CARBON CAPTURE OPTIONS FOR LNG LIQUEFACTION

Michael Coulson
Principal Process Consultant

Suzanne Ferguson
Senior Process Engineer

Tim Bullen
Manager CCS and Gasification

Foster Wheeler
Reading, Berkshire, United Kingdom
lng@fwc.com
www.fwc.com

ABSTRACT

The LNG liquefaction process is relatively efficient and is consequently a low emitter of carbon dioxide (CO_2) when compared with other natural gas monetization routes. Carbon capture and storage (CCS) applied to LNG liquefaction facilities could reduce these CO_2 emissions to near zero.

This paper provides an overview of the three main carbon capture technology routes, namely pre-combustion, post-combustion and oxyfuel combustion and the ways in which each of these could be integrated into an LNG liquefaction facility design. An evaluation of the capture technologies applied to LNG liquefaction facilities is reported.

A case study to evaluate three post-combustion capture options, considering direct gas turbine and electric motors to drive the main refrigeration compressors, has been undertaken and a techno-economic evaluation is provided.

INTRODUCTION

The LNG industry has improved the overall thermal efficiency of the LNG supply chain components with the aim of limiting greenhouse gas emissions and the concept for a zero CO_2 emission LNG chain has been mooted [1]. To achieve a zero or near zero CO_2 emission LNG chain would require LNG liquefaction facilities with CCS systems integrated into the plant design.

CCS is the process of removing or reducing the CO_2 content of streams normally released to the atmosphere and transporting the captured CO_2 to a location for permanent storage [2]. CO_2 can be captured from a wide range of large single-point sources, such as process streams, heater and boiler exhausts and vents across a range of industries, for example power generation, cement production, refining, chemicals, steel and natural gas treating. Once captured, the CO_2 is compressed, dried and transported to a suitable storage location such as saline aquifers, depleted oil reservoirs (where enhanced oil recovery could be employed) or depleted gas reservoirs.

SOURCES OF CO_2 AND CAPTURE POTENTIAL IN LNG LIQUEFACTION

In the LNG supply chain the LNG liquefaction plants typically produce in excess of 75% [3] of the total chain CO_2 emissions. The CO_2 emissions within an LNG liquefaction facility vary depending on the plant configuration. The plant configuration is dependent on parameters such as feed composition, feed pressure, products, product specifications, liquefaction technology, cooling media, compressor driver selection and the level of heat / power integration. The majority of the CO_2 emissions from LNG liquefaction plants arise from combustion of fuel and from CO_2 extracted from the natural gas feed stream. The CO_2 emissions for some LNG projects are presented in Figure 1 [4]. This provides an indication of the relative CO_2 emissions from fuel combustion and from feed gas; as much as 90% of the LNG liquefaction plants CO_2 emissions are from fuel combustion.

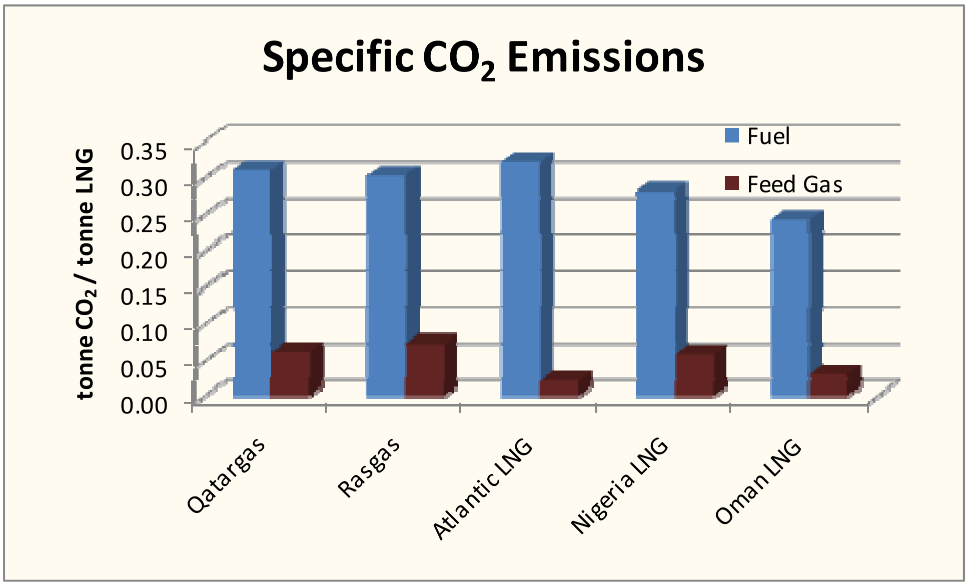

Figure 1. Specific CO_2 Emissions [4]

CO_2 Emissions from Feed Gas

LNG liquefaction plants separate the CO_2 from feed gas because this is necessary to achieve the required CO_2 specification in the feed gas to the liquefaction system to prevent freeze out in the liquefaction heat exchanger. The CO_2 emissions from feed gas depends primarily on the level of CO_2 in the feed gas and secondly on the plant overall thermal efficiency. For a fixed product slate and production rate, improving the facilities overall thermal efficiency reduces the CO_2 emissions in two ways. Firstly, the CO_2 emissions from fuel are reduced, because there is less fuel, and secondly, the CO_2 emissions from feed gas are reduced because using less fuel requires less feed gas. Because the CO_2 is readily separated from the feed gas and concentrated in the acid gas removal unit as part of the normal LNG gas treatment process, it is not unreasonable to assume that capture levels of virtually 100% are achievable.

All operational LNG plants, except Snøhvit, currently vent this CO_2 to atmosphere either directly or via a thermal incinerator or via sulphur recovery depending on the composition of the feed gas. Snøhvit LNG plant at Melkøya near Hammerfest has a CO_2 drying and compression system installed for export of some 700,000 tonnes per year of CO_2 to the Tubåen formation located 145 km offshore at a depth 2500 m below the sea bed [5].

For LNG liquefaction plants with CO_2 content in the feed gas in the range 0.75 to 2.28 mole% the CO_2 emissions are 0.02 to 0.07 tonne CO_2 / tonne LNG [4] respectively. Pro-rating these figures it is estimated that at CO_2 concentrations in feed gas at around 8 mole% the CO_2 emissions, from feed gas, approach the level resulting from fuel combustion, i.e. 0.24 tonne CO_2 / tonne LNG. Therefore, for an LNG facility where high CO_2 feed gases are processed, unless CCS of CO_2 from the feed gas is provided, the total CO_2 emissions will be significantly higher than current LNG industry benchmarks.

Both the Gorgon and Browse feed gases contain high CO_2 concentrations. The Gorgon LNG development, now in the engineering and construction phase, includes a CO_2 reservoir injection system for storage of the CO_2 removed from the feed gas in the Dupuy formation 2500 m below Barrow Island [6]. This scheme will reduce the CO_2 emissions by 0.20 tonne CO_2 / tonne LNG to 0.35 tonne CO_2 / tonne LNG [7]. Plans for the Browse LNG development, which will process a feed gas with a high CO_2 concentration include investigations into the export and storage of the CO_2 removed from the feed gas [8].

CO_2 Emissions from Fuel

Figure 1 shows that the CO_2 emissions from fuel for LNG liquefaction plants are typically in the range 0.24 to 0.32 tonne CO_2 / tonne LNG. With optimisation of the heat and power balance the fuel consumption and CO_2 emissions from fuel can be reduced by approximately 30% [3,9], leading to CO_2 emissions from fuel in the range of 0.17 to 0.22 tonne CO_2 / tonne LNG. Assuming capture and export of 90% of the CO_2 from the combustion flue gases, there is potential to reduce the CO_2 emissions from fuel to around 0.02 tonne CO_2 / tonne LNG. This paper focuses on the capture of CO_2 from flue gases which are typically the major contributor of greenhouse gas emissions from the LNG liquefaction facility.

CO_2 GENERATED FROM FUEL GAS COMBUSTION

Carbon Capture Technologies

There are three process routes that can be considered for CO_2 capture, these are:

- pre-combustion
- post-combustion
- oxyfuel combustion.

For each method an example process description and flow scheme is provided below together with options for integration into an LNG liquefaction facility.

Pre-Combustion – refer to Figure 2. Feed (solid or gaseous hydrocarbon feedstock) is routed to a gasifier or reformer where it is converted to synthesis gas (syngas), predominantly carbon monoxide (CO) and hydrogen (H_2). This syngas then undergoes a shift reaction which increases the H_2 content of the syngas whilst converting the CO to CO_2. The resultant high pressure, high temperature syngas is then cooled, before being washed with a solvent to absorb the CO_2 leaving a concentrated H_2 stream and a CO_2-rich solvent stream. The solvent regeneration process then releases the CO_2 into a stream which can be dried and compressed for export. This process offers a high degree of integration potential as it generates a concentrated high pressure hydrogen stream and the syngas cooling train can be used to raise significant quantities of high, medium and low pressure level steam. A range of CO_2 solvent removal systems are available comprising physical and chemical solvent-based systems as well as alternative technologies such as membranes and pressure swing absorption.

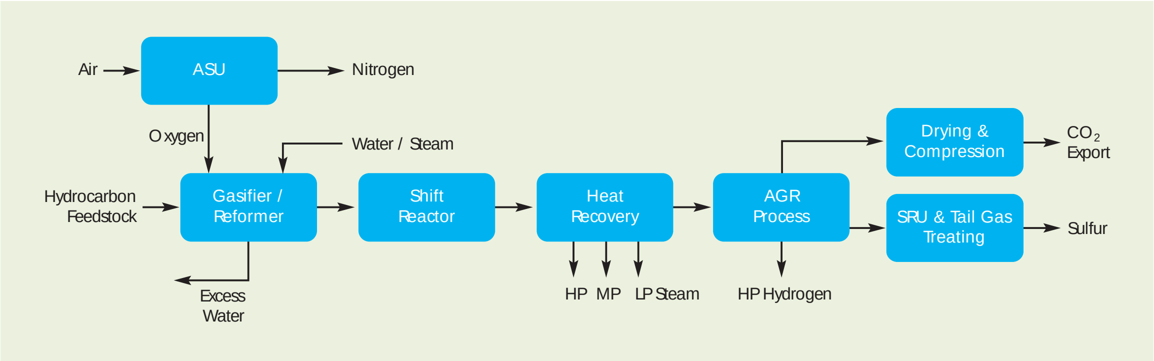

Figure 2. Pre-Combustion Flow Scheme

The pre-combustion capture scheme could be integrated into an LNG liquefaction facility as follows:

- The high pressure H_2 stream could be used as fuel for gas turbine drivers e.g. for the refrigeration compressors. In addition the generated steam could be used to provide process heating, motive power and / or power generation.
- For an LNG plant using electric motors for the refrigeration compressors, the high pressure H_2 stream could be used as the fuel for a combined-cycle gas turbine (CCGT) power plant and the generated steam used for similar duties.

- The high pressure H_2 stream could be used as fuel for boilers and the steam generated (including steam from the pre-combustion heat recovery process) used for heating, motive power and power generation.

For these alternatives the feed supply to the gasifier/reformer could either be a typical LNG plant fuel gas stream, consisting of LNG plant feed, end-flash gas (EFG) and boil-off gas (BOG) or feed gas only. Depending on plant location, coal, petcoke, fuel oils, municipal solid waste or biomass could be used as the gasifier feedstock which would allow more of the natural gas feed to the facility to be converted to LNG and other products e.g. LPG, condensate.

The CO_2 captured from flue gases can be combined with CO_2 captured from the natural gas feed, in the acid gas removal unit, and fed to a common CO_2 drying and compression system for export.

Post-Combustion – refer to Figure 3. Flue gas from fired equipment (e.g. gas turbines, boilers, fired heaters) is initially cooled in either a waste heat recovery unit (WHRU) or a heat recovery steam generator (HRSG) then is further cooled by direct water contact before entering a blower designed to overcome the absorption system pressure drop. The flue gas enters the absorption column, in which it is washed with a solvent such as Monoethanolamine (MEA). The flue gas is typically stripped of around 90% of its CO_2 content before being released to atmosphere from the top of the absorber. The CO_2 rich solvent is then regenerated in a stripping column where CO_2 is released then dried and compressed for export. A range of processes exist utilising different solvents.

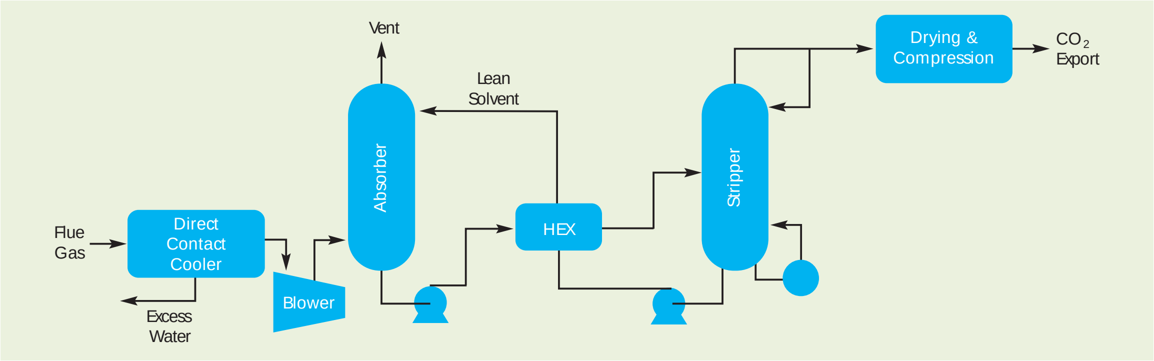

Figure 3. Post-Combustion Flow Scheme

The post-combustion capture scheme could be integrated into an LNG liquefaction facility as follows:

- 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.

In all cases the CO_2 captured from flue gases can be combined with CO_2 captured from the natural gas feed and fed to a common CO_2 drying and compression system for export.

Oxyfuel Combustion Process – refer to Figure 4. The feed is combusted with oxygen, from an air separation unit, in an oxyfuel combustor e.g. boiler or gas turbine. The temperature in the combustor is moderated by recycling a portion of the flue gas back to the combustion chamber. The flue gas passes through particle removal, by electrostatic precipitator, sulfur removal by limestone scrubbing and water removal by cooling and condensation. The remaining flue gas is then further processed to meet the required CO_2 product purity specification before being dried and compressed for export.

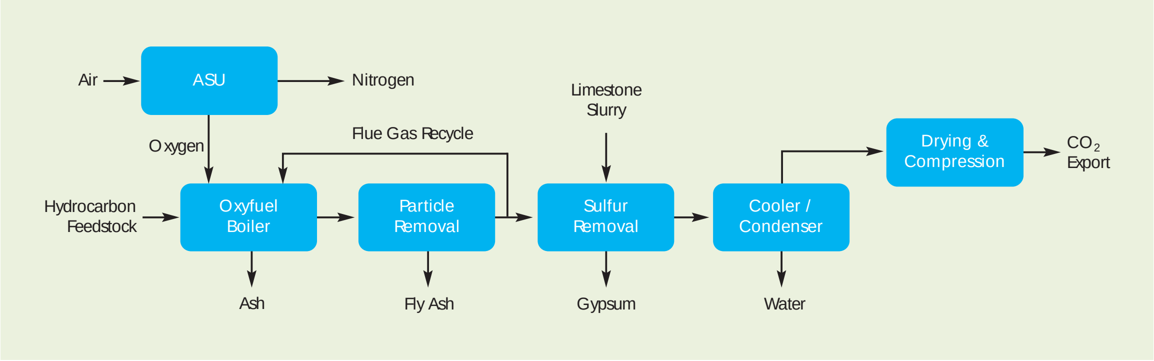

Figure 4. Oxyfuel Combustion Flow Scheme

The oxyfuel combustion capture scheme could be integrated into an LNG liquefaction facility in a number of ways.

- Steam could be generated in oxyfuel boilers and the steam generated used to provide the LNG facilities process heating, motive power and power generation requirements.
- Oxyfuel gas turbines could be employed:
    - either in a CCGT power plant used to provide power to an all electric motor LNG plant with process heating duties supplied from the power plant steam cycle
    - or in direct-drive service for the refrigeration compressors with steam generated, using a HRSG on gas-turbine exhaust, used to provide process heating, motive power and / or power generation as required

As for the pre-combustion options the feed supply to the oxy combustor could either be a typical LNG plant fuel gas stream, consisting of LNG plant feed, EFG and BOG, feed gas only or alternative fuels.

The CO_2 flue gas stream can be combined with CO_2 captured from the natural gas feed and fed to a common CO_2 drying and compression system for export.

Carbon Capture Technology Evaluation

The three main capture routes described above could all be applied to LNG liquefaction plants and each could achieve equivalent CO_2 capture levels. Both pre-combustion and post-combustion technologies are available for natural gas fired systems. Whilst pre-combustion capture could be applied, via the production of syngas from natural gas and its subsequent use within gas turbines, this would involve significant additional complexity and process equipment and associated capital and operating costs over and above that required for post combustion. It is likely that the availability would be reduced with 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 H_2 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.

Oxyfuel combustion of natural gas in gas turbines is under development by gas turbine vendors and not yet available or tested on a commercial scale. Due to the technical risks and uncertainties in design, oxyfuel gas turbines have not been considered further 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. Similarly, the availability would be reduced with loss of oxyfuel production causing a loss of LNG production.

Post-combustion technology, when compared to pre-combustion and oxyfuel combustion, is considered to provide comparable capture levels at no greater technical risk, process complexity, capital and operating costs [10]. Post-combustion technology is seen to offer the simplest means of integrating flue gas CO_2 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. Therefore, of the three main capture process routes, post-combustion has been considered the most appropriate for the case study conducted and reported in this paper.

CARBON CAPTURE CASE STUDY

Case Study Basis

Foster Wheeler has carried out a case study to assess the technical and economic impact of integrating post-combustion CO_2 capture into an LNG liquefaction facility design. The basis assumed for the evaluation is presented in Table 1. The evaluation is based on a new one-train LNG development processing a lean feed gas which requires minimal process facilities and a low process heating duty.

Table 1. Case Study Basis

Parameter	Basis
Development	Greenfield
No. of Trains	One
Feed Gas Composition	Nitrogen – 4.00 mole% CO_2 – 0.50 mole% Methane – 95.49 mole% Ethane – 0.01 mole%
Liquefaction Technology	C_3MR
Cooling Media	Air (24°C)
CO_2 Capture Technology	Post-combustion (MEA)
CO_2 Export Pressure	150 barg

Case Study Scenarios

These are:

- Base case – Gas-turbine drives; no carbon capture
- Option 1 – Gas-turbine drives with heat recovery; no carbon capture
- Option 2 – Gas-turbine drives with heat recovery without supplementary firing; with carbon capture
- Option 3 – Gas-turbine drives with heat recovery including supplementary firing; with carbon capture
- Option 4 – Electric-motor drives with CCGT power block; with carbon capture.

Table 2 provides an overview of the configurations for the scenarios and further details are provided below. For the three capture options, the CO_2 export system includes both CO_2 removed from feed and combustion flue gases.

Table 2. Case Study Scenario Configurations

System	Base Case	Option 1	Option 2	Option 3	Option 4
Refrigeration Compressor Drivers	2 x Frame 7 GTs each with 8 MW helpers	2 x Frame 7 GTs each with 8 MW helpers	2 x Frame 7 GTs each with 8 MW helpers	2 x Frame 7 GTs each with 8 MW helpers	3 x 65 MW electric motors
Electric Power Generation	4 x Frame 5 simple cycle GTGs	STGs	3 x Frame 5 simple cycle GTG plus STGs	STGs	CCGT 2 x Frame7 plus STGs
Heat Integration	WHRU on one GT	HRSGs on GT drives; cogeneration of all heat & power	HRSGs on GT drives; cogeneration of all heat & some power	HRSGs on GT drives with supplementary firing; cogeneration of all heat & power	CCGT provides steam for all process heating duties
CO_2 Capture & Export	No	No	100% from feed gas, 90% from GT driver flue gas, 0% from GTG flue gas	100% from feed gas & 90% from GT driver flue gas	100% from feed gas & 90% from CCGT flue gas

Base Case - the Base Case assumes a typical LNG train with the configuration presented in Figure 5.

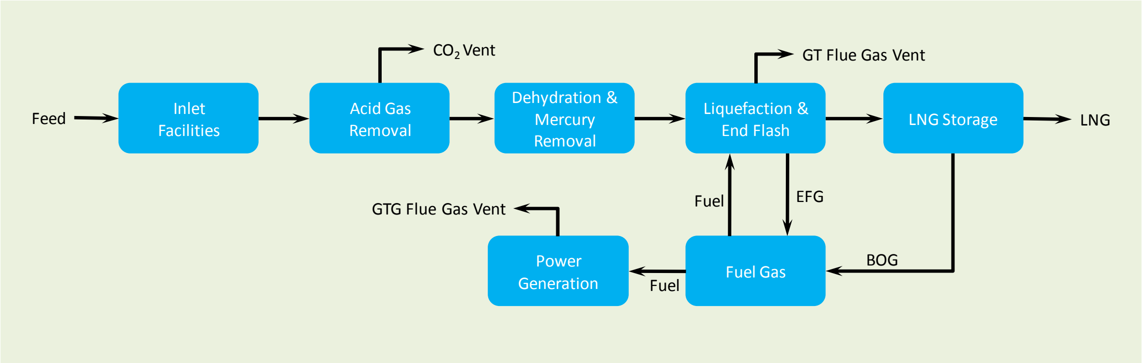

Figure 5. Base Case Flow Scheme

Option 1 – The configuration is presented in Figure 6. This option considers a facility employing gas-turbine drivers for the refrigeration compressors. HRSGs installed on the gas turbine drivers are used to generate steam for direct mechanical drive, process heating duties and to generate all the electric power requirements, via steam turbine generators (STG). Supplementary firing in the HRSGs is not required to satisfy the power and heating duties.

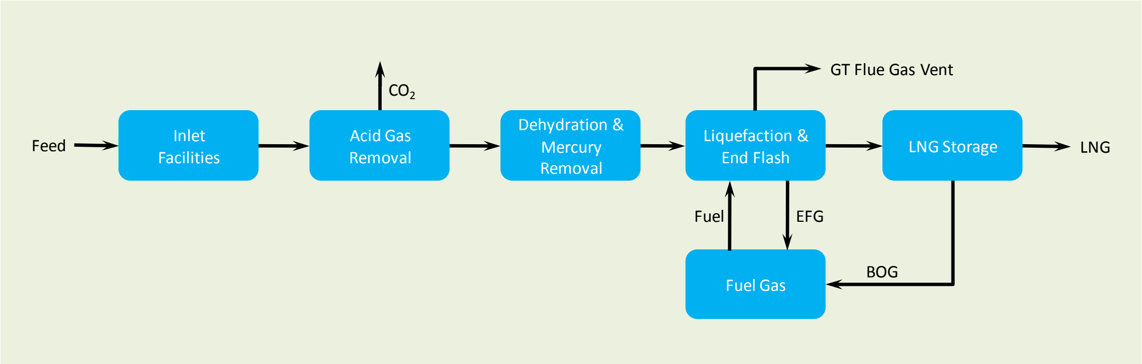

Figure 6. Gas Turbine Driver Full Heat Integration Flow Scheme

Option 2 – The configuration is presented in Figure 7. This option considers a facility employing gas turbine drivers for the refrigeration compressors. HRSGs installed on the gas-turbine drivers are used to raise steam which is used for direct mechanical drive, for process heating duties (including CO_2 capture system) and to generate some of the electrical power requirements via STGs. Supplementary firing in the HRSGs is not utilized; the balance of electric power is generated by simple cycle gas-turbine generators (GTG). A post-combustion capture system, using an amine based solvent is used to remove CO_2 from the combined gas-turbine driver flue gas streams downstream of the HRSGs. CO_2 in the GTG flue gases is not captured.

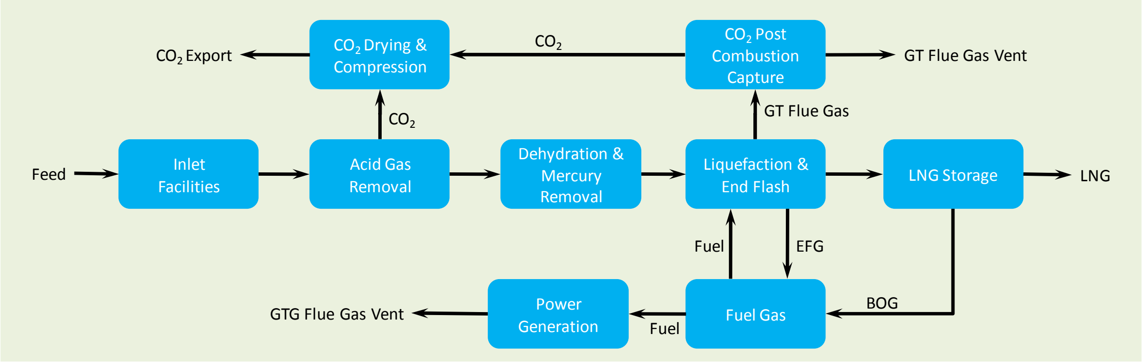

Figure 7. Gas Turbine Driver Partial Integration Capture Flow Scheme

Option 3 – The configuration is presented in Figure 8. This option considers a facility employing gas turbine drivers for the refrigeration compressors. HRSGs installed on the gas turbine drivers are used to generate steam for direct mechanical drive, for process heating duties (including CO_2 capture system) and to generate electrical power via STGs. Supplementary firing in the HRSGs is provided such that all power and heating requirements are satisfied without the need for additional GTGs or fired heaters. A post-combustion capture system is provided to remove CO_2 from the combined gas turbine driver flue gas streams downstream of the HRSGs.

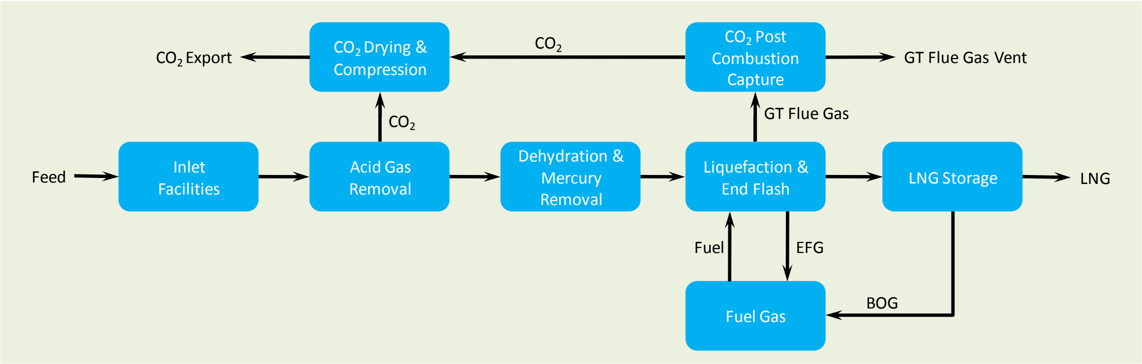

Figure 8. Gas Turbine Driver Full Integration Capture Flow Scheme

Option 4 – The configuration is presented in Figure 9. This option considers a facility employing electric motors for the main refrigeration compressors. Electrical power is provided by a combined-cycle gas-turbine (CCGT) power generation unit with cogeneration of steam for process heating duties (including CO_2 capture system). A post-combustion capture system, using an amine-based solvent, is integrated into the CCGT power plant design.

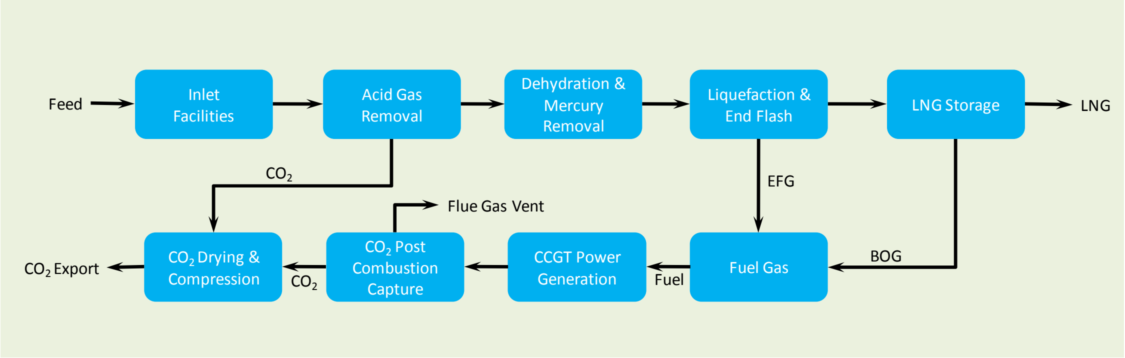

Figure 9. Electric Motor Drive CCGT Capture Flow Scheme

Case Study Results

The design and performance of the base case and option scenarios were developed using a combination of GE GateCycle™ and Aspen HYSYS™ simulations and Foster Wheeler's in-house LNG tools. The performance and Carbon balance derived for the base case and option scenarios are presented in Tables 3 and 4 respectively. The resultant CO_2 balance and specific CO_2 emissions are tabulated in Tables 5 and 6 respectively.

Table 3. Performance Summary

Parameter	Base Case	Option 1	Option 2	Option 3	Option 4
LNG Production (tpd)	13,560	13,560	13,560	13,560	13,590
Overall Thermal Efficiency (%)	91.9%	94.2%	92.6%	92.9%	93.1%
Total Fuel Gas Rate (tpd)	2,030	1,660	1,930	1,865	1,840
Total Electrical Load (MW)	60	42	72	73	272
Total Heat Load (MW)	34	34	124	140	136

Table 4. Carbon Balance

Parameter	Base Case	Option 1	Option 2	Option 3	Option 4
Carbon in feed gas (kmol/s)	10.23	9.98	10.16	10.11	10.11
Carbon in LNG product (kmol/s)	9.35	9.35	9.35	9.35	9.37
Carbon in captured CO_2 (kmol/s)	0.00	0.00	0.58	0.69	0.68
CO_2 emitted (kmol/s)	0.87	0.63	0.22	0.07	0.07
CO_2 emitted (tpd)	3,319	2,377	840	270	264

Table 5. CO_2 Balance

Parameter	Base Case	Option 1	Option 2	Option 3	Option 4
Total CO_2 (tpd)	3,319	2,377	3,062	2,904	2,835
CO_2 captured (tpd)	0	0	2,222	2,633	2,572
CO_2 captured (%)	0%	0%	73%	91%	91%
CO_2 emitted (tpd)	3,319	2,377	840	270	264
CO_2 emissions relative to Base Case (tpd)	0	-942	-2,480	-3,049	-3,056
CO_2 reduction relative to Base Case (%)	0%	28%	75%	92%	92%
CO_2 emissions relative to Option 1 (tpd)	n/a	0	-1,537	-2,106	-2,113
CO_2 reduction relative to Option 1 (%)	n/a	0%	65%	89%	89%

Table 6. Specific CO_2 Emissions

Parameter	Base Case	Option 1	Option 2	Option 3	Option 4
Tonne CO_2 / tonne LNG	0.24	0.18	0.06	0.02	0.02

Case Study Economic Evaluation

Capital cost estimates were generated, for the liquefaction facility, with Aspen K-Base™ software, benchmarked against Foster Wheeler’s recent CCS and LNG projects, based on equipment lists developed for the base case and all options. The costs of the options relative to the base case are presented in Figure 10.

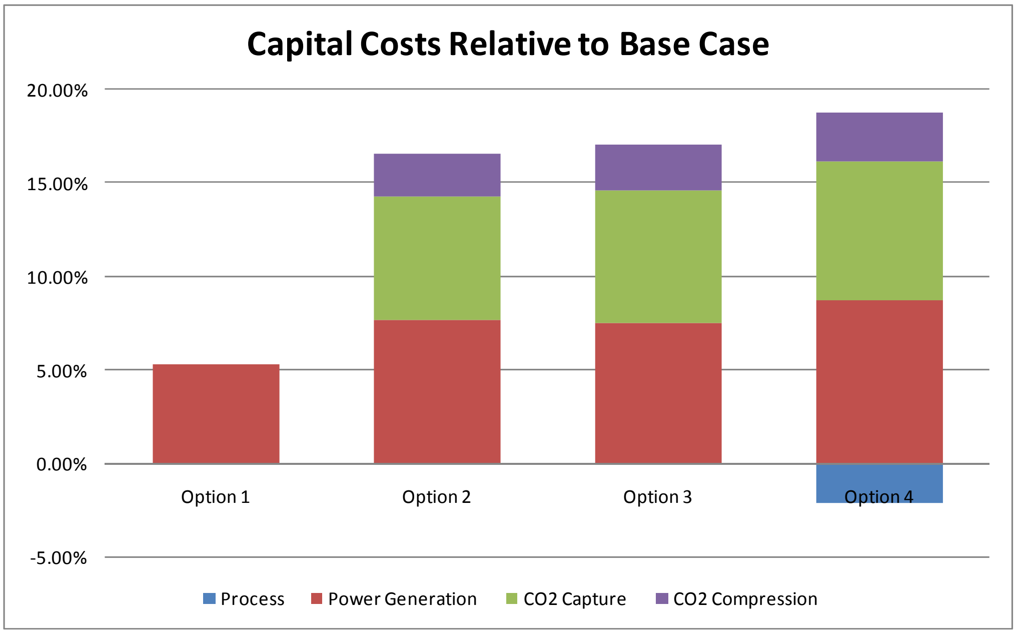

Figure 10. Capital Costs

It can be seen that the capture plant cost is at least as much as that of the power generation plant. The LNG production rates are essentially equal therefore the specific costs (US$/tpy of LNG), relative to the base case, are the same as the relative capital costs presented.

An economic evaluation has been carried using the following basis:

- feed gas cost of 3.5 US$/MMBtu
- normalised LNG cost (US$/MMBtu) for zero net present value (NPV) at 10% discount rate on the investment over 25 year project life
- availability as follows: Base case and the three gas-turbine direct drive options (Options 1, 2 and 3) assumed at 91%; the all electric motor driver case (Option 4) availability assumed 2% higher at 93%
- CO_2 emissions charge in the range of US$ 0 to US$160 per tonne CO_2 emitted
- Capital and operating costs for CO_2 export pipeline and storage are excluded

The results of the economic evaluation are presented in Figure 11 indicating the level of the CO_2 emissions charge that would be required for the capture options (Options 2, 3 and 4) to be economically attractive relative to the base case and Option 1. It can be seen that Option 1 with significant reductions in CO_2 emissions, resulting from the heat recovery and integration optimisation, becomes attractive at a CO_2 emissions charge of circa US$ 35 per tonne. Of the capture options the electric motor driver case (Option 4) is supported by a lower CO_2 emission charge of circa US$ 60 per tonne than the gas-turbine direct driver options (Options 2 and 3) which is attributed to the higher availability assumed for the all electric motor driver plant.

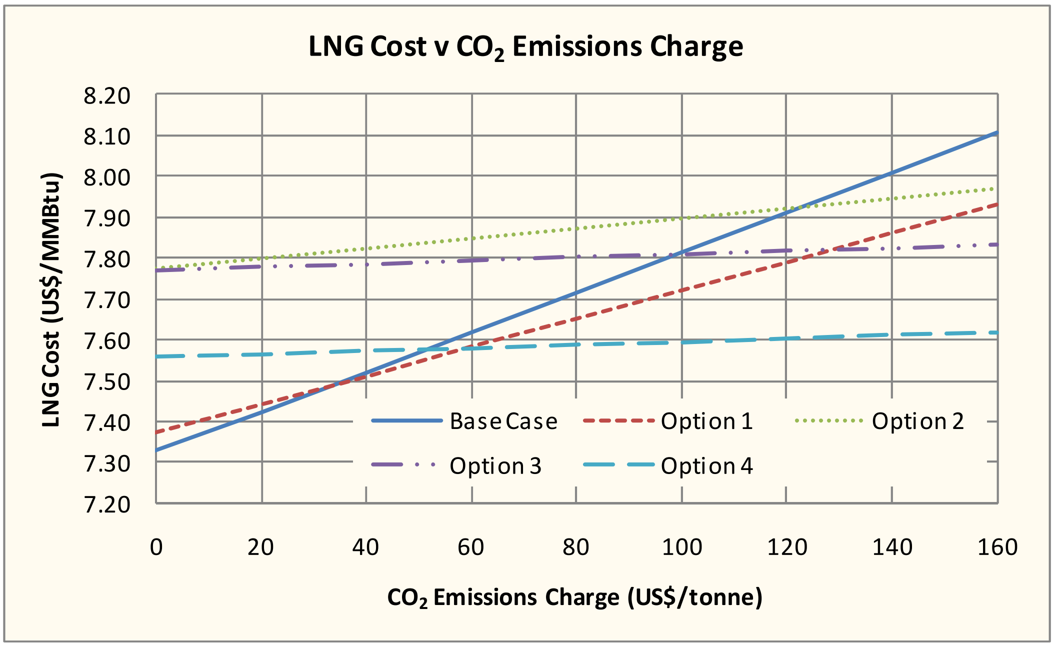

Figure 11. LNG Cost v CO_2 Emissions Charge

The specific cost for CO_2 capture provides a parameter that can be used for comparison with capture systems across different industries and for varying scale. Specific costs tend to be reported as CO_2 captured and CO_2 avoided.

The specific costs calculated, based on a CO_2 emission charge of 0 US$/tonne CO_2 emitted and LNG costs normalised for zero NPV at 10% discount rate, are presented in Figure 12. The figure indicates the avoided cost for Option 1 relative to the base case and the captured and avoided costs are for Options 2, 3 and 4 relative to Option 1.

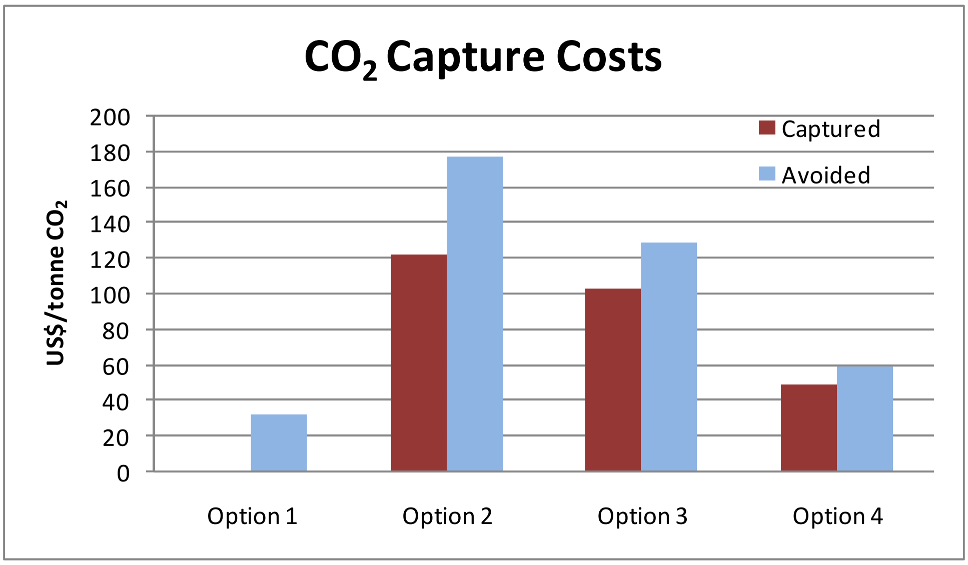

Figure 12. CO_2 Capture Costs

The basis for calculation of the specific costs is as follows:

- $$\text{Cost of CO}_2\text{ captured (US\$/tonne)} = \frac{\text{LNG cost}_{\text{capture}} - \text{LNG cost}_{\text{no capture}}\text{ (US\$/MMBtu)}}{\text{Specific CO}_2\text{ emissions (tonne/MMBTU LNG HHV)}}$$

- $$\text{Cost of CO}_2\text{ avoided (US\$/tonne)} = \frac{\text{LNG cost}_{\text{capture}} - \text{LNG cost}_{\text{no capture}}\text{ (US\$/MMBtu)}}{\text{Specific CO}_2\text{ emissions}_{\text{capture}} - \text{Specific CO}_2\text{ emissions}_{\text{no capture}}\text{ (tonne/MMBTU LNG HHV)}}$$

CONCLUSIONS

Carbon capture has the potential to reduce the total CO_2 emissions from the liquefaction facility to around 0.02 tonne CO_2 / tonne LNG. However, heat recovery and integration optimisation has the potential to significantly reduce CO_2 emissions at a relatively low specific CO_2 avoided cost when compared to capture options. The case study indicates that the cost of post-combustion capture equipment to remove CO_2 from gas-turbine flue gas sources requires significantly higher investment and consequently higher CO_2 emissions charges to provide an economic incentive.

With circa 90% of the carbon in the feed gas to the liquefaction facility leaving in the products, almost all of which will be combusted producing CO_2, greater reductions will be achieved by improving combustion system efficiency and capturing CO_2 at end users.

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