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PROJECT 401010-01060 - CCS LEARNING FROM THE LNG SECTOR

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<td>0</td>
<td>Final Report for Client Approval</td>
<td>G. Cox</td>
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<td>22-Nov-13</td>
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<tr>
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<td>G. Cox</td>
<td>S. Henzell</td>
<td>G. Cox</td>
<td>12-Dec-13</td>
<td>N/A</td>
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EXECUTIVE SUMMARY

The Global CCS Institute in its role of accelerating the development of carbon capture and storage (CCS) requested and supported this analysis of another complex industry that has undergone significant growth in recent times - the Liquefied Natural Gas (LNG) export industry. The goal of the analysis is to identify and understand the similarities and contrasts between these industries and look for solutions and lessons that may be comparable between the industries.

Key Findings from industry development experience of LNG:

- Early projects will experience disadvantages of small scale, single supply chain, one-to-one suppliers and off-takers, and needing to set up the entire value chain in a single project. Later projects will experience advantages of existing infrastructure, diverse range of suppliers and off-takers, mature competitive technology, and learning curve cost reductions.

- A commercial framework is required to support predictable valuation of CCS, apportioning benefits to value chain stakeholders, providing the basis for long term contract commitments, and thus supporting bankability of projects.

- Government intervention is required to both set up the needed commercial framework, and also to directly fund early projects or infrastructure so as to overcome the early project disadvantages.

- Market pressures such as project cost escalations and product price competition can be expected to occur at any stage of maturity of the industry.

- The target rate of CCS deployment to achieve GHG reduction targets requires growth rates and numbers of projects that seem to be unprecedented in the hydrocarbon and chemical process industries viewed from the perspective of recent buoyant LNG deployment.

1.1 CCS Development Targets and Challenges

Carbon capture and storage (CCS) is a greenhouse gas (GHG) mitigation technology that is proposed among a portfolio of low carbon technologies to reduce anthropogenic carbon dioxide emissions. There is an essential role for CCS to contribute to GHG emissions reduction. CCS is needed to assist in limiting GHG concentrations in the atmosphere at levels consistent with limiting global temperature rise to less than 2°C by 2050 as recommended by the Intergovernmental Panel on Climate Change.

The challenge for development of CCS is to demonstrate and commercialise the entire value chain and to have established a framework business case for CCS that enables the market to take over from early government intervention and establishment. The rate of commercialization ramp up must then be capable of attaining the targeted emissions reductions.

International Energy Agency (IEA) analysis indicates that a lowest-cost mitigation scenario consistent with 2°C rise requires CCS to be widely deployed across power generation and industrial processes. Forecast or target capture quantity will be required to reach 7 to 8 billion tonnes per annum (GTPA) from a current quantity of 25 million (MTPA). Three goals are set: 50 MTPA by 2020, 2,000 MTPA by 2030 and 7,000 MTPA by 2050. These goals correspond to approximately 40% to 50% annual growth rate between 2020 and 2030 followed by a more moderate average 6% to 7% annual rate
from 2030 to 2050. Assuming a typical 500 MWe coal fired station with 4 MTPA of carbon dioxide (CO₂) captured, the rate of growth corresponds to around 500 projects between 2020 and 2030 (50 per year) and 1,250 between 2030 and 2050 (60 per year). Effectively, the currently identified CCS large scale integrated projects (LSIP), which number around 65 would become an annual completion target for every year from 2020 till 2050.

This type of growth profile has few precedents in the complex hydrocarbons and chemical process industries, which are akin to the types of processes contemplated to achieve CCS. A number of barriers are perceived and these include:

- There is not a commercial or business case for investment in CCS that the market can rely upon to underpin the level of investment required to develop and deploy the technology and projects.
- The role of government intervention to establish the CCS industry is not clear, consistency is lacking and application of resources is not consistent with other government infrastructure investments.
- The investment amount per project is significant and across the total potential CCS industry is immense in comparison to other process industries.
- Capital required for demonstration projects is beyond the current funding mechanisms and insufficient funding is slowing development.
- Technology maturity and commercial readiness is not yet at a level that would support significant commercial competition, widespread deployment and a bankable asset class.
- No significant progress has been started on learning curve cost reductions that affect ability to deploy CCS LSIPs.

1.2 Liquefied Natural Gas Industry Development

The goals of this study have been to report and analyse the development of the LNG export industry and determine whether analogies and lessons may be interpreted from the industry’s history. The LNG export industry was established in the 1960s. Some cargos were exported from the USA to UK in 1959 and the first dedicated export trade was in 1964 between Algeria and UK, so the industry is now around 50 years old.

Over its history, LNG growth rate has been demand driven and vulnerable to competing energy prices and has grown at relatively slow pace during periods of low oil price. [In this report, historical demand means actual quantity of traded LNG and projected demand means predictions of future trade.}
Capacity is usually referred to LNG liquefaction plant capacity unless specifically stated otherwise, e.g., for regasification plants. The LNG quantity traded is always less than liquefaction capacity and the difference represents global capacity utilisation.

Significant growth has been sustained since the 1990s. From 2000 to 2010, global demand grew from around 100 MTPA to 220 MTPA. In 2012 it stood at around 240 MTPA. Projections are for around 390 MTPA by 2020 and 480 MTPA by 2030. To compare to the target CCS growth rates, LNG grew by 8% per annum and more than 30 liquefaction trains from 2000 to 2012. The industry is projected to achieve 6% annual growth from 2012 to 2020. Assuming LNG train capacities remain at between 4 to 8 MTPA as is the current benchmark, then there will be between 20 to 40 new trains between 2012 and 2020 (more than 20 are currently in construction).

It can be seen that at the targeted peak development of CCS, the required growth rate of 50 to 60 projects per year for 30 years is significantly greater than has been achieved or that is projected for LNG, which anticipates a peak of around 4 trains per year from 2010 to 2020. Considering the capacity constraints that have been observed recently for some LNG projects, the growth targets for CCS could result in significant project execution capacity constraints.

1.3 LNG Development Features and Comparison to CCS

LNG and CCS have a number of features that appear similar when considered at high level.

- Both are based on a value chain that links an underground reservoir / resource via production pipelines to a complex hydrocarbon or chemical process.
- LNG and CCS applications are comparable in complexity and cost. Both technologies cost in the order of billions to tens of billions of dollars for commercial scale plant. Both technologies at commercial scale produce millions of tonnes per annum of product per production train.
- Both feature large and relatively complex (due to scale) unit operations: compression, heat exchange and mass transfer (for capture). For both industries, capacity limits of production trains are due to limits of critical main equipment.
- The core liquefaction process (LNG) and capture process (CCS) are process intensive blocks but they make up only a portion of the total value chain investment.
- Both processes require careful pre-treatment of process feed streams to comply with the contaminant tolerance of the core process or downstream specifications.

A key lesson learned in the development of both LNG is that significant time elapsed before becoming commercial and being implemented in its current form. For LNG, patents were filed in 1914 and the first plant started in 1917. The first commercial plant started in 1941 and initial application was for
pipeline gas storage. International trade was finally established in the 1960s. For CCS, capture from both combustion flue gas as an industrial source of CO₂ and from treating of natural gas, synthesis gas or other chemicals processes have been practiced for many decades. Similarly, Enhanced Oil Recovery utilizing CO₂ has been practiced in the USA Permian Basin for over 30 years from natural CO₂ sources along with associated pipeline transport. Deep saline aquifer injection is more recent, since about mid-1990s (Sleipner).

1.4 Commercial Comparison

There are a number of situations in an energy delivery value chain for which LNG may be considered as a value adding block. Most often LNG is applied in order to develop reserves that are remote from possible markets. Other situations include capture of associated gas from oil production to prevent flaring and taking advantage of massive new gas reserves that would otherwise develop more slowly if constrained by the local market. LNG is often evaluated in comparison to other alternative utilization of the gas or upgrades such as power generation and chemicals in order to select the preferred development.

The LNG liquefaction industry is dominated by National Oil Companies (NOC) and International Oil Companies (IOC), which have the resources to develop these massive projects. A common commercial model is project Joint Ventures with multiple parties. With the exception of projects in developed nations such as in Norway, Australia and the USA, governments or their NOCs have always played a major role in the establishment and on-going development of the LNG industry.

There are a small number of second tier gas companies also entering the market. Other participants in the liquefaction projects include farm-ins or off-takers, often utility companies. Typically LNG liquefaction projects are based on committed future off-take from the project, although there is increasing spot trade of LNG. The capacity of regasification facilities far outweighs liquefaction and there are more buyers than producers.

For the CCS industry, it is widely recognized that government must have a direct interventionist role for the establishment of projects and commercial frameworks at this early stage of the industry development. As a minimum, government must enact a regulatory framework that allows and
governs the capture, transport and storage of CO\textsubscript{2}. But that will not provide a justification to install and operate CCS. A combination of a robust and stable business case justification and emissions mandates will be required for CCS justification. The extent of government involvement will depend on economic and environmental policy but could include any of:

- Funding support for technology and early project development
- Carbon tax or emissions trading that provides sufficient incentive for investment
- Infrastructure direct investment such as transport and storage systems for multiple emissions sources
- Direct investment in early projects to overcome high first mover costs

Currently only EOR applications have value adding business cases for underground storage of CO\textsubscript{2}. This excludes consideration of capture that is required for other process requirements, e.g., to meet natural gas pipeline specifications, and also excludes captured CO\textsubscript{2} that is directed to non-permanent utilization such as for food / beverage / soda ash products.

All deep saline aquifer injection projects (Sleipner, Snøhvit, In Salah, Gorgon) are in response to either government-imposed CO\textsubscript{2} tax (or other pricing), direct government support (sometimes multiple governments) for demonstration, or regulatory approval conditions for gas / LNG production.

For LNG, there is well understood pricing and valuation of LNG relative to crude oil or baskets of energy products. Such markets establish competition between alternative energy products (oil, gas, coal) between LNG suppliers and their projects and between technology providers and contractors. Investors can understand and evaluate the business case for LNG projects.

For CCS that is performed solely for sequestration of GHG, there is not a similar well understood market place. There are several local and regional emissions markets or taxes. However, they are not universal and they have not provided stable valuation for emissions management. Furthermore, the valuation that those mechanisms have placed on avoided emissions is not high enough to enable justification of early mover CCS at large scale.

For now there is a struggle to quantify what is the value add of CCS in the absence of mandates or incentives. This appears to be in contrast to the LNG industry. However, analysis of the LNG production capacity additions over time shows that after an early spike in projects in the late 1970s to early 1980s corresponding to increasing crude oil price, there was comparatively little activity through the 1980s and 1990s. It was not until the late 1990s and 2000s that first Asian growth and then increasing crude oil price spurred the recent significant LNG project activity.

1.5 Learning Curve Comparison

In common with many hydrocarbon and chemical process industries (oil refining, petrochemicals); the LNG industry has demonstrated that bigger is better. Plant capacity growth over time has resulted in train size increasing from around 1 MTPA in the early 1970s to around 2 – 3 MTPA for most of the 1980s and 1990s, then increasing rapidly to 4 – 5 MTPA currently. The new largest capacity plants are approaching 8 MTPA per train.

The growth in train capacity is clearly observed as a function of total installed capacity. Considering that the industry grew slowly during the 1980s and 1990s, there was comparatively little learning
curve effect during that period. The rapid industry capacity growth since the late 1990s has delivered a clear learning curve effect to the increase in train capacity.

![Train Capacity vs. Time](image1)

![Train Capacity vs. Industry Capacity](image2)

Specific cost learning curves of capital cost per unit capacity versus train capacity have also demonstrated expected cost reduction trends. However for certain recent projects, especially in Australia, other cost impacts have combined to override the learning curve benefits in overall project cost. The adverse cost impacts have been due to high equipment and materials costs, high labour costs due to resource shortage, exchange rate effects and remote construction locations.

It is expected that the process plant portions of CCS (capture and compression) should experience the same cost effects as demonstrated by LNG. Learning curve and technology competition can be expected to deliver larger capacities and lower specific costs. Actual project costs will reflect these benefits but also the adverse impacts of resources and materials availabilities and costs. CCS will compete in roughly the same industry sectors as LNG and other process industries for access to engineering design, equipment and materials, and construction labour and will be subject to the same cost escalation factors.

Intermediate storage of CO₂ (tanks) and transport (pipeline) are similarly expected to compete in the same sectors as the mature hydrocarbons industries. Since the technologies in those industries are relatively portable to CCS requirements, the opportunities for learning curve cost reductions might be less significant for the transport sector of CCS.

There should be considerable scope for technology “learning by doing” in the reservoir sector of CCS. Although EOR has been practised for over 30 years, the experience has been in a comparatively limited number of applications. Similarly there are only 3 or 4 large scale saline aquifer demonstrations so far. The unconventional gas industry provides an excellent analogy of the game changing effects of new technology or adaptation of existing technologies. Both shale gas in North America and coal seam gas in Eastern Australia have transformed energy markets as their unit cost reductions have accelerated deployment and greatly increased available supply and driven down overall production cost.

### 1.6 Project Lessons

LNG projects are typically funded by multiple producer partners and supported by committed off-take agreements. For CCS, the business case for the multiple parties in the supply chain will need to provide predictable and adequate justification supported by long-term commitments.
LNG projects have been impacted by cost-escalation that is caused mainly by non-technology and general project industry delivery constraints, including skilled resource shortage and labour costs as mentioned. Project development and construction strategies that have been applied to mitigate cost and schedule risks are likely to be applicable to CCS as they have been to LNG and other process industries. These include standardization of design, increasing high value engineering in low cost countries, global procurement, and modularization and shifting construction from field to shop / yard.

One distinct difference between LNG projects and many CCS locations is accessibility to marine unloading. Since all LNG liquefaction must be located at or near shore for the tanker loading port, there is usually good accessibility for off-loading of large constructed modules. In general, relatively few CCS proposed sites especially for power generation will be near marine facilities and transport plans will vary accordingly.

LNG projects have often been implemented in phases, with additional trains added in a sequence. This can be to match upstream development or off-take profiles, or to limit initial project expenditure or to match available construction resources. Development phasing could also offer benefit to CCS particularly for capture and storage development profiles.

1.7 LNG Lessons for CCS

This study has identified a range of issues for which development goals for CCS may be guided by the LNG industry experience, including establishment of supply chain, roles for government and national corporations, scale of investment, technology development, project development strategies, and potential constraints on growth rate. The LNG industry is not unique in providing relevant lessons and other recent examples such as unconventional gas development that is not associated with LNG can also provide needed information.

However, it is probably still the distinct difference of CCS lacking a clear business case, compared to natural gas or LNG that represents the most significant hurdle to CCS proceeding along a commercialization development.
2 INTRODUCTION AND SCOPE

Carbon capture and storage is a greenhouse gas mitigation technology that is proposed among a portfolio of low carbon technologies to reduce anthropogenic carbon dioxide emissions. CCS has an essential role to play for GHG emissions reduction. CCS is needed to assist in limiting GHG concentrations in the atmosphere at levels consistent with limiting global temperature rise to less than 2°C by 2050 as recommended by the Intergovernmental Panel on Climate Change.

The challenge for development of CCS is to demonstrate and commercialise the entire value chain and to have established a framework business case for CCS that enables the market to take over from early government intervention and establishment. The rate of commercialization ramp up must then be capable of attaining the targeted emissions reductions.

International Energy Agency (IEA) analysis indicates that a lowest-cost mitigation scenario consistent with 2°C rise requires CCS to be widely deployed across power generation and industrial processes. Forecast or target capture quantity will be required to reach 7 to 8 billion tonnes per annum (GTPA) from a current quantity 25 MTPA. Three goals are set: 50, 2,000 and 7,000 MTPA by 2020, 2030, 2050 respectively. These goals correspond to approximately 40% to 50% annual growth rate between 2020 and 2030 followed by a more moderate average 6% to 7% annual rate from 2030 to 2050. Assuming a typical 500 MWe coal fired station with 4 MTPA of CO₂ captured, the rate of growth corresponds to around 500 projects between 2020 and 2030 (50 per year) and 1,250 between 2030 and 2050 (60 per year).

This type of growth profile has few precedents in the complex hydrocarbons and chemical process industries, which are akin to the types of processes contemplated to achieve CCS. The Global CCS Institute has requested a report on the “Learning from the LNG Sector”, by which the developments of the LNG industry over time and with increasing maturity might be used as an analogue for possible developments in future CCS Sector. The LNG Industry is an apt comparison for possible future developments in CCS.

Starting from first commercial export facilities in the mid-to-late 1960’s and at plant capacities of approximately one million tonnes per annum (MTPA), the number and capacity of LNG facilities has been accelerating. LNG train capacities have risen from 1 to 7 – 8 MTPA. Reliability and efficiency have increased and capacity unit cost in real terms has decreased as the core liquefaction technology has improved. However, LNG projects are vulnerable to escalation of input costs such as for remote site development, materials and equipment price and construction labour costs. As a result, recent LNG projects in some regions are experiencing very high costs. Many of these effects may also be applicable to CCS projects at all stages of that industry’s development.

There are 35 exporting LNG sites around the world with a total of 120 trains either operating or under construction ranging from 7.8 MTPA down to 1.5 MTPA. A list of plants and locations are included in following Section 4.3.5. Some aspects of the desired development trajectory for CCS might be comparable to the demonstrated development of LNG.
Table 1 – LNG Facilities

<table>
<thead>
<tr>
<th>LNG FACILITIES</th>
<th>SITES</th>
<th>TRAINS</th>
<th>MTPA</th>
</tr>
</thead>
<tbody>
<tr>
<td>PRODUCING</td>
<td>35</td>
<td>94</td>
<td>290</td>
</tr>
<tr>
<td>UNDER CONSTRUCTION</td>
<td>14</td>
<td>26</td>
<td>100</td>
</tr>
<tr>
<td>TOTALS</td>
<td>49</td>
<td>120</td>
<td>390</td>
</tr>
</tbody>
</table>

This report summarizes characteristics of the LNG industry and compares to the CCS industry as follows:

Section 3 describes the technical features of the LNG value chain, from gas reserve through production, processing, liquefaction, storage and transport to regasification.

Section 4 summarizes the global status of the LNG industry, in aggregate and listing major LNG production facilities.

Section 5 provides a brief description of the CCS value chain. It is not intended that this section would provide comparable detail as for LNG. Many Global CCS Institute members and readers familiar with the CCS industry will already be aware of the detailed features of CCS development from other Global CCS Institute reports and resources.

Section 6 commences the comparisons and lessons that may be derived from LNG for CCS. With the preceding sections having described technical features of LNG and CCS, this section examines project implementation features of LNG and interprets pertinent points of comparison for CCS.

Section 7 continues the comparison with project technical points of comparison between LNG and CCS.

Section 8 examines the possibility for integration of CCS and LNG projects.
3 THE LNG VALUE CHAIN

Key Findings:
- LNG adds value to Natural Gas by allowing efficient transport over very long distance.
- LNG is a complex, multi-unit value chain but with similar configuration common to most developments.
- Stringent pre-treatment of feed gas is critical for LNG process performance.
- There are multiple technology providers for the core liquefaction process, in a competitive market, with two of them dominating.
- Storage, shipping and re-gasification are significant components of overall value chain.
- LNG has been applied to conventional and unconventional gas sources and to on-shore and off-shore reservoirs.

3.1 Overview of LNG process

LNG has developed as a significant industry (approximately $100 billion per year) because it allows the efficient movement of large volumes of natural gas over long distances. The efficient movement is facilitated by the much greater density of LNG than the feed gas and by the overall thermodynamic efficiency of the liquefaction process that has been achieved by process optimisation during the industry’s development.

Table 2 – Typical LNG Properties

<table>
<thead>
<tr>
<th>Typical LNG Properties:</th>
<th>Temperature at atmospheric pressure</th>
<th>-160°C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density:</td>
<td>450 kg/m³</td>
<td></td>
</tr>
<tr>
<td>Density ratio liquid / gas:</td>
<td>600</td>
<td></td>
</tr>
</tbody>
</table>

LNG liquefaction is a proven development concept which allows gas resources to be monetised by connecting the supply with markets in a flexible manner. The key to the LNG value chain is transport of the high energy density fuel to markets by a dedicated fleet of ships.

In order to allow the LNG liquefaction process to be operable and the product to be saleable, LNG composition must comply with composition and impurity specifications. A typical north Asian LNG spec is as follows:

Table 3 – LNG Specifications

<table>
<thead>
<tr>
<th>LNG Specifications:</th>
<th>Higher Heating Value:</th>
<th>1045 – 1145 BTU/SCF</th>
<th>39 – 42.8 MJ/m³</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nitrogen:</td>
<td>1.0 % mol. max.</td>
<td>Butane &amp; heavier:</td>
<td>1.9 % mol. max.</td>
</tr>
<tr>
<td>Methane:</td>
<td>85.0 % mol. min.</td>
<td>Pentane &amp; heavier:</td>
<td>0.09 % mol. max.</td>
</tr>
<tr>
<td>Impurities:</td>
<td>Hydrogen Sulphide:</td>
<td>Total Sulphur:</td>
<td>28 mg/N m³ max</td>
</tr>
<tr>
<td></td>
<td>4.8 mg/N m³ max.</td>
<td></td>
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</tr>
</tbody>
</table>
LNG specifications vary considerably by market or country, driven by historic supply arrangements and heritage specifications. The typical range of heating value (HHV) is 1000-1180 BTU/SCF. The Wobbe Index, which provides a good characterization for inter-changeability of natural gas streams, is used in many European markets.

Some LNG requirements for both the Japan and US market are as follows:

**Table 4 – Regional Variations – Gas specification**

<table>
<thead>
<tr>
<th>Description</th>
<th>Unit</th>
<th>Asia Pacific Specification</th>
<th>US West Coast Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum HHV</td>
<td>MJ/m³</td>
<td>43.7</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Btu/SCF</td>
<td>1170</td>
<td>-</td>
</tr>
<tr>
<td>Methane number</td>
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<td>84.0</td>
<td>80 min</td>
</tr>
<tr>
<td>Methane</td>
<td>Mole % minimum</td>
<td></td>
<td>6.0</td>
</tr>
<tr>
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<td>Mole % maximum</td>
<td></td>
<td>3.0</td>
</tr>
<tr>
<td>Propane</td>
<td>Mole % maximum</td>
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<td>3.0</td>
</tr>
<tr>
<td>Butane plus</td>
<td>Mole % maximum</td>
<td>2.0</td>
<td>-</td>
</tr>
<tr>
<td>Pentane plus</td>
<td>Mole % maximum</td>
<td>0.1</td>
<td>-</td>
</tr>
<tr>
<td>Nitrogen</td>
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<td>-</td>
</tr>
<tr>
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<td>5.0 (3.3)</td>
<td>-</td>
</tr>
<tr>
<td>Total Sulphur</td>
<td>mg/m³ maximum</td>
<td>30 (21)</td>
<td>-</td>
</tr>
</tbody>
</table>

**3.2 Technology Overview**

A block flow diagram of a full gas field development using LNG liquefaction is provided in Figure 1. While each plant or project will differ in detail, this schematic is common to most projects regardless of technology. The raw gas enters a receiver or slug catcher where the condensate is separated and stabilized for shipment. The remaining gas is treated to remove acid gas, water, and other impurities prior to entering the liquefaction section. After initial cooling of the gas, the heavy hydrocarbons and LPGs are recovered for fractionation and storage. At this stage the lean gas with less than 0.1% pentanes and heavier is suitable for entering the cryogenic section of the plant. The gas is cooled to approximately -160°C where it is liquefied and stored at slightly above atmospheric pressure until loading to LNG tankers. In general, the liquefaction is a significant part of the process, but it must be recognized that it is only a fraction of the total project in particularly, a green-field project.
Figure 1 Full Gas Field Development Block Flow Diagram
3.3 Reservoir

The reservoir is the source of gas feedstock to the LNG facility. It is the porous, permeable rock media in which the reservoir fluids are contained and through which the fluids flow into the wellbore. The gas feedstock can come from many sources:

- Conventional gas reservoirs in sandstone or carbonate sedimentary layers and trapped by cap rocks and seals
- Associated gas, which has been liberated from crude oil as part of the production and stabilisation process
- Unconventional gas reservoirs (essentially hydrocarbon resources not captured in permeable sandstone or carbonate sedimentary layers). These resource types are diverse and include:
  - Coal seam gas (also known as coal bed methane) – predominantly methane which is adsorbed on the surface of the coal. The adsorbed methane is released by reducing the pressure within the coal cleats.
  - Shale gas – sourced from shale formations which are sedimentary layers of very low porosity and permeability. Shale gas has become viable as an energy source with the development of techniques such as hydraulic fracturing to release the hydrocarbon resource at economic flow rates.
  - Methane hydrates - clathrate compounds which are a molecular structure in which water molecules bond to form an ice-like cage that encapsulates a methane molecule. Deposits are located on the ocean floor and in sediments associated with permafrost. There has been no commercial production of natural gas from methane hydrates.

In general, there is no significant difference in the gas feedstock to an LNG plant from either conventional or unconventional resources. The only exception is coal seam gas which is almost entirely methane with only small quantities of nitrogen, carbon dioxide and ethane – there is essentially no hydrocarbon component heavier than ethane in the gas stream.

3.4 Resource Size Required to Support an LNG Facility

A typical world-scale LNG plant train is in the range of 5 MTPA. Facility developments can consist of one to five trains, usually installed in phases. Thus total LNG production from a site can vary from less than 5 to more than 25 MTPA. Most plants are designed to run at a sustained plateau rate over their economic life of typically more than 20 years. Typically the gas reserves required for 1 MTPA over 20 years is 1.1 – 1.2 trillion cubic feet (TCF) depending upon the composition. Thus, a 5 MTPA facility requires about 6 TCF resource committed to the project; 6 TCF of gas represents approximately 3 months of natural gas consumption in the US.

3.5 Production Facilities

Production facilities allow the production of fluids from the reservoir and transport of the treated fluids to the LNG plant. The production facilities vary greatly but ultimately comprise:
• Wells which serve as the conduit for access to the reservoir from the surface. The wells comprise a drilled well-bore which is fitted with steel casing cemented into the surrounding rock. The cased well-bore houses tubing and associated subsurface production equipment which serve as the primary conduit for fluid flow from the reservoir to the surface.

• Wellheads and Christmas trees are fitted to the well to regulate the flow and safely contain the hazardous materials within the wellbore.

• A gathering system conveys the production from multiple wells to a centralized production facility. Flow assurance for the produced fluids may require management of liquid inventories, prevention of hydrate formation and management of corrosion.

• The production facility performs sufficient processing to allow the safe and reliable transport of the fluids to subsequent processing facilities, including the LNG facility. The facilities required vary considerably depending on the composition of the wellbore fluids, presence of noxious impurities, flowing pressures and temperatures, separation distance to the downstream processing plants and environmental conditions.

• Transportation pipelines from the production facilities to the LNG facility.

Production facilities for LNG plants have included:

• Onshore gas wells producing to a gas plant
• Offshore gas wells located on fixed steel structures
• Subsea gas wells producing to a hub facility located on fixed steel structures
• Subsea gas wells producing to a shore based gas plant

New developments include Shell’s Prelude floating LNG facility where the LNG and gas processing facilities will be located on a large hull and permanently moored in close proximity to the source gas reservoir (refer to Section 4.4.3). The nature and configuration of the production facilities vary considerably due to the differences in location and environment of the reservoir and the proximity to a suitable location for the LNG plant.

The facilities shown in Figure 2 are typical depending on the nature and conditions of the production fluids. These facilities are integrated with production fields and may be installed on off-shore platforms or distributed in several production facilities.

The raw gas stream will first enter a slug catcher to serve as a separator and reduce the surge effects from liquid slugs on the downstream process. The liquid streams are flashed to lower pressure and further separated into gas, liquid hydrocarbon (condensate or crude) and aqueous streams.

The separated condensate contains volatile components so that it is not suitable for storage or shipment. The condensate stabilizer strips the volatile components and reduces the vapour pressure of the condensate, which is then stored for export.

Many raw gas streams require hydrate inhibitor systems. These are typically glycols such as monoethylene glycol (antifreeze) or methanol and these suppress the hydrate formation temperature. The hydrate inhibitor is recovered from the production fluids and returned to the upstream injection point. Produced water must be treated to satisfy environmental discharge specifications.

Lower pressure flash gas from the separator and stabilizer are compressed and combined with gas feed to treatment. Conventional reservoir pressures are normally high and inlet compression is
usually not required for a newly developed LNG project. Unconventional gas reservoirs (coal seam gas and shale gas) tend to produce at lower well pressures and typically require pressure boosting.

Figure 2 Receiving Facilities

3.6 LNG Facilities

All LNG facilities include the following components:

- Gas conditioning to remove impurities from the natural gas stream
- Natural gas liquid separation to recover heavier hydrocarbons that have condensed from the gas stream during chilling
- LNG liquefaction which condenses the natural gas stream into a cryogenic liquid
- LNG storage in atmospheric storage tanks
- LNG ship loading facilities

Gas conditioning at the inlet of the LNG process train is designed to remove most non-hydrocarbon contaminants, including water, sulphur compounds, carbon dioxide, mercury and solids.

3.6.1 Acid Gas Removal

The acid gas removal unit (AGRU) is required to remove carbon dioxide (CO₂) and hydrogen sulphide (H₂S) from the inlet gas. CO₂ will freeze and block the liquefaction section and H₂S is toxic as well as corrosive. LNG specifications typically constrain H₂S content to very low levels.
Usually the acid gases are scrubbed by a regenerable solvent solution. The absorption solvents can be either chemical solvents which are most commonly used and which react with the acid gas components, or physical solvents that rely on preferential solubility of the acid gas components. The most common chemical solvents are alkanolamines such as methyldiethanolamine (MDEA). Physical solvents include Selexol (dimethyl ethers of polyethylene glycol) and Rectisol (methanol). Other processes for acid gas removal such as adsorption or reaction with solid beds are not commonly used. The inlet gas composition will determine the most cost effective treatment option.

Figure 3 shows a typical acid gas treatment flow schematic. The feed gas first enters a knockout vessel or a filter coalescer where any entrained liquid hydrocarbons or other contaminants will be removed from the gas to avoid contamination of the AGRU solution. Next, the feed gas flows into the bottom of an absorber while the lean solvent enters the top of the absorber flowing counter-current to the feed gas, thereby absorbing the acid gas. Typically, CO$_2$ is reduced to < 50 mol. ppm and H$_2$S to < 4 mol. ppm. The treated gas leaves the top of the absorber and is routed to the dehydration unit.

**Figure 3 -- Acid Gas Removal Unit**

![Diagram of Acid Gas Removal Unit]

The CO$_2$ rich AGRU solution leaves the bottom of the absorber. The solvent is routed to a flash vessel to liberate volatile hydrocarbons that are entrained and dissolved in the solution. The flashed vapours are typically used as fuel gas. The CO$_2$ rich solvent is then heated and enters the regenerator and is regenerated in a distillation column. The lean solvent from the bottom of the regenerator is cooled and returned to the absorber.

### 3.6.2 Dehydration

The liquefaction process requires gas water content to be < 1 mol. ppm. The gas from the AGRU is saturated with water and must be dehydrated to prevent freezing and plugging of the downstream cryogenic equipment. Molecular sieves are needed to attain this specification.
In Figure 4, treated gas from the AGRU is cooled by propane chilling to condense and remove a majority of the water via a separator vessel. Water removed in this vessel, is returned to the AGRU. Gas flows from the separator through molecular sieve beds, removing the water to < 1 ppm. After drying the feed gas is sent to the mercury removal system.

Multiple molecular sieve beds are used allowing the beds to rotate through a fixed cycle of treating, heating (removing impurities), cooling (preparing for treating service) and stand-by. There are on-line and spare beds with one being regenerated at all times. The molecular sieves progressively lose their ability to absorb water over time and need to be periodically replaced usually in line with the major turnaround of the LNG plant.

Regeneration of the molecular sieve beds is achieved by heating a recycle stream of dehydrated process gas and passing it through the saturated bed to desorb the impurities that have adsorbed on the molecular sieve. The recycle stream (typically around 10% of the treated gas flow) is returned to the process upstream of the Dehydration.

**Figure 4 -- Molecular Sieve Dehydration**

3.6.3 Mercury

Mercury in its elemental form is extremely corrosive for aluminium and can cause damage to the heat exchangers in the liquefaction section. The specification upstream of the heat exchangers is 10 nanogram / Nm³ of mercury. Concentrations at or above this level can create an amalgam with the aluminium and promote intercrystalline corrosion cracking of the aluminium. Most of the corrosion will occur during cool-down or warm-up of the cryogenic equipment when liquid mercury can be present.
Activated carbon is most often used to remove mercury with the gas being fed down through the adsorption bed. A filter is also required to remove any charcoal dust from the gas prior to entering the liquefaction section. The carbon beds cannot be regenerated and must be disposed and replaced periodically, usually in line with major plant turnarounds.

### 3.7 Natural Gas Liquids (NGL) Separation

Removal of heavier hydrocarbons is required for the following reasons:

- To reduce the heating value of LNG according to specification
- Prevent potential freezing of C5+ in the cryogenic section
- Extract ethane and propane to replace lost refrigerant
- Produce commercial grade LPG depending on the gas composition

The inlet receiver facilities separate heavier components from the gas feed as described in Section 3.5, and further separation is achieved in the scrub column which is essentially a demethanizer, see Figure 5. The scrub column that provides the feed to NGL separation is located in the propane pre-cooling train at the front end of the gas liquefaction process block.

**Figure 5 NGL Separation**

The resulting mixed NGL stream is fractionated in a series of distillation columns with a deethanizer generating an ethane overhead product, depropanizer and debutanizer. Each column overhead
product stream is cooled and the liquefied / chilled product delivered to storage – chilling relies on LP, MP and HP propane refrigeration. The products are stored for shipment or for refrigerant makeup. Ethane may be used as fuel or re-injected into the LNG stream depending upon the desired heating value. Propane and Butane are chilled and stored at close to atmospheric pressure. Pentane and heavier are most often combined with the condensate / oil stream.

3.8 LNG Liquefaction

LNG liquefaction can be grouped into two main categories:

- Small to mid-scale LNG which relies on single pure refrigerants
- Large-scale LNG which relies on mixed refrigerants

Small scale LNG tends to fit niche markets such as transport fuels, energy peak shaving facilities and small scale gas developments. Technology selection for small scale LNG is dictated by the sector demands such as intermittent service, minimum capital cost (at the expense of thermal efficiency), variable loads, etc. As such they don't provide direct analogy to the CCS industry and are not discussed further here.

For large-scale LNG there are several variations of the mixed refrigerant (MR) technologies including:

- Propane pre-cool (C3MR), single mixed refrigerant,
- Dual mixed refrigerant (DMR),
- Parallel mixed refrigerant,
- Mixed Fluid Cascade Process (MFCP), and
- C3 MR with a nitrogen refrigeration cycle (AP-X) process.

The main technology providers for MR technologies are Air Products and Chemicals Inc., (APCI), Shell, Statoil / Linde, and Axens. APCI, Shell and Linde technology has been employed on recent LNG plants. The C3MR process was developed by APCI, and although other technologies have been employed in recent projects, this remains the dominant technology for the industry – over 75% of the world's LNG plants are based on this technology. AP-X is a modified version of C3MR.

Pure refrigerant technology for large scale LNG projects is for the most part limited to the ConocoPhillips Optimized Cascade Process.

3.8.1 Propane Pre-Cooled Mixed Refrigerant Process (C3MR)

The C3MR process requires two steps in liquefaction (see Figure 7) - a pre-cooling circuit using pure propane followed by a mixed refrigerant circuit to complete the liquefaction. Propane cooling is used to cool the feed gas and to pre-cool and partially liquefy the MR. The treated inlet gas stream is cooled with propane chillers to about -30 to -35°C. Propane cooling may use up to four flash stages to achieve the desired temperature and is normally conducted with shell and tube type exchangers with the feed gas and MR (Figure 6).

As the process gas stream is cooled the heavier hydrocarbons are condensed and separated producing a lean gas stream before entering the cryogenic section of the liquefaction plant. The condensed heavier hydrocarbons are sent as feed to NGL separation.
A typical mixed refrigerant will contain nitrogen, methane, ethane, ethylene and propane. The MCHE is a spiral wound heat exchanger consisting of bundles with thousands of tubes to provide sufficient surface area needed for a close temperature approach between the inlet gas and the cooling.
medium. These bundles can be classified as warm and cold bundles and are arranged in a vertical shell with the warm bundle on the bottom and the cold on top.

The high pressure mixed refrigerant is first cooled by propane and is subsequently separated into light and heavy mixed refrigerant streams. The high pressure mixed refrigerant and feed gas streams flow upward through the tube side of the MCHE while the high pressure mixed refrigerant undergoes a series of flashes dramatically reducing the temperature. The cold flashed mixed refrigerant flows counter current (shell side) to cool both the inlet gas and the inlet mixed refrigerant. A final cooling stage is accomplished through a J-T valve or hydraulic expander to further cool the liquid and remove any excess nitrogen. At this stage, the gas stream is fully liquefied to \(-160^\circ\text{C}\), and is pumped to storage. The warm vaporized MR stream is taken off the bottom (shell side) of the exchanger and enters the first stage suction of the MR compressor. The compressed MR is first cooled with air or water followed by propane before returning to the MCHE to repeat the process.

AP-X is a version of C3MR which uses a final stage of nitrogen refrigeration after the MCHE to increase the LNG capacity of the design.

### 3.8.2 ConocoPhillips Optimized Cascade® Process

Liquefaction is achieved through three stages of cooling using pure refrigerants – propane, ethylene and methane. See Figure 8. Air or water cooling condenses propane; propane condenses ethylene; ethylene condenses methane and a series of methane flashes complete the liquefaction. Similar to the C3MR process the propane cools the inlet to \(-30\) to \(-40^\circ\text{C}\). Within each refrigerant cycle, different operating pressures are established to maximize throughput and improve efficiency. By balancing the loads between the refrigerants, liquefaction is possible for a wide range of gas compositions and conditions.

The refrigerant circuits are designed with two drivers/compressors for each refrigerant which provides a wide range of turndown capacity and a high degree of availability. For the propane cycle core-in-kettle type exchangers are used. Brazed aluminium plate-fin exchangers (cold boxes) are applied mainly in the ethylene and methane cycles. All the cooling, with exception of the propane chilling, takes place in the two cold boxes.
Figure 8 ConocoPhillips Optimized Cascade LNG Liquefaction Process

Figure 9 Linde Mixed Fluid Cascade LNG Liquefaction Process
3.8.3 Statoil / Linde Mixed Fluid Cascade Process (MFCP)

A combination of cascade and mixed refrigerant technologies was developed by Statoil and Linde for the Snøhvit LNG Project in Hammerfest, Norway. This process uses three separate mixed refrigerant systems to progressively cool the gas – Precooling Mixed Refrigerant, Liquefaction Mixed Refrigerant and Sub-cooling Mixed Refrigerant. Plate-fin exchangers are used in the first two stages of cooling and final liquefaction is accomplished in spiral wound heat exchangers (SWHEs) developed by Linde. A flow schematic of the Snøhvit project is provided in Figure 9.

The 4.3 MTPA plant uses 5 LM-6000 aero derivative turbines with waste heat recovery to generate electricity for the three compressor systems. This process provides for high energy efficiency since each MR can be tuned to the various cooling curves for each refrigerant system, and the use of aero derivative turbines further reduces the energy requirements. With the generators feeding into a common power grid this provides a greater flexibility if one the drivers is down. Flexibility would be diminished if there were upsets without the electric drives. Upsets could create significant down time depending on which refrigerant system is affected. Snøhvit is the first large-scale LNG plant to use variable speed electric motors to drive the refrigeration compressors. The Snøhvit project utilized modularization to minimize the onsite construction in the remote environment of Hammerfest, Norway.

Figure 10 Shell DMR LNG Liquefaction Process

3.8.4 Shell DMR Process

Shell's Dual Mixed Refrigerant in Figure 10 is an evolution of the C3MR design, where the pure propane refrigeration circuits are replaced by a heavy MR circuit and spiral wound heat exchangers. DMR suits colder climates where the mixed refrigerant can be condensed by heat exchange with air or cooling water.
Pre-cooling of the gas occurs in spiral wound heat exchangers using the PMR, heavy mixed refrigerant. Final cooling and liquefaction of the gas occurs using LMR light mixed refrigerant in a design essentially the same as for C3MR.

DMR has been applied for the Sakhalin LNG facilities on Sakhalin Island. It is also the technology chosen for Shell’s Prelude FLNG development.

3.9 LNG Storage

Storage tanks are a significant part of the LNG project cost. There are several basic designs including single containment, double containment, and full containment tanks using 9% nickel steel inner tank. A brief description of these is contained in the following sections.

The size of tank depends upon the plant capacity, ship size, ship speed, distance to market and potential delays. Tank sizes have been increasing to achieve greater economies. Darwin LNG has a single 188,000 cubic metre tank while most plants have multiple smaller tanks. The Gladstone LNG projects each have two full-containing storage tanks of 140,000 cubic metre capacity each.

The storage capacity is predominantly determined by the desired cargo sizes and working volume desired in the tanks. Because storage capacity is primarily driven by cargo size additional tanks are normally not required as extra trains are added to the LNG facility.

3.9.1 Single Containment

This system has an inner tank made of 9% Ni steel to withstand LNG storage temperatures of -162°C and the hydrostatic pressure exerted by the LNG. The outer container is made of carbon steel and cannot withstand the cryogenic temperatures. The space between the inner tank and outer shell is filled with insulation (usually micro-spheres of perlite). Leaks from the inner tank cannot be contained and will eventually exit the tank. This type of tank requires a significant ground containment (dike) to contain liquid LNG in the event of a rupture. These tanks are typically only used in remote locations with generous separation distances from third parties.

3.9.2 Double Containment

As with the Single Containment, the inner tank in 9% Ni steel can withstand the cold temperature and the pressure of the LNG. An outer container made of concrete provides a second barrier to contain the leak. However, a leak would be vented from the tank as the pressure would increase due to vaporization.

3.9.3 Full Containment

Full Containment tanks Figure 11 have the 9% Ni steel inner tank to withstand the extreme cold and the hydrostatic pressure of the LNG.

An outer layer made of pre-stressed concrete completely encases the tank to provide a second containment system. A leak from the inner tank would be contained and vented through a relief system. Full containment tanks have become the most common tanks installed in recent projects.
3.10 Transport

LNG Transport requirements include loading systems, port facilities and shipping. Jetties, breakwaters and ports may all be required aspects of marine infrastructure for exporting LNG.

The global fleet of LNG ships has grown exponentially, going from 100 ships in 1998 to 200 in 2006, and nearing 380 by the end of 2012. The average size is close to 155,000 m$^3$, but capacity varies up to the 210,000 m$^3$ (Q-Flex) and 260,000 m$^3$ (Q-Max) of the new Qatar ships.

Similar to LNG plants, LNG tankers have been increasing in size to achieve greater economies.

1 Woodside Energy Ltd www.woodside.com.au
Tankers are basically three types:

- Moss (Spherical), Figure 12
- Membrane, Figure 13, and
- Prismatic (flat deck).

Historically, most LNG ships used spherical (Moss) tanks but the trend is now towards membrane design due to their more efficient design.

**Table 5 LNG Tankers - Typical**

<table>
<thead>
<tr>
<th>Ship Type</th>
<th>Storage Capacity</th>
<th>Ship Dimensions</th>
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<tbody>
<tr>
<td>Moss Sphere</td>
<td>127,000 m³</td>
<td>272 m x 47.3 m</td>
</tr>
<tr>
<td>Membrane Tank</td>
<td>155,000 m³</td>
<td>285 m x 43.4 m</td>
</tr>
<tr>
<td>Q-Flex</td>
<td>210,000 m³</td>
<td>315 m x 50 m</td>
</tr>
<tr>
<td>Q-Max</td>
<td>260,000 m³</td>
<td>345 m x 54 m</td>
</tr>
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</table>

The membrane tank provided greater capacity for a smaller ship size and tonnage compared to Moss sphere designs. Apart from increased capacity, the membrane tanks also incurred lower tonnage costs for use of the Suez Canal.

The Q-Flex and Q-Max ships have emphasized capacity over flexibility. Their large beam limits transport routes available.

Some examples of these tankers are shown below.

**Figure 12 -- Moss Type Tanker**
3.11 LNG Regasification

LNG receiving terminals, also called regasification facilities, receive LNG ships, store the LNG until required, and send out gaseous methane into the local pipeline grid. The main components of a regasification facility are the offloading berths and port facilities, LNG storage tanks, vaporizers to convert the LNG into gaseous phase, and pipeline link to the local gas grid Figure 14.

LNG tankers may also be offloaded offshore, away from congested and shallow ports. This is accomplished using a floating mooring system (similar to that used for oil imports) via undersea insulated LNG pipelines to a land-based regasification facility.

93 LNG regasification terminals - including 11 floating facilities - were in operation at the end of 2012. Indonesia became the 26th importing country.

At the end of 2012, the combined nominal send-out capacity of the facilities reached 668 MTPA (902 BCM/y). With 406 tanks, total storage capacity was close to 46 million m$^3$ of LNG (liquid).

Half of the world’s regasification capacity is located in Asia.

Based on the GIIIGNL report from 2012, the annual LNG consumption was 236 MTPA. The global average utilization rate of receiving installations slightly decreased to 36%, while the utilization rate of Asian terminals remained stable (around 46%) but the European rate decreased to 31%. In the Americas, the average terminal utilization rate was around 10% but only 2% in US terminals.

The low utilisation of US terminals directly reflects the shale gas revolution that has converted the US from a gas importer to a planned gas exporter. Twelve LNG import terminals were constructed on the
Gulf of Mexico and along the US eastern seaboard in the expectation that LNG imports would be required to augment local supplies and pipeline imports from Canada and Mexico. With the glut of gas available from shale gas these LNG terminals have become essentially dormant. Owners are looking to realize the value in their assets by converting the import terminals to export terminals (see Section 4.4.5).

Figure 14 – Regasification Terminal
4 THE GLOBAL STATUS OF LNG

Key Findings:
- LNG is > 30% of global natural gas movement; Gas is > 20% of global primary energy
- Both LNG and natural gas are forecast to continue recent growth
- LNG development projects implemented in “waves” with different characteristics
- National oil companies and governments led early development, major international oil companies dominate current projects, smaller companies are entering
- One-to-one trade and long-term contracts have transitioned to more diversified supply and off-take and greater short-term and spot contracts

4.1 Overview

Natural gas is a very important component of the world’s supply of energy. BP’s Energy Outlook 2030 indicates that natural gas represents more than 20% of world primary energy and its share may increase over the next decade at the expense of coal and oil.

Figure 15 World Primary Energy Mix

Source: Developed from BP Energy Outlook 2030, January 2013
Natural gas is traded by pipeline and as LNG. While pipeline supply dominates, LNG represents more than 30% of transported natural gas movements.

Figure 16 shows the major trades of LNG from supplying countries to five regional markets; namely North America, South America, Europe, India and North Asia. The majority of energy flows are to North Asia (Japan, South Korea, China, Taiwan). As existing indigenous supplies are depleted and as nations continue to develop, the trade of LNG is expected to become more distributed across the globe. Another feature will be the addition of new sources of LNG from identified gas resources in North America and the east coast of Africa. As a result the fraction of natural gas transported as LNG is expected to increase.

LNG transport allows flexibility in joining suppliers and consumers, providing opportunities to respond to short term and specific events.
Figure 16 World Trade in Liquefied Natural Gas for 2012, MTPA

Source: Developed from GIIGNL report, “The LNG Industry in 2012”
4.2 LNG Demand

The LNG industry expects a sustained increase in LNG demand over the coming decade and has committed to many new projects in recent years. A consensus view of LNG supply and demand has been compiled from a range of sources including LNG operating companies and government bodies and is shown in Figure 17.

Existing supply (orange wedge) comes from the 94 existing trains documented in Section 4.3.5. The existing supply is predicted to decline due to depletion of their gas resources. New supplies (green wedge) will come from committed LNG projects, listed in Section 4.3.6. While they represent a significant increase in supply capacity, they are expected to be well balanced with LNG demand.

LNG demand (grey wedge) has been assumed to grow at the rate observed from 2000 to 2009. The significantly higher demand growth from 2009 to present reflects a number of effects such as Japan’s phasing out of nuclear energy and may not represent long term growth demand. The high demand growth scenario incorporates elements of this effect.

Figure 17 -- LNG Supply and Demand

A majority of the new commitments have been made in Australia from both conventional and unconventional (coal seam gas) resources. The Australian LNG projects are some of the most expensive developed by the industry to date (see Section 6.1.9) and the partners in these developments have been keenly studying the LNG market from both demand and supply perspectives.

The BG Group² owns QGC which is the operator for the QCLNG project at Curtis Island in Queensland. BG Group operates as a supplier, transporter and importer of LNG and has LNG production capacity in Trinidad and Egypt. Their opinion of the market is continued growth in

² BG Group Presentation “An Asian Perspective on LNG”, Dr Anthony Barker 17 July 2013
demand, which current existing and committed plants can meet demand up to the end of this decade. After this time there will be a growing supply gap.

Santos is the operator of the Gladstone LNG project in Queensland and partner in LNG projects in Australia and PNG. They were the first mover in the coal seam gas to LNG opportunity. Their opinion on LNG supply and demand closely aligns with BG’s views.

LNG demand is forecast to increase steadily over the next decade. There are many factors driving the observed and predicted increases in LNG demand which are described below.

4.2.1 GDP growth in developing nations

The BP Energy Outlook 2030 provides an insight into the effect of GDP growth.

*Population and income growth are the key drivers behind growing demand for energy. By 2030 world population is projected to reach 8.3 billion, which means an additional 1.3 billion people will need energy; and world income in 2030 is expected to be roughly double the 2011 level in real terms. Low and medium income economies outside the OECD account for over 90% of population growth to 2030. Due to their rapid industrialisation, urbanisation and motorisation, they also contribute 70% of the global GDP growth and over 90% of the global energy demand growth.*

Many of the non-OECD countries have transitioned from controlled economies to more free-market environments, which has been a part of this sustained growth in energy demand.

4.2.2 Depletion of Local Gas Resources

As local gas supplies are depleted there is a need to import energy from further afield. The UK has substantially depleted its indigenous gas resources in the North Sea in fulfilling local market demand. While major gas pipelines have been constructed which link Europe to the UK, there is still a requirement for alternative sources of gas. Approximately one third of the UK’s energy imports are through LNG (the balance being by pipeline). The UK is expected to increase LNG imports as its indigenous gas supplies continue to decline.

4.2.3 Conversion to Natural Gas

Natural gas is a versatile energy source and is the cleanest-burning fossil fuel, producing significantly lower carbon emissions than coal or oil. Natural gas has made up a large portion of new electric power generation capacity in recent years, particularly in countries which impose a cost for carbon emissions.

Natural gas is ideally suited to peaking power and intermittent power generation. Natural gas can be used in gas turbines which allow rapid starting and stopping of power generation. These gas turbine power generation plants also have lower capital cost requirements and can be constructed in smaller sizes than base scale power generation facilities using coal or nuclear fuel as energy sources.

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3 Santos Presentation “CLSA Investors’ Forum” Hong Kong, September 2013
4.2.4 Shutdown of Nuclear Power Generation Plants

The Fukushima Daiichi nuclear accident resulted in all nuclear power generation plants in Japan to be shut-down in response to the radioactive releases from the site. Nuclear power supplied 30% of Japan’s energy needs prior to the accident. With public opinion firmly against nuclear power generation in Japan, idled nuclear power plants are not expected to restart in the foreseeable future and many of the plants will be decommissioned.

LNG imports to Japan have doubled to offset the shortfall in electrical power generation from the nuclear power plants and now represent approximately half of the energy mix for electrical power generation.

4.2.5 Security of Energy Supply

Europe has become a major importer of energy from surrounding countries as its indigenous energy sources have depleted. As a result Europe has become dependent on a small number of large capacity gas pipelines from the east to supply its energy needs. A trade dispute between Russia and Ukraine resulted in gas transmissions to Europe being briefly shut-in – alerting the region to trade risks.

LNG imports have been an important tool in providing security of energy supply. LNG imports can be made from a broad range of suppliers into the Atlantic basin including Trinidad, Nigeria, Algeria and the Middle East.

4.2.6 Supply Flexibility and Pricing Signals

LNG is now traded in both long-term contracts and short term or spot cargoes. The short term trades allow more direct market responses to demand and pricing signals. For example a shortfall in other energy supplies can be compensated by buying LNG cargoes on a spot basis. An example is a cold spell in Korea can result in additional spot imports above the long term contract imports. Similarly, LNG can be imported to India to increase power generation capacity and meet a shortfall in local gas production.

4.2.7 Trends in LNG Demand

Overall world energy demand will continue to grow as developing nations increase their energy demands. Natural gas, along with renewables, is predicted to increase its share of the energy mix, particularly for power generation. With local gas resources in Europe depleting and a shortage of gas resources in northern Asia long distance transportation of gas is expected to increase to the advantage of LNG.

Without an extreme event, world LNG demand is expected to maintain a steady growth for the foreseeable future.
4.3 LNG Supply

4.3.1 The First LNG Plants (1960s-70s)

The first large-scale LNG plants were created to commercialise large gas resources that were stranded by distance to market. The first large scale, base load LNG plants in Algeria and Libya were constructed on the back of large non-associated gas resources.

The energy crisis of the 1970’s, when crude oil supplies were constrained, led to import dependent countries such as Japan seeking alternative energy supplies. Large gas discoveries in Malaysia, Indonesia and Brunei became an ideal source of alternative energy supplies as LNG. The governments of Malaysia, Indonesia and Brunei and their national oil companies were critical in getting the initial projects initiated. These original projects were base load LNG facilities with long term contracts for supply of LNG. They were one-to-one relationships between suppliers and users and required the construction of LNG processing facilities and corresponding LNG import facilities – connected by dedicated LNG carriers.

LNG supply grew in line with LNG demand by progressively adding LNG trains to these existing facilities. For example, Malaysia’s LNG facility at Bintulu has grown to 8 LNG trains and more than 22 MTPA nameplate capacity.

4.3.2 The Second Wave of LNG Projects (1980s-90s)

LNG sales from Australia commenced in 1989, through the North West Shelf Project, which developed liquids rich gas in the Rankin field. The North West Shelf project was one of the first to be developed predominantly by industry rather through the actions of governments and their national oil companies. While the project was led by Woodside, the backing of the partners was critical – Shell, Chevron, BP, BHP Billiton, Mitsui and Mitsubishi. The project required the combined efforts of some of the largest independent oil companies in the world and the assistance of the importers to share the risk and provide the credibility required to finance the project.

LNG from the North West Shelf Project was committed to eight Japanese utility customers under 20 year contracts. These long-term contracts underpinned the construction of the North West Shelf Project’s LNG export facilities at the Karratha Gas Plant in Western Australia in 1985 and the subsequent first delivery of LNG cargoes to Japan in August 1989.

The Middle East, and in particular Qatar, saw opportunities to commercialise their stranded gas resources. Qatar was relatively gas rich and oil poor compared to its neighbours in the region and sought to commercialise the gas in one of the largest gas fields in the world, the North Field. Qatar first exported LNG in 1997 and has grown its industry to be the leading exporter of LNG. Again government backing and national gas companies were critical in getting the project initiated.

While Qatar was much further from both the existing Atlantic and Pacific basin customers, it saw opportunities to capitalise on its large, relatively cheap gas resource. Qatar has worked extensively on energy and capital efficiency, driving the size of the LNG trains installed. For example the AP-X (Qatar Gas 2) technology train has a single train capacity of 7.8 MTPA, approximately 50% larger than industry standard trains.

Trinidad and Tobago’s LNG industry commenced exports in 1999 with the backing of the government. It supplies into the Atlantic basin, supplying North America, South America and Europe.
4.3.3 Recent LNG Developments

A number of recent projects have been initiated to capture gas that was previously being flared. Part of Angola LNG’s gas supply is coming from the northern Cabinda area, capturing gas that was being flared from oil production.

Similarly Nigerian LNG’s plants at Bonny Island receive associated gas from existing oil operations that was being flared.

With extensive LNG import terminal infrastructure available world-wide, there is a trend towards more customers per LNG facility, allowing increased diversification for LNG importers. As noted in BP’s Energy Outlook 2030, both the number of customers per exporter and number of suppliers per importer have increased from the industry’s early days. Typically each LNG facility is supplying to 8 different importers and each importer is receiving LNG from 6 different suppliers.

The diversification has extended to include more countries supplying into the market. Recent LNG projects have been constructed in Angola, Australia, Egypt, Equatorial Guinea, Indonesia, Nigeria, Norway, Papua New Guinea, Peru, Oman and Yemen. Many of these countries are joining the ranks of LNG exporters for the first time, increasing diversification of the supply market.

4.3.4 Unconventional Gas Sources

Unconventional gas sources are beginning to influence the LNG market both from a supply perspective and due to displacement of LNG imports. All the recent headlines have been focussed on unconventional gas in North America leading to a gas glut and displacement of virtually all LNG imports. Gas that was being piped into the USA from Canada is now seeking alternative markets and initial studies are underway for LNG exports from the west coast of Canada to the northern Asian market.

However before shale gas there has been a coal seam gas unconventional story. In the mid 2000’s projects were being studied for a pipeline from PNG to Queensland to supply natural gas to power generation and industrial users. Queensland’s conventional natural gas resources were in decline and sources from central Australia could not be committed to Queensland’s long term energy needs.

At the same time, the coal seam gas industry was experimenting with the best methods for accessing and producing the unconventional gas in Queensland’s substantial black coal resources. After more than two decades of experimentation and trialling of new technology, reliable methods of accessing the gas were identified. The successful development of the coal seam gas secured Queensland’s gas supply and led to the PNG to QLD gas pipeline project being abandoned. It directly led to the PNG LNG project in Papua New Guinea being initiated to commercialise the PNG gas assets.

Once the coal seam gas resource was assessed in the light of the new technology it was evident that the gas resource in Queensland far exceeded the state’s demand and the operating companies had more than 100 years of domestic production capacity available. Santos was one of the first companies to identify the opportunity to establish an LNG export industry. The LNG project would allow the timely production of the gas resource and also realise international gas prices. With the commitment to the LNG projects (and even prior to exports commencing) long-term gas prices in Eastern Australia have more than doubled.

The Queensland coal seam gas resource is arguably inferior to conventional LNG developed in the world to date. This is because the gas is characterised by having no liquid content and therefore no secondary product market available (all other projects generate hydrocarbon condensate which is a
valuable product in its own right). The coal seam gas industry requires many wells to be drilled to access the resource and has a higher input cost than many projects. Finally, development costs in Queensland are high due to the high labour costs - Australia and Norway are the only developed countries that export LNG in significant quantities. The US is expected to join this group in 2016 with the Sabine Pass development.

4.3.5 Listing of LNG Facilities

A list of LNG base load facilities is shown in the following table.
## Table 6 LNG Liquefaction Facilities – Worldwide

<table>
<thead>
<tr>
<th>Country</th>
<th>Facility</th>
<th>Owner</th>
<th>Number of Trains</th>
<th>Nameplate Capacity (MTPA)</th>
<th>Start Year</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Atlantic Basin</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.</td>
<td>Algeria Arzew GL-1Z (Bethouia)</td>
<td>Sonatrach</td>
<td>6</td>
<td>7.9</td>
<td>1981</td>
</tr>
<tr>
<td>2.</td>
<td>Algeria Arzew GL-2Z (Bethouia)</td>
<td>Sonatrach</td>
<td>6</td>
<td>8.3</td>
<td>1972</td>
</tr>
<tr>
<td>3.</td>
<td>Algeria Skikda GL1K</td>
<td>Sonatrach</td>
<td>3</td>
<td>3.2</td>
<td>1972</td>
</tr>
<tr>
<td>4.</td>
<td>Angola Angola LNG</td>
<td>Angola LNG</td>
<td>1</td>
<td>5.2</td>
<td>2013</td>
</tr>
<tr>
<td>5.</td>
<td>Egypt Egyptian LNG (Idku)</td>
<td>British Gas et al</td>
<td>2</td>
<td>7.2</td>
<td>2005</td>
</tr>
<tr>
<td>6.</td>
<td>Egypt SEGAS Damietta</td>
<td>SEGAS</td>
<td>1</td>
<td>5.0</td>
<td>2005</td>
</tr>
<tr>
<td>7.</td>
<td>Libya Marsa El Brega</td>
<td>Sirte Oil Company</td>
<td>4</td>
<td>3.2 (currently shut-in)</td>
<td>1970</td>
</tr>
<tr>
<td>8.</td>
<td>Nigeria Bonny Island (T1-T6)</td>
<td>Nigerian LNG Ltd</td>
<td>6</td>
<td>21.0</td>
<td>1999</td>
</tr>
<tr>
<td>9.</td>
<td>Equatorial Guinea EG LNG Project (Bioko Island)</td>
<td>Marathon</td>
<td>1</td>
<td>3.7</td>
<td>2007</td>
</tr>
<tr>
<td>10.</td>
<td>Norway Hammerfest</td>
<td>Statoil</td>
<td>1</td>
<td>4.3</td>
<td>2007</td>
</tr>
<tr>
<td>11.</td>
<td>Trinidad &amp; Tobago Atlantic LNG (T1-T4)</td>
<td>Atlantic LNG</td>
<td>4</td>
<td>15.5</td>
<td>1999</td>
</tr>
<tr>
<td><strong>Atlantic Basin</strong></td>
<td></td>
<td></td>
<td>35</td>
<td>84.5</td>
<td></td>
</tr>
<tr>
<td>Country</td>
<td>Facility</td>
<td>Owner</td>
<td>Number of Trains</td>
<td>Nameplate Capacity (MTPA)</td>
<td>Start Year</td>
</tr>
<tr>
<td>-----------</td>
<td>------------------------------</td>
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<tr>
<td>Pacific Basin</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12.</td>
<td>Australia</td>
<td>NWS Australian LNG (T1-T5) (Whitnell Bay)</td>
<td>Woodside</td>
<td>5</td>
<td>16.4</td>
</tr>
<tr>
<td>13.</td>
<td>Australia</td>
<td>Darwin LNG</td>
<td>ConocoPhillips</td>
<td>1</td>
<td>3.4</td>
</tr>
<tr>
<td>14.</td>
<td>Australia</td>
<td>Pluto</td>
<td>Woodside</td>
<td>1</td>
<td>4.3</td>
</tr>
<tr>
<td>15.</td>
<td>Brunei</td>
<td>Lumut</td>
<td>Brunei LNG</td>
<td>5</td>
<td>7.1</td>
</tr>
<tr>
<td>16.</td>
<td>Indonesia</td>
<td>Arun (Phase 1-3)</td>
<td>PT Arun NGL</td>
<td>2</td>
<td>4.2</td>
</tr>
<tr>
<td>17.</td>
<td>Indonesia</td>
<td>Bontang A-H (Kalimantan)</td>
<td>PT Badak NGL</td>
<td>8</td>
<td>22.3</td>
</tr>
<tr>
<td>18.</td>
<td>Indonesia</td>
<td>Tangguh</td>
<td>BP</td>
<td>2</td>
<td>7.6</td>
</tr>
<tr>
<td>19.</td>
<td>Malaysia</td>
<td>Bintulu MLNG 1 (Satu)</td>
<td>PETRONAS</td>
<td>3</td>
<td>8.1</td>
</tr>
<tr>
<td>20.</td>
<td>Malaysia</td>
<td>Bintulu MLNG 2 (Dua)</td>
<td>PETRONAS</td>
<td>4</td>
<td>9.3</td>
</tr>
<tr>
<td>21.</td>
<td>Malaysia</td>
<td>Bintulu MLNG 3 (Tiga)</td>
<td>PETRONAS</td>
<td>2</td>
<td>6.8</td>
</tr>
<tr>
<td>22.</td>
<td>Russia</td>
<td>Sakhalin 2</td>
<td>Sakhalin LNG</td>
<td>2</td>
<td>9.6</td>
</tr>
<tr>
<td>23.</td>
<td>Peru</td>
<td>Peru LNG</td>
<td>Hunt Oil</td>
<td>1</td>
<td>4.45</td>
</tr>
<tr>
<td>24.</td>
<td>US</td>
<td>Kenai</td>
<td>ConocoPhillips</td>
<td>1</td>
<td>1.5 (shutdown)</td>
</tr>
</tbody>
</table>

**Pacific Basin**

<table>
<thead>
<tr>
<th>Country</th>
<th>Facility</th>
<th>Owner</th>
<th>Number of Trains</th>
<th>Nameplate Capacity (MTPA)</th>
<th>Start Year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Pacific Basin</td>
<td>37</td>
<td>105</td>
<td></td>
</tr>
<tr>
<td>Country</td>
<td>Facility</td>
<td>Owner</td>
<td>Number of Trains</td>
<td>Nameplate Capacity (MTPA)</td>
<td>Start Year</td>
</tr>
<tr>
<td>------------------------</td>
<td>------------------</td>
<td>------------------</td>
<td>------------------</td>
<td>---------------------------</td>
<td>------------</td>
</tr>
<tr>
<td><strong>Middle East</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25. Oman</td>
<td>OLNG</td>
<td>Oman LNG</td>
<td>2</td>
<td>7.1</td>
<td>2000</td>
</tr>
<tr>
<td>26. Oman</td>
<td>Qalhat LNG</td>
<td>Qalhat LNG</td>
<td>1</td>
<td>3.6</td>
<td>2006</td>
</tr>
<tr>
<td>27. Qatar</td>
<td>QatarGas I</td>
<td>QatarGas</td>
<td>3</td>
<td>9.5</td>
<td>1999</td>
</tr>
<tr>
<td>28. Qatar</td>
<td>QatarGas II</td>
<td>QatarGas</td>
<td>2</td>
<td>15.6</td>
<td>2009</td>
</tr>
<tr>
<td>29. Qatar</td>
<td>QatarGas III</td>
<td>QatarGas</td>
<td>1</td>
<td>7.8</td>
<td>2010</td>
</tr>
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<td>30. Qatar</td>
<td>QatarGas IV</td>
<td>QatarGas</td>
<td>1</td>
<td>7.8</td>
<td>2011</td>
</tr>
<tr>
<td>31. Qatar</td>
<td>Rasgas I</td>
<td>Rasgas</td>
<td>2</td>
<td>6.60</td>
<td>1999</td>
</tr>
<tr>
<td>32. Qatar</td>
<td>Rasgas II</td>
<td>Rasgas</td>
<td>3</td>
<td>14.1</td>
<td>2004</td>
</tr>
<tr>
<td>33. Qatar</td>
<td>Rasgas III</td>
<td>Rasgas</td>
<td>2</td>
<td>15.6</td>
<td>2009</td>
</tr>
<tr>
<td>34. United Arab Emirates</td>
<td>ADGAS (Das Island I &amp; II)</td>
<td>ADGAS</td>
<td>3</td>
<td>5.80</td>
<td>1977</td>
</tr>
<tr>
<td>35. Yemen</td>
<td>Balhaf</td>
<td>Yemen LNG</td>
<td>2</td>
<td>6.7</td>
<td>2009</td>
</tr>
<tr>
<td><strong>Middle East</strong></td>
<td></td>
<td></td>
<td>22</td>
<td>100.2</td>
<td></td>
</tr>
<tr>
<td><strong>Worldwide</strong></td>
<td></td>
<td></td>
<td>94</td>
<td>289.7</td>
<td></td>
</tr>
</tbody>
</table>

Note that not all nameplate capacity is currently available to the market due to shortfall in gas supplies.
4.3.6 New LNG Facilities

The following projects have either been approved (received their financial investment decision approval) or under construction.

Table 7 LNG Liquefaction Facilities – Approved or Under Construction

<table>
<thead>
<tr>
<th>Country</th>
<th>Facility</th>
<th>Owner</th>
<th>Number of Trains</th>
<th>Capacity (MTPA)</th>
<th>Planned Start Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Algeria</td>
<td>Skikda GL2K</td>
<td>Sonatrach</td>
<td>1</td>
<td>4.5</td>
</tr>
<tr>
<td>2.</td>
<td>Australia</td>
<td>QLD Curtis LNG</td>
<td>BG</td>
<td>2</td>
<td>8.5</td>
</tr>
<tr>
<td>3.</td>
<td>Australia</td>
<td>Australia Pacific LNG</td>
<td>ConocoPhillips</td>
<td>2</td>
<td>9.0</td>
</tr>
<tr>
<td>4.</td>
<td>Australia</td>
<td>Gladstone LNG</td>
<td>Santos</td>
<td>2</td>
<td>7.8</td>
</tr>
<tr>
<td>5.</td>
<td>Australia</td>
<td>Gorgon LNG</td>
<td>Chevron</td>
<td>3</td>
<td>15.0</td>
</tr>
<tr>
<td>6.</td>
<td>Australia</td>
<td>Wheatstone LNG</td>
<td>Chevron</td>
<td>2</td>
<td>8.9</td>
</tr>
<tr>
<td>7.</td>
<td>Australia</td>
<td>Ichthys LNG</td>
<td>Inpex</td>
<td>2</td>
<td>8.4</td>
</tr>
<tr>
<td>8.</td>
<td>Australia</td>
<td>Prelude FLNG</td>
<td>Shell</td>
<td>1</td>
<td>3.6</td>
</tr>
<tr>
<td>9.</td>
<td>Columbia</td>
<td>Caribbean FLNG</td>
<td>Exmar</td>
<td>1</td>
<td>0.5</td>
</tr>
<tr>
<td>10.</td>
<td>Indonesia</td>
<td>Tangguh T3</td>
<td>BP</td>
<td>1</td>
<td>3.8</td>
</tr>
<tr>
<td>11.</td>
<td>Indonesia</td>
<td>Sengkang/ Donggi-Senoro</td>
<td>EWC</td>
<td>2</td>
<td>4.0</td>
</tr>
<tr>
<td>12.</td>
<td>Malaysia</td>
<td>Kanowit FLNG</td>
<td>PETRONAS</td>
<td>1</td>
<td>1.2</td>
</tr>
<tr>
<td>13.</td>
<td>PNG</td>
<td>PNG LNG</td>
<td>ExxonMobil</td>
<td>2</td>
<td>6.9</td>
</tr>
<tr>
<td><strong>Approved and Under Construction</strong></td>
<td><strong>26</strong></td>
<td><strong>100.1</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
4.4 Key LNG Projects

Each of the following projects represents a step-out in either technology or complexity compared to conventional base-load LNG facilities. Refer to 0 for datasheets on these key LNG projects.

4.4.1 Gorgon

The Gorgon LNG project is being constructed on Barrow Island, which is substantially covered by a nature reserve. The nature reserve has imposed significant constraints on the project:

- Constrained project footprint, which limits the amount and extent of infrastructure that can be constructed
- Rigorous quarantine management for all people and materials moving to site, to protect the nature reserve

The project is also handling a relatively impure feed stream which requires additional processing to meet LNG specifications. One key impurity is CO$_2$. The Gorgon project has committed to sequestering the CO$_2$ in a saline aquifer below Barrow Island. The project website states:

“The Gorgon joint venture is investing approximately $2 billion in the design and construction of the world’s largest commercial-scale CO$_2$ injection facility to reduce the project’s overall greenhouse gas emissions by between 3.4 and 4.1 million tonnes per year.”

The project will receive its entire feed from subsea wells. While this has been done before at the Snøhvit development in Norway, it has never been done before at this scale. Gorgon will be a factor of 4 times larger than Snøhvit in terms of LNG capacity.

The project has experienced significant cost growth. The cost estimate for the project has surged to $US52 billion, from $US37 billion when the project was sanctioned in September 2009. The contributions to this escalation include the project-specific constraints stated above and also general LNG and upstream industry cost escalation in this timeframe, which is discussed in Section 6.1.9.

4.4.2 Ichthys

The Ichthys development is being led by Inpex. Part of Inpex desire to be involved in the project is the ability to integrate the project vertically into its LNG import facilities in Japan. The Ichthys project will introduce a number of novel features. Ichthys will rely on a semi-submersible central production facility in the field – this will be one of the largest semi-submersibles ever constructed and will be located in a region prone to cyclones.

The gas transmission pipeline will carry gas from the central production facility 885 km to the LNG plant at Darwin. This will be longest LNG plant feed pipeline ever constructed.

4.4.3 Prelude Floating LNG

Shell is developing the Prelude field using a floating LNG facility. Depending on timing, this may be the first or second such facility every installed. The scale of the facility is enormous. Shell’s Prelude website states:

Longer than four soccer fields and displacing six times as much water as the largest aircraft carrier, the FLNG facility will be the biggest floating production facility in the world.
Despite its size, this will be a relatively modest LNG facility with a nameplate capacity of 3.6 MTPA. Furthermore, expansion opportunities are not possible with this facility – it is a one train facility only.

Prelude is very important to the industry. For example Woodside has recently committed to floating LNG production facilities for its Browse development nearby, turning away from a conventional shore based LNG facility because development costs had risen too far and land access was proving difficult. Three floating facilities will be required to develop the three fields in the block. Woodside has also considered floating LNG for its Sunrise development further east, in the Zone of Cooperation with Timor.

4.4.4 West Coast – North America

The shale gas revolution in the USA has led to a surplus of gas in the USA and Canada. While the surplus may be short term, the operators of the surplus gas are looking actively at opportunities to commercialise the gas.

Figure 18 Proposed and Approved LNG Export Facilities - US

The environmental approvals process in the USA is likely to prevent any LNG plants being constructed on the US west coast and LNG export through British Columbia is seen as being the easiest path to market. Projects are being investigated at Kitimat by Apache/Chevron (Kitimat LNG) and Shell (LNGCanada). A project is also being investigated on Prince Rupert Sound by PETRONAS (PacificNorthWestLNG).

The projects will have relatively short supply lines to the northern Asian markets.

4


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4.4.5 East Coast – North America

Shale gas has led to the LNG import terminals on the east coast of the USA becoming redundant or with very low demand. These facilities are looking to realise a credible return on their investment by reversing their operation (exporting LNG rather than importing).

Four export projects have been approved to date at Sabine Pass, Freeport, Lake Charles and Dominion Cove. The US government is discussing a further 21 applications for export.

In May 2013, Cheniere Energy announced that they had completed all milestones to start construction on the first four liquefaction trains being developed by Sabine Liquefaction. Preparatory construction on Trains 1 and 2 commenced in August 2012 and is approximately 30% complete. Construction on Trains 3 and 4 will commence shortly. Each train will produce 4.5 MTPA and first LNG is expected to be delivered by late 2015/early 2016.

With these facilities, the USA will turn from an LNG importer to an LNG exporter. The projects located on the Gulf of Mexico coastline will have the ability to supply the Atlantic basin and the Pacific basin (through the Panama Canal).

4.5 Liquefaction Capacity

Beginning with the first commercial-scale liquefaction export plant at Arzew in Algeria in 1964, global liquefaction capacity grew slowly if not steadily, reaching about 100 MTPA in the early 1990s and about 140 MTPA by 2000. But between 2000 and 2012, liquefaction capacity more than doubled to almost 290 MTPA, driven primarily by the series of massive LNG developments in Qatar and the early Australian developments. [Note, capacities here are liquefaction production capacity, not consumption demand.]

Over the last five decades, industry has seen a progressive broadening of the LNG supply base, with three waves of suppliers. The first wave was dominated by Algeria, Malaysia and Indonesia, which still collectively accounted for more than 60% of total LNG capacity as recently as 10 years ago, but which are expected to drop to about 20% of total capacity by 2020 due to a combination of declining output from these facilities and the increasing production capacity from new plants being added to the world market.

The second wave has been dominated by Qatar and Australia, which have been rising rapidly from about 20% of global LNG capacity in 2000 and are expected to account for about 50% of total global capacity by 2020. A huge wave of Australian LNG projects are slated for the second half of this decade. In the three years from late 2009, Australian operators have sanctioned more than 60 MTPA of green-field LNG projects — equivalent to about 25% of current global LNG demand. However, the overabundance of proposed but unsanctioned projects, are unlikely to proceed without secure off-take commitments.

The third wave could come from as many as 25 other countries, many of which currently have little or no capacity. Importantly, with the third wave, smaller operators are becoming increasingly involved with what used to be the exclusive domain of the major International Oil Companies (IOCs) and National Oil Companies (NOCs).
4.6  Technology Licensing

Several contractors have arrangement with Air Products and Chemicals Inc (APCI), to build propane pre-cool mixed refrigerant plants. These are KBR/JGC, Foster Wheeler, Chiyoda, and Technip. APCI is not limited to these. Any contractor can license and build an LNG plant assuming they have the expertise. APCI does not work with Bechtel or Linde which are competitors. The licensing fees associated with the LNG facilities are based on the service required and the size of plant.

APCI performs four levels of service including preliminary studies, engineering studies, equipment agreement, and technical services for start-up and commissioning. They do not provide detailed engineering for the refrigerant compressors. There are different fee structures for the various levels of service.

The main cryogenic heat exchanger is included in the equipment license. In return, APCI will perform the main heat exchanger design and construction, supply other pertinent data and assistance in the process design. Also, APCI will provide equipment and process guarantees. These agreements may be initially executed with the contractor or the owners, but there is one license agreement per train. The patents have expired on the propane pre-cooled mixed refrigerant process which allows other companies to build plants with this process. Subsequently, Shell Global Solutions provide a similar service for C3MR and dual mixed refrigerant plants.

ConocoPhillips offers a similar Licensing arrangement for the Optimized Cascade Process with Bechtel as the exclusive EPC contractor. In return for the Licensing fee ConocoPhillips/Bechtel will provide the liquefaction design, process guarantees, and performance guarantees, as well as start-up and project assistance.

4.7  Long Term Trends in the LNG Industry

4.7.1  Decline in Base Load Suppliers

Some of the original LNG developments in the 1970s and 1980s are reaching the end of their life, driven by the decline in gas supply to the facilities. In particular, the Indonesian LNG facilities at Arun and Bontang are in steady decline. Arun is planned to be converted to an LNG import terminal in the near future. Bontang requires new upstream gas developments to supply into the plant.

The North West Shelf project in Australia has extended its life by installing additional compression facilities at the North Rankin platform. However, this extends the plateau production to the early 2020’s before decline will commence. Given the majority of the surrounding gas is committed to other LNG developments in the area (Pluto, Gorgon, Wheatstone) there is a possibility that the North West Shelf project could also commence decline in the medium term.

4.7.2  LNG Liquefaction Technology and Capacity

Considerable development has occurred in LNG liquefaction technology over several decades, primarily to increase energy efficiency. This has generally corresponded with an increase in LNG train size. The two primary competing technologies for large scale LNG, APCI’s C3MR process and ConocoPhillips’ Optimized Cascade, give comparable efficiencies at their optimal sizes.

The core elements of the LNG plants are the cryogenic heat exchangers and the refrigeration compressors. Both are at design limits until further basic development occurs.
The refrigeration compressors are tied to the capacity of the industrial gas turbines that drive them. At present the largest available gas turbines are GE’s Frame 9 units. These units were initially for electrical power generation only (available since 1978) and GE have only recently developed mechanical drive units making them suitable for LNG refrigeration service (QatarGas 2009).

One possible trend is for the use of large aero-derivative turbines. While the largest units (such as Rolls Royce Trent) are only approximately half the size of the largest industrial gas turbines, they have several advantages:

- Improved thermodynamic efficiency
- Reduced planned maintenance downtime (by using replacement hot sections)

Shell has advanced the use of Dual Mixed Refrigerant systems as a way of increasing plant capacity. It is particularly beneficial in colder climates which can improve the thermodynamic efficiency in condensing the refrigerant. The technology was used on the Sakhalin LNG project (Sakhalin II). With a range of Arctic projects being considered in Russia, Alaska and Canada there is scope for increased thermal efficiency.

### 4.7.3 Source Gas Impurities

Many new projects have to deal with increased levels of impurities in the feed gas stream, compared to the original LNG projects. Gorgon took many years for the project to be sanctioned, partly because of the high CO₂ and N₂ content of the feed gas. In part, Gorgon became attractive when it was combined with the Io/Jansz fields which had lower levels of impurities.

CO₂ removal requires extensive processing facilities and is energy intensive. The CO₂ must be removed to low levels to preventing freezing in the cryogenic process.

N₂ is normally removed at the last stage of the LNG process (in the final flash before run down to storage) and is a parasitic load on the refrigeration system without benefiting LNG capacity.

Qatar’s North Field has shown that these impurities are not an obstacle in themselves – North Field has high levels of H₂S which must be removed and disposed of.

### 4.7.4 Floating LNG

Shell’s Prelude development will be the vanguard of large scale, floating LNG. Shell already has plans to roll out multiple units once the initial development has been proven. The first unit will be required to perform a number of first-of-a-kinds such as marining of the LNG liquefaction facilities (adapting the technology to the dynamics of a ship) and open water LNG transfers to the LNG carriers. It also requires a degree of compactness that will affect operability, maintainability and safety.

Once the lessons have been learned and incorporated into subsequent designs, the benefits of floating LNG can be realised:

- Standardised design, allowing rapid development of stranded gas fields
- Relatively low construction costs because fabrication and construction occur in a shipyard environment, rather than in a remote location
While most of the industry is waiting to see the outcome of Prelude, some players such as Woodside are already relying on the success of the concept by committing to floating LNG for the Browse area.

4.7.5 East Coast Africa

Industry focus has turned to the east coast of Africa, covering Uganda, Mozambique, Tanzania and Kenya. There have been numerous large discoveries offshore, far exceeding the capacity of the local market for natural gas. All of the countries are keen to initiate these projects as part of a nation-building development – in particular, the projects would need to invest in infrastructure such as ports, airports, warehousing and camps/towns.

The east coast of Africa is expected to become a major LNG province over the next two decades. The locations of the nations mean that they can supply both the Atlantic and Pacific basin markets.

4.7.6 LNG Contracting and Marketing

The LNG spot and short-term market has increased exponentially over the last 10 years and now represents 20 per cent of the total global market for LNG. In part this has been driven by Japan’s response to the Fukushima accident and shut down of its nuclear power generation facilities. But it is also a response to the maturity of the market. The number of LNG facilities supplying into the world-wide market has increased dramatically in recent years. Correspondingly, the number of LNG import facilities has also increased dramatically and significantly exceeds the industry’s production capacity.

This flexibility has allowed trading markets in LNG to develop. It also means that LNG projects are not relying on base contracts to be secured prior to project sanction to the same extent as the original developments. Producers are more willing to continue marketing negotiations after sanction knowing that alternative market outlets exist.

This trend of increasing use of LNG spot markets is likely to continue.

4.7.7 US as an Energy Exporter

The US has a surplus of natural gas due to the commercialisation of shale gas production with new production techniques. In the short term this has led to a major fall in the price of natural gas in the US, as seen in the benchmark price of Henry Hub gas. US LNG importers have seen their market vanish in the space of 5 years and are looking at ways of realizing the value locked up in their import terminals. Sabine Pass is leading the way to realize the value by becoming an exporter of LNG through their terminal.

Small scale exports of natural gas as LNG will have only a small impact on the price of natural gas in the US but once more LNG export projects are developed it is likely that natural gas prices in the US will rise to reflect the international price that can be realized through LNG trading. Domestic consumers of energy in the US are also rapidly transitioning to natural gas to the detriment of alternative energy sources such as coal. Once natural gas prices start rising it is likely that domestic lobby groups will influence subsequent approvals of LNG export licences. It is likely that the US LNG export industry will naturally be capped by market forces in natural gas pricing.

However it is certain that in the near to mid-term the US will be an energy exporter and that LNG imports to the US will be negligible.
5 THE CCS VALUE CHAIN

Key Findings:
- Status and volume of projects correspond to very small fraction of emissions reduction targets
- Maturity of CCS now may be similar to LNG corresponding maturity in 1960s to 1970s
- Capture technologies are typically classified Pre-Combustion, Post-Combustion and Oxyfuel
- Projects in operation and construction are dominated by capture from Natural Gas and Synthesis Gas processing – similar to Pre-Combustion Acid Gas Removal

5.1 Carbon Capture and Storage Value Chain

The CCS value chain can be described by Figure 19 below, beginning with the extraction of the fuel or mineral ores (raw materials), transport of fuel or raw materials, converting the fuel or raw materials to useful energy or finish goods, capturing of the produced CO₂, intermediate storage and transport of the CO₂ and finally CO₂ Storage (injection and sequestration) in large geological reservoirs.

Figure 19 – The CCS Value Chain

 CCS is often mistakenly perceived as an unproven or experimental technology. In reality, the technology is well understood and has been used for decades at a large scale in certain applications. For example:
- Large-scale CO₂ separation is performed in gas processing and many industrial processes
- CO₂ pipelines are an established technology, on land and under the sea
- Large-scale injection and geological storage of CO₂ has been safely performed in saline reservoirs for more than 15 years, and in oil and gas reservoirs for decades.

There are currently 12 operational large-scale CCS projects around the world, which have the capacity to prevent 25 (MTPA) of CO₂ from reaching the atmosphere. This quantity is approximately
equivalent to CO₂ emissions of six 500 MW coal fired power generators, which is a very small fraction of total CO₂ emissions. This may support the view that CCS current market development may be compared to the level of maturity that the LNG industry had in approximately the 1960s to 1970s.

The Global CCS Institute’s report on The Global Status of CCS: 2013\textsuperscript{5} report has identified 65 large-scale integrated projects (LSIP) in 2013.

Common to all is that CCS projects require energy input (energy demand) that gives rise to quantifiable energy penalties. The different solutions supply this energy demand in different ways, affecting the upstream value chain. The main energy demand for pre-combustion capture and oxy-fuel is the air-separation process (for gasification or oxy-firing). For post-combustion capture, the main energy demand is the process of regeneration of absorption solvent. For all the three CCS technology routes there is also an additional energy demand for CO₂ compression.

There are many stakeholders in the CCS value chain described above. In addition to the owners/operators and suppliers of the different steps in the chain; regulators, NGOs, financial institutions, consumers and others are also stakeholders. An overview is given in Figure 20. All the different stakeholders have different interests and concerns; this introduces risks for the various operators.

**Figure 20 - List of major stakeholders**

For the power plant or industrial processes production owner / operator, there is an opportunity to reduce the cost of CO₂ management where there is a significant cost of CO₂ emissions. However, that party is at the same time exposed to risks such as the future costs of depositing CO₂, variations in fuel costs, electricity prices, CO₂ taxation and the value of CO₂ allowances. For the capture plant owner / operator, (which can be the same entity as the power plant or industrial processes production owner / operator), the business opportunity is to reduce CO₂ cost by capturing CO₂ while handling the risks associated with the capture plant’s capital, operational costs, uptime and tariffs. For the pipeline or transport owner / operator, the business opportunity is to generate profit by transporting CO₂ while also handling the construction cost risks and technical risks such as flow assurance, corrosion and mechanical damages. For the storage owner / operator, the business opportunities are to generate profit by injecting and safely storing CO₂ in geological formations or increase revenue from enhanced

\textsuperscript{5} The Global CCS Institute 2013, “The Global Status of CCS: 2013”
oil recovery (EOR). The risks associated with CO\(_2\) include reservoir feasibility, containment measurement, monitoring and verification and the transfer of responsibility once the injection stops. For the storage owner / operator and pipeline or transport owner / operator, a lack of public acceptance is another risk.

Important issues that need to be assessed are how different capture technologies influence the CCS value chain, the total storage capacity of different storage sites and achievable storage transport and injection rates. CCS imposes an economic penalty on the upstream value chain and so all CCS costs must be economically optimized; costs of carbon dioxide (CO\(_2\)) capture, compression, transport, storage, and injection.

### 5.2 CO\(_2\) Capture

Carbon capture involves the removal of CO\(_2\) from a gas stream. This gas stream can be any CO\(_2\) containing gas stream including natural gas production, process gas from a chemical process, or flue gas from power generation and other combustion sources. There are three technology process routes that are commonly considered for CO\(_2\) capture that were introduced in Section 5.1 above. The three processes are:

- **Post-combustion capture (where CO\(_2\) is captured in a low pressure, low CO\(_2\) concentration, oxidising environment flue gas stream)**
  
  This process involves separating CO\(_2\) from combustion exhaust gases. CO\(_2\) can be captured using a liquid solvent. Once absorbed by the solvent, the CO\(_2\) is released by heating to form a high-purity stream of CO\(_2\). This technology is used to capture CO\(_2\) for use in the food and beverage industry.

- **Pre-combustion capture (where CO\(_2\) is captured in a pressurized reducing environment process gas stream)**
  
  This process involves converting fuel into a gaseous mixture of hydrogen and CO\(_2\) such as by gasification or reforming plus shift reaction. The hydrogen is separated and can be burnt without producing any CO\(_2\) but modification to combustion equipment would be required for burning high-hydrogen fuel. The CO\(_2\) is usually captured in an absorption solvent and when released by thermal regeneration it can be compressed for transport. The fuel conversion steps required for pre-combustion are more complex than the processes involved in post-combustion, making the technology more difficult to apply to existing power plants or other combustion sources. Pre-combustion capture is used in industrial processes that already require the generation of hydrogen or synthesis gas but has not been demonstrated in larger power generation projects.

- **Oxyfuel combustion capture (where a flue gas stream of almost pure CO\(_2\) stream is captured)**
  
  This process involves using oxygen rather than air for combustion of fuel. This produces an exhaust gas that is mainly water vapour and CO\(_2\), which can be easily separated to produce a high purity CO\(_2\) stream. Some of the CO\(_2\) is recycled to dilute the oxygen in the combustion gas.

Further details on the three technology routes can be found on the Global CCS Institute website "[http://www.globalccsinstitute.com/understanding-ccs/how-ccs-works-capture](http://www.globalccsinstitute.com/understanding-ccs/how-ccs-works-capture)" and also in a number of study reports published by Global CCS Institute.
In natural gas processing, the sources of natural gas contain levels of CO₂ that must be separated out before the gas can be sold on the market. This process produces a pure stream of CO₂ and creates a relatively low-cost opportunity to use that CO₂ for EOR or geological storage. Carbon capture has been deployed commercially in gas processing, and there are several projects around the world that remove CO₂ from produced gas and then re-inject it back into the subsurface (e.g. the Sleipner project).

Most of the CO₂ from natural gas processing is currently vented, but in some locations it is used for EOR, especially in North America. Currently, around 25 MTPA of CO₂ is able to be captured and stored from gas processing and other high purity sources. A further 13 MTPA of CO₂ will be added to this when current projects under construction (e.g. Quest and Gorgon) become operational in the next few years.

Pre-combustion capture is also used commercially in some chemical sectors where the CO₂ needs to be separated from a gas stream (e.g. hydrogen or ammonia fertiliser manufacturing). These processes require the CO₂ to be removed from an intermediate process stream and this produces a pure CO₂ stream that is relatively convenient for application of CCS. All that is required is drying, compression, and injection. Pre-combustion capture can also be applied to power generation via application of Integrated Gasification Combined Cycle technology with shift reaction and CO₂ absorption. A commercial scale CCS project utilising IGCC technology is currently under construction in the Kemper County project.

Post-combustion carbon capture has been demonstrated at power plants of approximately 10 per cent commercial size. Plants of commercial size with carbon capture are currently under construction in the Boundary Dam project. These are expected to be fully operational in 2014. The main challenges for power generation and especially post-combustion capture are the energy penalty associated with carbon capture and the increased capital and operational costs. CO₂ capture can also be applied to other combustion flue gases for example in the production of LNG, steel, cement, chemicals and other industries.

### 5.3 CO₂-Compression, Dehydration and Liquefaction

The next part of the CCS Value Chain after the capture process, the CO₂ stream will be compressed by a multi-stage CO₂ compressor, dehydrated by a drying unit that would be regenerated with low pressure steam, and if required refrigerated and liquefied prior to being stored in intermediate buffer storage tanks for loading on to either ships or road/rail tankers.

For pipeline transport the refrigeration and liquefaction process step is not required as the compressed and dried CO₂ is transported in the dense phase fluid state, at or near ambient temperatures. According to the Global CCS Institute Global Status 2013 report⁶, pipelines continue to be the primary method chosen for the transport of the high quantities of CO₂ associated with CCS.

Pipeline transport has been identified in 94 per cent of all Global CCS Institute’s Large Scale Integrated Projects (LSIPs) in 2013. Eighty per cent of CO₂ pipelines are entirely onshore, 20 per cent are onshore-to-offshore pipelines. Offshore pipelines are mostly used or considered in Europe. One is being considered in Australia’s CarbonNet project.

Three projects have indicated that transport will occur by ship, down by one since 2012. Two of the projects planning to ship the CO₂ are Korea–CCS 1 and Korea–CCS 2. The third is the Dongguan
Taiyangzhou IGCC with CCS Project in China, which changed its transport plans from pipeline to shipping in 2013.

The compression, dehydration and liquefaction process is shown in the Figure 21 below.

**Figure 21 – Typical CO₂ compression, dehydration process**

![Diagram of CO₂ compression, dehydration process](source: WorleyParsons)

At the current state of maturity of the CCS Value chain, typical conditions of the CO₂ after compression, dehydration and liquefaction process are show in Table 8 below. Typical LNG conditions (at atmospheric pressure) are shown for comparison. Buffer storage means intermediate buffer storage in vessels at the CO₂ capture site before loading / unloading on to ship or road (or rail) transport to the final injection and storage (sequestration) site.

**Table 8 - Typical produced Liquefied CO₂ conditions compared with LNG**

<table>
<thead>
<tr>
<th>Properties</th>
<th>Units</th>
<th>Typical LNG</th>
<th>Typical CO₂ Buffer Storage &amp; Transport by Ship⁶</th>
<th>Typical CO₂ Buffer Storage &amp; Transport by Road⁷</th>
<th>Typical CO₂ Transport by Pipelines</th>
<th>Typical CO₂ Injection and Storage (Sequestration)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid State</td>
<td>- Liquid</td>
<td>Liquid</td>
<td>Semi refrigerated liquid</td>
<td>Semi refrigerated liquid</td>
<td>Supercritical fluid (dense phase)</td>
<td>Supercritical fluid (dense phase)</td>
</tr>
<tr>
<td>Density</td>
<td>kg/m³</td>
<td>450</td>
<td>1163</td>
<td>1078</td>
<td>838</td>
<td>702</td>
</tr>
<tr>
<td>Density ratio liquid / gas</td>
<td>-</td>
<td>600</td>
<td>588</td>
<td>545</td>
<td>424</td>
<td>355</td>
</tr>
<tr>
<td>Pressure</td>
<td>kPag</td>
<td>5</td>
<td>650</td>
<td>2000</td>
<td>7300– 15,000</td>
<td>10,000</td>
</tr>
<tr>
<td>Temperature</td>
<td>°C</td>
<td>-160</td>
<td>-52</td>
<td>-30</td>
<td>20</td>
<td>35</td>
</tr>
</tbody>
</table>

*Source: WorleyParsons

⁶ “Liquefaction of captured CO₂ for ship-based transport” - A. Aspelund (SINTEF) et al
⁷ “Loy Yang Large Scale Demonstration PCC Plant Prefeasibility Scoping Study - 2012” - WorleyParsons
⁸ “Preliminary Engineering Study - Vales Point PCC Demonstration Plant - 2011” - WorleyParsons
The CO₂ conditions for transport by pipeline have high pressure and ambient temperature that is more suited for comparisons with conventional natural gas transport by pipelines.

For CO₂ transport by road (or rail) and ship the conditions as compared to LNG conditions are shown in the Figure 22 below. The road transport CO₂ conditions in the Table 8 and Figure 22 are based on current commercial scale (30 tonne) transport of product CO₂ in the general industry. These were design bases for two post combusition capture demonstration projects’ feasibility studies delivered by WorleyParsons. The CO₂ conditions for economic large-scale (> 0.5 million tonne/year) transport by ship in Table 8 and Figure 22 are proposed in the paper by Aspelund et al.⁶

![Figure 22 - Comparison of LNG with typical Liquefied CO₂ conditions](image)

Source: WorleyParsons

The Pressure-Temperature phase diagram in Figure 23 below shows the three different transport modes (ship, road and pipeline) of CO₂ conditions together with the CO₂ captured conditions of three different technology suppliers (labelled Technology A, B, C). The typical CO₂ storage (injection & storage) condition is also shown. Due to the need to maintain stored and transported CO₂ at above the triple point, ambient pressure cryogenic storage is not possible as is practised with LNG.
5.4 CO₂ Transport

5.4.1 By Road

Road transport by truck requires that CO₂ is compressed to about 2100 kPa and liquefied by cooling to approximately -30°C in a process similar to many liquefaction processes. The CO₂ will be compressed, dried and refrigerated using an ammonia or propane refrigeration cycle. It will then be transported in bulk tankers mounted on trucks to the storage site. At the storage site, the CO₂ will be pumped to the required pressure and heated to the required temperature before injection.

Liquefaction of CO₂ is well understood at the scale proposed. Industrial gas suppliers such as Air Liquide and BOC Linde have extensive experience in this area.

5.4.2 By Ship

Large-scale transport of CO₂ by ship is likely to be in semi-refrigerated condition at pressure above the triple point e.g. at 750 kPa and -52°C. At this pressure, the technology and experience from building and operation of LPG (ethylene, propylene, propane) tankers may be utilized. Care must be taken to avoid dry ice formation in the process plant, tank storage and when loading and unloading. Large-scale liquefaction of CO₂ is best achieved in an open cycle, using the CO₂ feed as the refrigerant where the refrigeration is partly or fully provided by the feed gas itself.
5.4.3 By Pipelines

Captured CO₂, once separated from the flue gases of a power plant, energy or industrial complex, must be compressed from regeneration pressure, at which it exists as a gas. The gas is compressed up to a pressure suitable for pipeline transport, at which CO₂ is in either the liquid or ‘dense phase’ regions, depending on its temperature.

When CO₂ is in the gas phase, a compressor is required for compression, but when CO₂ is in either liquid or dense phase, a pump can be used to boost the pressure. It can be assumed that the ‘cut-off’ pressure for switching from a compressor to a pump is the critical pressure of CO₂, which is 7380 kPa.

Therefore for pipeline transport of CO₂ the pressure should be above the critical pressure of CO₂ of 7380 kPa up to 15,000 kPa (or depending on specified delivery pressure).⁹

The pipeline transport conditions shown in Figure 23 above provide a typical range example.

Further according to a study by McCoy and Rubin 2008¹⁰, it is generally recommended that a CO₂ pipeline operate at pressures greater than 8600 kPa where the sharp changes in compressibility of CO₂ can be avoided across a range of temperatures that may be encountered in the pipeline system.

5.5 CO₂ Reservoir Storage

Storing CO₂ underground is not a new or emerging technology – it is an existing reality. In fact, there are numerous geological systems that naturally contain CO₂ and have stored this geologically sourced CO₂ for millennia. As well, the oil and gas industry has used CO₂ for decades for EOR, where incidental storage is associated with the activity.

There are many geological systems throughout the world that are capable of retaining centuries’ worth of CO₂ captured from industrial processes. Finding and characterising a suitable geological storage site is a requirement that should be addressed early in a CCS project and many regional surveys around the world have highlighted potential storage sites.

Although geologic storage of gases occurs naturally and has also been used safely by industry for many decades, it remains a challenge to describe this process to the public.

Geological storage involves injecting CO₂ captured from industrial processes into rock formations deep underground that have the capacity to store large volumes of the greenhouse gas and containment characteristics that will not allow it to leak. In this way, the CO₂ is permanently removed from the atmosphere.

Typically, the following geologic characteristics are associated with effective storage sites:

- rock formations have enough voids, or pores, to provide the capacity to store the CO₂

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⁹ “Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity” - McCollum, David L and Ogden, Joan M University of California, Davis

¹⁰ “An engineering-economic model of pipeline transport of CO2 with application to carbon capture and storage” - Sean T. McCoy, Edward S. Rubin
pores in the rock are sufficiently connected, a feature called permeability, to accept the amount of CO\textsubscript{2} at the rate it is injected, allowing the CO\textsubscript{2} to move and spread out within the formation

- the pores in the rock are not so open that water will easily displace stored CO\textsubscript{2} when injection stops
- an extensive cap rock or barrier at the top of the formation to contain the CO\textsubscript{2} for thousands of years and longer

There are many locations globally that have formations with these characteristics and most are in vast geological features called sedimentary basins. Almost all oil and gas production is associated with sedimentary basins, and the types of geologic formations that trap oil and gas (and also naturally occurring CO\textsubscript{2}) include sandstones, limestone, and dolomites that are similar to those that make good CO\textsubscript{2} storage reservoirs. It is the natural geologic characteristics, the ones that resulted in oil and gas being trapped for millions of years before they were discovered, that make secure geologic storage of CO\textsubscript{2} such a viable option for greenhouse gas mitigation. Many coal deposits are also associated with sedimentary basins, so coal–fired power plants, which are a significant source of CO\textsubscript{2} emissions, can sometimes be co-located near storage sites. In other instances and for other industries, suitable storage locations may be considerable distances away.

The different types of storage options available are:-

- Deep saline aquifer is a storage type often referred to in the CCS literature, which means any saline water-bearing formation (the water can range from slightly brackish to many times the concentration of seawater, but is usually non-potable)
- Depleted oil or gas fields that are no longer economic for oil or gas production, but have established trapping and storage characteristics
- Enhanced Oil Recovery (EOR) which involves injecting CO\textsubscript{2} to increase oil production from mature oil fields
- Enhanced Gas Recovery (EGR) which involves injecting CO\textsubscript{2} to increase gas production from mature gas fields
- Enhanced coal-bed methane (ECBM) in which CO\textsubscript{2} is injected into coal-beds to exchange CO\textsubscript{2} with methane.

### 5.6 Global Status of CCS Projects

The global status of CCS projects is shown in the Figure 24 below. This data is from the Global CCS Institute’s 2013 report.\textsuperscript{5} As of August 2013, the Institute had identified 65 CCS LSIPs.

The LSIPs are defined by the Global CCS Institute as those which involve the capture, transport and storage of CO\textsubscript{2} at a scale of:

- At least 800,000 tonnes of CO\textsubscript{2} annually for a coal-based power plant, or
- At least 400,000 tonnes of CO\textsubscript{2} annually for other emission-intensive industrial facilities (including natural gas-based power generation).

The full list of LSIPs is appended under Appendix A.5 (2013 LSIPs listing) within the Global CCS Institute’s 2013 report.\textsuperscript{5}
There are twelve projects in total listed on the LSIPs 2013 as in the Operate stage. Eight projects are in the natural gas processing industry. These include new operational projects such as Lost Cabin Gas Plant in the US and Petrobras Lula in Brazil.

The other four projects in Operate stage are in the “other industries” category which includes synthetic natural gas production, fertiliser production and hydrogen production. The hydrogen production project is undertaken by Air Products where CO$_2$ is captured from a steam methane reformer to produce hydrogen, which is then used at an oil refinery for producing liquid fuels.

Additional industrial projects are under construction and will become operational in the next couple of years were identified in the Global CCS Institute’s 2013 report are as follows:

- Agrium is an existing project producing ammonia-based fertiliser. Pre-combustion capture would already be in place to remove CO$_2$ from the syn-gas feeding ammonia synthesis. Additional plant will be retrofitted to the plant to capture, compress and export around 585,000 TPA of CO$_2$. The CO$_2$ capture is expected to become operational in 2015.
- The Illinois Industrial Carbon Capture and Storage Project builds on the Decatur demonstration project; the construction of additional capture facilities is underway. When operational in 2014, the project will capture 1 MTPA of CO$_2$ from ethanol manufacturing.

- The Gorgon project has constructed the first of three amine absorber columns on the plant site. This project will capture CO$_2$ from natural gas processing. The natural gas will be liquefied to LNG and exported. The project is expected to be operational by 2015.

- The Northwest Redwater project will capture CO$_2$ from a gasifier that uses refinery waste from the North West Sturgeon Refinery to produce hydrogen. The CO$_2$ will be captured using the Lurgi Rectisol process from this hydrogen production process; the hydrogen will be used for processing bitumen into liquid fuels. The project is expected to be operational in 2015.

- The Quest project commenced construction in late 2012. This project will capture CO$_2$ from a steam methane reformer from the Scotford Upgrader to produce hydrogen. The project will use a proprietary technology from Shell Global Solutions. The hydrogen will be used to produce liquid fuels from oil sands.

- The Uthmaniyah project is under construction in the Eastern Province of Saudi Arabia. The plan is to capture 0.8 MTPA of CO$_2$ at the Hawiyah natural gas processing plant and transport it by pipeline to the depleted Uthmaniyah area of the Ghawar field. It is expected to commence operation in 2014 with a total duration of three to five years.

The global status of CCS projects that have been identified above in the operational and construction stages are mainly within the gas processing and other chemicals industries (fertilizer production and hydrogen production). CCS is facilitated by the requirement for these industries to already remove CO$_2$ from their process gas streams.
6 PROJECT DEVELOPMENT CONSIDERATIONS

Key Findings:

- Projects are developed via familiar stage-gate systems for both LNG and CCS
- LNG projects take up to 10 years or more to select preferred concept, then 4 – 5 years to define and deliver, similar to limited data from CCS LSIPs
- Individual CCS projects are not as costly as LNG projects ($ billions vs. $10s of billions) but total global target capacity and number of required projects are greater
- Project partners spread investment cost load, even among largest IOCs and NOCs
- Current CCS commercial basis is virtually limited to EOR with capture from gas processing but these sources and sinks have limited volume to contribute to global CCS targets
- LNG has clear demand-driven commercial drivers but for CCS, lack of adequate and predictable GHG mitigation price means there is no commercial basis to justify uptake
- LNG is bankable but with no commercial basis for CCS, finance availability is extremely challenging
- Governments and NOCs led early LNG market and now government intervention is required to set policy that supports a predictable CCS market
- CCS could utilise multiple parallel capture trains similar to LNG liquefaction trains for capacity limits and project phasing
- LNG experienced CAPEX escalation (more than doubling in last decade) and CCS could be susceptible to similar risk, with resulting impact on production cost
- There is much greater energy penalty for CCS than for LNG
- There is much greater technology selection variability and risk for CCS than for LNG

A LNG project is developed and implemented as a result of a resource owner / developer identifying that LNG is the preferred (or one of several) upgrade routes for the gas that will be produced from the resource. The resource owner / developer usually start as the exploration and development company that made the reservoir discovery. If that company is one of the large IOCs / NOCs, then the development of the project will probably continue to be led by that company, possibly with farm-in by other majors to spread the investment load. However, if the E&D company is a minor company, then the development lead may be taken over by the farm-in of a major.

The concept evaluation and selection will usually be performed with support from engineering and technology providers. The timing and extent of contracting of engineering studies during these early phases will be dependent on the internal capability of the owner / developer. The service providers will usually have some degree of specialization in sections of the value chain, e.g., pipelines, LNG plants, LNG process technology, tanks, shipping and regasification.

To develop the selected concept, the owner / developer will proceed with definition, detailed feasibility study, site selection and approvals applications, design (FEED) and cost estimating to allow investment decision. At the same time, the project proponents will seek off take contract
commitments, additional investors and finance for the project. Having defined and justified the project and with necessary regulatory approvals, the proponents will make a Final Investment Decision (FID) to proceed with execution of the project.

Usually the implementation of the multiple blocks in the LNG value chain will be by multiple EPC contracts and sub-contracts.

LNG projects are complex developments that can take ten years or more from initial resource discovery to operation. Some projects currently under consideration have still not finalised concept selection 40 years after the discovery of the gas field. Developments are in the range of tens of billions of dollars. CCS developments are and will be similarly complex and costly. CCS will have added complexity of a greater range of sources and sinks, greater range of project costs, and greater diversity in development sites.

CCS almost certainly has a greater diversity of candidate CO₂ sources and sinks that may be incorporated into the eventual value chain than is the case for LNG. Also certainly many of these can be expected not to reach a significant volume of mature commercial application as the industry evolves. Examples of CO₂ reservoirs include EOR, depleted oil and gas reservoirs, and deep saline aquifers of various morphology and geo-chemistry. Examples of CO₂ sources include:

- Extraction from reducing pressurized environments (pre-combustion) such as processes for gas conditioning, LNG, synthesis gas clean up, hydrogen production, ammonia, methanol, synthetic fuels, and IGCC
- Extraction from oxidizing low-pressure environments such as post-combustion capture from power generation, cement, and iron and steel flue gases

These sources and sinks and the candidate technologies still under development to enable the CCS value chain are all familiar to Global CCS Institute members and readers familiar with CCS developments. Some aspects of the variety of sources, sinks and process paths are discussed in this report in Section 5 and extensively elsewhere, including Global CCS Institute reports and resources.

CCS is also more likely to have a greater range of commercial and business models. Capture will range from relatively low cost capture from conventional gas processing and chemicals production to higher cost capture retrofit to power generation. Sinks will range from high value disposition in EOR to higher cost storage in sequestration reservoirs.

CCS is also more likely to have a greater range of application sites compared to LNG. LNG terminal and storage sites are constrained to locations at or near a shore or floating production due to LNG marine transport. LNG facilities must also draw from suitably sized gas resources for which LNG has been selected as the preferred (or one of several) development pathway(s). These resources need to be within an economic pipeline distance from potential shore locations. By comparison, the capture plants for CCS will be located at a very diverse range of emissions sources such as coal fired power stations, natural gas processing plants, chemicals and fertilizer manufacture, cement, iron and steel, ethanol bio-fuel production and many more. The site selections for the source processes will often be industry-specific and not related to potential storage formations.

Although large scale LNG has relatively more narrow application than CCS, there are still comparisons that may be interpreted from the LNG industry development. The issues from the LNG industry that may be relevant to CCS are examined in this Section 6 for project commercial basis justification and optimisation aspects, and in Section 7 for project technical definition aspects.
6.1 Development Justification and Strategy

- Individual LNG projects cost tens of billions of dollars
- LNG annual investment in new production capacity will be ~ $40 billion for ~ 3 – 4 trains per year from now till 2030
- CCS annual investment in capture plant will be ~ $70 billion for ~ 50 – 60 capture plants per year from 2020 till 2050

LNG projects require huge investments. For example, current Greenfield projects in Australia range from three projects in Queensland based on coal seam gas that total in excess of $50 billion to the massive Gorgon project on Barrow Island, Western Australia, which includes CCS, forecast to cost in excess of $50 billion in a single development. These levels of investment are required to produce LNG in the range of ~ 8 MTPA per project (Queensland LNG) to ~ 15 MTPA for Gorgon. Specific investment for the whole project is in the range $3,000 per TPA and delivered LNG prices (at regasification terminal receiving) from projects in this cost range are more than $10 / GJ or ~ $500 / tonne. Export net-back from such projects has the potential to affect source market pricing. Pipeline gas prices on the Australian East Coast are predicted to rise to reflect alternative sale value to LNG export. Globally LNG production capacity now stands at 290 MTPA, with consumption demand at 240 MTPA and this is forecast to approximately double by 2030. If incremental production capacity is installed to exactly match incremental demand (capacity utilisation factor increases from 83% to 91%), then at current specific investment this implies total new investment of ~ $700 billion. This represents annual investment of ~ $40 billion per year from now till 2030.

The total investment in the LNG supply chain can be broken down into blocks according to the following approximate “rule of thumb” CAPEX breakdown in Table 9.

Table 9 -- LNG Supply Chain CAPEX Breakdown

<table>
<thead>
<tr>
<th>Supply Chain Block</th>
<th>Fraction of Total CAPEX</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upstream Development</td>
<td>10%</td>
</tr>
<tr>
<td>LNG Plant</td>
<td>40%</td>
</tr>
<tr>
<td>LNG Transportation</td>
<td>30%</td>
</tr>
<tr>
<td>Receiving &amp; Re-gasification Terminal</td>
<td>20%</td>
</tr>
</tbody>
</table>

WorleyParsons experience is that the Upstream Development cost can be significantly greater than indicated from this reference. For some recent Australian North West Shelf projects, the upstream, off-shore cost was almost 60% of the combined upstream and LNG Plant project. It should be expected that field exploration and production costs will be highly variable depending on the development.

11 “RULES OF THUMB FOR SCREENING LNG DEVELOPMENTS”, Presentation to IEAust., Perth, 2/10/12, Nick White, Clough
The LNG Plant CAPEX (i.e., the 40% component above) can be further broken down as shown in Table 10.

### Table 10 – LNG Plant CAPEX Breakdown

<table>
<thead>
<tr>
<th>LNG Plant Section</th>
<th>Fraction of LNG Plant CAPEX</th>
</tr>
</thead>
<tbody>
<tr>
<td>Receiving, stabilization, NGL fractionation and storage, gas pre-treatment</td>
<td>6% to 15%</td>
</tr>
<tr>
<td>Liquefaction</td>
<td>40% to 50%</td>
</tr>
<tr>
<td>Utilities</td>
<td>16%</td>
</tr>
<tr>
<td>LNG Storage</td>
<td>15% to 18%</td>
</tr>
<tr>
<td>Loading Facilities, jetty</td>
<td>10% to 12%</td>
</tr>
</tbody>
</table>

The large cost range on the plant front-end units (receiving, stabilization, NGL fractionation and storage, gas pre-treatment) reflects the variability of production fluids composition. The core liquefaction process only makes up 20% of total LNG supply chain CAPEX (50% for liquefaction of 40% for the LNG Plant).

The capital costs can also be expressed across various plant and process areas, as shown in Table 11.

### Table 11 – LNG Plant Cost Categories

<table>
<thead>
<tr>
<th>Cost Category</th>
<th>Fraction of LNG Plant CAPEX</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment</td>
<td>30%</td>
</tr>
<tr>
<td>Materials</td>
<td>15%</td>
</tr>
<tr>
<td>Field Labour</td>
<td>30%</td>
</tr>
<tr>
<td>Contractor (Site &amp; Office)</td>
<td>25%</td>
</tr>
</tbody>
</table>

By comparison, the cost, scale and speed of development that is desired from the CCS industry is even more massive than for LNG. For typical 500 MW coal fired power generation station with post-combustion carbon capture, “total overnight costs” for the capture plant in the range of $1,600 to 2,800 / kW are reported, implying project costs of ~ $0.8 to 1.4 billion each. CO₂ captured is likely to be in the range 4 MTPA per station meaning specific investment in the range $200 to 350 per TPA has been estimated.

CCS targets for contribution to GHG reduction scenarios are in the range 7 – 8 GTPA by 2050, implying new investment of between $1.4 to 2.8 trillion will be required. This rate of spending of roughly $70 billion per year between 2020 and 2050 does not seem so much more significant than
LNG spending roughly $40 billion per year from now till 2030. However the estimated LNG spending is based on recent high cost projects in Australia, while the estimated CCS spending is based on cost estimates for LSIPs that have not been demonstrated. Also the LNG project costs are for the full upstream and LNG plant costs, while the CCS project costs are for the capture plant only. The number of CCS capture projects is much greater at around 50 – 60 per year over 30 years compared to LNG of around 3 – 4 trains per year over less than 20 years.

A comparable breakdown of a CCS project into its component blocks cannot be made to the same level of detail as for LNG projects but it is commonly understood that the capture plant is the most capital intensive item in a CCS project.

These numbers for both industries are order-of-magnitude at best and based on distant forecasts or targets of volumes and current cost performance or prediction. They ignore learning curve or paradigm shift cost reductions for improvements in technology or project execution. Nevertheless they illustrate that while CCS might draw lessons from LNG, the scale of the CCS development task is much greater. LNG is a relatively complex process and value chain, as is CCS. LNG recent investments have been significantly challenged by cost escalation associated with input costs. As CCS project activity ramps up, it can expect to deal with project implementation cost and schedule risks, both between coinciding CCS projects and also in competition with LNG and other process industry sectors. Some of those project implementation and risk issues are discussed in the following sections.

6.1.1 Reservoir

- LNG now produces from extremely diverse reservoir types, several of which would not have been anticipated at the birth of the industry
- CCS reservoirs must be proved with high certainty to support CCS projects
- Current value-adding CCS via EOR has limited volume potential

The net economic benefit that is obtained from development of an oil and gas reserve is dependent on the total fluids that can be extracted and upgraded to saleable products over the production lifetime, balanced against the capital and operating costs of the development facilities. LNG may be produced in any combination of:

- Dry gas, with little or no co-produced LPG or liquid products, such as from Coal Seam Gas production in Queensland, Australia
- Co-produced LPG and condensate or crude oil can justify additional process recovery and storage units and augment the revenue from an LNG-based field development such as from North West Shelf and Timor Sea, Australia
- LNG process can provide a solution for co-produced gas from oil production, avoiding flaring or reducing gas re-injection, such as Nigerian LNG
- LNG can consume a portion of total gas production from a reservoir, with the remainder supplying distribution pipelines, power plants or other industrial consumers, such as North West Shelf, Australia
LNG can be a merchant off-take from an existing pipeline distribution system that may have multiple production suppliers, such as may be the case for conversion of LNG import / regasification terminals in the USA into liquefaction / export terminals based on shale gas.

LNG can be a land-based facility based at or near a shore line and fed from either on-shore or off-shore reservoirs, which has been usual, or it can be a floating production, storage and off-loading (FPSO) facility for remote off-shore reservoirs, such as is being developed by Shell for the Prelude field, off-shore Western Australia.

**Comparison for CCS**

The lesson for CCS from the LNG industry development is that multiple commercial niches may develop over time that are not initially anticipated and that arise due to evolving market conditions and production technologies. Unconventional gas resources such as coal seam and shale gas would not have been predicted from the early development of the LNG industry. Their development was enabled by improved production technology, e.g., directional drilling and hydraulic fracturing, that drove down production costs and made their business cases viable.

The development of coal seam gas in Queensland in particular has been synergistic with the LNG industry. The maturity of the LNG market, volume growth outlook and attractive export pricing relative to domestic market prices encouraged the development of the Coal Seam Gas production, which had resources that could underpin commercial scale LNG projects.

However, the characterization of CCS reservoirs needs to have a high level of certainty of injection rate, total storage capacity over the life of the project, and long term security of storage. This characterization must be achieved during development and prior to decision making to utilize the reservoir. By comparison a gas reservoir must be assessed for production rates and total reserves to support a LNG plant but the gas is in place, allowing exploration and assessment.

CCS currently has a limited range of viable business cases, with carbon price and emissions constraints at current settings. Enhanced Oil Recovery (EOR) is by far the largest market for CO$_2$ (apart from internal supply for Urea production, see Figure 25) and EOR offers a positive value for captured CO$_2$.

EOR is mostly supplied from natural sources, with only 20% from industrial sources. The most attractive capture sources to supply current or expanded EOR are from acid gas removal processes for natural gas or synthesis gas (e.g., hydrogen production) due to the capture process being an existing requirement.

However acid gas removal sources can only provide a fraction of the overall CCS volume target and EOR can only provide a fraction of overall storage. For example it is estimated that USA disposition to EOR could grow to as much as 400 to 500 MTPA by 2030. This is equivalent to about 50 to 60 GW of generating capacity or 20% of USA coal fired power generation, but the EOR demand could easily be met by high purity CO$_2$ sources alone, without requiring recovery from other sources. Additionally, EOR is a specific regional opportunity such as in North America, Arabian Gulf or China – many other regions will not have oil production that is amenable to enhancement.

The range of alternative CCS pathways and the inability with current information to rank and predict clear winners means that commercial market demonstration and competition will be required to
screen the candidates. Also a maturing CCS market will probably facilitate new applications that are not currently anticipated. In other words, CCS must learn by doing.

**Figure 25 – Current USA CO₂ Market**

6.1.2 Production / field development

- Reservoir management and optimisation will likely differ between CCS and Oil&Gas
- While LNG benefits from O&G technology, no resource extraction technology was developed by or for LNG alone but CCS must develop its own specific technology

The integrated field development planning for oil & gas and LNG will consider the construction and production phasing of all the facilities required to produce and export the extracted and processed fluids. Production facilities could consist of a combination of:

- Subsea wells, manifolds, flow lines for off-shore fields
- Production platforms and top-side process or Floating Production and Storage Off-loading vessel (FPSO)
- Production pipelines from off-shore platforms to on-shore facilities
- Access to on-shore well-sites (roads, competing land use)
- Drilling and well stimulation such as hydraulic fracturing
- Well head facilities such as separators
- Field gathering networks and satellite facilities such as compressor stations

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12 The US DOE R&D program to reduce GH emissions through beneficial uses of CO₂. 2011 Society of Chemical Industry and John Wiley & Sons, Ltd
Process facilities such as described in Section 3.2

Optimization will consider the number, type and location of wells based on reservoir characteristics and production scenarios. Production phasing can include the timing of wells to balance the facilities spending and the ramp up or maintenance of production from the field. Production phasing can also consider the decline of reservoir pressure as fluids are withdrawn, pressure / production maintenance strategies such as re-injection or compression, changing fluid compositions and other characteristics over time, blending of production from multiple wells / reservoirs and impacts of changing production on downstream recovery and upgrade facilities.

Total reserves and recovery will be estimated and utilized to justify production capacities as explained in the following sections.

Comparison for CCS

The optimization of integrated gas field development, whether or not it includes LNG, considers the facilities scope, investment and production profiles. The economic development of the field depends on the rate and conditions at which fluids can be withdrawn and processed. The skills, tools and methodologies developed over time for oil and gas field development optimization may be adaptable to CCS optimization.

However there are differences in reservoir rock and fluid characteristics that are optimum for extraction of a hydrocarbon resource (needs a seal cap and favoured by high mobility of fluids through rock) compared to the characteristics that are optimum for injection and immobilization of CO₂. Resulting strategies for CCS are likely to differ considerably. For example hydrocarbon extraction can be favoured by fracturing or enhancement by injection of another fluid (water, CO₂), while CCS might avoid fracturing and favour enhancement of injection by removing another fluid (water). The differences are subject of entirely separate fields of study and outside the scope of this study, which concentrates on the LNG industry.

A significant difference between LNG and CCS is that although LNG industry facilitated some novel hydrocarbon production technology by providing a value upgrade for the gas production, there is not any upstream development that was uniquely for or by the LNG industry. LNG was based on production developments that had general value for hydrocarbon production. While a value-adding CCS outlet like EOR similarly takes advantage of the already existing techniques and general value of enhancing oil production, most other CCS storage methods will be developed for CCS only. That means that as noted elsewhere, for the most part CCS must develop its technology, install its projects and operate all components of its value chain simultaneously. This adds considerable risk from the interdependency of the segments of the value chain that were not encountered by LNG.

6.1.3 Project Life

- Project economic and design life will have similar meaning for LNG and CCS
- Most LNG facilities are not integrated with other production but CCS facilities must integrate with source process(es) and must consider life issues of those facilities
- CCS has on-going storage requirement following active injection life (MMV)
As stated in Section 3.3, over a typical design economic life of 20 years, an LNG plant will require recoverable gas reserves of 1.1 – 1.2 trillion cubic feet (TCF) per million tonnes per annum (MTPA).

The target economic project life for LNG is typical for hydrocarbon and chemicals process industries. Project life impacts both technical and economic decisions. The design life of plant and equipment sets design standards such that with reasonable levels of plant maintenance, the facility can be expected to operate safely and reliably over its design life. Usually with diligent maintenance and inspection and increasing levels of renewal investment, many such facilities continue to operate for up to 40 years, or more. The Kenai, Alaska LNG plant was mothballed this year (2013) due to shortages of gas for local markets after operating 44 years since start-up in 1969.

The economic implications are that future revenues beyond the economic life are fully discounted, the plant is fully depreciated (except for renewal investment) and that decisions as to whether to continue operating the plant can be based on economic analysis at the time. Such analysis would include on-going revenue; consideration of (non-)competitive operating costs from old process technology, weighed against possibly increasing maintenance and inspection costs.

**Comparison for CCS**

During injection life of CCS, the technical and economic design life of the CCS facilities will have similar implications. However CCS has some additional considerations due to the upstream sources of CO₂ and the requirement to securely store CO₂ for long term sequestration. Capture plants can be expected to be applied to both new-build sources of CO₂ and retrofitted to existing production fleets. For new-build, the design life for the capture plant must be consistent with that of the source plant. For retrofits, the economic life of the capture plant might need to consider the remaining economic life of the existing plant.

CCS transport project life may have parallels to both gas pipeline and LNG industries. For gas, pipeline transport is typically favoured for shorter distances under 1,000 to 2,500 km (off-shore and on-shore respectively) and LNG is typically favoured for greater distances or if a pipeline is infeasible, e.g., due to geographic obstacle. For CCS, assessment of alternatives for the Rotterdam ROAD project found that barge transport on the Rhine is favoured over on-shore pipeline for distances under 100 – 200 km. However, ship transport to distant off-shore sites is favoured over off-shore pipeline for distances over 100 – 200 km.¹³ The significantly smaller distance for break-even between shipping and pipeline was attributed to CO₂ liquefaction relatively lower energy consumption than for LNG.

Pipeline economic life and asset integrity management are likely to be similar between gas pipeline and CCS industries and there is already considerable experience from CO₂ pipeline asset management for EOR especially in North America.

Above ground storage and transport conditions are different for CO₂ compared to LNG and this will result in different tanker design. However such tankers would probably resemble semi-refrigerated hydrocarbon type (relatively moderate temperature liquid at moderate pressure), rather than LNG (cryogenic liquid at atmospheric pressure). In most respects tanker design life and asset management would have precedents from the hydrocarbons and chemicals industries.

¹³ Michael Tetteroo and Cees van der Ben - CCS Projects – Presentation at the Global CCS Institute Members’ Meeting: 2011
6.1.4 Production Capacity

- CCS should probably develop similar parallel train concepts as LNG to handle very large emissions sources, subject to critical equipment capacity constraints.

The preceding sections are general for the production of any oil and gas reserves. In planning for the integration of LNG plants into full field development, the number, capacity and phasing of LNG train installation must be considered and optimized.

As was explained in Section 4.7.2, there is a long term trend of increasing train sizes to capture benefits from improving economies of scale. The details of capital cost efficiency and specific capital cost of capacity relative to plant production are provided in Section 6.1.9. In summary, similar to many complex industrial processes, specific capital cost ($ per TPA capacity) reduce as capacity increases up to limits imposed by critical equipment. This is illustrated by the familiar 2/3 power rule. Beyond these capacity break points, additional capacity must be obtained by multiple equipment items or process trains and any further specific capital cost reduction is diminished. Additional cost reductions beyond these limits require fundamental breakthrough to processes and technology.

The critical equipment in LNG processes that set the train capacity breakpoints are:

- Refrigeration compressors,
- Their gas turbine drivers, and
- The liquefaction heat exchangers.

The selection and design of these items must match to deliver target train capacity.

Over the development timeframe of the LNG industry, discrete jumps of capacity have been observed with prime movers (industrial gas turbines), such as was observed with a 15% power increase from GE Frame 5C to 5D.

Current LNG train capacity is limited by size of single heat exchangers, e.g., the spiral wound exchangers with APCI/C3MR technology. Further capacity expansion is anticipated by revised process flow schemes to add refrigeration duty external to the spiral exchanger of APCI or by parallel installation of plate fin exchangers for Optimised Cascade.

Subject to the capacity limits of individual LNG trains, total target LNG production capacity can be achieved by the installation of multiple LNG trains in parallel. The facilities that have multiple LNG trains are shown in Section 4.3.5.

Comparison for CCS

Similar concepts should be applicable to CCS of maximizing train capacity up to critical equipment limits, installing parallel equipment and trains to achieve target total capacity, sharing common process systems and infrastructure. Preliminary comparisons of post-combustion capture scrubber sizes to similar FGD scrubbers seems to indicate that multiple scrubbers might be required for generator capacities exceeding between 500 – 1,000 MW, as limited by scrubber diameter of ~ 20m. There may be other critical equipment items that would require multiple parallel units and it is outside the scope of this study to identify these items. Economic optimization, including consideration of reliability and availability would determine whether multiple scrubbers could be provided from common amine regeneration units or dedicated regeneration units service each scrubber or generator.
6.1.5 Project Phasing, Trains, Stages

- CCS should probably develop similar project phasing as LNG to control investment levels and risk and reduce costs of subsequent phases
- Early CCS projects will lack multiple large-scale capture plants and might resemble very early single train LNG developments

In an overall LNG value chain project, there can be multiple reservoirs, each with multiple wells tying back to satellite gathering and production facilities, then the economic minimum number of large production pipelines (preferably one only) over long distance to the LNG plant, which may then consist of multiple trains of liquefaction.

Multiple trains can be installed simultaneously to obtain rapid production ramp up and maximize early revenue from full field production capacity. They can be installed in sequence to limit impacts from constrained upstream production ramp up or construction resources. They can be installed sometime after initial development to accommodate upstream production development profile, project funding constraints or expanded market off-take.

Although the duplicated LNG trains themselves will have essentially similar materials and construction costs, overall facilities costs can still deliver economies of scale due to shared process facilities. Shared facilities include gas supply pipelines, LNG storage and loading, and utilities, and non-process infrastructure, e.g., site development and buildings.

Expansion trains executed as Brownfield projects are more predictable and economically more attractive than Greenfield trains for development, costing approximately 25% less. Often site allocation for additional trains is already provided in the preceding plant development. Cost savings due to shared facilities with the foundation project can be similar to multiple train economies of scale as described above.

Comparison for CCS

Similar concepts for CCS have been proposed as for oil and gas development, including parallel capture trains, production hubs or trunk lines collecting CO₂ from multiple sources, minimum / single large transport pipelines, distribution to multiple reservoirs, multiple injection wells. Examples include Rotterdam ROAD, SouthWest Hub and CarbonNet. Phasing installation can be planned to achieve production profile targets or limit risks from funding or resource constraints. The limited level of available funding and the small number of capture projects so far mean that, like the early days of the LNG industry, CCS developments now are constrained to relatively small size. This smaller scale increases capture costs per unit of capacity.

6.1.6 Cost of Production

- Production costs of LNG are significantly affected by project CAPEX
- LNG projects CAPEX per unit production has more than doubled in the last decade
- CCS could expect similar effects and CCS projects will compete with each other for resources and with other process industries such as LNG
The overall cost of production includes the cost to develop the upstream reservoir and production facilities and the LNG liquefaction, storage and export facilities, and shipping and regasification. Production revenue from co-product sales is credited and operating variable costs, including the energy cost of internal fuel gas consumption, are accounted for in net variable costs. Project funding / financing costs, financial return criteria, other fixed costs, depreciation and taxes can be amortized and combined with variable costs to imply a cost of production for export LNG.

Similar to other process industries, cost curves can be constructed from the cumulative production capacity of the many market participants and their respective costs of production. Such curves can be utilized along with market volume and price predictions to infer the economical entry of particular producers or from a class of producers such as new unconventional gas sources.

From a variety of sources, the (pre-GFC) delivered cost of LNG ranged from $2.50 - $5.00 / GJ for conventional gas reserves and from LNG projects that averaged approximately $1,200 million / MTPA capital cost (see Section 6.1.9). Since then, the capital cost of recently sanctioned and proposed projects has escalated to more than $2,600 million / MTPA. Australian projects in particular average more than $3,000 million / MTPA including from conventional reserves, e.g., Gorgon and unconventional Coal Seam Gas projects in Queensland. [See Section 6.1.9 for explanation of causes.]

From the recent Australian projects, the production costs provide break-even at more than $10 / GJ. These projects costs include the full value chain from upstream production and are fully Greenfield developments. By contrast, proposed projects to convert USA LNG terminals into liquefaction and export facilities, on Brownfield sites, and supplied from existing pipeline infrastructure with low cost Henry Hub (incremental spot price marker) shale gas, are predicted to produce LNG at around $8 / GJ.

The core liquefaction technology and much of the on-shore gas plant facilities are similar between reference LNG projects. However, the production cost impacts of project-specific costs is demonstrated by the information above. This is especially true of the cost escalation that is analysed further in Section 6.1.9. The production cost impacts are not judged to have reached levels that would have supply curve impacts on already approved projects, i.e., approved projects are likely to proceed and likely to operate at intended production volumes. However for those projects, the terms of trade will be challenged by price pressure (see following section) and margins will be further challenged by production costs.

**Comparison for CCS**

In spite of a buoyant market and being a mature industry with well-practiced project execution models, the LNG market is experiencing the cost escalation and market dominance shifts described above.

For CCS, many more projects will need to be implemented to meet emissions targets. Projects will tend to be clustered in regions that have emissions-intensive industries and suitable storage reservoirs and stakeholder support. Similar regional resource constraints might be expected to result in similar “overheating” of construction markets. This effect has been observed across several industries such as national oil refining clean fuels specification compliance projects and mining industry investment “booms”.

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**WorleyParsons**

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CCS projects will be competing with each other for qualified personnel, equipment and materials but also with other industries such as hydrocarbons and chemicals process industries and power generation. Considering the ambitious market forecasts for natural gas and LNG and the similarly ambitious emissions reduction targets for CCS, both industries can expect to have to manage cost and schedule risk issues for the outlook period.

Additionally, CCS must manage the new technology risk that will also tend to impact cost and schedule. This risk includes technology scale-up risk for any individual new blocks in the CCS value chain, such as new gasifier technology for IGCC or new scrubbing technology for post-combustion capture. New technology risk will also apply to possible impact of delays in an individual new development impacting the entire value chain. This would in turn impact the business case and project execution to enable all blocks of the new value chain being available to deliver when required from source to sink.

### 6.1.7 Product Value / Price

- LNG price mechanisms are under pressure from customers exposed to high prices
- LNG producers are under pressure from high project costs
- Competition in LNG and energy markets and high energy demand and price have not yet threatened active projects but future project commitments have been revised
- CCS does not have a market or clear government policy intervention to take the place of a market to deal with cost and price pressure
- CCS is (usually) dealing with a low-valued / high-cost imposition

LNG contracts are typically priced by one of three mechanisms; indexing to crude oil price, indexing to a basket of energy products, and indexing to spot market price. The largest importing nations are Japan and South Korea and oil-indexed contracts have been used primarily in Japan, Korea, China and Taiwan.

Recently price pressure from consumers has resulted in questioning of the contract price basis. There are some signs of customer trading blocs forming and the rejection of previous contract bases that underpinned significant projects. For example, Korea’s Kogas withdrew from prior commitment to Gorgon off-take due to failure to win Korean government approval.

Movement away from long term contracts and indexing to oil and towards spot pricing, e.g., Henry Hub plus toll processing fee, is being resisted by traditional IOC and NOC producers citing the large investment scale required for Greenfield production and liquefaction facilities. North American potential export based on merchant market natural gas feed is promoting alternative price markers and spot pricing, since input price is one of their significant competitive advantages.

### Comparison for CCS

CCS differs from LNG in many aspects that make comparison and analogy difficult. Following are some key differences.

- LNG is an energy source competing with other energy sources in a mature, somewhat free, market. However, early LNG projects were driven by government intervention and NOCs.
CCS relies on government intervention to attempt to put a value on externalities resulting from GHG emissions. CCS must similarly to LNG transition to a business case that is based on an adequate and predictable price on CO₂.

- LNG added value to the existing oil and gas industry. CCS downgrades value from CO₂ sources except via valuation of emissions.
- An exception to these preceding two points is that the value of CCS to EOR should rise as crude oil price rises, and LNG is also a product linked to crude price.
- LNG is a fraction (~30%) of overall gas production, which in turn is a fraction (< 25%) of global energy demand. Although both are predicted to grow substantially, the competition with other gas and energy markets means that supply curves allow some predictability and certainty for development planning. CCS will need to provide virtually the entire contribution to decarbonizing current and future fossil fuel usage (excluding emissions intensity reduction from efficiency and fuel switching). There might be relatively limited inter-changeability with other low emissions technology uptake.
- LNG developed gradually to maturity based largely on the existing oil and gas industry. CCS will for many applications need to install and start up the entire value chain in one go. Hub models and transport infrastructure would reduce the extent to which individual capture projects needed to also supply downstream facilities. However there is a chicken-and-egg dilemma to provide incentive for the downstream infrastructure development.

However some analogies are possible with other markets.

- For capture projects installed and operated by the same entity that generates the CO₂, e.g., a power station operator, the valuation of CCS could be similar to emissions compliance projects or “polluter pays” license fees (albeit at much larger scale).
- For capture projects installed and operated by third-parties, toll-processing fees could underpin the project justification for the capture operator with carbon pricing risk continuing to be borne by the entity that generates the CO₂. This would be similar to proposals for LNG production toll-processing based on Henry Hub priced gas feed, with price volatility risk being borne by the off-taker.
- Transport operations (pipelines and marine) should have similar stakeholders and business models as for conventional hydrocarbons systems.
- Reservoir development and storage could be similar to oil and gas production sharing arrangements.

6.1.8 Production OPEX

- LNG technology competition and optimisation has driven down energy consumption, with small variation between alternatives
- Technology competition between CCS alternatives has not converged
- CCS energy penalty of 20% - 40% (PCC on PF power) is much greater than LNG energy consumption of 7% - 10% of feed gas
The major production variable cost for LNG liquefaction is energy consumption in refrigeration compressors, which are usually driven directly or indirectly by gas turbines fired by a portion of the feed hydrocarbons. The overall thermal efficiency of LNG (energy of products exported/energy of feed streams) is ~ 90 – 93% and there are only small differences between the main process technology alternatives. Note that this includes all the typical value chain units that were described in Section 3 including the Acid Gas Removal Unit for capture of CO₂ from process gas, but not any additional energy required for compression for CCS, if installed. Overall non-energy OPEX is typically 3% of CAPEX per annum.

**Comparison for CCS**

Compared to the relatively minor process technology cost differences for LNG, there are major cost differences between the technologies that are still in contention for CCS. Capture technology has not yet been subject to years of competitive market to obtain "natural selection" of technology and providers and to obtain technology performance improvement.

- Acid Gas Removal from natural gas or synthesis gas processing (for chemicals, ammonia, hydrogen, gasification, CTL, SNG) is mature and the selections for existing applications are relatively simple. Required capture units are usually already in place in these processes; only compression, drying, transport and injection of the acid gas are required. Hence, the costs are relatively low to achieve CCS compared to pre- and post-combustion systems from power generation but the total volume contributed only represents a small fraction of the CCS targets.

- Post-combustion application seems to be favoured for retrofit to existing fleets of flue gas sources (conventional power generation, cement, iron & steel, coking, oil refining, ethanol) BUT there has not been an open and competitive market to select winners for retrofit

- Post-combustion on some flue gases (untreated conventional coal PF power generation) are so large and impose such a total CAPEX and energy penalty OPEX that significant integration is required to minimize the penalty. Typically energy penalty for post-combustion capture is in the range 20% to 40% of gross generation capacity.

- For new build driver fuel systems, especially power generation, there has not been an open and competitive market that includes a GHG emissions price at a level and consistency to select between the broad range of a) non-capture but low GHG intensity, e.g., NGCC / CHP, b) pre-combustion, e.g., IGCC / poly-generation, c) advanced coal with post-combustion, e.g., USC, d) and others. In the absence of a sustained high GHG emissions price, coal firing with pioneering CCS has not been able to compete with NGCC.

- Pre-combustion on coal firing requires either repowering retrofit of existing power stations or IGCC new build, both very high cost
### 6.1.9 LNG Facilities CAPEX Cost Trends

- LNG liquefaction learning curve demonstrates approximate halving of unit cost from 1980s to 2000s
- Project cost escalation last decade has caused total project costs to approximately double
- All process industries have been affected by escalation
- Cost increase is due to escalation in project costs (equipment, materials, labour)

As explained already, the CAPEX of LNG developments and recent cost escalation results in impact on overall production costs. That impact can affect project viability and shift global cost competitiveness. It is important to understand the separate cost movements that have resulted in reducing cost due to technology learning curve and increasing cost due to project market constraints and other factors. This section examines the longer term trends and extracts the comparisons between CCS and LNG.

Two sets of costs are typically discussed for LNG developments, one for the core liquefaction and LNG plant itself, the other for the full project development from reservoir to load out. The first number is most useful to consider the effects of technology learning curve because it is the most repeatable unit. The latter number is most useful to consider the overall cost effectiveness of delivering the LNG product and examining project cost competitiveness issues.

The core liquefaction plant costs during the LNG industry development up until the last decade had technology improvements in liquefaction plants with the effect of reducing costs. In the 1980s, LNG liquefaction plant cost was ~ $350 per TPA. As previously mentioned, the liquefaction plant represents approximately 20% of the whole supply chain cost. In the early 2000s, it was ~ $200 per TPA. This cost reduction can be attributed to LNG technology learning curve effect, which includes increasing train capacity as a function of industry experience. However, construction costs of Greenfield LNG projects increased from the middle of the last decade. Currently liquefaction plant costs over $500 per TPA. The increase is due to a combination of industry factors such as constraints of equipment supply and cost pressure due to construction raw materials and labour cost.

Although the liquefaction plant makes up only about 20% of the overall LNG value chain, it is nevertheless the core and enabling process technology for this industry. It has been stated several times that plant costs have benefited due to technology development learning curve and production economies of scale.

The following figures, which pre-date the large cost escalation of the last 7 years, demonstrate the technology-related increasing train size. Bechtel and ConocoPhillips, the providers of the Optimized Cascade process, reported these trends in 2001, before some even larger train sizes were implemented\(^\text{14}\). That report shows plant capacity increasing from around 1 MTPA in 1970 to 3 MTPA in 2000. At the same time unit cost data for liquefaction plant decreased from $250 – 300 /MTPA for < 2 MTPA train capacity to $150 – 200 /MTPA for train capacity > 4 MTPA.

WorleyParsons research, including more recent projects and multiple process types, allows the train size curves to be extended in Figure 26. Also the learning curve effect on train capacity can be

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observed by plotting train capacity against cumulative industry capacity in Figure 27. Cost data for selected pre-2006 plants are listed in Table 12 and and when these are plotted, as shown in Figure 28, it shows the cost reduction associated with increasing plant size.

**Figure 26 -- LNG Train Size Growth (pre-2010)**

![Train Capacity v.s. Time](image)

**Figure 27 -- LNG Train Size Growth (vs. Industry Capacity)**

![Train Capacity v.s. Industry Capacity](image)
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## Table 12 – OVERALL PROJECT SIZE AND COST COMPARISON

<table>
<thead>
<tr>
<th>Project</th>
<th>Process/Type</th>
<th>Capacity (MTPA)</th>
<th>Cost (USD$B)</th>
<th>$/TPA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tangguh</td>
<td>C3MR, Greenfield</td>
<td>7.6(2X3.8)</td>
<td>$1.8</td>
<td>237</td>
</tr>
<tr>
<td>NWS Tr. V</td>
<td>C3MR, Expansion</td>
<td>4.5</td>
<td>$1.8</td>
<td>400</td>
</tr>
<tr>
<td>Sakhalin II</td>
<td>DMR, Greenfield</td>
<td>9.6(2X4.8)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>QatarGas</td>
<td>AP-X, Expansion</td>
<td>15.6(2X7.8)</td>
<td>$4.0</td>
<td>256</td>
</tr>
<tr>
<td>Nigeria</td>
<td>C3MR, Expansion</td>
<td>12.3(3X4.1)</td>
<td>$3.7</td>
<td>301</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>$283</strong></td>
</tr>
<tr>
<td><strong>Optimized Cascade Projects</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ALNG (Tr. 4)</td>
<td>Expansion</td>
<td>5.2</td>
<td>$1.2</td>
<td>231</td>
</tr>
<tr>
<td>ALNG (Tr. 1-3)</td>
<td>Gr &amp; Exp.</td>
<td>9.9</td>
<td>$2.4</td>
<td>242</td>
</tr>
<tr>
<td>Egypt LNG</td>
<td>Gr &amp; Exp.</td>
<td>7.2</td>
<td>$1.9</td>
<td>264</td>
</tr>
<tr>
<td>Darwin LNG</td>
<td>Greenfield</td>
<td>3.3</td>
<td>$1.2</td>
<td>364</td>
</tr>
<tr>
<td>Equatorial Guinea</td>
<td>Greenfield</td>
<td>3.4</td>
<td>$1.4</td>
<td>412</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>$279</strong></td>
</tr>
</tbody>
</table>

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**Figure 28 -- Unit liquefaction plant cost against plant capacity excluding recent cost escalation**

![Unit cost against plant size](image-url)

- **Single Train**
- **Multi-Train**
LNG experience implies doubling capacity every decade while there is a driver. Figure 26 shows train capacity growth over time. During periods of high activity such as the 1970s and 2000s there is considerable growth of train capacity. However, the almost constant train capacity from the mid-1980s to 90s shows the limited growth when investment is not driving development. By plotting train capacity as a function of industry installed capacity in Figure 27 it can be seen that train capacity rises almost continuously as a function of project activity. This could be interpreted as learning by doing – improvement will occur due to activity. Currently however, apart from the Qatar LNG very large trains, demand for further increasing capacity may have stalled in the LNG industry. Since the technology is available currently to install larger trains, the lack of demand may reflect other business concerns with commitment to such large capacity and required investment.

Project cost escalation during the last decade has already been mentioned and the effect is to negate learning curve cost reductions. Process industry construction costs are tracked by a variety of cost indices, either for specific industry sectors or more general indices. One of these is the IHS CERA UCCI, which tracks the costs of equipment, facilities, materials and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of 28 onshore, offshore, pipeline and LNG projects.

Figure 29 -- IHS CERA Upstream Capital Cost Index

In common with other cost indices, UCCI shows significant cost escalation from 2005 to 2008 and for the UCCI portfolio the increase is over 100%. There is some moderation due to the global financial crisis of 2007–2008, which caused a general decline in raw material and equipment prices. This may

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have reduced the construction cost of LNG plants but it was short lived and the index has now returned to pre-2008 levels. According to IHS\textsuperscript{16} the latest 2013 data indicates that the index is holding at near record. In spite of recent moderation of costs, the trend of cost escalation is expected to resume in 2014.

The main reasons cited for rising costs in the LNG industry going against earlier trends of technology learning curve reductions are:

- Capacity of EPC contractors due to active global petroleum project market
- High raw material prices (steel, alloys, concrete) due to high demand
- Lack of skilled and experienced workforce in LNG industry projects
- Devaluation of US dollar / appreciation of local currencies such as Australian dollar, causing growth in local denomination costs (construction cost)

Considering the CAPEX trends for full project development from reservoir to load-out, overall the cost trends and timing are similar to the trends for the LNG plant portion. Prior to the cost spike from ~2003, projects were developed in the $500 to $1,500 per TPA range. Current projects are experiencing the massive increases in capital costs illustrated by the UCCI discussed above. Deutsche Bank estimates historical LNG project average cost of $1,200 per TPA and current sanctioned and proposed project average cost of more than $2,600 per TPA.\textsuperscript{17} Current CAPEX of Greenfield LNG developments in Australia (includes upstream development and LNG plant) are in the range $2,300 to $3,400 per TPA\textsuperscript{18}

As stated above, these costs are not perceived to be at levels that will have supply curve impact on already sanctioned projects. Likely impacts are that projects not yet approved but subject to the same cost pressure (other Australian projects) have already been deferred, cancelled or development plans revised. This provides opportunities for competition from projects that are not subject to the same cost pressure, namely from USA shale gas-based LNG or from new African projects averaging less than $2,000 per TPA.

**Comparison for CCS**

CCS projects will be subject to similar CAPEX cost pressures as for LNG but for a plant that produces low value product. If CCS projects and capacity ramp up as hoped for, these projects will further contribute to hydrocarbon and process industry cost escalation, since they will add to the demand for engineering, equipment, materials and labour.

Early CCS LSIPs will not yet benefit from technology learning curve cost reductions as was experienced for LNG projects immediately prior to the recent cost spike. The comparable LNG projects would be the pioneering projects of pre-1980. As the LNG analysis shows, specific cost of LNG plant in 1980 was almost double that of 2000 in real terms. For CCS LSIPs to demonstrate

\textsuperscript{16} E-mail communication, IHS to WorleyParsons, 12 December, 2013

\textsuperscript{17} Deutsche Bank Global Market Research, The Australian LNG Handbook, 6 September 2011

\textsuperscript{18} Credit Suisse Global Equity Research, Global LNG Sector Update, 7 June 2012, and project proponent web-sites.
technology learning curve reductions, they must be completed in sufficient numbers in a competitive market.

6.1.10 Production Contracts

- Production contracts for LNG underpin project bankability
- EOR is the only significant CCS market that has value adding to support bankability

Typically LNG projects are underpinned by contracts or off-take agreements that forward sell a large proportion of planned production capacity. Such agreements are common in resource development projects including LNG and mines, where large CAPEX is required to bring the resource to production. Securing off-take prior to FID and letting of EPC contracts improves the ability to attract financing for the project.

For example, for the Gladstone LNG (GLNG) project, binding off-take agreements for 7 MTPA were secured for total production of 7.8 MTPA prior to FID. Similarly, prior to FID the Gorgon project was understood to have agreements of 80% - 90% in place. Following the Kogas withdrawal of its off-take from the Gorgon project, it is estimated that the project currently has 35% uncommitted capacity, which is considered high but manageable due to market maturity and demand growth.

Comparison for CCS

Projects that require CO₂ capture as a step in an existing gas or industrial process have a business case for capture that is dependent on the rest of the host process value chain. This is normally the case for conventional LNG process Acid Gas Removal Units. Projects that deliver CO₂ to EOR have a business case that is dependent on the extraction of additional oil. There may be cases where process requirement and EOR disposition work together, such as the Dakota Gasification Company SNG production where CO2 is removed from synthesis gas from gasified lignite. This step is required in the production of SNG. CO₂ is sold as by-product to EOR consumers.

Ideally, CCS that is performed for GHG mitigation will have a price for captured CO₂ that provides value return from the additional costs that are associated with CCS. This can also work together with other drivers for performing capture such as gas processing specifications. In the Sleipner CCS application, CO₂ is removed to meet natural gas specifications and combined with CO₂ offshore tax there is incentive for CCS.

There is not a robust business case for other variants of CCS for which there is no base case driver to remove or capture CO₂, no value add disposition such as EOR, and no GHG pricing to incentivize CCS. Therefore there is no basis for off-take agreements and no other business case for CCS without government intervention, e.g., license conditions for Gorgon LNG, or grants for demonstration facilities, e.g., In Salah. With the lack of business case and commercial commitments, there is no finance available for CCS.

The requirements for government to provide demonstration funding and put in place policy framework that provides certainty for a business case for CCS is discussed in more detail in Global CCS Institute Global Status reports and other reports.
6.1.11 Project Proponents

- LNG has clear proponent stakeholder value propositions and models for engagement and as a result has large and diverse stakeholder participation
- High risks, high early mover costs and unclear returns means government leadership similar to early LNG development is essential for establishment of large scale CCS

Due to the massive costs of LNG projects, the developments are usually supported by multiple partners. The initial LNG developments of the 1970's were led by national oil companies; the projects required the backing of government and their subsidiaries. In more recent times, these can be via farm-in of other oil and gas production companies, e.g., Gorgon is led and operated by Chevron and the development partners are ExxonMobil, Shell, in addition to Osaka Gas, Tokyo Gas and Chubu Electric Power. Also off-takers can purchase interest in the project, e.g., for GLNG the major off-take commitments are by KOGAS and PETRONAS and these are also partners in the project along with Santos (lead) and Total.

Comparison for CCS

The stakeholders in the CCS value chain are described in Section 5.1. Of the listed stakeholders, the commercial participants will be the owner / operators and suppliers of the steps in the chain and probably governments and financial institutions. However until the conditions are in place to support the business case for CCS, the exact model for stakeholder participation will remain unclear. For example, all of the capture unit operator, pipeline operator and storage operator need to be able to define their respective incentive for the installation, operation and maintenance of their facilities – who is paying them and on what basis?

This particularly applies to on-going responsibility for Monitoring, Measurement and Verification of the closed-in reservoir following the cessation of injection. What is the recognition of future costs for maintenance and MMV, what is the mechanism to capture in pricing during the injection phase, what is the limitation of the storage operator’s responsibilities, and what authority assumes responsibility after commercial responsibilities have ceased?

6.1.12 Project Funding and Finance

As described above, LNG projects are financed on the basis of obtaining forward production off-take commitments under price terms of defined supply price indexation. Obtaining finance for the projects is similar to other resource development projects. Projects compete for finance and the cost of finance reflects capital availability and relative risk of the investment portfolio.

Comparison for CCS

Similar to the sections above, the ability to obtain finance for CCS projects will depend on the establishment of policy framework and business case that provides tolerable investment risk. Only if finance providers can evaluate predictable and transparent business models for each of the capture and transport and storage operators will they be willing to consider funding such projects.
6.2 EPC Strategy

As described in Section 4.6, the main liquefaction technology providers are Air Products and Chemicals Inc., (APCI) for C3MR and ConocoPhillips for Optimized Cascade. ConocoPhillips offers the Optimized Cascade Process with Bechtel as the exclusive EPC. ConocoPhillips / Bechtel strategy for providing low cost LNG facility includes project selection, standard designs and aggressive EPC LSTK bidding. Plant designs from previous projects (e.g., ALNG) are modified to fit other locations. Standardized plant design is a strategy of other contractors and in other industries such as ethylene to reduce EPC cost.

As yet it is not possible to make similar EPC strategy comparisons to the CCS industry. Pre-combustion capture is usually dictated by the requirements of the process train that it is integrated into. The capture processes and technology providers are mature, e.g., aMDEA from BASF, Selexol from UOP, Rectisol from Lurgi, and multiple amines from multiple providers such as Dow. Projects that implement a pre-combustion AGRU will not usually separate the provision of the AGRU from the remainder of the process train and so will normally be implemented under the same EPC strategy as the remainder of the project.

For post-combustion capture there is still a wide range of candidate technology providers with capture technologies in development. The combination of capture process with proprietary equipment and project integration and delivery has multiple possible strategies and so far there are a low number of Large Scale Integrated Projects from which to observe the performance of these combinations.

6.3 Delivery Project Schedule and Strategy

Typical LNG project development and delivery schedule could be considered in two phases:

- Concept Selection
- Definition and Delivery

Concept Selection would consist of project development phases known as Identify and Evaluate (see Section 6.5). Activities would consist of quantifying and characterizing the gas / oil reservoir, identifying the field development options, preliminary concept studies to screen options, concept selection and feasibility studies. This early phase is characterized by significant variability in schedule duration due to the many options that can be considered. Data that is required for option evaluation must be obtained or developed. In some cases novel upstream production technology or development options must be defined. The market for the product must be defined.

Usually major companies will apply a stage-gate project development methodology to such developments and they will require a high degree of certainty for the selected concept prior to committing to the high development costs of project definition. There is a cost driver to minimize the number of developments that are approved for Define phase (FEED) but which subsequently are not approved for Final Investment Decision (FID). As such it is usually preferable to spend longer to ensure the robustness of selected concepts and in some cases projects will be “recycled” in evaluation in order to obtain the required robustness.

The fastest LNG project from reservoir discovery to start-up is Pluto (2005 – 2012). However some LNG developments can take much more than 10 years to finalise concept selection.

Definition and Delivery would consist of Define (FEED) and Deliver (EPC) phases to build and start-up the selected concept. These project phases have much more predictable schedules since single
selected concepts with limited uncertainty are to be developed. There is a cost driver to minimize change and minimize deviation from the approved schedules. Usually also there is an opportunity driver to bring production to market according to the planned schedule.

Definition and Delivery durations are typically 4 to 5 years from initial approach to the engineering contracting market at commencement of FEED. Typical overall FEED phase can take between 8 and 13 months depending on competitive bidding process, extent of project standardization, and familiarity of contractor with the selected process technology. Typical overall EPC phase can take from 3 to 4 years.

**Table 13 -- Typical Development Schedule Durations**

<table>
<thead>
<tr>
<th>Years from commencement of FEED</th>
<th>-5</th>
<th>-4</th>
<th>-3</th>
<th>-2</th>
<th>-1</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concept Selection short duration</td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>Concept Selection long duration (up to 10+ years)</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>FEED short duration</td>
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<tr>
<td>FEED long duration</td>
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<tr>
<td>EPC short duration</td>
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</tbody>
</table>

The main variability in FEED and EPC schedules is the type of competitive process for contractor selection and the continuity or “roll over” to select the FEED contractor based on its ability to execute the project EPC. The classical sequential approach would competitively bid both the FEED and EPC and would possibly result in the changeover to a different contractor between these phases. This approach takes longest, at up to 5 years from commencement of FEED phase bidding till completion of EPC.

An alternative strategy, which is offered by contractors in LNG and other industries, commences with negotiated award of FEED and provides an “Open Book” method for establishing LSTK price. The main saving is due to reducing or eliminating front end competitive durations and reducing FEED and early order durations. This is possible if the FEED / EPC contractor has sufficient repeat experience on standardized design and if the owner is willing to award the overall project prior to final negotiated committed price. The owner and EPC contractor review supplier and subcontractor bids and assemble a complete cost. Then the EPC price is fixed and “the book closed”, the EPC builds the plant and does not reopen the book. According to proponents this method can reduce schedule by as much as a year, reduce cost and with less risk to owners.

As yet it is not possible to make reliable schedule comparisons to the CCS industry due to the low number of completed LSIPs. Some CCS projects in development show similar planned durations, e.g., Rotterdam’s ROAD and Saskatchewan’s Boundary Dam projects are both planned to be approximately 3 years for execution. The challenge is that some of the LSIPs are not completing FID due to lack of clarity on project justification.
6.4 Project Risk Management

While there are some common risks across the LNG industry, such as cost escalation, many risks have differing priority for each project depending upon location, complexity and timing. Following are items that are often considered in project risk assessment.

- Environmental (Storms, ecological, pollution)
- EPC Strategy (Lump sum, cost plus, project management)
- Procurement (Long lead items, cancellation fees)
- Partner Relations (Approvals needed, financial)
- Site Risks
- Political/Regulatory/Societal (Government approvals, public opinion, tax regime changes)
- Labour/Material Pricing/Availability
- Economic/Financial/Management (Market issues, demand, capital)
- Organization
- Technical/Operational

Many of these will also apply to CCS projects, as noted often above in discussion of costs.

Also as noted often already, the CCS technology is not as mature as for LNG. So whereas LNG risk analysis would not normally identify significant liquefaction-specific technology risks, early CCS projects could be expected to pay greater attention to technology selection, scale-up, commercialization, and performance issues.

The lack of business model and commercial framework and precedents for CCS has also been noted. Whereas LNG project economic risk management will assess relatively transparent product pricing and production cost risk issues, for CCS the economic risk assessment must include fundamental analysis of the stability and robustness of the market that must be underpinned by policy intervention.

For LNG, as for other oil and gas production ventures, the local political environment may be an issue in some unstable areas and could be a concern for the safety of workers and facility integrity as well as the success of the project. Generally though, LNG is understood and accepted as a mature process industry with economic benefits, controllable environmental and safety hazards and risks and mature handling by the relevant local regulatory authorities to ensure consideration of all relevant stakeholders. Community resistance to CSG development that supports Queensland LNG projects has more to do with the upstream production technology, similar to community suspicion of shale gas in North America, than it does to the mid-stream LNG industry, i.e., the liquefaction plant.

For CCS, the policy environment, regulatory support and community stakeholder engagement is under continuing development and the Global CCS Institute annual global status reports on policy, legal and stakeholder issues. Community concerns will include feared hazards from a “new” and not well understood process industry. Objections should also be anticipated to the economic impact of carbon price policy settings that are required for the business case of CCS, and from the anti-fossil fuel ideology that perceives CCS as a mechanism to continue supporting the coal industry.
In the development of LNG projects, most proponents and contractors proceed through a project development system consisting of sequential stages and gates. Such systems are typically represented by project lifecycle diagrams such as the following figure. These systems are familiar and well understood and will not be elaborated here.


**Figure 30 -- Typical Project Lifecycle**

![Project Lifecycle Diagram](image)

In the development of the CCS value chain, the current adopted CCS project lifecycle is shown below in Figure 31.

A project is considered to be in ‘planning’ when it is in the Identify, Evaluate, or Define stages. A project is considered to be ‘active’ if it has made a positive FID and 1) has entered construction (Execute stage), or 2) is in operation (Operate stage), or 3) is in the process of ceasing operations (Closure stage). As a project progresses through each stage and the scope, cost, risk, and schedule become clearer, the project becomes more defined. This approach reduces uncertainty while managing upfront development costs. In the Identify stage, a proponent carries out early studies and preliminary comparisons of alternatives to determine the business viability of a broad project concept. For example, an oil and gas company believes it could take concentrated CO₂ from one of its natural gas processing facilities and inject and store the CO₂ to increase oil production at one of its existing facilities. To start the process, the company would conduct preliminary desktop analysis of both the surface and subsurface requirements of the project to determine if the concept is viable and attractive. It is important that during the Identify stage, proponents consider all relevant aspects of the project (stakeholder management, project delivery, regulatory approvals, and infrastructure, as well as physical CCS facilities). Before progressing to the Evaluate stage, all options that meet the overall concept should be clearly identified.
In the Evaluate stage, the range of options that could be employed is examined to build on the broad project concept. For the oil and gas company, this would involve exploring:

- Which of its facilities, and possibly even facilities of other companies, might be best placed to provide the concentrated CO₂ for the project
- Pipeline routes that could be utilised from each of these sites, and even alternative transport options such as shipping, if relevant
- Which oil production field is suitable for CO₂ injection based on its proximity to the concentrated CO₂, stage of oil production at the field, and other site factors?

For each option, the costs, benefits, risks, and opportunities are identified. During the Evaluate stage, project proponents must continue to consider, for each option, all relevant aspects of the project (i.e. stakeholder management, project delivery, regulatory approvals, infrastructure, as well as physical CCS facilities). At the end of this stage, the preferred option is selected and becomes the subject of the Define stage. No other options are studied in the Define stage.

In the Define stage, the selected option is investigated in greater detail through feasibility and FEED. For the oil and gas company, this would involve determining the specific technology to be used,
design and overall project costs, required permits and approvals, and key risks to the project. Other activities during the Define stage include conducting focused stakeholder engagement processes, seeking out finance or funding opportunities, and undertaking tender processes for engineering, procurement, and contracting suppliers.

At the end of the Define stage, the project must be sufficiently defined for an FID to be made. The level of confidence in costing estimates should be ±10–15 per cent for overall project capital costs and for project operating costs. Collectively, the Identify, Evaluate, and Define stages take between four and seven years. Development costs to reach an FID can be in the order of 10–15 per cent of overall project capital cost, depending on the size, industry, and complexity of the project.

In the Execute stage, the detailed engineering design is finalised, construction and commissioning of the plant occurs, and the organisation to operate the facility is established. Once completed, the project then moves into the Operate stage.

In the Operate stage, the CCS project is operated within regulatory requirements, and maintained and modified, as needed, to improve performance.

In the Closure stage, the CCS project is decommissioned to comply with regulatory requirements. The site is rehabilitated for future defined use and resources are allocated to manage post-closure responsibilities.

In the Post-closure stage, the project is considered 'Closed', with assets having been decommissioned and a post-closure monitoring program implemented. The project is then considered inactive and is therefore closed.
7 TECHNICAL ASPECTS OF PROJECT

Key Findings:

- For LNG, the reservoir (source) location is fixed. Site selection refers to LNG process plant, storage and marine. For CCS, capture (source) is fixed. Site selection refers to injection.
- LNG plant layout is driven by managing hazard risks due to inventories of flammable material. CCS (capture and compression) layout is driven by integration with capture source.
- Modularisation has been applicable to LNG plant construction and may be applicable for CCS.
- CCS hazards are very different than LNG but containment and dispersion strategies could be adapted.
- LNG Acid Gas Removal Unit technology is similar to pre-combustion capture but very different to post-combustion. Low pressure, very large volume and oxidising environment will require different pre-treatment, solvent selection and equipment design.
- Compression selection is broadly similar for LNG refrigeration and CCS. Driver selection will be site-specific.
- Utilities and infrastructure for LNG are usually provided with the project for green field locations. For CCS, integration with host facility is required.

The process technologies for producing LNG were described at some length in Section 3 and for CCS in Section 5, mainly by reference to literature already familiar to readers from the CCS community. Section 6 then discussed project implementation and execution issues at the level of the justification and broad strategies that must be considered by industry in the development of projects. This Section 7 will examine some of the more detailed non-process, technical and engineering issues that must be defined during design of an LNG project, with comparison to anticipated CCS issues. These include:

- Site Identification, Assessment and Selection
- On-shore Design Strategy
- LNG Plant Engineering Design
- Upstream Production Design

7.1 Site Identification, Assessment and Selection

7.1.1 Site Selection Process

For LNG project development, site selection usually refers to the main production facilities location, especially the LNG plant. The gas reservoir is fixed and possibly the only flexibility in reservoir location is the optimization of well placement to access the reservoir. In CCS, site selection normally refers to the storage site (the reservoir). Selection of the CCS storage site can be more flexible than for gas production, especially when extensive deep aquifers are considered. The capture location however is relatively fixed by the capture source.
The LNG site selection methodology is an iterative process that requires a review of the environmental, social, geotechnical, meteorological-ocean data, and other physical aspects, their cost impact and their ability to satisfy defined criteria and targets. A diagram of this process is provided in Figure 32.

Many of the criteria and issues will be similar between LNG and CCS but with two major differences, the marine location of LNG plants and the significance of Greenfield development for LNG.

Due to required port facilities for the LNG tanker loading / off-loading, all export / import LNG facilities are located at or near shore or off-shore. By comparison, many CCS facilities will have no requirement for marine access. Apart from eliminating consideration of marine conditions and facilities, the possible impact on CCS will be elimination of marine landing facilities at the CCS plant location. For LNG plant construction, especially remote Greenfield development, it is often convenient to land equipment, materials and personnel adjacent to the new development. This has led to increasing extents of modularization in recent projects. In contrast, a land-locked CCS facility may need to develop alternative transport and construction strategies.

Many LNG projects are developing new resources, which may be remote from any other development. This raises many issues of site access and development, infrastructure provision, indigenous populations and environmental values and others. By comparison, the sources of CO₂ for capture are commonly in developed areas (eg industrial precincts or power generation utilities) and would already have put in place all the requirements for development and would be governed by operating permit conditions. The new development components for CCS include the transport pipeline and the injection site which will need to obtain permits as the are likely in non-developed areas. While these might not be in already developed areas, the economic imperative is to find suitable reservoirs within as short a distance as possible from the CO₂ source, reducing the possibility that truly remote developments will be required.
7.1.2 Site Assessment Aspects

- Site assessment supports site identification and selection by the gathering of the criteria information necessary to perform the selection process as shown above, defines site data gathering and surveys scope, and provides complete and consistent site information for subsequent design development. Site assessment is a multi-discipline activity including...
contributions from especially Layout and Plot Plan, Civil and Geotechnical Design, Marine Engineering, Construction, Environmental, Social and Cultural specialists and studies. Some aspects that are examined for assessing LNG sites include:

- **Geotechnical**
  - Characteristics of the site / soil
  - Input to foundation design and levelling of the site
  - Input to preliminary plot plan
  - Seabed characteristics for jetty and material offloading wharf
  - Harbour dredging

- **Meteorological**
  - Meteorological and oceanographic data are combined into met-ocean data: bathymetry, air temperature, humidity, rainfall, wind, currents, wave heights, tidal conditions, storm surge, sea level rise
  - Air temperature and humidity affect designs: turbines/compressors, instrument air, HVAC, cooling systems
  - Ambient temperature causes plant production variation ~ 1.5% per °C, results in day / night production rates variation
  - Wind data affects overall layout: flare locations, harbour design, turbine intakes
  - Rain data affects foundations designs, drainage, soil loading
  - Wave height, direction and duration affect marine design and plant location

- **Environmental**
  - Air quality, foliage, animal habitats, sunlight, aquifers
  - Effect of environment upon the plant operations
  - Effect of the plant on the surroundings
  - Compiled into Environmental Impact Assessment to document effects and mitigation
  - Environmentally sensitive sites can take time and high cost to measure, monitor and mitigate impact
  - Compliance with all Federal, State, and local laws and regulations
  - If no guidelines in a country, World Health Organization guidelines are typically used
  - Most common considerations in EIA are emissions (CO₂, NOₓ, SO₂, Hydrocarbons), effluents (waste water), effects on sea water temperature, noise and effects of dredging

- **Infrastructure Requirements**
  - Roads, fences, communications, medical facilities, power, fuel, construction camps, workshops, warehouse, and other common facilities
Remote, undeveloped areas require more infrastructure to be provided by the project
Site access is a key factor in selecting a suitable plant site

- Seismic
  - Seismic data drives structures and foundations

- Hydrology
  - Drainage and effects of the plant on the site are included in site evaluation
  - Sensitive aquifers, erosion, and ground water impacts are studied

- Social
  - Community attitude to the development, consultation, engagement
  - Demographics, governance, communication, travel
  - Population settlements, resettlement, displacement
  - Livelihood, land use, occupation, ownership
  - Economic activity, natural resources
  - Public facilities, education, health
  - Cultural heritage sites
  - Local content opportunities, employment, contracting

### 7.2 On-shore Design Strategy

#### 7.2.1 Facility Layout

The objectives of the LNG facility layout are to:

- Ensure the plant is safe and economical to construct, operate, maintain and meet the necessary insurance codes.
- Provide adequate separation between major facilities, LNG tanks, and between parallel process trains so that an incident at one facility would not cause physical damage and loss of production to the others.
- Ensure adequate spill containment.
- Permit safe evacuation of people inside the plant and those living close to the fence-line during a hazardous event.
- Meet thermal radiation levels and flammability contours from gas or LNG pool fires.
- Limit blast loads in the event of ignition of flammable clouds to acceptable levels.

It can be seen that many of these objectives relate to mitigating the hazard risks from the processing and storage of large volumes of flammable material. Many of these will not apply to CCS. CCS will have risks due to loss of containment involving plant personnel and neighbouring community /
habitation exposure to CO₂ vapour clouds and perhaps spill containment of liquid. It would not be expected that there would be propagation or escalation via mechanisms such as blasts and fires.

Another difference is that most of the LNG projects that have been discussed in this report are minimally integrated with any neighbouring facilities. Thus there is little requirement to optimize the LNG layout in relation to its surrounding facilities, except to ensure the separation distances discussed above. Usually though the capture unit of CCS must integrate closely with its host source facility in order to have economical flue gas supply and return ducts and provision of utilities from the host source unit.

Therefore many of the considerations for LNG plant development may not apply to CCS and different optimization strategies will be required. For completeness, the typical layout development considerations for LNG are listed here.

- Accessibility (Roads, airstrip etc.) during construction, operations and emergencies
- Elevation (Excavation, pumps, runoff, etc.)
- Rainfall (Flooding, erosion, runoff etc.)
- Construction Materials Availability
- Bathymetry Data (Jetty/Marine)
- Sea Conditions (Breakwater/Jetty)
- Water Availability (Sea and Fresh)
- Prevailing Winds (Flare location, turbine exhaust, vapour dispersion, jetty, etc.)
- Soil Conditions (Foundations)
- Adequate spacing of Storage Tanks to Process/Utilities
- Separation distance between functional modules
- Fire Protection/Fire Zones
- Minimization of Material Costs (Pipelines)
- Impact of property beyond the plant fence

The following images of PNG LNG project demonstrate some layout concepts such as:

- Multiple parallel process trains, including new trains in planning or construction
- Separation between trains and between process units and storage
- Separation between trains adequate to allow construction of new train next to existing train in operation
- Incoming gas pipeline, slug catcher, separation and treatment units upstream of LNG trains
- Storage tank proximity to marine loading
- Separation distance to flare
- Buffer spacing to surrounding facilities / communities
Figure 33 – PNG LNG Plant (Source: Google Earth Pro)
Figure 34 – PNG LNG Layout of Primary Elements (Source: PNG LNG EIS)
LNG plant plot size is typically 700m to 800m long, liquefaction train dimensions about 150m wide and 250m long. Approximate plot area is given for several LNG plants in Table 14. The average area is 41 Hectares per Train.

Table 14 – Size of Various LNG Sites

<table>
<thead>
<tr>
<th>Location</th>
<th>Hectares</th>
<th>Trains</th>
</tr>
</thead>
<tbody>
<tr>
<td>ALNG</td>
<td>84</td>
<td>4</td>
</tr>
<tr>
<td>Darwin LNG</td>
<td>65</td>
<td>1</td>
</tr>
<tr>
<td>NWS</td>
<td>167</td>
<td>5</td>
</tr>
<tr>
<td>QatarGas</td>
<td>170</td>
<td>3</td>
</tr>
<tr>
<td>Egypt</td>
<td>165</td>
<td>3</td>
</tr>
<tr>
<td>Oman</td>
<td>74</td>
<td>2</td>
</tr>
<tr>
<td>Yemen</td>
<td>100</td>
<td>2</td>
</tr>
</tbody>
</table>

7.2.2 Modularisation

Modularisation is a construction concept by which process plant equipment and piping are assembled into modules in off-site construction yards or workshops. The extent of the modules can include several large equipment items or complete pipe rack sections (up to 2000t). The extent of off-site preparation includes full insulation, instrumentation and electrical equipment. The modules are transported to the construction site and connected and assembled into the finished plant. This method has developed as an alternative to traditional delivery of equipment and materials to the site for erection and assembly, sometimes termed “stick built”.

Modularisation has become increasingly applied across construction and building industries including hydrocarbon and chemical process industries. The driver is a desire to minimise site workforce and maximize work in shops and yards. This is due to workforce availability, productivity and cost on construction sites. Examples of the benefits include reduced requirement for mobilization, transport and accommodation of a large construction workforce. Productivity can be higher in fabrication yards due to reduced impact from weather (sheltered), time consumed moving to and from the work site, and permit restrictions for work in operating plants.

Modularisation has been applied to some recent LNG projects including North West Shelf Train V, Pluto, Gladstone LNG projects, and Gorgon.
Modularisation is not a universally applicable trend but it can provide benefit under specific circumstances. It may be particularly applicable for LNG plants since they have good port access to use Marine Offloading Facilities and there is close proximity between port and plant allowing very large modules to be employed.

Application to CCS projects would first need to consider the extent of modularisation that could be achieved, considering the likely very large equipment size of items such as post-combustion scrubbers, and the extent of integration of CCS plant with existing source plant. Transport plans to the CCS plant site would need to inform the size of modules that could be delivered. It is still likely that some extent of modularisation could be achieved, for example in solvent regeneration units.

### 7.2.3 HSE/Hazard/Risk

As stated in the discussion related to facility layout, the safety risks of LNG and CCS are not easily compared. The main risks resulting from loss of containment are fire and explosion for LNG, while personnel asphyxiation from CO₂ is the main risk from CCS.

The safety of LNG, like most hydrocarbons facilities, is a multi-tiered approach to prevent loss of containment, fire prevention, fire protection and fire fighting measures and adequate spacing between parts of the facilities to ensure that a failure, fire or explosion in one area does not escalate into surrounding areas.

While the hazards are different for CCS, some of the features of hydrocarbons plants that are intended to prevent the initiation or escalation of incidents would also be applicable to CCS. These features aim to prevent loss of containment and prevent hazardous accumulation of released fluids and could include:

- Measures to confine or divert spills, using curbs, dikes and trenches where necessary
- Systems to prevent or limit releases, e.g. remote operable valves, minimum flanges and small-bore connections, minimum use of sight glasses
A drainage system layout that limits the travel distance of potential spills and heavier than air gas clouds

A layout of processing facilities and the overall plant, which promotes natural ventilation and dispersion of potential vapour clouds, which is at a safe distance to perimeter fence

Natural ventilation of multi-storey plant structures by using grated floors rather than closed concrete decks, thus avoiding accumulation of released vapours into a relative confined space

Process control and instrumented protective systems

Emergency shutdown (ESD) systems

Emergency depressurising (EDP) systems

Gas detection systems

Buffer zones to prevent CO₂ cloud from reaching permanently occupied areas

Setting aside the main hazard risk differences between LNG and CCS, other aspects of Health, Safety and Environmental protection of personnel working at the facility and in the surrounding communities will be addressed by LNG and CCS projects in a similar manner. Addressing HSE requires consideration of all phases of the project lifecycle. The facility development will be guided by HSE principles and policies defined for the project with reference to:

- Local legal requirements
- Policies issued by the Project Owners and Joint Venture Partners
- Industry standards (API, ANSI, ISO)
- Domestically and internationally accepted norms and standards
- World Bank’s Environment, Health and Safety guidelines in the absence of more stringent national standards

Health hazards shall be minimized during all phases of the project. Design standards shall address chemical, physical, ergonomic and biological health hazards. This development should include the following aspects:

- Health Impact Assessment – may be required to assess impact on affected communities
- Health Risk Assessment – exposure to health hazards should be controlled by plant design and procedures to minimize the need for personal protective equipment
- Chemical Hazards – minimize exposure of personnel and environment to chemical processes by use of closed systems
- Noise – design noise level limits established for: Absolute limit, Work area limit, workshops and machinery structures, computer rooms, offices and control rooms, and other occupied areas
- Other Physical Hazards include: Vibration exposure, Ionising radiation exposure, Non-ionising radiation exposure, Visible light, Thermal stress
• Biological Hazards: Drinking water, Catering and food hygiene, Hazardous bacteria (Legionella), Accommodation and sanitary facilities

The establishment of environmental basis and development of an Environmental Impact Assessment is part of the site assessment and selection process described above. The EIA is legally required and establishes the basis used to predict and check during design and development:

• The hazards posed by the Project and the effects on the environment
• To ensure that the Project complies with the general HSE principles and policies
• That the applicable Environmental Quality Standards are not exceeded
• Ensure measuring, monitoring and verification to support compliance with targeted and licensed performance during construction and operation

Development of an EIA will also be required for a CCS project and will address the issues identified above.

7.3 LNG Plant Engineering Design

Some comparisons and contrasts are made between LNG and CCS engineering design features and strategies. The comparisons are made across the main LNG process blocks that were described in more detail in Section 3.2. The comparison will be limited to post-combustion capture on power generation to simplify the discussion.

The case of pre-combustion capture is a trivial comparison. Acid gas removal units for gas separation plants, synthesis gas processes and others chemical processes are already established and mature technology. Selections for the main pre-treatment and capture technologies are usually clear and matched to the existing requirements of the capture source process.

The case of oxy-fuel capture is difficult to compare directly. The capture mechanism is to produce a highly enriched CO₂ flue gas from the core processes of combustion in oxygen from an ASU combined with recycled CO₂. This bears little resemblance to capture of CO₂ from a natural gas process stream.

7.3.1 Sulphur Removal, Dehydration, other Gas Conditioning Technologies

The main gas conditioning technologies for LNG are:

• Acid gas removal (for H₂S, mercaptans and CO₂) – to prevent downstream corrosion and freezing and meet product specifications
• Dehydration – to prevent downstream freezing
• Mercury removal – to prevent downstream alloy heat exchanger corrosion
• Solids removal – to prevent interference with other gas conditioning processes, e.g., foaming / fouling

For CCS the main conditioning technologies are:
• SOx and NOx polishing – to prevent downstream corrosion, reduce potential for formation of Heat Stable Salts in the absorber to reduce solvent makeup and meet product specifications

• Dehydration – to prevent downstream sweet corrosion and freezing and meet product specifications

• Mercury removal – to prevent downstream alloy heat exchanger corrosion and meet product and flue gas specifications

• Solids removal – to prevent interference with other gas conditioning processes, e.g., foaming / fouling and meet flue gas specifications

• Other criteria pollutants, e.g., NOx, HCl, HF, etc.

• Flue gas cooling and pressure boost to meet requirements of a CO₂ separation process

Criteria pollutants for flue gas (SO₂, NOₓ, particulates) will often already have targeted reduction processes on flue gas such as FGD, SCR, and ESP, depending on the coal composition and local regulations. Application of solvent based capture technologies must consider whether existing flue gas removal specifications are adequate to protect the capture scrubbing or must be improved. Sulphur and water in particular must either have improved or new technology for capture pre-treatment.

Figure 36 -- PCC Plant Block Flow Diagram

With LNG the incoming gas is in a reducing environment and most sulphur species are in the form of H₂S or mercaptan. Acid gas removal by absorption process typically captures sulphur compounds along with CO₂ down to the requirements of the downstream liquefaction process. If required in other gas separation processes, selective removal of acid gas components is possible but for LNG removal down to low levels is required for all components. CO₂ is usually vented to the atmosphere from the solvent regeneration. If emissions limits prevent direct venting of the H₂S (depends on levels in feed gas), then various strategies can be applied, including oxidation so that the venting is of SO₂ instead (for low levels) or sulphur recovery.

In the oxidizing environment flue gas for post-combustion capture, the sulphur is already in oxidized form (SO₃). Depending on coal (or fuel) quality, this might already be a criteria pollutant and flue gas desulphurization (FGD) units might already be in place to achieve emissions criteria. However even low level concentration of pollutants from these units will result in formation of heat stable salts in the capture alkanolamine solvent. An additional or improved SOx and NOx polishing step is typically required. Development of post-combustion solvent systems is still underway and their performance will determine the required extent of pre-treatment FGD.
Dehydration for LNG is a critical pre-treatment step to prevent freezing and blockage in the cryogenic heat exchangers. The required low moisture levels dictate utilization of molecular sieve adsorbents and to obtain economical on-line / regeneration cycles, process gas is chilled to just above hydrate formation temperature in order to condense as much water as possible.

For post-combustion capture, two locations will be required for water removal. First, absorption processes work best at low temperature and so flue gas is desirably cooled prior to scrubbing for capture. By a combination of heat exchange and / or quenching, the temperature reduction would also have the effect of condensing a portion of the flue gas water content. This has the benefits of reducing condensation and thus dilution that could occur in capture scrubbing, and the contacting of flue gas with condensed or quench water will remove some additional contaminants. Second, the captured CO$_2$ that is released from solvent regeneration is saturated with water. In order to prepare CO$_2$ for pipeline specification, which might also require refrigeration and liquefaction, dehydration will be required, to prevent free water and sweet corrosion at minimum. Depending on the moisture specification, either combined chilling and molecular sieve adsorption may be applied, same as for LNG, or an alternative such as glycol dehydration (TEG) might be effective and sufficient.

### 7.3.2 Capture processes

In typical gas processing acid gas removal, absorption is conducted at low temperature and high pressure. The conditions at which the process gas stream is available tend to be the ideal for effective absorption. Then regeneration is at low pressure, which moderates the energy input required to strip the acid gases. Low pressure regeneration is effective for AGR in gas processing because typically the stripped gas is vented to atmosphere or another low pressure disposal.

By comparison, post-combustion capture is at low pressure and flue gas must be cooled first to provide low temperature. Regeneration then requires relatively large energy input to strip the acid gas and low pressure regeneration requires costly compression to rise to CCS pipeline pressure. Further, the absorption is under oxidizing conditions and the amine can be subject to oxidative degradation, which is an operating cost, environmental and corrosion concern. Thus, amine systems with proprietary additives including activators and corrosion inhibitors that were developed for gas processing are not necessarily optimal for post-combustion capture. Further development is in progress by many researchers and technology providers to address these issues and to reduce the energy demand of the stripping process.

Due to the contrasting conditions of high pressure, low temperature process gas stream in natural gas treating compared to low pressure and very high volume flue gas in post-combustion capture, it is quite likely that absorption contacting devices will need to take different configurations for economical application.

### 7.3.3 Comparison of compressors and gas turbines

There are two types of compressors considered for LNG – axial and centrifugal. There is more experience with centrifugal compressors in the LNG industry (and also for similar industries such as ethylene and large oil refinery duties). Centrifugal machines are more durable, can handle process upsets and are less susceptible to surging or stalling. Axial compressors are slightly more efficient but have a narrower operating range. Typically, axial compressors require more stages than centrifugal compressors.
The expected CO₂ flow from typical power station capture and the compression pressure rise from regeneration conditions to pipeline pressure are likely to mean that compressors for CCS will be within the same selection range. Namely a single train or integrally geared (bull gear) centrifugal compressor of approximately 4 to 6 stages per generator unit. This has been demonstrated with designs for some semi-commercial scale demonstration plants. Integrally geared centrifugal compressors are typically specified for large PCC CO₂ streams.

**Figure 37 – Centrifugal Compressors**

Driver selections are likely to be more diverse for CCS due to available energy sources and utilities. In an LNG plant, the ultimate source of energy is the natural gas that feeds the plant. The most direct
and economical means to convert the gas to driver power is via gas turbine drivers. There are several strategies to optimize the cost and efficiency of driving the compressors. These include:

- Moderation of gas turbine inlet air conditions
- Utilisation of low pressure gas streams for fuel such as flash and boil-off gas or stabilization flash gas
- Selection of industrial (larger) or aero-derivative (more efficient) turbines
- Multiple shaft or single shaft models and integration of multiple driven units on single driver shaft
- Parallel turbine & compressor units providing overall refrigerant flow requirement
- Combined cycle heat recovery on turbine exhaust such as HRSG and provision of steam to steam turbine drivers
- Combination of electric motor drivers

For CCS compression requirements, gas will not always be available or economical as a fuel, e.g., at a coal fired power station. It is likely that there will be a much greater diversity of driver selection including gas turbines at gas fired generation (open and combined cycle) or steam at steam cycle power generation (PF or NGCC), or electrical from any power generation. One small semi-commercial demonstration plant design utilized an electric motor driver powered from gross station generation.

### 7.3.4 Cooling Systems

In LNG plants, a lot of energy needs to be removed by cooling systems, especially for refrigeration cycles and sometimes power cycles. Air or water cooling or a combination is used. Air cooling has several advantages the most significant being reduced water consumption, which has been increasingly important in the last two decades. Water use is particularly important for arid locations and for which sea water is the main source. Any plant water consumption represents additional energy consumption for desalination and additional thermal and brine reject impacts on water outfalls.

The biggest disadvantages of air cooling are that the attainable process temperatures are higher compared to water cooling and the effect on process performance from fluctuation air temperature. Although fans require less power than water pumps, overall plant efficiency is greater with water cooling.

Heat transfer area of air coolers is huge due to lower heat transfer rate. As a result, air cooled plants require a larger foot print to accommodate the coolers. Typically air coolers are mounted above the main pipe rack.

For CCS, post-combustion capture has large cooling duties and cooling medium selection will be subject to site-specific issues of available excess cooling capacity (if any), net make-up water demand accounting for water produced by condensation from flue gas in the quench system, plant footprint requirements, and capital and operating cost optimization.
7.3.5 Power Generation

Power generation for LNG is ultimately derived from consumption of some of the natural gas feed. Driver selection optimization for power generation is usually integrated with selections for refrigeration drivers. The relevant strategies are summarized in Section 7.3.3. For CCS, power requirements will most likely be provided from the host power station gross generation capacity.

7.3.6 Flare System

The pressure relief and flare systems are critical to the hazard risk management, integrity, design and layout of an LNG facility. Virtually the entire process and refrigeration systems comprise large inventories of flammable hydrocarbons under pressure. To ensure the integrity of containment systems under upset and emergency scenarios, including fire exposure, depressurizing systems and pressure relief are required. There are two separate flare systems associated with an LNG plant; the warm/wet system and the cold/dry system, which collect from different parts of the process train. These systems are further divided into low and high pressure systems. Plant layout requires allocation of a flare zone “sterile area” which is spaced away from process units and occupied areas.

For CCS, the relief facilities should be simpler conceptually. The majority of process fluids will not be flammable and so relief can be to a vent stack at a safe location that allows for dispersion of the relieved material subject to exposure levels at defined locations. Until the compression of CO₂, the main processes are at low pressure and close to ambient temperature, removing design requirements for depressurizing and low temperature fluids handling.

7.3.7 Heating Requirements

The Heating Medium Requirements for LNG and CCS include:

- Amine Reboiler (both LNG and CCS)
- Mole Sieve (or alternative dehydration) Regeneration (both LNG and CCS)
- Fractionation Reboilers (LNG only)
- Scrub Column Reboilers (LNG only)
- Water Desalination (possibly both dependent on site utilities concepts)
- Defrost Gas (LNG and possibly CCS dependent on storage concept)
- Defrost Steam (LNG and possibly CCS dependent on storage concept)

LNG heating duties can be provided by combinations of direct fired hot oil, hot water from direct fired heaters or waste heat recovery, or steam from boilers or waste heat recovery. For CCS, site specific integration with the host source firing and steam cycles will need to be selected and optimized.

7.3.8 Plant Water System

For Greenfield LNG projects, potable water and demineralised water systems are required. Water is often provided to these systems from desalination plants that may utilize low level process heat recovery in multi-effect evaporation systems. Sanitising and demineralization units are required depending on the water destination. For CCS, water systems will most likely be integrated with the host source unit’s systems.
7.3.9 Other Systems

Additional systems will be required for both LNG and CCS. For Greenfield LNG projects, these will be provided as new units, while for Brownfield or integrated CCS projects, the CCS requirement will be integrated with the host source unit’s systems. The additional systems include:

- Instrument Air
- Nitrogen Generation
- Fuel System
- Fire Protection
- Waste Water Treatment / Disposal (from process, utility unit and general sources)
- Waste chemicals disposal
- Defrost Gas
- Telecommunications

7.4 Upstream Production Design

7.4.1 Well design and construction

Well design and construction are core elements of the upstream component of LNG projects. Injection wells are a routine element in oil and gas developments, being used for reservoir management or for disposal of waste streams. The oil and gas industry routinely injects CO₂, natural gas and water into wells.

CO₂ injection wells for the CCS industry should be able to rely heavily on the technology and knowledge of the oil and gas industry.

7.4.2 Development drilling

A key aspect of the oil and gas industry is the management of uncertainty in the resource being developed. The description of the reservoir is developed based on interpretation of remote measurements and sensing and extrapolation of data available from sparse wells within the reservoir. A typical well intersects the reservoir through a hole with a diameter of approximately 150 to 200 mm and this information needs to be extrapolated to the entire reservoir which can extend kilometres from the well penetration.

Seismic data can be used to infer the surface and internal structures of the reservoir but rely on adjustments to convert from travel time to depth.

When development drilling commences, the only certainty is that the development wells will differ from the original plans. The development drilling campaign is typically adjusted after each well, based on reinterpretation of the results of the previous wells.

The CCS industry can be expected to face the same challenges of reservoir and development uncertainty as the oil and gas industry and can benefit from the same strategies and risk management plans.
7.4.3 Reservoir Surveillance

Reservoir management consists of processes that require the interaction of technical, operating, and management groups for success. The complexity of the problem and size of the asset will dictate the type and number of personnel assigned to the task.

Reservoir surveillance ensures that the optimum recovery from the reservoir is realised. It incorporates a feedback loop from surveys and performance data which lead to updated reservoir descriptions and development plans. Deviations from the original plan may lead to opportunities being identified.

These techniques for reservoir surveillance from the oil and gas industry should be adaptable to the CCS industry.

7.4.4 Reservoir Management

Oil field reservoir management aims to maximise the recovery of hydrocarbons in an economic timeframe and at economic flow rates. The ultimate criteria for the oil field operator are to maximise value and minimise risk.

Figure 38 Reservoir Management Plan

Source: Petroleum Engineering Handbook Volume V

With CCS, the parameters will be altered – value is not a key driver in reservoir management. A key extra parameter is ensuring integrity of the CCS storage location. Injection pressures and overall reservoir pressures need to be managed to prevent fracturing of the seal rocks. Active pressure management of the reservoir (by water draw-off) could be a key element of the reservoir strategy. While the parameters may vary the overall practices of the oil and gas industry should still be applicable to the CCS industry.
8 OPPORTUNITIES FOR INTEGRATION OF LNG WITH CCS

Key Findings:

- CO₂ emitted from LNG Acid Gas Removal Unit regeneration can be incorporated into CCS relatively easily and operational plants have done so for years.
- Capturing flue gas emission from gas turbine exhaust is more difficult. Post-combustion capture is favoured but CO₂ concentration is low due to gas firing.

With the considerable infrastructure that is installed and planned for LNG, and with the CO₂ emissions of the LNG Value Chain, various options for integrating CCS with LNG could be considered to achieve synergies between the goals of each industry. The relatively more straightforward integration is to capture the process and combustion CO₂ emissions from the LNG value chain for sequestration. The relatively more difficult integration is the reuse of gas production facilities to form part of eventual CCS facilities.

For capture of the CO₂ emissions of the LNG Value Chain, the two main sources to be considered are the Acid Gas Removal (AGRU) regeneration vent of CO₂ to atmosphere and the gas turbine driver exhaust gas. The AGRU regeneration vent source is already the subject of CCS in projects that are implemented (Snøhvit, In Salah) or in development (Gorgon) and these are described below. The possible integration of combustion flue gas from LNG plants is discussed in Section 8.1.3 below.

8.1 Projects and Studies for LNG with CCS

The following projects and studies have considered or are developing concepts for CCS integration with LNG production.

8.1.1 Gorgon Project

The Gorgon Joint Venture Participants are investing in the design and construction of the world’s largest commercial-scale CO₂ injection facility to reduce the Project’s overall greenhouse gas emissions by between 3.4 and 4.1 MTPA. Injection will be to saline aquifers.

The Australian Government has committed $60 million to the Gorgon Carbon Dioxide Injection Project as part of the Low Emissions Technology Demonstration Fund.

The Gorgon project is described in Section 4.4.1 and 0.

8.1.2 Snøhvit CO₂ Injection

The Snøhvit LNG project was constructed to exploit the resources of three gas fields in the Barents Sea: Snøhvit, Albatross and Askeladd, which lie about 140km northwest of Hammerfest in Norway. The gas production system is one of the first in Europe to use a subsea production platform, which feeds gas via 143km of pipeline with multiphase flow to a 4.2 MTPA LNG processing plant on Melkøa Island near Hammerfest.

Carbon dioxide (CO₂) is removed from the gas stream and piped 152 km back to the field for injection into an offshore deep saline formation through a dedicated well. Since 2008, around 0.7 MTPA of CO₂ have been safely injected and stored.
8.1.3 Source – Confidential Report - Assessment of Options for LNG Carbon Capture Readiness

On behalf of a confidential client, WorleyParsons has investigated the potential role of Carbon Capture and Storage (CCS) in reducing the carbon intensity of their LNG business, specifically in terms of options regarding carbon capture from flue gas at LNG processing facilities.

Making LNG plants carbon capture ready (CCR) enables retrofitting at a lower cost at some point in the future, at the expense of a relatively small upfront pre-investment cost. The main requirement for CCR is that sufficient space and access are provided for future deployment of capture equipment and systems.

The analysis yielded some important conclusions and implications for decision-makers:

- Retrofitting a CCR plant with CCS technology is more cost effective than on a carbon capture ignorant plant (in NPV terms), no matter what year the retrofit is made;
- Of the CCR brownfield retrofit options studied, retrofit of post combustion capture from the aero-derivative turbines in liquefaction trains has the highest NPV irrespective of changes in discount rate, carbon price, fuel gas price, and retrofit year;
- The option value of being Carbon Capture Ready is highly dependent on the retrofit year and the carbon price, all other things being equal;
- The higher the carbon price, the higher the option value of pre-investment in CCR;
- If we must retrofit for CCS, earlier action is preferable.

8.1.4 Technical Options for CCS Integration with LNG

In LNG processing there are two major CO₂ streams where CCS can be implemented.

- CO₂ capture at the gas conditioning process where CO₂ occurring in gas feed is removed by the Acid Gas Removal Unit (AGRU) as described in Section. The CO₂ has to be removed to meet LNG downstream process specifications.
- CO₂ capture from combustion sources (flue gas) from the various gas turbine drivers in the LNG process, in particular the LNG liquefaction process as described in Section 3.8.

The CO₂ captured from the AGRU is already part of CCS where the CO₂ will be sequestered in saline aquifer for example on the Gorgon and Snøhvit projects.

The other source of CO₂ is then from the flue gases of the various gas turbine drivers where the option of post combustion capture can be implemented as a retrofit or green field installation. From the WorleyParsons confidential report described in Section 8.1.3, post combustion capture is more viable than pre-combustion capture.

Oxyfuel combustion capture was not considered in the WorleyParsons confidential report as oxyfuel capable gas turbines are still under development.

8.1.5 Post-Combustion Capture

Figure 39 below shows the post combustion capture that can be integrated into a LNG facility to capture CO₂ from the flue gas streams. This CO₂ capture stream can be combined with the CO₂
stream from the AGRU for CO\(_2\) sequestration, thus completing the CCS value chain in LNG processing.

**Figure 39- Post Combustion integration of CCS with LNG plant**

For the post-combustion capture CCS option itself, there are several ways in which the CCS can be implemented.

Possible scenarios are:-

- Provide capture of CO\(_2\) from the flue gases of distributed fired equipment such as gas turbine drivers, gas turbine generators, fired heaters and boilers. Various options, with varying levels of heat integration, are available for configuration of the capture equipment, for example:
  - Flue gases can be moved to a common centralised capture unit serving all CO\(_2\) emitters
  - Solvent can be pumped around the facility from a common stripper to individual absorbers located at each CO\(_2\) emitter
  - Individual capture systems can provided local to each CO\(_2\) emission source
  - Or a combination of the above.

- Provide capture of CO\(_2\) from the flue gases of a CCGT power plant used to provide power for an all-electric motor LNG facility. Process heating duties can be supplied from the power plant steam cycle.

- Provide capture of CO\(_2\) from the flue gases of a centralised boiler plant used to generate steam for the LNG facilities heating, motive power and power generation requirements.

### 8.1.6 Discussions

While is it possible to integrate the pre-combustion, oxyfuel and post combustion CCS capture routes into LNG production, a few points of comparisons between the three capture techniques is discussed here.

- Pre-combustion capture could be applied, via the production of hydrogen from natural gas and its subsequent use within modified hydrogen gas turbines. In a brownfield scenario, this would involve significant additional complexity and process equipment and associated capital and operating costs over and above that required for post combustion. In a green field
scenario, gas turbines with hydrogen capability are commercially available. However it is likely that the availability of the LNG plant would be reduced with a loss of syngas production causing a loss of LNG production.

- A potentially more favourable application for pre-combustion within an LNG application might be where there are other adjacent markets for syngas and/or H₂ to be supplied “over the fence” for other applications, e.g. ammonia production, Fischer-Tropsch, further power generation. Use of syngas in this way in addition to the LNG plant would then warrant a larger syngas production facility, with corresponding economies of scale and potential operating flexibility benefits. However with natural gas valued at LNG net back, expanded derivative consumption might not be economical.

- Oxyfuel combustion of natural gas in gas turbines is still under development by gas turbine OEMs and not yet available on a commercial scale. Due to the technical risks and uncertainties in design, this option was not considered as a means for carbon capture on LNG plants.

- Oxyfuel boilers could be applied to generate steam from natural gas and the steam used for power needs. However, like pre-combustion this would involve significant additional complexity, process equipment and costs, compared with that required for post-combustion. There are only 5 oxyfuel combustion LSIPs listed in the Global CCS Institute 2013 report. Similarly to pre-combustion, the availability would be reduced with loss of oxyfuel production causing a loss of LNG production.

- Post-combustion capture, when compared to pre-combustion and oxyfuel combustion, is considered to provide comparable capture levels at lower technical risk, process complexity, capital and operating costs. Post-combustion technology is seen to offer the simplest means of integrating flue gas CO₂ capture into LNG liquefaction facilities design either at the outset or as a later retrofit to a capture-ready plant. The post-combustion capture and export system could be designed to be bypassed, during planned and unplanned outages, such that there is minimal impact on LNG production availability.

Reuse of LNG production facilities for future CCS facilities has not been studied in detail. Many disadvantages are perceived including generally remote location of many LNG plants, shipping transport to those plants, different shipping and storage conditions, smaller volumes and higher costs for shipping and storage than for LNG, and generally long production life of LNG meaning CCS utilisation could only commence far in the future.
9 SUMMARY AND CONCLUSIONS

9.1 DEVELOPMENT HISTORY OF LNG

Although the LNG industry is perceived to have developed rapidly, it is based on quite old foundations. Some key development milestones include:

- Michael Faraday liquefied methane in 1820
- Karl von Linde developed compressor refrigeration machine in 1873
- First LNG plant built in 1912 in West Virginia, began operation in 1917
- Patent filed for LNG in 1914
- First commercial liquefaction plant built in 1941 in Cleveland, Ohio
- First LNG disaster in 1944 in Cleveland, Ohio
- First LNG tanker, the Methane Pioneer, carried first cargo of 7,000 bbl. LNG in 1959 from Louisiana to UK
- First export / import trade in 1964 between Algeria and UK
- One of the longest continuously operated LNG plants at Kenai, Alaska, started in 1969 and shut down in 2013
- LNG is a demand driven industry and demand is determined by competing energy sources, mainly oil and coal
- From the start of the international trade in the 1960s, LNG demand reached 50 MTPA in 1990, then 100 MTPA in 2000, and 240 MTPA in 2012
- Production is expected to approximately double between 2012 and 2030

9.2 DRIVERS AND ENABLERS FOR LNG DEVELOPMENT

- LNG density is 600 times greater than gaseous NG
- Energy density on volume basis is 2.4 times CNG and 60% of diesel fuel
- Natural Gas (& LNG) is clean, low carbon intensity, relatively secure and diverse supply, and not nuclear
- Future Natural Gas supply (& LNG) is supported by advances in upstream production technology allowing access to vast unconventional resources
- LNG allows technically and economically feasible NG transport over very long distances (longer than pipelines and where pipelines are infeasible)
- LNG developed over extended timeframe. Upstream natural gas production was already feeding pipeline systems before the LNG industry. Early LNG liquefaction and regasification development was for storage rather than export. Therefore LNG industry did not need to develop all parts of the value chain at the same time.
Early LNG developments were driven by government development intervention and NOCs.

Learning curve benefits have been demonstrated due to improved process technology performance (led by technology provider competition), increased maximum train production capacity (facilitated by key equipment providers for compressors, motors, heat exchangers) and improved project execution (led by EPC contractors).

Plant capacities increased from 1 MTPA per train in 1960s to 5 MTPA (Atlantic LNG Train 4) in 2005 to 8 MTPA (QatarGas II) in 2009.

**9.3 CHARACTERISTICS OF LNG VALUE CHAIN**

- LNG market has evolved from long term contracts between suppliers and off-takers that underpinned LNG projects to increasing commodity trading.
- Process requirements for liquefaction and LNG product specifications mean that stringent treatment of feed natural gas streams are required to remove contaminants (acid gas, water, mercury).
- Upstream production facilities are dependent on location and characteristics of reservoir/source.
- Co-production of LPG, condensate or crude are dependent on the source.
- Core liquefaction process accounts for only half the cost of an LNG plant, which in turn could be less than half the cost of the total LNG supply chain.
- Bigger is always better for capital and operating cost efficiency up to critical equipment constraints.
- Competitive technology market has resulted in two main providers.
- Maximum train capacity and configuration is set by gas turbine, refrigeration compressor and heat exchanger technology.
- Multi-train plants allow phasing of investment and production, greater total production (than maximum single train) and greater capital cost efficiency (shared infrastructure).
- Project EPC providers and execution strategies are driven by the business models of the technology providers (exclusive or not, equipment supply or not).
- During peak project development activity of the last decade, resource constraints (personnel, skills, materials) have caused significant capital cost escalation.
- Project schedules typically are 4 – 5 years for execution from project sanction (FID). Development schedules prior to FID can be much longer and more variable as upstream development concepts are defined and markets and off-takes committed.
- LNG storage, marine facilities and tanker fleet are major components of the value chain.
- Size and configuration of storage and shipping have grown along with size of LNG plants and number of LNG tankers increases in relation to overall production.
• Regasification facility capacity significantly exceeds liquefaction capacity. This means that a greater number of consumers buy from a lesser number of producers, each producer has multiple markets available.

• All LNG export facilities are constructed at or near shore for marine facilities access

• Near shore location drives site selection and construction strategy

• Site selection is subject to environmental and community stakeholder considerations which can be stringent and constraining

• Facilities layout is optimised for construction, phasing (addition of trains), hazard risk mitigation, site conditions, modularisation

• Hazard risks of LNG production include those of other gas processing (flammability, explosion)

• Additionally materials of construction suitable for cryogenic conditions are required and rapid phase transition explosion is a risk for contact with water

9.4 COMPARISONS OF CCS TO LNG

• CCS may be integrated with LNG to varying extent and with varying cost and difficulty for CO₂ captured from both process gas stream and flue gas

• Some capture technology has not yet been subject to years of competitive market to obtain “natural selection” of technology and providers and to obtain technology performance improvement

• Candidate capture technologies for pressurized reducing streams (pre-combustion) are mature and highly portable from other industries while technologies for low pressure oxidizing streams (post-combustion) are still in development

• Some candidate capture technologies may be implemented on to CO₂ source with relatively little integration requirement while others require extensive adaptation of critical equipment and integration into overall system

• Capture technology energy penalty varies significantly ranging between 10 to 40% of source process energy output. LNG energy penalty is less than 10% of incoming natural gas feed.

• Business case for CCS is not yet established. By analogy, CCS may be considered to be at equivalent LNG development stage as the 50’s / 60’s with first export concept implementation, albeit that the associated natural gas pipeline industry was already well established at that time. There are some specific examples from the CCS value chain that have a market such as capture from chemicals production synthesis gas and transport and injection for enhanced oil recovery.

• While some marine movement of CO₂ could be applicable for regions that lack suitable storage reservoirs, most CO₂ movement will be by pipeline and so gas pipeline industry development may provide better analogy than LNG, which is based on shipping.

• Marine tankers for CO₂ may be more difficult to achieve large scale like LNG due to CO₂ storage above the triple point (> 5 bar) to maintain liquid phase compared to atmospheric pressure for LNG. Density of liquid CO₂ is twice that of LNG.
• CCS Value Chain may have more stakeholders and require more complex commercial settings for all participants than early LNG development, which was largely one-to-one long term contracts

• Definition, access and development of CCS reservoirs seems to correspond to early gas exploration, such as may be demonstrated by recent developments of unconventional gas sources

• For many early projects, all components of the CCS Value Chain (capture, transport, storage) need to be developed at the same time by the project proponent.

• LNG has facilitated advancement in oil and gas industry development by handling gas from oil production and allowing monetising of stranded reserves (no other accessible market, hence economic enabler) whereas CCS integration seems to impose varying extent of penalty on source industries

• CCS development objectives seem to aim for very rapid transition of capacity from small semi-commercial demonstration to full scale capture, whereas LNG train capacity and industry production ramp up occurred more gradually as a consequence of technology and energy market competition, i.e., LNG is market driven while CCS is policy driven

• LNG market growth was not at uniform rate over time and has declined and accelerated with competing energy prices, whereas CCS aims for rapid and consistent growth once commercialised in order to achieve GHG emissions reductions

• Project execution strategies from LNG have many applicable lessons (as do many other complex process industries), including economies of scale, shared infrastructure, learning curve cost reduction, resource constraint cost escalation, site selection, regulatory approvals, and community stakeholder engagement

9.5 CONCLUSIONS

CCS can learn from the industry development experience of LNG. The main lessons to be drawn are:

• Early projects will experience disadvantages of small scale, single supply chain, one-to-one suppliers and off-takers, and needing to set up the entire value chain in a single project. Later projects will experience advantages of existing infrastructure, diverse range of suppliers and off-takers, mature competitive technology, and learning curve cost reductions.

• A commercial framework is required to support predictable valuation of CCS, apportioning benefits to value chain stakeholders, providing the basis for long term contract commitments, and thus supporting bankability of projects.

• Government intervention is required to both set up the needed commercial framework, and also to directly fund early projects or infrastructure so as to overcome the early project disadvantages.

• Market pressures such as project cost escalations and product price competition can be expected to occur at any stage of maturity of the industry.

• The target rate of CCS deployment to achieve GHG reduction targets requires growth rates and numbers of projects that seem to be unprecedented in the hydrocarbon and chemical process industries viewed from the perspective of recent buoyant LNG deployment.
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### Appendix 1. Glossary

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<th>Term / Acronym</th>
<th>Definition</th>
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<tr>
<td>AGRU</td>
<td>Acid Gas Recovery Unit</td>
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<td>ALNG</td>
<td>Atlantic LNG (plant)</td>
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<td>ANSI</td>
<td>American National Standards Institute</td>
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<td>APCI</td>
<td>Air Products and Chemicals Inc.</td>
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<td>API</td>
<td>American Petroleum Institute</td>
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<tr>
<td>AP-X</td>
<td>Air Products C3MR LNG process with nitrogen refrigeration cycle</td>
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<tr>
<td>ASU</td>
<td>Air Separation Unit</td>
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<td>ATR</td>
<td>Auto-Thermal Reformer</td>
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<td>BG</td>
<td>BG Group</td>
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<td>BHP</td>
<td>BHP Billiton</td>
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<td>BOC</td>
<td>A member of the Linde Group</td>
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<td>BOG</td>
<td>Boil Off Gas</td>
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<tr>
<td>BTU</td>
<td>British Thermal Unit</td>
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<tr>
<td>C3MR</td>
<td>Propane Mixed Refrigerant (LNG process)</td>
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<tr>
<td>C₅⁺</td>
<td>Pentane and heavier hydrocarbons</td>
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<tr>
<td>CAPEX</td>
<td>Capital Expenditure</td>
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<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
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<td>CCS</td>
<td>Carbon Capture and Storage</td>
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<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
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<tr>
<td>CNG</td>
<td>Compressed Natural Gas</td>
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<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
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<tr>
<td>CO₂CRC</td>
<td>Cooperative Research Centre for Greenhouse Gas Technologies</td>
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<tr>
<td>CSG</td>
<td>Coal Seam Gas (also CBM – Coal Bed Methane)</td>
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<tr>
<td>DMR</td>
<td>Dual Mixed Refrigerant (LNG process)</td>
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<tr>
<td>E&amp;D</td>
<td>Exploration &amp; Development</td>
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<td>ECBM</td>
<td>Enhanced Coal Bed Methane</td>
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<td>EDP</td>
<td>Emergency De-Pressurisation</td>
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<td>End Flash Gas</td>
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<td>EGR</td>
<td>Enhanced Gas Recovery</td>
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<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>EIA / EIS</td>
<td>Environmental Impact Assessment / Study</td>
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<td>ELNG</td>
<td>Egypt LNG (plant)</td>
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<td>EOR</td>
<td>Enhanced Oil Recovery</td>
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<td>EPC</td>
<td>Engineering, Procurement &amp; Construction (contract)</td>
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<td>EPCM</td>
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<td>ESD</td>
<td>Emergency Shut Down</td>
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<td>Electro-Static Precipitator</td>
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<td>FEED</td>
<td>Front End Engineering Design</td>
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<td>FGD</td>
<td>Flue Gas De-sulphurisation</td>
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<td>FID</td>
<td>Final Investment Decision</td>
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<td>FPSO</td>
<td>Floating Production, Storage and Off-loading</td>
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<td>GDP</td>
<td>Gross Domestic Product</td>
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<td>GFC</td>
<td>Global Financial Crisis</td>
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<td>GHG</td>
<td>Green House Gas</td>
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<tr>
<td>GIGNL</td>
<td>International Group of Liquefied Natural Gas Importers</td>
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<tr>
<td>GJ</td>
<td>Giga Joule</td>
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<tr>
<td>GLNG</td>
<td>Gladstone LNG (project)</td>
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<tr>
<td>H₂S</td>
<td>Hydrogen sulphide</td>
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<tr>
<td>HHV</td>
<td>Higher (gross) Heating Value</td>
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<td>HRSG</td>
<td>Heat Recovery Steam Generation</td>
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<tr>
<td>HSE</td>
<td>Health, Safety and Environmental</td>
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<tr>
<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>IGCC</td>
<td>Integrated Gasification Combined Cycle</td>
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<td>JGC</td>
<td>JGC Corporation</td>
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<td>KBR</td>
<td></td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
</tr>
<tr>
<td>LPG</td>
<td>Liquefied Petroleum Gas</td>
</tr>
<tr>
<td>LSIP</td>
<td>Large Scale Integrated Project</td>
</tr>
<tr>
<td>LSTK</td>
<td>Lump Sum Turn Key (contract)</td>
</tr>
<tr>
<td>MCHE</td>
<td>Main Cryogenic Heat Exchanger</td>
</tr>
<tr>
<td>MEA / MDEA</td>
<td>Mono-Ethanol Amine / Methyl Di-Ethanol Amine</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------</td>
</tr>
<tr>
<td>MEG / TEG</td>
<td>Mono-Ethylene Glycol / Tri-Ethylene Glycol</td>
</tr>
<tr>
<td>MFCP</td>
<td>Mixed Fluid Cascade Process</td>
</tr>
<tr>
<td>mg</td>
<td>Milligram</td>
</tr>
<tr>
<td>MJ</td>
<td>Mega Joule</td>
</tr>
<tr>
<td>MMV</td>
<td>Measurement, Monitoring and Verification</td>
</tr>
<tr>
<td>mol. / mole</td>
<td>Quantity of atoms or molecules</td>
</tr>
<tr>
<td>MR</td>
<td>Mixed Refrigerant</td>
</tr>
<tr>
<td>MTPA</td>
<td>Millions of tonnes per annum</td>
</tr>
<tr>
<td>NG</td>
<td>Natural Gas</td>
</tr>
<tr>
<td>NGCC</td>
<td>Natural Gas Combined Cycle</td>
</tr>
<tr>
<td>NGL</td>
<td>Natural Gas Liquids</td>
</tr>
<tr>
<td>Nm³</td>
<td>Normal cubic metres (of gas at Normal conditions)</td>
</tr>
<tr>
<td>NOC</td>
<td>National Oil Companies</td>
</tr>
<tr>
<td>NPV</td>
<td>Net Present Value</td>
</tr>
<tr>
<td>NWS</td>
<td>North West Shelf</td>
</tr>
<tr>
<td>OECD</td>
<td>Organisation for Economic Cooperation and Development</td>
</tr>
<tr>
<td>OEM</td>
<td>Original Equipment Manufacturer</td>
</tr>
<tr>
<td>OPEX</td>
<td>Operational Expenditure</td>
</tr>
<tr>
<td>Oxyfuel</td>
<td>Combustion in oxygen (rather than air) with dilution of oxygen usually by recycled CO₂</td>
</tr>
<tr>
<td>PCC</td>
<td>Post-Combustion Capture</td>
</tr>
<tr>
<td>PF</td>
<td>Pulverised Fuel</td>
</tr>
<tr>
<td>PNG</td>
<td>Papua New Guinea</td>
</tr>
<tr>
<td>Post-Combustion Capture</td>
<td>Process to separate CO₂ from flue gas after combustion</td>
</tr>
<tr>
<td>ppm</td>
<td>Parts per million</td>
</tr>
<tr>
<td>Pre-Combustion Capture</td>
<td>Process to separate CO₂ from fuel gas prior to combustion</td>
</tr>
<tr>
<td>QCLNG</td>
<td>Queensland Curtis LNG (project)</td>
</tr>
<tr>
<td>QGC</td>
<td>A BG Group business</td>
</tr>
<tr>
<td>SCF</td>
<td>Standard cubic feet (of gas at standard conditions)</td>
</tr>
<tr>
<td>SCR</td>
<td>Selective Catalytic Reduction</td>
</tr>
<tr>
<td>SMR</td>
<td>Steam Methane Reforming</td>
</tr>
<tr>
<td>TCF</td>
<td>Trillions of cubic feet (of gas)</td>
</tr>
<tr>
<td>TPA</td>
<td>Tonnes per annum</td>
</tr>
<tr>
<td>UK</td>
<td>United Kingdom</td>
</tr>
</tbody>
</table>
Appendix 2. Key LNG Projects Datasheets

LNG Project: Ichthys

Partners: INPEX (Operator), TOTAL, Tokyo Gas, Osaka Gas, Chubu Electric Power and Toho Gas

Resource: Ichthys gas field, Browse Basin, North West Australia

Project Budget: $33 billion (press article)

Development Concept: Gas in the Ichthys field will ultimately be developed by approximately 50 subsea wells drilled from more than 10 drill centres. The raw gas production will be produced to a Central Production Facility which will provide gas-liquid separation, gas dehydration, gas export and well control. Liquids will be transferred to a FPSO for condensate dewatering and stabilisation, condensate storage and export and other utility services.

Dehydrated gas will be exported to the new LNG plant in Darwin by an 885 km long, 1.07 metre diameter pipeline. The LNG facilities will be installed at a new site in Darwin Harbour and will comprise two LNG trains

Initial Capacity: 2 trains x 4.2 MTPA

Technology: APCI C3MR

Start-up: End 2016 planned
<table>
<thead>
<tr>
<th>LNG Project:</th>
<th>Prelude FLNG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Partners:</td>
<td>Shell 67.5% (Operator), Inpex 17.5%, CPC 5%, Kogas 10%</td>
</tr>
<tr>
<td>Resource:</td>
<td>Prelude gas field, Browse Basin, North West Australia</td>
</tr>
<tr>
<td>Project Budget:</td>
<td>$12 billion (speculated)</td>
</tr>
<tr>
<td>Development Concept:</td>
<td>Subsea wells in the Prelude field will produce to a Floating LNG facility (FLNG). The FLNG vessel will receive the raw gas, treat it and feed it to a LNG facility located on the deck of the vessel. LNG and associated by-products (LPG and condensate) will be stored in tanks in the hull of the vessel. The vessel will be 488m long and 74m wide. It will be the largest floating offshore facility in the world.</td>
</tr>
</tbody>
</table>

| Initial Capacity:    | 1 train x 3.6 MTPA                               |
| Technology:          | Shell DMR                                       |
| Start-up             | 2016 planned                                    |
LNG Project: Gorgon LNG

Partners: Chevron (approx. 47.3%) (Operator), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and Chubu Electric Power (0.417%)

Resource: Gorgon, Jansz-Io gas fields, Carnarvon Basin, North West Australia

Project Budget: $52 billion (press release)

Development Concept: The Gorgon Project is developing the Gorgon and Jansz-Io gas fields, located within the Greater Gorgon area, between 130 and 220 kilometres off the northwest coast of Western Australia. The subsea gas-gathering system will be located on the ocean floor over the Gorgon gas fields west of Barrow Island in 200 to 1,350 metres of water.

The project includes the construction of a 15.6 MTPA LNG plant on Barrow Island (Class A Nature Reserve) and a domestic gas plant with the capacity to supply 300 Tera Joules of gas per day to Western Australia. Construction is limited to a 300 hectare development area.

Gorgon LNG will be off loaded via a 2.1 kilometre long loading jetty for transport to international markets. The domestic gas will be piped to the Western Australian mainland.

CO2 recovered from the gas treatment process will be injected into a saline aquifer. The CO2 injection location is on the central eastern coast of Barrow Island near the gas processing plant. This site was selected to maximise the migration distance from major geological faults and limit ground disturbance. The injection wells will be directionally drilled from discrete surface locations to minimise the area of land required for the well sites, surface facilities, pipelines and access roads. Monitoring wells will provide a sample point within the injection area.

A range of monitoring activities is planned, including:

- Routine observation and recording of injection rates and surface pressures at the injection wells
- Surveillance to detect the unlikely event of CO2 migrating to the surface
- Measurement via well and/or seismic surveys to track the migration of the CO2 plume in the subsurface
Initial Capacity: 3 trains x 5.2 MTPA
Technology: APCI C3MR
Start-up: 2015 planned
LNG Project: Sabine Pass LNG Terminal

Partners: Cheniere Energy Partners

Resource: Domestic gas, USA

Project Budget: $4 billion (EPC contract value for T1 and T2)

Development Concept: 
The Sabine Pass LNG Terminal is located on the Sabine Pass River on the border between Texas and Louisiana. It was originally designed as an LNG import terminal and commenced service in April 2008, but demand for LNG import to the USA declined significantly with the advent of shale gas.

The LNG import terminal is being converted to an export terminal by the construction of 4 LNG trains. Construction has commenced on the first two trains.

Initial Capacity: 4 trains x 4.5 MTPA

Technology: Optimized Cascade

Start-up: 2015 planned