions of technical and financial assumptions used. No known cost studies of capture from ethylene oxide plant exist.

A key issue with using cost estimates from the current literature is the comparability of assumptions within and between sectors (i.e. different high purity sources). Different studies typically use different financial assumptions including the cost of capital and financial periods over which capital costs are discounted. Similarly, the use of different energy costs in the calculation of operating costs (mainly relating to compressor power requirements) may vary significantly leading to inconsistency in the basis for comparing abatement costs. This partially reflects the variability of project settings

described in the literature, which may in turn reflect typical regional lending terms, energy prices etc. The relatively large component of energy to the overall cost of capture from high purity sources suggests the usefulness of a comparative cost study for these sources based on available, or new, data. Similar issues arise when considering the dates when cost studies were produced - prices relating to both capital and operating costs vary over time as well as regions. Finally, there is little detail in the literature concerning the potential scale economies associated with projects undertaken at high purity sources. This concerns the potential to capture CO_2 more cost-effectively from integrated facilities (e.g. sites which produce both ethylene and ethylene oxide) as well as the economics relating to different plant and CO_2 volume sizes.

5.1.2 Information gaps

A number of information gaps exist in addition to the data gaps highlighted above. These generally relate to the need to gain a more detailed understanding of the following aspects for CCS deployment:

- Technical information
- Economic factors

Technical information
An important factor affecting the potential to deploy CCS in natural gas venting is the capacity to co-dispose acid (CO_2) and sour (H_2S) gas. Further analysis of any potential technical limitations posed by co-disposal of CO_2 and H_2S may be warranted given that future gas reserves are not only affected by CO_2 contamination, but more often H_2S contamination. Introducing incentives for CCS deployment for natural gas producers which allows for co-disposal may alter the economics of H_2S waste management, and potentially create perverse incentives for co-disposal (see Section 5.2.2).

In ammonia and fertiliser production, further analysis of the implications for CCS on fertilizer production pathways may be warranted. Currently around a third of all CO_2 produced in ammonia plant is used for urea production. There may be scope to alter pathways for delivering nitrogen-based fertilisers other than urea, freeing up CO_2 for CCS (IEA, 2008c). However, it is unclear in this context what the optimum pathway would be in terms of life-cycle CO_2 emissions (IEA, 2008c). The introduction of incentives for CCS for ammonia producers could force changes in fertiliser production processes depending on the economics of the different CO_2 use options. This could pose implications in terms of creating perverse incentives for fertiliser producers (see Section 5.2.2).

An improved understanding of CO_2 emissions from integrated ethylene/ethylene oxide/ethylene glycol plants may also improve the understanding for CCS potential in this sector.

There is limited data available on the number of planned CTL projects worldwide. Consolidation of current project proposals, including an assessment of their status, would facilitate a better understanding of future emissions in the sector.

Furthermore, two additional areas that have not been considered in this assessment may also warrant further research: the scope for application of CCS in methanol production, which currently produces about 2.5 million tonnes of H_2 per year (Figure 5); and, pure hydrogen production, as this could be major source of CO_2 if widespread uptake of hydrogen powered fuel cells occurs in the future.

Economic factors

In all cases where process offgas streams are concerned[1], there is scope for perverse outcomes in terms of modification to underlying processes to maximise CO_2 production and subsequent abatement through CCS. The nature of this relationship warrants further investigation prior to considering the types of incentives applicable to CCS for high purity CO_2 sources. For example, providing incentives for CCS at high CO_2 natural gas field developments (green-field developments) could alter the ranking/valuation of company portfolios of gas reserves because of potential revenues from CCS operations, and/or by altering pathways for fertiliser production so as to optimise CCS deployment potential. Further research on these aspects, including analysis of the factors affecting decisions over future valoration of high CO_2 gas reserves may be warranted. However, it is questionable whether oil and gas producers would be prepared to disclose information about their gas reserves and the decisions affecting investment in these assets.

Enhanced oil recovery was flagged as a major 'pull' factor for CCS amongst workshop participants (Box 3).

Box 3   Enhanced oil and gas recovery and high purity CO_2 sources

Enhanced oil recovery using CO_2 should act as a major pull factor to potentially develop early opportunity CCS projects using CO_2 from high purity sources. The evidence that this can be achieved is demonstrated through the network of CO_2 infrastructure in the United States. Here low cost and mined CO_2 is supplied at a price of about USD 35/tCO_2 at the wellhead to oil field operators for tertiary oil recovery in mature fields; the economic benefits are clear as 1tCO_2 can deliver 2-3 incremental barrels of oil (this adds around USD 11-17 to the marginal production cost per barrel in these regions, which is still economically attractive). This issue was key theme of the Abu Dhabi workshop, where a focus was maintained on the role of CO_2-EOR in pulling in high-purity CO_2 sources as a form of early demonstration for CCS technology (in the absence of CO_2 price incentives).

However, for those regions with emerging large high purity sources (e.g. ammonia production in the Middle East) the marginal oil production cost for green-field projects is typically very low (e.g. <USD 10/barrel produced). This means that there is little incentive to leave these fields closed and substitute production with CO_2-EOR from more mature reservoirs production, where the marginal production cost could be USD 20-30/barrel. The imposition of OPEC quotas also means that flexibility in production is required in those regions. In most cases in the Middle East, use of CO_2 in EOR would substitute the use of natural gas for pressure maintenance, which would also mean that a strategy would be required to handle the balance of natural gas, especially if the gas is associated gas (i.e. produced in association with oil). Further analysis of these issues is required to articulate a clearer business case for implementing CO_2-EOR in oil-rich regions.

5.1.3 Knowledge gaps

Some additional gaps in the current knowledge base were identified in the Abu Dhabi workshop relating to understanding the scope for CCS deployment in a given region through source-sink matching, and the lack of experience with offshore CO_2-EOR.

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[1] For example, HFC-23 offgas production from HCFC-22 manufacture, which has been subject to considerable controversy within the UN clean development mechanism.

Source-sink matching and early opportunities

There is a need for more studies that can provide an assessment of matching sinks and sources (existing/future) – this should be carried out on a regional scale. In the context of high purity CO2 sources, it is also unclear whether high purity CO_2 sources alone are sufficient to provide large enough quantities needed for CO_2-EOR in some regions. Further analysis on a region-by-region basis is required to establish whether this is a genuine constraint to deployment.

Enhanced Oil Recovery offshore

Offshore CO_2-EOR has not been undertaken anywhere in the world – refurbishing on an offshore platform is expensive. The additional weight of compression and surface facilities for handling of breakthrough CO_2 will be determined by the ullage[8] present on a particular platform. Also, matching supply and demand is important as EOR may not necessarily require a continuous feed of CO_2 on a daily/monthly/annual period. Venting of CO_2 offshore may pose new occupational health & safety concerns for operators (e.g. asphyxiation risk) and needs to be more clearly understood prior to commencing any projects of this type.

5.1.4 Policy and cross-cutting gaps and issues

Workshop participants identified the following policy and cross-cutting related gaps that should be highlighted in the Roadmap.

Incentives

The lack of a carbon price signal which attaches a cost to venting of the CO_2 and/or allows the generation of tradable carbon commodities ("credits") for CCS is a major barrier to CCS deployment in developing regions. Presently CCS only creates additional costs and risks with no tangible (non-environmental) benefits.

Legal and regulatory, liability

No developing country has a legal framework which sets out regulatory conditions for CCS operators. Developed regions are still embarking on this process, and fully-fledged and tested systems do not exist anywhere in the world. In certain instances, high-purity applications may bypass these requirements (e.g. the In Salah CO_2 injection project, which is regulated under existing gas field management regulations). CO_2-EOR may also be able to by-pass these concerns by allowing regulation under existing oilfield management regulations.

Finance

The lack of sufficient and sustainable incentives for CCS means that it is virtually impossible to raise debt finance for projects.   Where public financial support in the form of grants, soft loans etc is not available, this means that CCS projects must be financed from company balance sheets. It is unclear whether high purity sectors have sufficient finance available to make investments at the scale needed (Figure 18).

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[8] Ullage in this context refers to the spare weight capacity of the civil engineering assets on an offshore platform

Policy-makers focus

Whilst some efforts have been made to work towards CCS deployment in early opportunities (e..g work by the CSLF/IEA on behalf of the G8), the focus of policy-makers tends to be on CCS deployment in the power sector.

Operator perception

In the Middle East region, there is concern that CO_2 could contaminate hydrocarbon resources. Further development of the evidence base is warranted.

Transport gap

Regional transport infrastructure was highlighted in the workshop as a key issue. In many regions there is no infrastructure which can gather high purity CO_2 sources and transport them to end users, in particular potential EOR operators.

5.2 Actions and Milestones

A number of areas for further research were highlighted in the previous section. Based on these, some near term actions and milestones that could be implemented for high purity CO_2 sources include:

- Update technical and cost information in several key areas
- Identify candidate regions where CCS potential from high purity sources may be greatest
- Improve engagement with the high purity CO_2 sector on CCS issues
- Improve awareness of the benefits of CCS 'early opportunities' with policy-makers
- General capacity building

5.2.1 Update technical and cost information

There is significant scope to improve the current technical information that could help facilitate improved understanding of the potential for CCS application in the high purity CO_2 sector. Possible actions include:

- Update IEA GHG database of CO_2 emissions sources (IEA GHG, 2006) to improve information included. This is partly contingent on improving engagement with industry, as described in the previous section.
- Revisit and update IEA GHG work on early opportunities (IEA GHG, 2002b). The study should be updated and its results re-evaluated in order to allow clearer assessment and communication of CCS early opportunities.
- An update of the IEA GHG CO_2 emissions database (*ops cit.*) and an update review of 'early opportunities' could help to identify candidate regions which may include e.g. Arabian Gulf/Gulf of Thailand/South China Sea; North East Shelf Australia; North Sea.
- CO_2 demand side issues seem critical to getting early projects off the ground in the absence of a CO_2 price for emitters. CO_2-EOR requirements, technical challenges and acceptance by operators, all need to be clarified to enhance the "market pull" of CO_2 use in EOR.
- Thorough review and further analysis of capture costs from high purity CO_2 sources. A study of project costs on a comparative basis using recent data inputs would also help to inform

consideration of candidate regions and describe key cost variables such as investment costs, energy prices and scale/process integration effects.

A further area that may need development is in monitoring and reporting protocols for high purity CO_2 sources. This could help improve the resolution at which data is reported for individual high purity sources.

Identify candidate regions

An improved level of up to date technical and cost information for high purity sources would provide a more robust basis for identifying candidate regions for CCS deployment of early opportunities within this sector.

Regional reviews of CCS potential could be developed focusing on low cost CO_2 capture sources i.e. high purity sources, informed by characterizing relevant factors and issues including e.g.

- Proximity of high purity industrial sources to suitable storage sites; including as assessment of project deployment scale (total CCS potential) according to transport distances and onshore and offshore storage media (media type, capacity, etc)
- Potential for CO_2-EOR use, based on an understanding of market and policy factors influencing current and expected regional EOR demand
- Outlook for production - including changes in process and patterns of energy use -within the high purity sector of each region
- Cost factors influencing relative abatement costs from CCS deployment (e.g. identifying low-cost opportunities based on *inter alia* energy prices, investment environment and project loan risk, ability to integrate CCS into new-build plant, scale factors)

5.2.2 Improve engagement with industry

In order to close some of the data and information gaps highlighted previously, it will be important to improve the way in which the industries associated with high purity CO_2 sources engage with the CCS debate; to date, the focus of the CCS debate has largely been on the power sector.

Some specific actions in this context could include:

- Establish a natural gas producers working group to attempt to gain a better understanding of current CO_2 venting emissions from natural gas production, potential future emissions and the effects of CCS on production economics. This could be similar to the Global Gas Flaring Reduction Public Private Partnership of the World Bank, which has been effective in establishing and communicating the technical and economic factors affecting flaring of associated gas. The International Petroleum Industry Environment Conservation Association (IPIECA), The International Association of Oil & Gas producers (OGP), or International Gas Union could facilitate this process.
- Improve communication between the ammonia industry and the CCS community. This could be achieved through the establishment of a dialogue between the International Fertiliser Association (IFA), national fertiliser associations (e.g. The Fertiliser Association of India; FAI) and leading players in the CCS community e.g. the IEA or the Global CCS Institute (GCCSI).
- Similarly, better communications between the CCS community and the chemicals industry is warranted, as it cross-cuts both ammonia production and ethylene oxide production.

More generally, the GCCSI or IEA should consider setting up a CCS "early opportunities" working group with a view to improving the dialogue between these key sectors.

Some specific milestones in these contexts could include:

- At least one global CCS conference and information exchange with key players in the high purity CO_2 source sector should be held within the next 12 months;
- A dialogue with potential industry forums which could act as a focal point for CCS within the relevant sectors should be completed within the next 6-12 months.

5.2.3 Raise Awareness with policy makers

Policy makers need a better understanding of the potential for applying CCS for high purity sectors, including an understanding of the sources of high purity CO_2 emissions (sectors, scale), and the potential benefits the sector offers in terms of CCS demonstration, especially early demonstration of CO_2 storage. In this context:

- Many of the actions referred to previously could help close the knowledge gap in this respect, and the challenge will be to successfully communicate this with policy-makers. Revisiting and revising the work by the CSLF/IEA on early opportunities could help bring the topic to the attention of policy-makers, especially in key regions.
- Development of regional CCS strategies can kick start discussions on creating CCS enabling policy frameworks. Raising awareness about the long-term role that CO_2-EOR can play in oil producing regions needs to be undertaken. Greater awareness and cooperation should allow governments to develop industrial strategies that support early utilization of high purity CO_2 sources in CCS demonstration, especially demonstration of storage (e.g. site selection, regulation, monitoring etc). Gulf States are an early opportunity for CCS – greater cooperation through existing forums is an important first step to raising awareness in this region (e.g. Gulf Cooperation Council, OPEC).

Other more obvious cross-cutting issues for policy-makers include:

Incentives
CCS needs to be recognized as a mitigation activity under CDM or other incentive mechanism applicable in developing countries. Suitable international emission reduction mechanism need to be developed which includes CCS (e.g. Nationally Appropriate Mitigation Actions). Monitoring, reporting and verification requirements under such schemes need to be clearly outlined.

Role of EOR
It is unclear whether CO_2-EOR will be recognized as a climate mitigation technology. More detailed analysis of the life-cycle carbon emissions associated with EOR activities should be undertaken to better inform the debate.

5.2.4 Build capacity

For all issues raised, there is broad need to build capacity amongst industry and policy-makers, especially in some high purity CO_2 sources sectors (e.g. ammonia production) and in developing countries.

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