Carbon Capture and Storage: Ukrainian Perspectives on Industry and Energy Security
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What is Carbon Capture and Storage (CCS)

Carbon Capture and Storage (CCS) reduces greenhouse gas emissions by capturing the carbon dioxide (CO2) generated by large point sources before it is released to the atmosphere, and then transporting it to a secure underground storage facility for permanent storage. CO2 can be captured and stored from a wide range of point sources including, fossil fuel power plants, refineries, iron and steel plants, cement facilities and biofuels plants. CCS enables the production of low carbon electricity from fossil fuels and low carbon industrial products. Potentially with the use of biomass or biofuels CCS can remove CO2 from the atmosphere reversing the effects of climate change.

CO2 must first be captured and separated from the point source using a variety of chemical or mechanical processes. A pure stream of CO2 is then compressed to a high pressure liquid like state for transport, usually in pipelines. The CO2 is then delivered to a suitable storage site, where it is injected more than a kilometre below the surface to the permanently trapped and immobilised in rock layers.

Figure 1 Example of a coal power plant fitted with CCS

CCS offers the potential to radically reduce CO2 emissions from large point emissions such as coal and gas fired power plants and emission-intensive industrial facilities. In the case of energy intensive industrial applications CCS offers the only current means to significantly reducing emissions. CCS will be necessary decarbonisation component for all heavy industrial and CO2 intensive economies. No single technology holds the answer to averting damaging climate change. Only full use of all available technologies and measures such as renewable energy, enhancing energy efficiency, curbing emissions from agriculture and forestry, in addition to deploying CCS will we successfully reduce damaging emissions.

CCS is a prominent decarbonisation technology in many national and global strategies to tackle climate change. Numerous studies from bodies such as the Intergovernmental Panel on Climate Change, the Major Economies Forum and the International Energy Agency have indentified to the need for substantial global
deployment of CCS in industrial and power sectors to efficiently meet climate targets. The 2013 International Energy Agency “Carbon capture and Storage Technology Roadmap” identified CCS delivering 17% of cumulative CO2 reduction by 2050 (Figure 2). Buy the same year approximately 8 billion tonnes of CO2 will be captured and stored per annum from a diverse range of sectors, with the majority of facilities located in non-OECD countries (Figure 3). Although the developed world is expected in these projections to take a lead in establishing and deploying CCS technologies, more than two thirds of the required CCS installations will be in China, India and developing countries in 2050. It is clear that CCS will also be necessary in any decarbonisation of the Ukrainian economy.

Cumulative spending between 2007 and 2012 on projects that demonstrate CCS or component technologies in the CCS chain at large scale reached almost USD 10.2 billion with USD 7.7 billion of this total came from private financing. Similarly research and development funding from government and industry has driven a compound annual growth rate of 46% in CCS-related patent applications between 2006 and 2011 (IEA, 2013)

Figure 2 CCS contributes 14% of total emission reductions through 2050 in the two degree warming scenario, compared to the six degree warming scenario1 (IEA, 2013)

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1 Numbers in brackets are shares in 2050. For example, 14% is the share of CCS in cumulative emission reductions through 2050, and 17% is the share of CCS in emission reductions in 2050, compared with the 6 degree warming scenario.
CCS in the EU

CCS is regarded as a key technology in the decarbonisation of European power generation and industry. The EU’s energy policy sets out ambitious energy and climate change objectives, including a compulsory 20% reduction in greenhouse gas emissions by 2020 compared with 1990 (European Commission, 2007). A commitment has been made to further decarbonise the European economy by 2050, reducing greenhouse gas emissions by 80–95% compared with 1990 levels (European Commission, 2011).

Published in 2011, the Energy Roadmap 2050 estimates the projected contribution of CCS and other technologies over the period to 2050. The share of power generation from CCS equipped fossil-fired power stations range from 7 to 32% (Figure 4). The report concludes that in order to reach the decarbonisation targets, CCS will have to be deployed at all fossil fuelled power plants from 2030 onwards. CCS is also necessary for decarbonisation of sectors other than power generation, such as several heavy industries. The EU Energy Roadmap 2050 also highlights the need for carbon negative solution, stating that negative carbon emissions technologies may be needed to meet overarching targets.
The EU has incentivised the development of CCS technologies and facilitated deployment through research and development programmes, legislative frameworks, demonstration funding and the Emissions Trading System (ETS) placing a price on CO2 emissions.

- The EU introduced Directive 2009/31/EC on the geological storage of CO2, known as the ‘CCS Directive’ (European Commission, 2009). This Directive to be implemented in all Member States is a legal framework for the management of environmental and health risks related to CCS, including requirements on composition of CO2 streams, permitting, monitoring, reporting, inspections, corrective measures, closure and post-closure obligations.

- The development of a cross-border network for CO2 transport has been included in the European Commission’s 2011 proposal for the regulation and support of critical trans-European energy infrastructure. This seeks to streamline permit granting procedures and to provide the necessary market-based and direct EU financial support to enable implementation of projects of common interest.

- In 2010, the European Energy Programme for Recovery allocated €1 billion in funding to six CCS demonstration plants. A second source of funding for additional CCS demonstration projects is the ‘NER300’ funding Programme. This is funded through the allocation of 300 million EU allowances set aside from the New Entrants Reserve of the EU ETS. The scheme was intended to support demonstration of CCS technologies and innovative renewable. In the event, the value of EU allowances from the ETS was substantially below that anticipated due to decline in allowance price caused by economic recession. Due to this the no CCS projects were funded in the first round, with most CCS projects not been confirmed by their host Member States, and therefore were ineligible for funding.
Initially the European commission anticipated the ETS should provide sufficient economic stimulus for the development and deployment of CCS technology in Europe. However the current underperformance of the ETS is leading to a revaluation of incentive schemes. In 2013 the Commission launched a consultative communication on the future of CCS in Europe to solicit input from stakeholders and stimulate a debate on implementing European initiative on CCS.

The Role of CCS in Ukrainian Energy and Industry

Ukraine is one of the most energy-intensive economies in Europe. In terms of energy consumption per unit output Ukraine has one of the highest levels in the world at 2,369 tonnes of CO2 equivalent per million dollars of GDP, more than five times the EU average (IBP, 2013). The carbon intensity is critically high due to the presence of energy intensive industries combined with the inefficient use of carbon intensive coal, gas and oil being the predominant energy sources (Figure 5). Ukraine is counted among the top twenty countries with the highest CO2 emissions worldwide (Martyniuk & Ogarenko, 2012). As global climate rules become increasingly stringent Ukraine will require CCS technologies to address emissions from future fossil fuel power plants and energy intensive industries such as iron and steel production.

Figure 5 Primary energy mix, 2010 (IEA, 2012)

In 2011 Ukrainian CO2 emissions totalled 305 million tonnes, with energy use and industrial process responsible for 88% of the total (unfccc, 2012). Table 1 gives a breakdown of current annual emission from the major CCS applicable industries in Ukraine, electricity generation, iron and steel ammonia production and cement. Electricity sector emissions are currently responsible for approximately 33% of Ukrainian emissions and can be addressed through a variety of measures such as fuel switching, renewable deployment and CCS. Heavy industrial are dominant in Ukraine and also account for approximately 33% of emission. However the
only available technology to significantly reduce emissions from these industrial sectors is CCS. This is due to both CO2 being an unavoidable by product of the industrial process, known as process emissions, and limited opportunities for fuel switching, such as cooking coal in the iron and steel industry.

Table 1 Breakdown of CCS applicable energy, industrial and process CO2 emissions in Ukraine (unfcc, 2012)

<table>
<thead>
<tr>
<th></th>
<th>Energy emissions (million tonnes CO2)</th>
<th>Process emissions (million tonnes CO2)</th>
<th>Total emissions (million tonnes CO2)</th>
<th>Electricity Sector emissions (% national total CO2 emissions)</th>
<th>Industrial Sector emissions (% national total CO2 emissions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity and Head</td>
<td>103</td>
<td>-</td>
<td>103</td>
<td>33.7 %</td>
<td>-</td>
</tr>
<tr>
<td>Iron and Steel</td>
<td>42.5</td>
<td>23.7</td>
<td>66.2</td>
<td>-</td>
<td>21.6 %</td>
</tr>
<tr>
<td>Ammonia Production</td>
<td>7.7</td>
<td>6.8</td>
<td>14.5</td>
<td>-</td>
<td>4.7 %</td>
</tr>
<tr>
<td>Cement Products</td>
<td>9.6</td>
<td>10.9</td>
<td>20.5</td>
<td>-</td>
<td>6.7 %</td>
</tr>
<tr>
<td>Total</td>
<td>162.8</td>
<td>41.4</td>
<td>204.2</td>
<td>33.7 %</td>
<td>33.1 %</td>
</tr>
</tbody>
</table>

The Ukrainian electricity supply industry is characterised by high energy intensity and poor efficiency (Table 2). The thermal power generation fleet, dominated by coal, is antiquated and in need of modernisation. As of the end of 2010, 81 % of thermal power-station modules exceeded their planned life span of 200,000 hours of operation and are in need of modernisation or replacement (Ministry of Energy and Coal Industry of Ukraine, 2012). The primary concern for the modernisation of thermal power plants is the need to reduce air pollution such as SO2, NOx and particulate matter while increasing the energy conversion efficiency. Ukraine’s energy sector is in need of large and sustained investment to ensure its modernisation, security and competitiveness. The scale of investment required is on the order of EUR 170 billion in the period to 2030 (IEA, 2012). However, the modernisation of Ukraine’s energy production, transmission and end-use segments has barely started. In addition to the vast investment outlined above, significant sums will be needed to implement the European Union Large Combustion Plant Directive as planned by 2018.

Table 2 Installed capacity of power plants 2010 ((Ministry of Energy and Coal Industry of Ukraine, 2012)

<table>
<thead>
<tr>
<th>Type of Power Plant</th>
<th>Installed capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal power</td>
<td>30,536</td>
</tr>
<tr>
<td>Nuclear power</td>
<td>13,835</td>
</tr>
<tr>
<td>Hydro power</td>
<td>4,596</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>861</td>
</tr>
<tr>
<td>Renewable</td>
<td>156</td>
</tr>
</tbody>
</table>

In recent years significant uncertainty has surrounded the future make up of the electricity generation system in Ukraine. The government approval of the “updated Energy Strategy of Ukraine until 2030” may go some
way to clarifying what energy sources are anticipated to make a contribution to Ukrainian electricity production. Indigenous coal use for electricity production is attractive to Ukrainian energy planners due to the increased energy supply security, job creation, and relatively low cost when compared to imported natural gas (proven coal reserves in Ukraine are estimated 56.7 billion tons).

Figure 6 describes three scenarios for the role of highly carbon intensive coal generation to 2030 (Ministry of Energy and Coal Industry of Ukraine, 2013) (UNDP, 2007). The pessimistic scenario sees a small decline in coal generation capacity, however due to the installation of new capacity overall coal electricity output remains stagnant. Meanwhile in both the base and optimistic scenarios installed coal generation capacity increases, as does the overall coal energy output. In all three scenarios CO2 intensive coal generation remains the key (or expanding) energy provider to the Ukraine. This will inevitably result in increased CO2 emission and a carbon intensive power generation system far beyond 2030 due to the expected operational life of new coal power plants. Ukrainian industry is the major consumer of electricity responsible for 48% of consumption in Ukraine (Figure 7). As such Ukraine’s continued dependence on coal fired power generation will result in a high carbon intensive throughout the economy. The future deployment of CCS will be the only means to significantly reduce CO2 emissions while enabling the use of domestic coal resources.

![Figure 6: Expected installed coal generation capacity (GW) and coal output (TWh) scenarios (I - pessimistic, II - Base, III - optimistic) (Ministry of Energy and Coal Industry of Ukraine, 2013)](image-url)
Emissions intensive industries are critical to the Ukrainian economy; industry contributes to 26% of GDP while providing 32% of employment. In 2010 metal products alone accounted for 34.5% of all exports, where fertiliser accounted for approximately 2% (MIT, 2013). The iron and steel industry of special importance, in 2007 crude steel production peaked at 42.8 million tonnes (USGS, 2007). CO2 Capture and Storage is the only technology that can deliver the deep emission cuts required by several Ukrainian energy-intensive industries (ZEP, 2013). Future requirements on Ukraine to substantially reduce CO2 emissions will therefore require CCS to be deployed to the iron and steel industry along with fertilizer, cement and refining.

The use of coking coal can be used as an indicator of future CO2 emissions from the iron and steel industry. Figure 8 shows the GHG effect of increasing coal consumption from mining, combustion and iron and steel production to 2030. Coal use by coking industry was anticipated to increase almost twice from 2005 to 2010, and is expected to increase gradually to 2030. It is evident that GHG emissions under current projections are set to increase from both energy production and the iron and steel industry.
Figure 8 Expected GHG emissions from coal production and consumption in basic scenario (thousands tones CO₂ equivalent) (Ministry of Fuel and Energy of Ukraine, 2006)
CCS Guide Book

Ukraine’s economic composition dominated by energy intensive industries and a growing reliance on CO2 emissions from industrial processes. The efficient deployment of CCS in Ukraine post 2030 requires the building capacity technical. This report aims to provide an introduction of CCS systems, providing practical guidance for decision makers. The following chapters include a detailed description of the process required for the capture and storage of CO2 from point sources, the transport of CO2 and the development and operation of permanent CO2 storage sites (Figure 9).

Figure 9 Simplified capture and storage value chain

CO2 Capture Technologies

A variety of technologies to capture CO2 from energy and industrial process are available. Table 3 gives a summary of the applications of major CO2 capture technologies in different sectors. The selection of capture technology will be dependent on a variety of factors including technical, economic, legal, deployment, operation and public outreach aspects.

Post-combustion/process capture

CO2 is separated from a mixture of gases at the end of the production process, for instance from combustion flue gases. Post combustion capture can be deployed at a wide variety of CO2 source facilities, including power plants, refineries, cement plants, iron and steel plants. This route is referred to as post combustion capture is generally suitable for retrofitting to existing facilities. The cost associated with post combustion capture is the need for heat to regenerate the CO2. Approximately 80% to 90% of the CO2 can be captured using post-combustion capture.
**Oxy-fuel combustion**
Pure (or nearly pure) oxygen is used in place of air in the combustion process to yield a flue gas of high-concentration CO2. While in oxy-fuel combustion a specific CO2 separation step is not necessary, there is an initial separation step for the extraction of oxygen from air, which largely determines the energy penalty. The oxyfuel process is versatile having applications in power production and industry including iron and steel and cement production.

**Syngas/hydrogen capture**
Through the process of gasification a mixture of hydrogen, carbon monoxide and CO2, can be generated from fossil fuels or biomass. The CO2 can be removed, leaving a combustible fuel. In some cases, where either pure hydrogen or additional emission reductions are required, the syngas can be shifted to hydrogen while converting the carbon monoxide to separable CO2. This route is referred to as pre-combustion capture in power generation applications. Such a technology is an Integrated Gasification Combined Cycle (IGCC) coal power plant. Here coal is gasified and converted to hydrogen and CO2, with the hydrogen combusted in a gas turbine.

**Inherent separation**
Generation of concentrated CO2 is an intrinsic part of the production process. Facilities such as ammonia fertilizer plants, gas processing plants and the fermentation-based biofuels produce high purity CO2 streams. At present CO2 generated at such facilities is ordinarily vented to the atmosphere.
**Table 3 Proposed use of CO2 capture technologies in different CO2 intensive sectors (IEA, 2011)**

<table>
<thead>
<tr>
<th></th>
<th>Post-Combustion</th>
<th>Oxy-Fuel combustion</th>
<th>Syngas-Hydrogen</th>
<th>Inherent Separation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Power Generation</strong></td>
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<td></td>
</tr>
<tr>
<td>Coal</td>
<td>Pulverised coal</td>
<td></td>
<td>Oxy-fuel</td>
<td>Integrated</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>combustion</td>
<td>gasification</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>combined cycle</td>
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<tr>
<td></td>
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<td></td>
<td></td>
<td>(IGCC)</td>
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<tr>
<td>Gas</td>
<td>Natural gas</td>
<td></td>
<td>Oxy-fuel</td>
<td>Gas</td>
</tr>
<tr>
<td></td>
<td>combined cycle</td>
<td></td>
<td>turbine</td>
<td>reforming</td>
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<tr>
<td><strong>Industry CCS</strong></td>
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<tr>
<td>Iron and Steel</td>
<td>Blast furnace</td>
<td></td>
<td>Oxy-fuel</td>
<td>Hydrogen</td>
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<tr>
<td></td>
<td>capture</td>
<td></td>
<td>combustion</td>
<td>reduction</td>
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<tr>
<td>Refining</td>
<td>Process heaters</td>
<td></td>
<td>Oxy-fuel,</td>
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<td></td>
<td></td>
<td>process</td>
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<td></td>
<td>heaters</td>
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<td></td>
<td>Hydrogen</td>
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<td></td>
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<td></td>
<td></td>
<td>production</td>
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<tr>
<td>Cement</td>
<td>Rotary kiln</td>
<td></td>
<td>Oxy-fuel</td>
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<td></td>
<td></td>
<td></td>
<td>rotary kiln</td>
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<td>Calcium</td>
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<td>looping</td>
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<td>Chemicals</td>
<td>Process heater</td>
<td></td>
<td>Oxy-fuel,</td>
<td></td>
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<td></td>
<td>and CHP</td>
<td></td>
<td>Process</td>
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<td></td>
<td>heater and</td>
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<td></td>
<td></td>
<td></td>
<td>CHP</td>
<td></td>
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<td></td>
<td></td>
<td>Fertiliser</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>production</td>
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<tr>
<td>Gas</td>
<td>Process heaters</td>
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<td><strong>Carbon-Negative</strong></td>
<td>Biomass</td>
<td>Biomass-fired</td>
<td>Combustion</td>
<td>IGCC</td>
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<td></td>
<td>Bio fuels</td>
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</tbody>
</table>

**CO2 Compression & Drying**

Large multi stage CO2 compressors are currently commercially available. The types of compressor selected is highly dependent on the starting pressure, which is 1 Bar for most post-combustion capture and Oxy-fuel combustion while syngas/hydrogen capture inlet pressure may be 1.3 bar to 34.5 bar (Wolk, 2009). To meet the low water content required for CO2 transport multi stage compressors utilize dehydration units between stages (Aboudheir & McIntyre, 2008).

The compression necessary to transport supercritical CO2 at between 80 and 200 Bar requires significant amounts of energy. Contributing up to 5% of the energy penalty to a CCS equipped power plant. The CO2 compressor power required for a pulverized coal (PC) power plant is 8 to 12 percent of the plant rating. The Boundary Dam coal CCS project in Saskatchewan Canada rated at 110 MW plant requires a 14 MW CO2 compression unit (Couturier & Mello, 2013).

CO2 compressors are currently supplied by companies such as Dresser-Rand & Ramgen, MAN Diesel & Turbo and GE(Kuzdzal, 2012).
Front End Engineering and Design (FEED) studies:
Below is a list of relevant FEED studies for the application of CCS to different coal fired power plants.

Scottish Power, Longannet project, UK completion, Department of energy and climate change
• Proposed retrofit of post combustion amine CO2 capture to an existing pulverised coal plant

E-On, Kingsnorth project, UK completion, Department of energy and climate change
• Post combustion amine capture at a proposed new build pulverised coal power plant

ROAD CCS, Non-confidential FEED study report, Special report for the Global Carbon Capture and Storage Institute (2011) Rotterdam Capture and Storage Demo project
• Post combustion amine capture at a proposed new build pulverised coal power plan

Lessons learned from the Jänschwalde project, A European CCS Demonstration Project Network Report Knowledge Sharing Event Cottbus, (2012)
• Proposed oxy-fuel combustion at a new coal unit

Emissions from CCS Power Plants
CO2 capture at the power plant will reduce CO2 emissions to the atmosphere by 85–98%. CCS technologies also lead to a reduction in other harmful pollutants, including SO2, NOx, and particulate matter. Table 4 indicates the relative change in the emission factor of a substance owing to the application of a certain CO2 capture technology (Koornneef, et al., 2011). A value of 1.0 indicates no change in emission factor when compared with a European reference plant without CO2 capture. NOx, SO2 and particulate matter will generally reduce or remain unchanged compared with emissions at facilities without CO2 capture. For example in the case of a coal fired power plant equipped with post-combustion CO2 capture, SO2 emissions are reduced significantly compared to a power plant without capture. This is a result of the requirement for improved flue gas desulphurization (FGD) facilities prior to the post-combustion capture unit.

<table>
<thead>
<tr>
<th>Capture Technology</th>
<th>CO2</th>
<th>SO2</th>
<th>NOx</th>
<th>PM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Post Combustion</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>0.1</td>
<td>0.15</td>
<td>0.94</td>
<td>0.71</td>
</tr>
<tr>
<td>Gas</td>
<td>0.13</td>
<td>-</td>
<td>1.00</td>
<td>-</td>
</tr>
<tr>
<td>Oxy</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>0.05</td>
<td>0.06</td>
<td>0.42</td>
<td>0.06</td>
</tr>
<tr>
<td>Syngas</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>0.11</td>
<td>0.45</td>
<td>0.85</td>
<td>1.00</td>
</tr>
</tbody>
</table>

Carbon Capture and Storage Ready (CCSR)
Easy and low cost steps can be taken now to help ensure the timely and cost effective implementation of CCS technologies in the future. CCSR is not a CO2 mitigation option, but a way to facilitate CO2 mitigation in the future. CCSR in its most basic form requires prospective developers of large CO2 point sources assess the applicability of CCS to the facility. Often including an assessment of possible storage sites, CO2 pipeline routes and set-aside space for CO2 separation and capture units.
CCSR is a policy option that can ensure new facilities are designed, approved and constructed in a manner that enables a retrofit of CCS technologies at an appropriate future time. This can help both operators and the wider economy avoid locking-in potentially costly and inappropriate high emitting technologies. CCSR also makes investors aware of the eventual prospect of CCS deployment, informing their investment decisions today, helping to reduce the prospect of stranded asset in the future.

In the EU CCSR is already a requirement, under article 9a of the Large Combustion Plant Directive and article 33 in the CCS Directive.

**Article 9a**

1. Member States shall ensure that operators of all combustion plants with a rated electrical output of 300 megawatts or more for which the original construction licence or, in the absence of such a procedure, the original operating licence is granted after the entry into force of Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide, have assessed whether the following conditions are met:

   - suitable storage sites are available,
   - transport facilities are technically and economically feasible,
   - it is technically and economically feasible to retrofit for CO2 capture.

2. If the conditions in paragraph 1 are met, the competent authority shall ensure that suitable space on the installation site for the equipment necessary to capture and compress CO2 is set aside. The competent authority shall determine whether the conditions are met on the basis of the assessment referred to in paragraph 1 and other available information, particularly concerning the protection of the environment and human health.

In practice, the article require all new thermal electricity plants with a capacity greater the 330MW to carry out an assessment of whether suitable storage is available as well as a technical and economic feasibility of CO2 transport and retrofitting of CO2 capture technology.

CCSR is especially valuable in countries such as the Ukraine, where at present and into the medium term future the prospect of a sufficient CO2 price to drive CCS is absent. In this way CCSR can provide a regulatory backstop, preparing industry and the energy sector to deploy CCS technologies. CCSR is critically the first necessary step in CCS technology deployment.

**Recommended reading:**

“Global CCS Institute 2012, CCS READY POLICY AND REGULATIONS – THE STATE OF PLAY, Progress towards the implementation of CCS Ready policy and regulatory frameworks”


Bellona (2011) CCS readiness at Šoštanj: Ticking boxes or preparing for the future?
EXAMPLE:
A representative modern 380 MWe super-critical pulverised coal power plant with 90% CO2 capture would result in 2.65 million tonnes of CO2 being stored per year. A typical capture technology for such a facility would be a post combustion amine unit, with the ability to capture 10,000 tonnes of CO2 per/day. The addition of a post combustion capture unit results in an electricity output penalty (EOP) due to parasitic energy consumption. This is a result of steam extraction to regenerate solvent, power requirement of compression and smaller amounts to power capture plant ancillary equipment (Singh, 2013). Steam use for regeneration of solvent is responsible for approximately 55-70% of the total energy penalty, with the reaming the result of compression, solvent circulation pumps and blowers (Zahra, 2009). The electricity output penalty results in a net reduction in efficiency in return for low carbon electricity. The IEA report “cost and performance of carbon dioxide capture from power generation 2011” estimates post combustion capture at a coal plant to reduce net efficiency by 25% resulting in a increase in fuel consumption to generate equivalent power output.

\[
\text{EOP} = 1000 \times \left[ \frac{\text{Loss of generator output} + \text{Compression power} + \text{Ancillary power}}{\text{CO2 Mass flow}} \right]
\]

<table>
<thead>
<tr>
<th>Electricity output penalty (EOP)</th>
<th>(kWhe/tonne CO2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loss of steam turbine generator output</td>
<td>(MW)</td>
</tr>
<tr>
<td>Compression power</td>
<td>(MW)</td>
</tr>
<tr>
<td>Ancillary power</td>
<td>(MW)</td>
</tr>
<tr>
<td>CO2 mass flow</td>
<td>(tonne/hr)</td>
</tr>
</tbody>
</table>

However when replacing or upgrading existing plants with CCS enabled facilities net efficiency can increase over the original antiquated generation facilities. This is due to the installation of modernised boilers and turbines along with capture equipment, resulting in decrees in fuel use and the production of low carbon electricity. In Saskatchewan Canada, the comprehensive upgrading of unit 3 and the installation of post combustion capture at the boundary dam coal power plant resulted in an efficiency increase from the original 31% to 34%. Similarly the front end engineering and design (FEED) study for the proposed Janschwalde CCS project in Germany concluded that a new CCS equipped unit would match the net efficiency (36%) of existing unabated units operating at the plant. This effectively means that there would be no energy penalty between a new low carbon generation unit including compression and an older unabated operating plant (Vattenfall, 2012).

**Transport**

Transporting CO2 by pipelines is a proven technology. In fact, CO2 has been transported at scale by pipelines in the USA since the 1970s. A large network of pipelines for CO2 transport has developed in USA, Canada and Hungary for the use in Enhanced Oil Recovery (EOR). As a result wealth of operational experience has been accrued; with operational pipelines exhibiting high reliability. Here the CO2 has traditionally been sourced from naturally occurring CO2 reservoirs and transported to oil fields where it is injected to increase the oil production. Due to increased demand for CO2, owing to the commercial success
of EOR activities, CO2 is increasingly sourced from anthropogenic (manmade) sources, such as fertiliser production facilities and gasification plants.\(^2\) (GCCSI, 2012)

CO2 is transported in carbon steel pipelines of the same general type and specification used for high pressure natural gas transport. Usually API 5L Grades X65 or X70 grade pipeline steel is adopted, due to the high operating pressure (Seiersten & Kongshaug, 2005). Additional challenge do exist, primarily of corrosion, plugging and flow assurance, most resulting from impurities present in the CO2 stream such as H2O. Corrosion is a result of excessively wet CO2 stream. CO2 and water form a mild carbonic acid that over time can damage steel pipeline. However, corrosion can be avoided with simple operational measures and sufficient drying of the CO2 stream.\(^3\) Similarly plugging of pipelines caused by the formation of hydrates in wet CO2 streams can be mitigated with sufficient drying.\(^4\)

Table 5 Overview of the main identified issues associated with various components

<table>
<thead>
<tr>
<th>Component</th>
<th>Properties</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO(_2)</td>
<td>••••••••</td>
<td>Non-flammable, colourless, no odour at low concentrations, low toxicity, vapour heavier than air</td>
</tr>
<tr>
<td>H(_2)O</td>
<td>•</td>
<td>Non-toxic</td>
</tr>
<tr>
<td>N(_2)</td>
<td>•</td>
<td>Non-toxic</td>
</tr>
<tr>
<td>O(_2)</td>
<td>•</td>
<td>Non-toxic</td>
</tr>
<tr>
<td>H(_2)S</td>
<td>• (●)</td>
<td>Flammable, strong odour, extremely toxic at low concentrations</td>
</tr>
<tr>
<td>H(_2)</td>
<td>•</td>
<td>Flammable, non-condensable at pipeline operating condition</td>
</tr>
<tr>
<td>SO(_2)</td>
<td>•</td>
<td>Non-flammable, strong odour</td>
</tr>
<tr>
<td>CO</td>
<td>•</td>
<td>Non-flammable, toxic</td>
</tr>
<tr>
<td>CH(_4)</td>
<td>•</td>
<td>Odourless, flammable</td>
</tr>
<tr>
<td>Amines</td>
<td>●</td>
<td>Potential occupational hazard</td>
</tr>
<tr>
<td>Glycerol</td>
<td>(●)</td>
<td>Potential occupational hazard</td>
</tr>
<tr>
<td>Ref. Sec.</td>
<td>3.3.3 4.5.3 23.5 4.5.11 5 5.6 5.5 5.1 7</td>
<td></td>
</tr>
</tbody>
</table>

\(^3\) Det Norske Veritas (2010) Recommended Practice Dnv-Rp-J202 Design And Operation Of CO2 Pipelines 2010
\(^4\) CO2 hydrates are an ice like substance, stable at specific temperatures and pressures
Table 6 Pipeline specification proposed by Dynamis and Ecofys project

<table>
<thead>
<tr>
<th></th>
<th>DYNAMIS</th>
<th>ECOFYS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂</td>
<td>&gt;95.5%</td>
<td>&gt;95%</td>
</tr>
<tr>
<td>H₂O</td>
<td>500 ppm</td>
<td>&lt;500 ppm</td>
</tr>
<tr>
<td>SOₓ</td>
<td>100 ppm</td>
<td>Not critical</td>
</tr>
<tr>
<td>NOₓ</td>
<td>100 ppm</td>
<td>Not critical</td>
</tr>
<tr>
<td>H₂S</td>
<td>200 ppm</td>
<td>&lt;200 ppm</td>
</tr>
<tr>
<td>CO</td>
<td>2000 ppm</td>
<td>&lt;2000 ppm</td>
</tr>
<tr>
<td>H₂</td>
<td>&lt;4 vol%</td>
<td>&lt;4 vol%</td>
</tr>
<tr>
<td>Ar</td>
<td>&lt;4 vol%</td>
<td>&lt;4 vol%</td>
</tr>
<tr>
<td>N₂</td>
<td></td>
<td></td>
</tr>
<tr>
<td>O₂</td>
<td>100-1000 ppm</td>
<td>&lt;2 vol%</td>
</tr>
<tr>
<td>CH₄</td>
<td>&lt;2 vol%</td>
<td></td>
</tr>
</tbody>
</table>

Transport specifications

CO₂ is always compressed to a high pressure before pipeline transportation. This is done to reduce the volume needed to be transported and also to ensure that the CO₂ is in a state in which it can be easily transported in a pipeline. The most cost-effective option for CO₂ pipelines is to transport CO₂ in dense phase above its ‘critical point’. Current CO₂ pipelines operate from 86 bar to approximately 200 bar with ambient temperatures ranging from 4°C to 38°C (Seevam, et al., 2008). Additionally, CO₂ compression pressure entering a pipeline will vary from site to site, depending on the required downstream injection pressure for CO₂ storage, minimising or avoiding recompression needs. 5

![Figure 10 Typical compression and pressure envelope for CO₂ transport and storage operations.](image)

Reuse of existing gas pipeline network

Ukraine is host to a vast gas pipeline network. If current trends continue large parts of this network will become underutilised and available for new economic useless. In some cases such pipelines may be repurposed for CO2 transport for storage or use. This is attractive as the recycling of old pipelines may reduce the cost of CCS projects, particularly early commercial projects while simultaneously utilising a national infrastructure.

The reuse of gas pipelines for CO2 transport may be limited as CO2 transport requires pipelines to operate at higher pressures than most existing natural gas pipelines. Where pipeline integrity is well established, it may be possible to reuse existing natural gas pipelines for transporting CO2, providing that use with CO2 meets the appropriate design codes. Pipeline reuse in the Ukraine is likely to be limited to CO2 gas phase transport. The two primary specifications to be met are the operating pressure (consistent with existing materials, rights of way) along with carefully examination of minor components such as valves and O-rings to ensure these are fully compatible with CO2 transport. Two proposed CCS demonstration projects in Scotland (Longannet and Captain Clean energy) sought to reuse existing high pressure natural gas pipelines to transport CO2 (National Grid plc, 2012). In many cases reuse of pipelines may not be feasible due to inappropriate capacity, limited remaining lifespan, limited warranty for alternative use, decommissioning practices or poor location.

The assessment of pipeline reuse will require:

- An integrity management approach to assess suitability of a pipeline to develop a baseline plan of action. (Rabindran, et al., 2011)
- Data gathering and risk assessments are key to development of the plan and will address any possible issues that will need to be attended to for reuse of a pipeline.

International CO2 Pipeline Standards
Recommended best practice is rapidly being formulated and globally standardised.

ISO/TC 265 - Carbon dioxide capture, transportation, and geological storage
Standardization of design, construction, operation, environmental planning and management, risk management, quantification, monitoring and verification, and related activities in the field of carbon dioxide capture, transportation, and geological storage (CCS).

Recommended Reading:


US Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells & Class VI Rule

USA regulatory experience
In the US, dense-phase CO2 pipelines have been classified as hazardous-liquid pipelines, and are therefore regulated under the US Department of Transportation’s Code of Federal Regulations 49CFR195. Most
operators appear to have designed their pipelines conservatively using the ASME B31.8 code for gas pipelines, as this code is more restrictive than the hazardous-liquid design code and also takes into account population density in the determination of the maximum allowable stress in the pipeline (CCSa, 2010).

**CO₂ Storage**

CO₂ is permanently stored deep underground in suitable rock formation. Suitable geological formations are found in layers of porous rock which have space available for the CO₂ similar to the way a sponge has space available for water. To be sure that the CO₂ is contained in the porous rock layer, a solid, non-porous, layer of rock must lie on top of the porous layer, providing a 'cap' that does not allow CO₂ to permeate upwards. Storing CO₂ underground uses much of the same techniques and principals found in the oil and gas industry. The process is closely analogous to Underground Gas Storage.

Geological storage of CO₂ can be undertaken in a variety of geological settings in sedimentary basins. Possible storage formations within these basins are oil fields, depleted gas fields, deep coal seams and saline formations. Conditions exist for onshore CO₂ storages in Ukraine in the Dniep-Donets Basin in the east and the Lviv & Moldova slope in the west (Figure 11).

![Figure 11 Sedimentary Basing Ukraine](image-url)
CO2 can generally be stored in deplaned oil and gas reservoirs. These have the advantage that there is extensive information available from production operations. However the CO2 storage capacity of depleted hydrocarbon reservoirs in Ukraine is often limited. Similar formations, know as saline formations offer far greater potential for CO2 storage in Ukraine. Saline formations are deep sedimentary rocks saturated with formation waters or brines containing high concentrations of dissolved salts, these formations are generally identical to hydrocarbon reservoirs, but with no hydrocarbons present. Saline formations are extensive in the Ukraine, and have the potential to permanently store large volumes of CO2.

The Sleipner Project in the North Sea is one examples of CO2 storage in a saline formation. The offshore gas field Sleipner, in the North Sea, has been injecting 1 Mt CO2 per year since September 1996 without any indication of leakages.

Storage requirements: How do we assess CO2 storage sites?
In general, geological storage sites should have:

- adequate capacity and injectivity
- a satisfactory sealing caprock or confining unit
- a sufficiently stable geological environment to avoid compromising the integrity of the storage site

Identifying secure CO2 storage sites that meet all these requirements is not an insignificant process. Only a fraction of the total potential storage in Ukrainian sedimentary basins will be viable CO2 storage sites. The process of characterisation can be divided into three steps:

- Basin-Scale/formation assessment and site screening
- Detailed site characterisation
Site deployment or “bankable” storage

The primary initial concern when addressing CO2 storage are the porosity and thickness (for storage capacity) and permeability (for injectivity). The storage formation should be capped by extensive confining units such as shale, salt or anhydrite beds to ensure that CO2 does not migrate into the overlying, shallower rock units. Similar units trap and store oil and gas for millions of years. In practice, the CO2 is compressed prior to injection to a dense fluid state known as "dense phase" or "supercritical" CO2. Depending on the rate that the temperature increases with depth in the earth's crust, the density of CO2 will increase with depth, until about 800 m or greater, where the injected CO2 will be in a dense supercritical state. Using this data along with an estimate for CO2 storage efficiency and the expected pressure increase allowable in the formation it is possible to provide an initial estimate of CO2 storage capacity of the formation (Equation 1). Table 7 describes the recommended minimum criteria for CO2 storage sites.

Equation 1 CO2 storage potential

$$Q = A \cdot D \cdot \phi \cdot \rho_{CO2} \cdot hst$$

Table 7 Recommended criteria for candidate CO2 storage sites

<table>
<thead>
<tr>
<th>Reservoir properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth</td>
</tr>
<tr>
<td>Formation thickness</td>
</tr>
<tr>
<td>Porosity</td>
</tr>
<tr>
<td>Permeability</td>
</tr>
<tr>
<td>Salinity</td>
</tr>
<tr>
<td>Stratigraphy</td>
</tr>
<tr>
<td>Reservoir Efficiency</td>
</tr>
<tr>
<td>Static storage capacity</td>
</tr>
<tr>
<td>Dynamic storage capacity</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Caprock</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lateral continuity</td>
</tr>
<tr>
<td>Thickness</td>
</tr>
<tr>
<td>Capillary entry pressure</td>
</tr>
</tbody>
</table>

| Reservoir Efficiency                 |
| Static storage capacity              |
| Dynamic storage capacity             |

Table 7 Recommended criteria for candidate CO2 storage sites

6 Water filled space between rock grains
7 The effective interconnectivity of water filled space between rock grains
8 The anticipated pore volume utilized when storing CO2
9 $Q$ is the storage capacity in kg, $A$ is the areal distribution of the aquifer (m2), $D$ is the cumulative thickness of good reservoir rocks (m), $\phi$ is the effective porosity (<1), $hst$ is the storage efficiency (<1), and $\rho_{CO2}$ is the density (kgm-3) of pure CO2 under reservoir conditions.
Data Gathering
The storage site and its surroundings need to be characterized in terms of geology, hydrogeology, geochemistry and geomechanics (structural geology and deformation in response to stress changes). The greatest emphasis will be placed on the reservoir and its sealing horizons. However, the strata above the storage formation and caprock will also need to be assessed. Extensively faulted and fractured sedimentary basins or parts thereof, particularly in seismically active areas, require careful characterisation to be good candidates for CO2 storage.

Documentation of the characteristics of any particular storage site will rely on data that have been obtained both directly from the reservoir and remotely. Direct measurements include core and fluids samples produced from wells at, or near the proposed storage site and injectivity and pressure tests to verify seal efficiency. Indirect measurements such as 2D and 3D seismic reflection data, and regional hydrodynamic pressure gradients are also critical tools.

The timely acquisition and integration of all of the different types of data is needed to develop a reliable and robust understanding of the subsurface.

CO2 Modelling in the subsurface
Computer simulation also has a key role in the design and operation of field projects for underground injection of CO2. Predictions of the storage capacity and evolution of the CO2 plume over time are vital in initial assessment of storage security and feasibility. Simulation can be used in tandem with economic assessments to optimize the location, number, design and depth of injection wells. These models present us with the expected behaviour of CO2 underground during storage project lifetime. The modelled behaviour is subsequently compared to real world observations made during CO2 injection operations (Smith, et al., 2012).

Numerical simulators currently in use in the oil, gas and geothermal energy industries provide important subsets of the required capabilities. They have served as convenient starting points for recent and ongoing development efforts specifically targeted at modelling the geological storage of CO2.

Existing models for injection and storage of CO2 are subject to considerable uncertainties because of complex geology. Measurements taken at wells provide information on rock and fluid properties at that location, but statistical techniques must be used to estimate properties away from the wells. When simulating a field in which injection or production is already occurring, a standard approach in the oil and gas industry is to adjust some parameters of the geological model to match selected field observations. This proves that the model is inaccurate, but it does provide additional constraints on the model parameters. However, better models and simulation tools are required.

The characterisation process and “Bankable” Storage
Below is a simplified description of how a typical organisation would explore, characterise and permit a CO2 storage site in a saline aquifer. Once a storage site is deemed suitable for long term CO2 storage and is permitted it is described as “bankable”.

**Preliminary site selection:**

The initial steps include a pre-selection phase, during which a portfolio of possibly suitable sites is drawn up. This will include a table top and field analysis of existing data, including, well core data, 2D and 3D seismic where available, outcrop data, identification of potential storage lithologies and caprocks and finally the preliminary identification of geological trapping structures. Due to the risk of any one site failing to be suitable for CO2 storage, two or more sites from the initial portfolio will be appraised further (Smith, et al., 2012).

**Site Characterization:**

This phase includes a more rigorous suite of geological and petrophysical studies required for appraisal and eventual modelling of CO2 in the proposed storage site (ieaghg, 2011).\(^\text{10}\)

- **2D followed by 3D seismic surveys:** needed to further define the sub-surface geological structure and identify faults or fractures that could create leakage pathways.
- **First risk analysis:** includes a detailed analysis of the trapping structure(s) identified through the seismic surveys. Including preliminary estimates of storage capacity, identification of spill points, and large faults and seal integrity. Preliminary modelling of CO2 in potential reservoir.
- **First well drilling:** will be used to validate seismic data, reservoir characteristics and caprock integrity. Will provide geochemical data on reservoir rock and formation water quality samples to demonstrate the isolation between deep and shallow groundwater.
- **Second risk assessment:** Detailed modelling of CO2 in the reservoir.
- **Injection test licensing:** Permission to inject a limit quantity of CO2/water into reservoir
- **Injection Test:** Asses the injectivity of the reservoir, monitor the pressure response of the reservoir.
- **Permitting:** Authorities accept storage site is adequate, site becomes bankable.

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\(^\text{10}\) In the case of depleted oil and gas field prior knowledge from hydrocarbon exploration, drilling and operation would already provide much of the data.
How long does storage characterisation take?
Timely access to available CO2 storage capacity will be the foremost concern of any future prospective CCS projects in Ukraine. Providing sufficient characterised storage takes time, and so work must begin well in advance of any capture plant construction. Figure 13 indicates the expected lead times necessary to provide bankable storage for “highly suitable” and “possible” CO2 storage areas.

Figure 13 Decision gate analysis for the characterisation of a CO2 storage site (ieaghg, 2011)
The lead times for highly suitable areas are between 4 to 12 years, similar to experience with underground gas storage development, which worldwide ranges from 4 to 10 years, with an average value of 8 years for natural gas storage projects in aquifers. In order to avoid costly delays of CCS deployment in the future it will be necessary to begin the process of characterisation now. Simple steps such as identification of the most promising areas would be excellent first steps. Subsequently focusing expertise on these areas to collate existing data on porosity, permeability, possible cap rocks and legacy wells would provide the necessary basis for further more in-depth investigations. European countries have already set down this path with Norway compiling a CO2 Storage Atlas in the North Sea, while Energy Technologies Institute in the UK has developed an online database for CO2 storage appraisal. Similarly EU funded projects such as GeoCapacity have resulted in preliminary assessments of storage potential in most European countries. Such work is has already begun in Ukraine, with the EU funded “Low-Carbon Opportunities Industrial Regions of Ukraine” (LCOIR-UA) project. In the Donets Basin the work identified Devonian saline aquifers in conjunction impermeable salt deposits, presenting ideal candidates for CO2 storage in close proximate to large industrial and energy CO2 emissions sources (Figure 14). Further more detailed quantitative assessment is needed to progress this to bankable CO2 storage, such as structural analysis, seismic surveys, injectivity testing and modelling. A sustained effort is needed to continue knowledge building so as storage is available economically and timely.

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12 ETI (2012) “ETI license The Crown Estate and British Geological Survey to host & develop online database”
14 Shestavin, Bezkrovena, Osetrov & Yurchenko (2012) “Preliminary Assessment of the Potential CO2 Sources and Sinks of the Eastern Ukraine”
15 Low-Carbon Opportunities Industrial Regions of Ukraine
Natural Gas Storage in Ukraine.

Underground gas storage (UGS) and Carbon Storage (CCS) share many legal, planning, technical and operational similarities. Ukraine has the largest UGS capacity in Europe, totalling almost 33,000 mcm, approximately 160% of the total German gas storage capacity (Gas Infrastructure Europe, 2012). The UGS industry has been operating for decades in the Ukraine, with technical and professional requirements quite similar to those for CO2 storage. However, unlike UGS, CCS aims to permanently store a non combustible gas, and for UGS a structural trap is generally a requirement (ieaghg, 2011). The same skills developed as Ukraine expands upon its current storage capacity will be directly applicable to CO2 storage (EurActiv, 2013). Regions that have successfully been prospected for UGS will also be good candidates for CO2 storages. As the geological properties and structures necessary for UGS and CCS are so similar, it will be possible for work

undertaken to expand UGS to directly benefit CO2 storage site characterisation. However, for this to take place, information gathered will need to be made available to prospective CO2 storage operators.

### Table 8 Natural gas storage facilities in the Ukraine

<table>
<thead>
<tr>
<th>Facility</th>
<th>Company</th>
<th>Type</th>
<th>Storage Capacity (mcm)</th>
<th>Withdrawal Capacity (mcm/day)</th>
<th>Injection Capacity (mcm/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bogorodehany</td>
<td>UkrTransgas</td>
<td>Depleted Field</td>
<td>2300</td>
<td>50.04</td>
<td>13.44</td>
</tr>
<tr>
<td>Bilche-Volytsa</td>
<td>UkrTransgas</td>
<td>Depleted Field</td>
<td>18150</td>
<td>122.4</td>
<td>100.8</td>
</tr>
<tr>
<td>Mryn</td>
<td>UkrTransgas</td>
<td>Aquifer</td>
<td>1500</td>
<td>12.96</td>
<td>8.4</td>
</tr>
<tr>
<td>Dashava</td>
<td>UkrTransgas</td>
<td>Depleted Field</td>
<td>2150</td>
<td>24.96</td>
<td>18</td>
</tr>
<tr>
<td>Glebivka</td>
<td>Chernomornetegaz</td>
<td>Depleted Field</td>
<td>620</td>
<td>6.24</td>
<td>4.8</td>
</tr>
<tr>
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<td>UkrTransgas</td>
<td>Depleted Field</td>
<td>700</td>
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<td>5.04</td>
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<td>UkrTransgas</td>
<td>Depleted Field</td>
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<td>4.68</td>
<td>3</td>
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<td>Aquifer</td>
<td>310</td>
<td>3</td>
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<td>Opary</td>
<td>UkrTransgas</td>
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<td>2400</td>
<td>20.04</td>
<td>13.2</td>
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<td>Proletarka</td>
<td>UkrTransgas</td>
<td>Depleted Field</td>
<td>1000</td>
<td>12.24</td>
<td>6</td>
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<td>Solokha</td>
<td>UkrTransgas</td>
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<td>1200</td>
<td>9.48</td>
<td>6.6</td>
</tr>
<tr>
<td>Ugerske</td>
<td>UkrTransgas</td>
<td>Depleted Field</td>
<td>1800</td>
<td>23.04</td>
<td>12</td>
</tr>
<tr>
<td>Vergunka</td>
<td>UkrTransgas</td>
<td>Depleted Field</td>
<td>400</td>
<td>4.08</td>
<td>2.76</td>
</tr>
<tr>
<td><strong>Ukraine</strong></td>
<td></td>
<td></td>
<td><strong>32965</strong></td>
<td><strong>300.84</strong></td>
<td><strong>196.632</strong></td>
</tr>
</tbody>
</table>

### Storage mechanisms and security

Natural accumulations of relatively pure CO2 are found all over the world in a range of geological settings. The CO2 has been trapped in such natural reservoirs for many millions of years, which is a clear indication that injected CO2 can be stored for millions of years (Wilkinson, et al., 2009).

The storage mechanism physical trapping of CO2 in a porous rock below the caprocks and residual trapping as CO2 moves through the storage formation are effective immediately. In the longer term, significant quantities of CO2 dissolve in the formation water, sinking deeper into the storage formation. Over time the CO2 can undergo a sequence of geochemical interactions with the rock and formation water (Figure 15).
The effectiveness of geological storage depends on a combination of physical and geochemical trapping mechanisms. The primary mechanisms for secure storage are physical and residual CO2 trapping, where solubility and mineral trapping generally play an increasing role in long term.

**Physical trapping**

The most effective storage sites are those where CO2 is immobile because it is trapped permanently under a thick, low-permeability seal. Sedimentary basins have such closed, physically bound traps or structures, which are occupied mainly by saline water, oil and gas. Structural traps include those formed by folded or fractured rocks, and the traps are formed by changes in rock type caused by variation in the setting where the rocks were deposited. When CO2 is injected, care must be taken not to exceed the allowable overpressure to avoid fracturing the caprock or re-activating faults.

When CO2 is injected into a formation, it displaces saline formation fluid and then migrates buoyantly upwards, because it is less dense than the water. When it reaches the top of the formation, it continues to migrate as a separate phase until it is trapped as residual CO2 saturation or in the local structural trap within the sealing formation. Trapping can also occur in saline formations that do not have a closed trap, but where fluids migrate very slowly over long distances.

**Residual Trapping**

As the supercritical CO2 is injected into the formation it displaces fluid as it moves through the porous sponge like rock. As the CO2 continues to migrate, fluid replaces it, trapping the CO2 as residual droplets in the pore spaces, rendering it immobile. This is often how the oil was held for millions of years.
Solubility trapping

In the longer term, significant quantities of CO2 dissolve in the formation water and then migrate with the groundwater. Where the distance from the deep injection site to the end of the overlying impermeable formation is hundreds of kilometres, the time scale for fluid to reach the surface from the deep basin can be millions of years. The primary benefit of solubility trapping is that once CO2 is dissolved, it no longer exists as a separate entity, thereby eliminating the buoyant forces that drive it upwards.

Mineralisation

CO2 in the subsurface can undergo a sequence of geochemical interactions with the rock and formation water that will further increase storage capacity and effectiveness, a mechanism known as geochemical trapping, or mineralisation. CO2 dissolved in water will form ionic species that can react with the rock and form stable carbonate minerals. This is also referred to as mineral trapping, which is the most permanent form of geological storage. Mineral trapping is comparatively slow, potentially taking thousands of years or longer. Nevertheless, the permanence of mineral storage, combined with the potentially large storage capacity present in some geological settings, makes this a desirable feature of long term storage.

Risks Management throughout project cycle

These main concerns when selecting and operating a CO2 storage site are:

- Risk of leakage
- Effect of pressure build up in storage formation

In a correctly chosen storage site with well defined trapping and secure caprock the risk of any significant leakage is very small. In any event small leakage volumes may not reach the surface as CO2 may migrate horizontally through porous layers or may be stopped by additional impermeable layers. Disused, abandoned or improperly completed wells are the primary candidates for focused leakage, where CO2 may attempt to migrate up through a well casing or concrete. For this reason it is critical that all legacy wells in the vicinity of a prospective storage be logged and documented.

During injection of CO2 into a reservoir, pressure build-up might increase the stress within the reservoir and the seal, as well as in the formations above, ultimately leading to fracturing of reservoir rock and caprock. As such it is critical that sufficient knowledge of the properties of the reservoir rock, and especially fracture pressure and fault properties Excessive pressure build up should be avoided to prevent possible damage to cap rock integrity. Abnormal pressure build up in the injection wells must be monitored carefully, with injection halted if the issue persist. The Snøhvit CO2 storage project in northern Norway experienced such injectivity issues. Here it was decided to move injection to an alternative reservoir, which corrected the problem. This highlights the need for flexibility in planning and the operation of storage sites, using all available data to make prudent informed decisions (Aagaard, 2013).

Monitoring, measurement and verification (MMV)

Monitoring, measurement and verification is a critical component of all CO2 storage campaigns. Identification and tracking of CO2 in the subsurface is necessary optimise operations, insuring that the CO2 remains within performance predictions and demonstrating long term storage security. Monitoring plays a
critical role in handover of the storage site to the state after storage security if sufficiently demonstrated. A wide variety of monitoring techniques may be used, with technologies selected on a site by site basis, depending on the legislative, geographical and geological characteristics. Monitoring will begin prior to injection and continues throughout the life and after injection is completed until sufficient storage security can be demonstrated and site closure.

Before monitoring of subsurface storage can take place effectively, a baseline survey must be taken. This survey will provide the point of comparison for subsequent surveys. The survey includes establishing a baseline of natural CO2 fluxes in order to later distinguishing natural fluxes from potential storage-related releases. This may be done through groundwater testing from existing shallow wells (TransAlta, 2013).

Standard procedures of monitoring during operational phase include: routine measurements of injection rates and pressures, monitoring the distribution and migration of CO2 in the subsurface with seismic surveys, monitoring injection well integrity and monitoring local environmental effects (Smith, et al., 2012).

During injection and monitoring operations, simulation models can be calibrated to match field observations. Then they can be used to assess the impact of possible operational changes, such as drilling new wells or altering injection rates, maximising the CO2 storage potential or the reservoir while avoiding migration of CO2 past a likely spill-point.

Below is a brief example of the planned monitoring programme at the Quest Carbon Capture and Storage Project in Alberta Canada. As this storage project is aiming to assess the effectiveness of different monitoring technologies an exhaustive array will be used. It is probable that future CO2 storage operations will use a more tailored and targeted MMV plan.
Good practice in public engagement on CCS

Public support of CCS technologies and activities will be necessary for an efficient deployment of the technology.

As Ukraine is just beginning the path to CCS deployment, the opportunity exists to form a positive native of CCS across actors and stakeholders. To achieve this outcome it is important that early national debates on CCS technologies in Ukraine lay the foundation for later local public acceptance.\(^\text{17}\) This paper among other aims to engender such debate, informing the key role that CCS can play in cost effectively and compatibly decarbonising the Ukrainian economy. Early inclusion of CCS in national climate change debates, forming acceptance of the technology alongside other low carbon technologies such as wind, solar and biomass will greatly ease the path to deployment.

It is important to note that in the absence of such discussions surrounding the merits of various low carbon technologies public negative sentiments and opposition may become entrenched, fuelled by speculation and misrepresentation. Such an outcome which may severely limit the potential contribution of CCS irrespective of its technical and economic merits would increase climate mitigation cost for all sectors of the Ukrainian economy and public in the long term.

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A moderate scale pilot or demonstration of the technology would act as a catalyst for such a debate to introduce the concept and possibilities of CCS to Ukraine. Such a demonstration would over time build popular familiarity, reducing the novelty of CCS while grounding the debate in reality. Similarly such a demo would inform Ukrainian centric strategies for public engagement approaches at the local level. As effective methods for synthesising and disseminating information are cultural, national and site specific. The Shell Quest project in Alberta Canada is currently undertaking this role, using different forms of stakeholder engagement such open houses and dedicated phone line for public consultations in areas of planned pipeline and storage operations.

Extensive work has been carried out preparing effective guidelines and toolkits to approach public education on both CCS technologies generally and when planning individual projects. Major resources include guidelines on good practice in stakeholder engagement:

- IEEP (2010) Review of the public participation practices for CCS and non-CCS projects in Europe

Constant key messages are present in all stakeholder engagement strategies for the planning of individual CCS projects.

- A consistent message is that engagement cannot be rushed, and sufficient time should be built into project schedules.
- The public expects that their concerns are listened to and taken seriously.
- Communication outreach experts should be integral members of the project team.
- Public outreach should be an integral component of project management, enabling the project to be adjusted to its social context.
- Public trust in those providing information is crucial. Potentially involving experts from academia or independent organizations who will be seen to be independent.
- Engagement should have real substance, taking the form of an active and constructive two-way dialogue.

**Liability**

Suitable liability protection for CO2 storage operators can in certain legislations be a major cost or roadblock to CCS deployment. It is important that Ukraine developed legislation that requires CO2 storage operators to perform to the highest standards but does become overly onerous to discourage investment. Liability protection reflects the fact that if damages are caused by injection and long-term storage of CO2, the injecting party may bear financial liability. Several types of liability protection schemes have been suggested for CO2 storage, including bonding, insurance and government guarantees.

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18 Len Heckel (2012) QUEST CCS PROJECT, Petroleum Technology Alliance Canada (PTAC), Towards Clean Energy Production Forum October 15
19 Ashworth, Bradbury, Feenstra, et al. (2011a). Communication/engagement toolkit for CCS projects. CSIRO, Australia
20 Desbarats, Upham, Riesch, et al. (2010). Review of the public participation practices for CCS and non-CCS projects in Europe. IEEP
21 Hammond & Shackley (2010). Towards a public engagement and communication strategy for carbon dioxide capture and storage projects in Scotland. Scottish Carbon Capture and Storage Centre
Liabilities are described in detail in two Articles of the EU Storage Directive 2009/31/EC. However, many commentators now believe the liability provisions in the Storage Directive to be overly onerous, potentially slowing the development of CCS.

- Article 19 contains guidelines for financial security items: proof of adequate provision needs to be established prior to the commencement of operations and periodically adjusted to take into account the assessed risk of leakage and the estimated costs of all obligations arising under the permit. The liability is risk-based.

- Article 20 of the Directive states that a financial contribution will be made available to the Competent Authorities before the transfer of liabilities in order to cover monitoring costs for 30 years. These contributions are also meant to cover costs associated with permanent CO2 containment and related corrective actions, such as re-plugging wells etc.

Some US State Governments have enacted legislation which assigns liability to the injecting party (NETL, 2013).

- In North Dakota and Louisiana liability is transferred to the state ten years after the cessation of injection operations, pending reservoir integrity certification.
- In the case of Louisiana, a trust fund of five million dollars is established for each injector over the first ten years of injection operations. This fund is then used by the state for CO2 monitoring and, in the event of an at-fault incident, damage payments.

Recommend Reading
DIRECTIVE 2009/31/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL

Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells & Class VI Rule

**How much does CCS Costs?**

CCS is a diverse technology, with application possible to a wide variety of CO2 sources. As such the additional cost resulting from the fitting of CCS to industry or power plant strongly depends on the technology choice of both the CO2 emitter and capture process, if the project is new build or retrofit, type of fuel, the site location, as well as on financial boundary conditions such as depreciation time, interest rate, as well as fuel and commodity price. The length of pipeline and characteristics of the CO2 storage reservoir also play a role in total project costs. Figure 17 describes the cost breakdown of an Australian CCS project on the basis of dollar per tonne of CO2 avoided (GCCSI, 2012). Figure 18 describes an example timeline for planning, construction, operation and post closer of the three primary sections of a simple CCS project.
Without CCS the costs of the EU meeting its greenhouse gas reduction goal of 30% by 2030 could be up to 40% higher than with CCS (European Commission, 2008).

**Cost of CO2 Capture Technologies**

The cost of CO2 capture from a power plant or industrial site generally contributes to the lion’s share of capital and operational cost of a CCS project.

The cost influences of CO2 capture are:

- The concentration of CO2 in source
- Capture technology most suited to a point source
- New build or retrofit to existing facility
- Utilisation rate
- Availability of steam to power the process
**CCS and Electricity Generation**

In the case of electricity generation, the levelised cost of electricity (LCOE) is often used as a basis for comparison of different technologies. LCOE attempts to take into account total life cycle cost, including initial plant capital cost and operational cost over the expected life time of the plant. Table 9 describes the present and the expected evolution of LCOE in Euros per megawatt hour for CCS technologies applied to different thermal power plants (ZEP, 2011) (GCCSI, 2011) (IEA, 2011) (IEA, 2011). Anticipated improvements in technology and design experience are anticipated to reduce both capital and operational cost.

Table 9 Levelised cost of electricity (LCOE) (excluding transport and storage) in Euros per megawatt hour (€/MWh)

<table>
<thead>
<tr>
<th></th>
<th>IEA 1st of a kind</th>
<th>GCCSI 1st of a kind</th>
<th>GCCSI nth of a kind</th>
<th>ZEP 1st of a kind</th>
<th>ZEP nth of a kind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal (base)²⁴</td>
<td>50</td>
<td>53-55</td>
<td>-</td>
<td>48</td>
<td>-</td>
</tr>
<tr>
<td>Coal PCC</td>
<td>81</td>
<td>82-90</td>
<td>79-88</td>
<td>73</td>
<td>67</td>
</tr>
<tr>
<td>Oxy-fuel⁵⁵</td>
<td>77</td>
<td>77-82</td>
<td>75-81</td>
<td>76-87</td>
<td>63-69</td>
</tr>
<tr>
<td>IGCC</td>
<td>79</td>
<td>84</td>
<td>82</td>
<td>80</td>
<td>71</td>
</tr>
<tr>
<td>Natural Gas (base)²⁸</td>
<td>58</td>
<td>64</td>
<td>64</td>
<td>72</td>
<td>69(64)</td>
</tr>
<tr>
<td>Gas PCC²⁹</td>
<td>77</td>
<td>83</td>
<td>82</td>
<td>104</td>
<td>92(64)</td>
</tr>
</tbody>
</table>

Another popular method of comparing the cost of CO2 capture technologies is the “CO2 avoided cost” or the cost to capture one tonne of CO2 (Figure 19). However, this method although simple can be misleading as it does not reflect the capital costs or the quantity of CO2 needed to be captured to produce equivalent electricity. For example, post combustion capture of CO2 from a natural gas power plant is approximately double that of capture from coal gasification facility, however, the coal gasification will produce approximately double the amount of CO2.

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²² 1st of a kind refers to early commercial CCS plants  
²³ Nth of a kind refers to mature and optimized CCS plant  
²⁴ Coal (base) = representative Coal power plant  
²⁵ Coal PCC = Post combustion CO2 capture from pulverised coal power plant  
²⁶ Oxy-fuel = Oxy-fired coal power plant  
²⁷ IGCC = Integrated gasification combined cycle coal power plant  
²⁸ Natural Gas (base) = Representative modern natural gas combined cycle power plant  
²⁹ Gas PCC = Post combustion CO2 capture from a natural gas combined cycle power plant
The application of CCS in electricity production increases the cost of electricity, generally by a factor of 30-45%. The cost of low carbon CCS electricity must be weighed against the cost of other decarbonisation strategies, particularly electrical system cost. Table 10 lists estimated levelised costs of different low carbon technologies. CCS in the electricity generation has unique properties and benefits that should be taken into account when compared to other forms of low carbon energy:

- Continued use of indigenous fuels that might otherwise be “un-burnable” (Carbon Tracker, 2013)
- On-demand low carbon electricity
- High capacity credit and energy supply security
- National scale CO2 reductions from single site, one-off projects
- Use of indigenous Ukrainian expertise
- Re-use of existing national infrastructure (electricity grid, mining operations)
- Cost may be offset, especially in early projects with the use of EOR

<table>
<thead>
<tr>
<th>Technology</th>
<th>Levelised cost (€/MWh)</th>
<th>Levelised cost (€/t CO2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geothermal</td>
<td>32-46</td>
<td>-29.0</td>
</tr>
<tr>
<td>Hydropower</td>
<td>39-45</td>
<td>-20.0</td>
</tr>
<tr>
<td>Wind onshore</td>
<td>51-65</td>
<td>-6.15</td>
</tr>
<tr>
<td>Nuclear</td>
<td>51-71</td>
<td>-5.19</td>
</tr>
<tr>
<td>Biomass</td>
<td>61-85</td>
<td>7.37</td>
</tr>
<tr>
<td>CCS (coal)</td>
<td>67-105</td>
<td>22-69</td>
</tr>
<tr>
<td>CCS (gas)</td>
<td>81-90</td>
<td>51-80</td>
</tr>
<tr>
<td>Wind offshore</td>
<td>110-162</td>
<td>68-133</td>
</tr>
<tr>
<td>Solar thermal</td>
<td>140-200</td>
<td>138-153</td>
</tr>
<tr>
<td>Solar photovoltaic</td>
<td>166-200</td>
<td>137-180</td>
</tr>
</tbody>
</table>
**CCS in Industry**

The costing of CCS in industry applications such as iron and steel, cement or chemical plants is more complex. This is due to substantial site-by-site variability, different bases for engineering design and costing, and technological uncertainty (Pershad, et al., 2013) (IEA, 2011). Capacity, plant configuration, process arrangement and age of a facility will also have a significant effect on the choice and cost of capture technology. At present there are insufficient studies on the costs of industrial CCS, so cost estimates are highly uncertain. Figure 20 Illustration of CO2 avoidance costs and sizes of CO2 sources for capture at archetypal industrial sites attempts to provide arrange estimates of the cost of CCS at a variety of industrial facilities. However, it is apparent that the cost of CO2 capture from certain industrial process has the potential to be lower than CO2 capture from power plants (ZEP, 2013).

- CO2 capture and storage (CCS) is the only technology that can deliver the deep emission cuts to several Ukraine energy-intensive industries.

![Figure 20 Illustration of CO2 avoidance costs and sizes of CO2 sources for capture at archetypal industrial sites (IEA, 2013)](image)

**Cost of transport**

The cost influences of CO2 transport networks are:

- The design and materials used
- The length and diameter of pipeline needed
- Permits and rights of way
Typically CO2 transportation cost only form a relatively minor part of total CO2 capture and storage cost. Capital expenditure accounts for approximately 90% of CO2 pipeline cost. Table 11 describes the cost estimates for a mature pipeline network servicing a cluster of two large point source emitters, such as a coal fired power plant and steel plant. The cost of CO2 transported (Euro/tonne) increases relative to pipeline distance. Identifying CO2 storage capacity near to major centres of CO2 emissions is the foremost way of limiting transportation cost. Similarly onshore pipelines have a significant cost advantage over offshore pipelines, so perusing onshore storage will also reduce cost and technical complexity. Thus enabling the development of onshore storage should be a key goal of Ukrainian CCS policy. This will require public outreach and trust building from the outset. The major cost associated with CO2 transport costs are initial capital costs, including rights of way, materials, engineering and labour. Figure 21 illustrate the indicative total costs of a 16 inch CO2 pipeline of various lengths in the US Midwest (McCoy & Rubin, 2008)(GCCSI, 2012).

Table 11 Cost estimates for large scale CO2 pipeline networks of 20 Mtpa (EUR/tonne CO2). In addition to the spine distance, networks also include 10 km long feeders (2*10 Mtpa) and distribution pipelines (2*10 Mtpa) (ZEP, 2011)

<table>
<thead>
<tr>
<th>Spine Distance</th>
<th>180</th>
<th>500</th>
<th>750</th>
</tr>
</thead>
<tbody>
<tr>
<td>Onshore</td>
<td>1.5</td>
<td>3.7</td>
<td>5.3</td>
</tr>
<tr>
<td>Offshore</td>
<td>3.4</td>
<td>6.0</td>
<td>8.2</td>
</tr>
</tbody>
</table>

30 ZEP (2011) The costs of CO2 transport: post-demonstration CCS in the EU
Pipeline diameters

The CO2 pipeline diameter needed will depend on the volume of CO2 to be transported, the distance of transport and pressure needed for CO2 storage. Figure 22 describes the effect of increasing flow rate of CO2 on diameter of an 80km pipeline, at an inlet pressure of 150 Bar with a pressure drop of 50 bar over its length, while maintaining a single phase flow in the pipeline with no recompression stages. If fully utilised larger pipelines are more cost effective at transporting volumes of CO2, as pipeline diameter increases non-linearly with CO2 transport volumes. As such, sharing transport infrastructure in the form of transport hubs can reduce the cost of CO2 transport.
Storage Costs

The cost influences of CO2 Storage are

- Site screening and evaluation
- CO2 reservoir capacity
- Storage permits and pore space acquisition
- Injection wells
- Injection equipment
- Liability bond (dependent on regulatory framework)
- Monitoring

Storage costs can be broken down into five categories: site screening and evaluation, injection wells, injection equipment, O&M costs, monitoring and closure (Figure 24). Cost uncertainty is primarily due to natural variability between storage reservoirs such as reservoir capacity and well injectivity. Depleted oil and gas fields are anticipated to have a lower cost due to the site already being well characterised, plentiful information and the possible reuse of existing wells. However in Ukraine depleted oil and gas fields are anticipated to have a limited storage capacity, along with the possible added legacy costs in well remediation (ZEP, 2011). Saline aquifer storages is anticipated to be more costly, primarily do to the added costs of characterisation, however larger storage capacities are possible, potentially reducing the cost. Figure 23 describes the anticipated cost ranges of onshore CO2 storage in Europe (ZEP, 2011). Estimates for US storages cost are similar, with storage cost of $6 in the Illinois basin and $6.50 per tonne of CO2 stored (NETL, 2013).
**CCS Cluster & Hubs**

A CCS cluster constitutes the sharing of transport and/or storage infrastructure by more than one CO2 capture project. Cost saving are primarily a result of CO2 pipeline costs becomingly significantly cheaper per tonne of CO2 transported as capacity increases (Figure 25). CCS clusters may also include shared CO2
capture plant infrastructure, such a power plant and an industrial facility sharing a single Air Separation Unit (ASU) for oxy-firing (ZEP, 2013).

The benefits of CO2 capture and storage Hubs has been clearly documented, providing efficiency gains across the entire CCS value chain. The shared use of efficiently deployed pipeline transport infrastructure and storage capacity providing economies of scale while lowering the threshold of entry for new CCS projects in the vicinity of the transport network (Cockerill, et al., 2012) (Lovseth & Wahl, 2011). CCS clusters also simplify planning a regulatory approval process, while minimising environmental impacts associated with infrastructure development. CCS clusters will also lead to increased CO2 transport system stability as more sources feed into a shared transport network, reducing flow variations (ZEP, 2013). In Europe cost savings of 25–40% have been estimated for clustering approaches compared with point-to-point connections. Optimising the overall development of CO2 transport networks to enable the cost efficient development of clusters should be a key priority in CCS planning.

Many of the most prominent CCS deployment proposals integrate the concept of CCS clusters. In the UK the Yorkshire and Humber region has begun mapping out its future as a low carbon energy and industrial CCS cluster (CO2sense, 2010). The region is an ideal location for CCS due to its high concentration of power stations and large industrial plants in close proximity to offshore storage opportunities beneath the North Sea. Current proposals are to establish a shared user CO2 pipeline and large-scale storage facility.

Figure 25 Cost effects of CO2 transport clusters
Donetsk CCS Cluster

Similar advantages can be found in the Donetsk region, with a highest concentration of electricity production, energy intensive industries and local fuel operations in Ukraine. The LCOIR-UA[^31] project has identified potential CO2 sources and storage sites in the region. The analysis includes existing coal and gas power plants, iron & steel works, cement plants, chemical and refineries. A limitation in planning such CCS clusters in the Donetsk region is uncertainty surrounding the CO2 sources into the future. More detailed planning will require greater clarity over the future of CO2 sources such as the redevelopment of ageing coal fired power plants. It is clear that the Donetsk region will remain the major industrial region, with CCS necessary to achieve any meaningful decarbonisation. Planning for the development of CCS clusters, such as investigations on possible CO2 transport routs and rights of way, will increase the efficiency of CCS deployment in the region.

[^31]: Low-Carbon Opportunities for Industrial Regions of Ukraine
Further Reading

Ieaghg (2011) Global Storage Resources Gap Analysis for Policy Makers
ECCO report FP7
ZEP (2011) The costs of CO2 transport: post-demonstration CCS in the EU

Lovseth “ECCO Tool: Analysis of CCS value chains” (2012)
CO2Europipe “Towards a transport infrastructure for large-scale CCS in Europe” (2009)
GCSSI “Rotterdam CCS Network Project: Case Study methodology report” (2011)
GCSSI “Carbon dioxide (CO2) distribution infrastructure (2011)

**CO2 Capture, Utilisation and Storage (CCUS)**

CO2 Capture, Utilisation and Storage (CCUS) refer to industrial processes where CO2 can be used as a valuable feedstock to realise value, such as for Enhanced Oil Recovery (EOR) in the hydrocarbon sector.
Other opportunities include the use of CO2 in chemical industry and enhanced coalbed methane recovery. However in the case of chemicals industry the volumes of CO2 required are generally small. In the case of coalbed methane, questions remain over the suitability of Ukrainian coal deposits to enhanced methane recovery using CO2 injection (Stevens, et al., 1998).

CO2-EOR has the greatest ability to act as an incubator for the nascent CCS industry, providing real-world experience, customers for CO2 technologies, development of CO2 infrastructure and critically providing a wide variety of engineers, technicians and operators with the skills necessary to store CO2.

**Enhanced Oil Recovery (EOR)**

CO2 can also be injected into oil and gas fields to increase oil or gas production. CO2 has been used in commercial Enhanced Oil Recovery (EOR) projects since the early 1970s. In simple terms the process involves the injection of CO2 into a mature oil reservoir. Here under the correct conditions the CO2 mixes with the oil, increasing the oil’s mobility, resulting in additional oil recovery and greater ultimate resource extraction (Alvardo & Manrique, 2010). Some of the CO2 injected for EOR will remain stored for thousands of years, but in current operations a CO2 is recycled back into the reservoir (Figure 28).

CO2-EOR has been most extensively deployed in the United States; here over 2,414 km of CO2 pipelines have been developed to transport CO2 from natural sources to oil fields (Figure 29) (GCCSI, 2012). Increasingly anthropogenic sources of CO2 are being used to supply rapidly growing CO2 demand, such as CO2 from the ethanol and ammonia fertiliser plants (NEORI, 2012). In Canada the Weyburn EOR project utilises CO2 from a coal gasification facility, and at the soon to be completed Boundary Dam CCS project CO2 from a coal fired power plant will be used for EOR (GCCSI, 2012). CO2-EOR projects also exist in Hungary and Turkey, with upcoming projects in the United Arab Emirates (Arabian Oil & Gas, 2012).

![Figure 28 Visualisation of CO2 injection and enhanced oil recovery](image-url)
**CO2 EOR and CCS**

The use of captured CO2 for EOR is acknowledged as the primary and most synergetic method of monetising large volumes of CO2, generating relevant skills, infrastructure and investment that provide long-term and sustained benefits for CCS deployment. Revenue generated through the recovery of oil will help enable early CCS projects to have a more robust business case, easing financing and increasing the probability of a positive final investment decision.

CO2-EOR when deployed at scale will also provide the foundations for dedicated CO2 storage sites. As CO2-EOR project grow in scale, dedicated CO2 storage operations will be needed to manage the varying CO2 demand intrinsic in CO2-EOR campaigns. As such CO2-EOR and dedicated CO2 storage are co-reliant (ARI, 2010) (Gozalpour, et al., 2005).

CO2-EOR can play an important role in leveraging CCS deployment in Europe. However CO2-EOR alone will not drive large scale deployment of CCS, and is should be regarded as a part of a wider system of incentives to enable the first commercial CCS projects.

**Lifecycle Emissions**

The lifecycle CO2 emissions of CO2-EOR are an important consideration for the technology. It has been demonstrated that many CO2-EOR projects will have a positive CO2 footprint due to the combustion of
recovered hydrocarbons (Jarmillo, et al., 2009). The degree of GHG emissions will be highly dependent on the source of CO₂, the capture technology employed, the oil recovery rate from the reservoir and the CO₂ recycle rate. If sufficient CO₂ is available a CO₂-EOR campaign may be optimised for CO₂ storage, with a lower CO₂ recycle rate and possibly co-current storage operations (ARI, 2010) (Gozalpour, et al., 2005). It is clear that any increased emissions resulting from extra oil production due to CO₂-EOR will shrink into insignificance when compared to the total CO₂ avoidance contribution of CCS.

**Oil production in Ukraine**

Ukraine has a long history of oil and gas production with the Dolina gas field discovered in 1860. In the period between 1972 and 1975 oil production peaked at 14.5 million tonnes, by this peak date Ukraine had only produced 14% of the ultimate recoverable reserve (Sorrell, et al., 2009). In the same period gas production reached 68.7 billion m³ at the time the biggest producer in the world (Guoyu, 2011).

Current oil production stands at approximately 3.3 million tonnes falling far short of geological potential, particularly in the Dnieper-Donets Basin (Figure 30) (IHS, 2012). The development of existing fields as well as exploration for new prospects in Ukraine has been hampered by low levels of investment as well as limited application of technology, such as 3D seismic, horizontal drilling and production management through pressure maintained such as CO₂ injection. The U.S. Geological Survey, using a geology-based assessment, estimated the mean volume of undiscovered recoverable oil at 84 million barrels for the Dnieper-Donets Basin Province (USGS, 2010).

Ukraine already has some experience with advanced production management and injection techniques, such as the installation of a compressor to increase production at the Shebelinskoye gas field. Similarly nitrogen injection, a similar but less developed technology to CO₂-EOR has been used to a small extent in Ukraine in the past (IHS, 2012). Increasing oil production through the use of CO₂-EOR would be another valuable tool in achieving the goal of bolstering national energy production while simultaneously providing the foundation for a future low carbon economy (Ministry of Energy and Coal Industry of Ukraine, 2012).
**CO2 EOR in the Dnieper-Donets**

CO2-EOR could play a significant role in reinvigorating mature and declining hydrocarbon fields in Ukraine, in particular in the east of the country where CO2 sources are most common and the Dnieper-Donets Basin has many candidate fields. The largest deposits of hydrocarbons are in the areas surrounding Hnidyntsi, Leliakivka, and Talalaivka. They form the basis of the region's oil and gas industry contributing to over 50% of national reserves and 80% of production.

CO2-EOR is not applicable to all hydrocarbon fields and where it is the oil recovery rate is dependent on among others on geology, oil type, structure, production history, heterogeneity and depth (Alvardo & Mantighe, 2010). Figure 31 describes the approximate suitable depth and oil viscosity of a reservoir for CO2-EOR. In addition a minimum list of criteria must be met before an oil field can be considered for the application of CO2-EOR. Table 12 and Figure 31 display basic screening criteria that could be used to preselect applicable fields.

It is probable that not all oil reservoirs in the area will be suitable for CO2-EOR. This is due primarily to many of the oil reservoirs being relatively deep. Other factors include a complex trapping mechanisms and oil charge history, along with complex and poorly imaged structural geology. However, the oil reservoirs of the Dnieper-Donets Basin are geologically diverse and it is probable that many would benefit from CO2-EOR techniques.

Openness of information may present a barrier to CO2-EOR deployment in the Ukraine. Quality geological information is patchy or not available. For example so far only 10%-20% of the prospective areas of the Dnieper-Donets Basin are believed to have been covered by 3D seismic (IHS, 2012). In addition, occasional poor record keeping of production history, operational information, abandoned wells and geological data increase obstacles to employing modern techniques such as CO2 injection. Small operators and tail end oil
producers may not have the resources or expertise to deploy CO2-EOR technologies, limiting the benefits of the technology to larger operators.

![Figure 31 Approximate conditions for effective CO2-EOR](image)

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adequate Pressure</td>
<td>The minimum miscibility pressure must be reached for effective CO2 EOR operations</td>
</tr>
<tr>
<td>Oil Gravity</td>
<td>&lt; 900 kg/m³</td>
</tr>
<tr>
<td>Oil Saturation</td>
<td>&gt;25%</td>
</tr>
<tr>
<td>Porosity</td>
<td>&gt;15%</td>
</tr>
<tr>
<td>Permeability</td>
<td>&gt;1 md</td>
</tr>
<tr>
<td>Size</td>
<td>&lt;28 STOIP M³</td>
</tr>
<tr>
<td>Mature field</td>
<td>Water Injection, Gas Injection, WAG</td>
</tr>
<tr>
<td>No Significant Gas Cap</td>
<td>The presence of a large gas cap (if export route is available) may reduce the probability of a project due to (Mathiassen, 2003) &amp; (Kuuskraa &amp; Koperna, 2006)</td>
</tr>
</tbody>
</table>
Commercial EOR projects in Ukraine

High purity CO2 sources are attractive for early commercial CCS projects such as EOR as the lower cost of CO2 available reduces both capital and operating costs of a project. High purity CO2 is an industrial by-product from numerous processes, such as natural gas conditioning, ammonia production and coal gasification. All of these processes are present in the Ukraine presenting significant opportunities for increased oil production through CO2 injection.

Ammonia

Ammonia (NH3) is produced by separating hydrogen from carbon atoms in natural gas, a process that produces pure CO2 as a by-product. Ammonia fertiliser production in the Ukraine was 5.7 million tons in 2011, generating between 1.6-3.8 tonnes of CO2 per tonne of ammonia produced, of which around 70% comes directly from the production of hydrogen for ammonia (ICM, 2012). Ammonia production is the primary process of the Ukrainian chemical industry, with six major fertilizer plants located mainly in eastern Ukraine.

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Ukraine, CherkasskAzot, SeveroDonetsk Azot, Stirol, Odesa Port Plant, RivneAzot, and DniprAzot. The chemical sector accounts for 7% of GDP and 8% to 10% of Ukraine’s total export earnings.

As high purity CO2 is an industrial by-product of the process, CCS for ammonia production merely requires energy to compress CO2, and the infrastructure to transport and utilises it. Depending on the cost of transport and storage, this could mean a cost as low as 13 EUR per tonne of CO2. Due to this low cost CO2 from ammonia production is increasingly sought for use in the oil industry for EOR. Ukraine is still a globally significant producer of ammonia, and has ample scope to utilise CO2 in commercial activates such as EOR. Global fertiliser demand is expected to increase significantly in the next decades, providing continued opportunities for this industry in Ukraine. An early application of CCS in this industry would give the Ukraine a strong position as a sustainable leader in this market, improving the counters industrial image while also proving a first opportunity for Ukraine suppliers and industry to develop CCS technologies and practices. The Ukraine is host to major fertiliser factories, all of which emit more than 1 Mt/year of CO2.

Gas Processing
The natural gas processing industry offers favourable conditions to provide low cost CO2 for EOR. Natural gas when extracted from the earth often contains a CO2. This CO2 must be reduced in order for the gas combust reliably, meet transport and sales specification (Gasco, 2010). Must gas processing plants already operate large CO2 separation units, producing large volumes of pure CO2 that s currently vented to the atmosphere. Similarly the stabilisation of natural gas liquids and gas liquefaction may also result in high purity CO2 streams. The volumes and quality of CO2 streams produced is dependent on the initial CO2 content of the raw natural gas and the separation process employed. For this reason gas processing plant must be individually identified to assess their suitability to supply CO2.

IFA: Fertilizer Outlook 2010 - 2014
Where suitable gas processing plants make attractive partners in a CO2-EOR campaign as the facilities have high utilisation and year round operation. Operators have experience of gas handling and project management, along with a deep knowledge of the hydrocarbon sector. In many cases the owner of the gas processing plant and the CO2-EOR site may be the same, reducing commercial complexity. Such synergies may exist between the closely located Ukrnafta operated Hnidyntsivsky gas process plant and the Ukrnafta operated Chernihiv oil fields (IEA, 2006) (Naftogaz, 2004).

**Biofuel facilities**

High purity CO\(_2\) is available at many biofuels production facilities – which means an absence of the need for capture technology equipment – results in low costs of CCS integration, likely among the least costly of any CCS application. The addition of capture and compression equipment to a large 235 million litre/yr. 1st generation bioethanol plant is expected to have little impact on the OPEX of the plant, while CAPEX will only be marginally affected with an increase of 0.9% (Rhodes & Keith, 2003).

The reuse of captured CO\(_2\) from biofuel plants for EOR would be an early commercial opportunity to advance CO\(_2\) knowledge and infrastructure in Ukraine. Commercial Bio-CCS and EOR projects are already operational, notably in the US. In 2009, the petroleum firm Chaparral Energy started purchasing one million tonnes of CO\(_2\) a year from a bioethanol production facility in Liberal, Kansas. The captured CO\(_2\) is transported 90km to Texas, where it is injected into an ageing oilfield for EOR. This project is entirely commercially motivated, operating under a framework with no CO\(_2\) price and zero incentives for carbon negative (Chaparral Energy, Inc, 2011).

**Enabling CO2 EOR**

In a European context, Ukraine with its mature hydrocarbon industries and ready supply of low cost CO\(_2\) from industry has compelling opportunities for early commercialisation of CO2-EOR. Ukraine should follow the lead of other European national institutions and begun to estimate to possible contribution of CO2-EOR to industry and CCS development. The Norwegian Petroleum Directorate (NPD) quantifies the huge potential of CO2-EOR on the Norwegian Continental Shelf, with the possible recovery of an additional 300 million Sm\(^3\) of oil, which is equivalent to approximately doubling all ongoing and proposed hydrocarbon development in Norwegian waters (NPD, 2012). Similarly Scottish Enterprise estimates that CO2-EOR projects could contribute approximately 15% of UK oil production by 2030 (Scottish Enterprise, 2012). Finally the Rotterdam climate initiative has begun the first steps in developing a CO2 hub, with the aim of providing CO2 to the North Sea for EOR (RCI, 2012).

Additional Ukrainian oil field operators and potential CO2 suppliers should be made aware of the benefits of CO2-EOR technology. These commercial actors will begin to realise the value of unutilised high purity CO2 resources already operating in the vicinity of hydrocarbon activities. Commercial drivers will result in a higher profile of CO2 as a profitable commodity, drawing in industries and facilities that possess low cost upgradable CO\(_2\) streams but are currently unfamiliar with EOR as a commercial opportunity.

**CCS & Carbon Negative**
CCS when combined with sustainable biomass or biofuels is the only available technology to provide substantial negative CO₂ emissions. Emissions resulting from combustion of sustainably produced and processed biomass are recognised as being neutral. If CO₂ emitted in such processes is captured and stored, carbon-negative value chains are attained which withdraw more CO₂ from the atmosphere than they emit. The introduction of sustainable biomass to CCS equipped fossil power plants or the use of CCS at biofuel production facilities will produce a net uptake of CO₂ out of the atmosphere as shown in Figure 34 (IEA, 2011).

![Figure 34 Carbon balance of energy from different systems](modified from news.mongabay.com)

**Carbon Negative at coal fired power plants**

Co-firing at coal power plants involves the use of two or more fuels at a plant such as coal and woody biomass. The use of biomass as an energy source reduces the CO₂ intensity of the electricity generation and has been used in countries such as the UK as a cost effective way to reduce emissions (Thornley, 2011). Co-firing with biomass in a plant fitted with CCS can produce a double benefit. In such a case, not only are the emissions from the combustion of coal prevented from entering the atmosphere, but the biogenic CO₂ contained in the biomass is also captured and stored leading to a reduction of CO₂ in the atmosphere, producing a carbon negative effect. Ukraine has extensive solid biomass resources, with the potential to sustainable developed and supply significant amounts of carbon negative electricity (Geletukha, et al., 2010).

The main challenges of co-firing are related to the properties of different fuel types combusted, particularly the calorific value, moisture content, ash production and combustion characteristics. As such, various technologies perform differently dependent on the biomass type and the quantities co-fired.

**Pulverised Coal Combustion (PCC)**

Biomass may be blended with coal and combusted in existing coal burners. This incurs very low capital costs but limits the amount of biomass utilisation to a few percentage of thermal input. Separate handling of biomass from coal and the installation of dedicated biomass burners may allow for 20% thermal input from biomass, though this process involves higher capital costs. It is also important to note that to date biomass co-firing has not been demonstrated at ultra-supercritical temperatures (Gough & Upham, 2010).

**Gasification (IGCC)**

The utilisation of biomass in the gasification process is relatively straightforward offering no major technological or operational hurdles over coal gasification. Gasification allows for the flexible utilisation of high percentages of biomass if sufficient fuel is available (Rhodes & Keith, 2005)
As such the technology choice of future solid fuel power should be carefully analysed to maximise the possibility of poly-fuel use. IGCC plant in the form of future coal facilities will be ideal candidates for co-firing of biomass. As such co-firing may be implemented at new generation plant with CCS with little technological or commercial risk. Co-firing technology is rapidly advancing, and possesses low risks to the operation, performance or integrity of new build plant (Livingston, 2011).

**Carbon Negative at biofuel production facilities**

The integration of CCS to biofuel production plants would result in the production of biofuels with negative lifecycle emissions (Carbo, 2011). The incremental cost of CO$_2$ capture from biofuel production such as ethanol fermentation is generally very low, as the CO$_2$ by-product streams are often of high purity. The pure stream of CO$_2$ negates the need for additional separation equipment, with only driers and compression units necessary to prepare the CO$_2$ for transport to a storage site.

**Bio Ethanol**

The fermentation of sugary or starchy plant matter produces ethanol transport fuel and CO$_2$ in equal quantities. These compounds are easily separated as both exist in different phases. In an idealised case approximately 67% of the carbon is retained within the ethanol fuel while the remaining 33% is available for capture and storage (Table 14)

**Bio-diesel**

Bio-diesel is produced from oil seed such as rapeseed or sunflower. While current biodiesel production has little potential for low-cost CCS deployment, 2nd generation biodiesel made through biomass gasification offers promising prospects. The biomass, the sourcing of which can be versatile, is gasified at high temperatures, subsequently the CO$_2$ is separated and the remaining syngas fed through a Fischer-Tropsch (FT) process where it undergoes liquefaction.

**Hydrogen fuel**

Hydrogen fuel may moreover be produced from biomass, providing the maximum potential CO$_2$-negative biogenic fuel. Hydrogen is then generated through the gasification of solid biomass, with the carbon monoxide and carbon dioxide separated. Hydrogen is a versatile fuel, which can be utilised in fuel cells in transport vehicles, heating installations and electricity generation. The production of hydrogen may take place at standalone gasification units or at co-fire equipped IGCC plants.

### Table 13 Comparison of Biomass Co-Firing Fraction with Various Combustion Technologies (Klein, 2011)

<table>
<thead>
<tr>
<th>Combustion method</th>
<th>Biomass fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulverised Coal</td>
<td>3% - 20%</td>
</tr>
<tr>
<td>IGCC</td>
<td>10% - 100%</td>
</tr>
</tbody>
</table>

### Table 14 Potential for CO2 Negative from Various Biofuels

<table>
<thead>
<tr>
<th>Process</th>
<th>CO$_2$ Purity for Capture</th>
<th>CO$_2$ Negative (of initial biomass)</th>
</tr>
</thead>
</table>
Carbon content)

<table>
<thead>
<tr>
<th></th>
<th>Ethanol</th>
<th>Bio-Diesel</th>
<th>Hydrogen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>99%</td>
<td>&gt;95%</td>
<td>&gt;95%</td>
</tr>
<tr>
<td>Content</td>
<td>15-35%</td>
<td>50%</td>
<td>&gt;95%</td>
</tr>
</tbody>
</table>

**CCS industry and export opportunities for Ukraine**

The scale of European CCS deployment by 2050 envisioned in IEA CCS roadmap will require a massive industrial effort to produce and install capture facilities, absorber columns, stripper columns, compressors, heat exchangers, air separation units, pipelines and other ancillary equipment. Ukrainian heavy industries, foundries and fabricators are ideally suited to supply the European market with components necessary for CCS deployment.

Machinery equipment currently accounts for 15.6% of Ukrainian exports, with compressors, valves, specialised industrial parts and heating and cooling equipment all contributing (MIT, 2013).

Due to a strong history of industrial engineering and proximity to market, supplying CCS equipment could become a large export opportunity for Ukraine. However, it will be important the companies and suppliers are aware of the potential of CCS markets in order to begin strategically developing capabilities and know how now.

**CO2 Pipelines**

A potentially attractive market for Ukrainian producers will be the supply of CO2 pipelines. Ukrainian steel pipe production was 1.754 Million tonnes in 2010, with exports of 1.09 million tonne valued at USD 1.3 billion (Steelguru, 2012). The scale of CO2 transport necessary was estimated in the CO2 europipe project, with approximately 15,000 km of trunk line installed by 2030, forming the backbone of the network, increasing to 22,000 km by 2050 (Table 15).

Similarly, JRC with a more conservative estimate on European CCS deployment predicts a future CO2 transport network to be 8,800 km by 2030, expanding to 20,000 by 2050, requiring a total investment of 29 billion Euros (Morbee, et al., 2010) (Figure 35). This is equivalent to building 30% of the European natural gas transit network. It is clear that the scale of transport pipeline deployment offers lucrative business opportunities. For Ukrainian companies to successfully enter this market they will needed to produce pipeline to an adequate specification, including specially designed CO2 valves, seals and Orings.

<table>
<thead>
<tr>
<th>Year</th>
<th>Reference Scenario</th>
<th>Offshore-Only Scenario</th>
<th>EOR scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>2300</td>
<td>4200</td>
<td>5300</td>
</tr>
<tr>
<td>2030</td>
<td>15000</td>
<td>20000</td>
<td>21000</td>
</tr>
<tr>
<td>2050</td>
<td>22000</td>
<td>33000</td>
<td>33000</td>
</tr>
</tbody>
</table>
**Pipelines manufacture specification: example Jänschwalde CCS project**

At the Jänschwalde CCS project in Germany it was decided to use steel pipelines for CO2 transport, material L485MB, material number 1.8977 (API5L standard X70). The pipelines had a design pressure of 140 bar, a length of 52,090 m and a total volume of 4,453 m³.
The pipeline had no inner coating, with an inner diameter: 330.6 mm, wall thickness: 12.5 mm and an isolation material PUR-foam: 137 mm. The outer coating HDPE: 40.2 mm with a total diameter of 710mm, a roughness of 0.15mm, a steel density of 7.850kg/m³, a PUR density of 70kg/m³, a HDPE density of 950kg/m³ and a steel thermal conductivity of 48.4W/mK. (Vattenfall, 2012).

Steel fabrication
Steel fabrication is a critical component of the Ukrainian economy accounting for 13% of total inward investment in 2010, equivalent to USD 5.6 billion (Steelguru, 2010). Ukrainian steel fabricators along with suppliers to the oil refining and chemical industries are well placed to take advantage of future commercial opportunities in supplying carbon capture equipment and components.

The CO2 stripper column installed at Boundary Dam CCS facility in Saskatchewan, Canada weighs 300 tonnes, measuring 43 meters tall and 8 meters in diameter. The vessel was fabricated in one piece and transported 920km on a flatbed truck with 224 tires from Tofield, Albert to the power plant (Morgan, 2012). Europe will require hundreds to thousands of such pieces to achieve CCS deployment goals.
Recommendations for the Ukraine

CO2 Capture

- Clarify the role of CCS in the Updated Energy Strategy of Ukraine to 2030
  - Long-term emissions control targets accompanied by a national policy package would allow energy and industrial firms to strategically plan their investments.

- Include CCS in Industrial policy planning, particularly with regard to the iron and steel industry.

- Set a clear and realistic retirement schedule for old inefficient power plants and equipment.

- Ensure all new fossil power plants are designed and constructed CCS ready (CCSR) for the future when more aggressive emission reductions will be required from Ukraine.
  - Ensure that all new coal and gas power plants constructed employ the most efficient technology available, such as supercritical and ultra-supercritical coal-fired power plants.
  - Investigate provisions for encouraging the co-firing of biomass and coal.

- Investigate the possibilities of CCS with biomass and biogas production where Ukraine has a competitive advantage
Ukrainian companies, in particular energy intensive industries should play a more active role in international CCS bodies and research organisations.
  o Learning from initiatives in other continents through establishing effective two way exchanges of experience and information.

Create conditions to spur innovation and domestic technology development in CCS technologies.
  o Investigate international partnership options to developed, fabricate or licence CCS technologies.
  o Inform national technology companies and domestic pollution control firms of the commercial opportunities in CCS supply industry. Provide tax reductions and subsidies for to attract national and international CCS research and development.
  o Consider economic instruments in addition to direct financing from State Environmental Fund to promote pilot or demonstration scale CCS technology research and testing. Such as loan guarantees, tax credits, or subsidies.

CO2 Storage
  • More robust estimates of national CO2 storage capacity are necessary for wider climate, energy and industrial planning.

  • A modest strategic investment should be made assess the potential for CO2 storage in Ukraine. Basin scale analysis of the Dniper-Donets in the east and Lviv Slope in the west is needed to create a foundation for future detailed site characterisation.

  • Investigate and begin development CO2 storage regulations, learning from international best practice and avoiding some of the mistakes made in other jurisdictions.
    o Build internal expertise within relevant regulatory agencies through participation in international CCS forms, such is the IEAghg.

  • The development of a regulatory framework should be an inclusive process involving regulatory bodies in collaboration with potential developers and other stakeholders. A CO2 storage framework should address the following issues:
    o How terms should be set in permitting of storage CO2. Including CO2 plume migration in the concession area.
    o The long-range pressure impacts of large scale CO2 injection
    o Rules governing potential conflicts between different subsurface uses such as hydrocarbon extraction including hydraulic fracturing, geothermal energy, gas storage and permanent CO2 storage
    o Rules governing the use of CO2 for Enhanced Oil Recovery (EOR)
    o Liability transfer for different storage arrangements
Pilot or demonstration scale CO2 injection projects will be necessary to provide real world data on Ukrainian CO2 storage potential. Such a pilot scale injection scheme could be modelled on similar schemes such as those at Ketzin in Germany and Lacq in France.

**CO2 transport infrastructure**

- An integrated and strategic approach should be taken to developing Europe’s CO2 transport infrastructure, both pipelines and ships, which should be on a par with critical developments in Ukraine’s extensive gas pipeline network offers many advantages to the deployment of CCS. Re-use of underutilised pipelines may significantly reduce complexity and cost of CCS projects. This particularly applicable to early CCS projects which require simple point to point transport infrastructure and have limited volumes of CO2.

- Where existing pipeline infrastructure is not sufficient due to higher pressure and larger volumes of CO2 to be transported re-use of pipeline rights of way should be investigated. Ukraine should preliminary map out a future CO2 pipeline network and clusters, identifying existing pipeline rights of way and new rights of way for necessary tie-in pipelines. Such future pipeline infrastructure should be considered in national development and planning processes.

- Recognising the importance of integrated CO2 transport networks, a future CCS demonstration should potentially include two sources feeding into a single storage facility. Such a project should be located in an emissions intensive region such as Donetsk, potentially forming the basis for a wider CCS cluster.

**Public Support**

- CCS should be introduced and debated as an integral technology to the eventual decarbonisation of the Ukrainian economy. The early introduction of CCS as a technology tool alongside other technologies such as renewable and bio energy will increase awareness and to put decisions to proceed with CCS on a firmer footing.

- The advantages of CCS technologies in the Ukrainian setting should be highlighted from the outset, including the benefits to Ukrainian heavy industries and the continued use of indigenous energy sources.

- The planning and operation of any pilot or demonstration plant should be transparent, with active outreach and sustained communication with local groups and interested stakeholders.