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Whole of Life Greenhouse Gas Emissions Assessment of a Coal Seam Gas to Liquefied Natural Gas Project in the Surat Basin, Queensland, Australia

Final Report for GISERA Project G2

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Executive summary

Australia has become a significant exporter of Liquefied Natural Gas (LNG) with exports predicted to increase from $17bn in 2015-16 to an expected $42bn in 2021-22 as Australian natural gas is sold in international markets to Japan, China, Korea and India.

This research project seeks to fill gaps in our understanding of GHG emissions associated with the Australian CSG-LNG industry in the production and export of natural gas. This work also compares the relative GHG emission impacts of CSG compared with Queensland thermal coal when combusted for generation of electricity in Australia.

A unique feature of this research project is the use of commercial-in-confidence data from a CSG to LNG project in the Surat Basin, Queensland to provide for the first time accurate estimates of life cycle GHG emissions associated with CSG-LNG operations in Australia. Data from company accounts has been collected over two financial years and (2015/16 and 2016/17) before and during commissioning of the LNG trains, and then harmonised to estimate GHG emissions, based on a future output scenario. The future output scenario assumed production of CSG at 576 petajoules (PJ) per year, comprising 100 PJ directed to the Australian domestic market, and 476 PJ sent as feedstock for production of LNG.

This study uses two separate approaches to estimate emissions from different components of the gas supply chain. These assessment methodologies are multi-regional input-output (MRIO) and life-cycle assessment (LCA). Using these two methodologies, this study estimated Scope 1 ('direct'), 2 ('indirect') and 3 ('external') emissions for upstream CSG operations to LNG production. Estimation of emissions occurring from shipping, regasification and combustion of natural gas in Asia are calculated separately.

MRIO is an established method for obtaining an account of carbon emissions attributing them to the consumption of goods and services (products). MRIO is comprehensive and mathematically complete in estimating the total direct and indirect GHG emissions from the company's operations in Australia.

The LCA methodology, conducted using established procedural methods, converted raw inventory and CSG production data into GHG emissions. This approach utilises mass and energy balances over each unit stage of the production process (CSG extraction, water treatment, processing, pipeline compression and transport, and liquefaction) to calculate GHG emissions estimates per unit of production. The LCA analysis provided emissions estimates for CSG and LNG production that also included shipping, regasification, and combustion components that occurred outside Australia.

For the purposes of the MRIO and LCA methodologies in this research project, emissions scopes were defined as:

- Scope 1 - emissions *directly* due to activities within the company during production of CSG and LNG;
- Scope 2 - all *indirect* emissions associated with generation and transmission of electricity used by the company to produce CSG and LNG; and
- Scope 3 - emissions are also indirect and *external* to the company, and they refer to emissions associated with production of goods and services that the company has purchased.

For the future output scenario of 576 PJ per year production of two LNG trains, this research project found total direct, indirect and external Scope 1, 2 and 3 GHG emissions within Australia for this company (including well head, gas processing, water treatment, dehydration, pipeline compression and transport, and liquefaction to LNG) were 4.38 Mt CO_2-e/year (MRIO) and 5.94 Mt CO_2-e/year (LCA).

Direct and indirect emissions (scope 1 and 2) comprised an upstream CSG production component of 2.35 Mt CO_2-e /year (MRIO) and 3.22 Mt CO_2-e /year (LCA) and a downstream LNG production component of 1.88 Mt CO_2-e /year (MRIO) and 2.72 Mt CO_2-e /year (LCA).

Scope 3 emissions for combined CSG and LNG production were estimated at 0.16 Mt CO_2-e/year (MRIO, excluding downstream combustion in Australia and Asia).

A further 38.76 Mt CO_2-e/year (LCA) emissions were generated by shipping LNG, re-gasification and combustion of gas in Asia.

In terms of emission intensity, scope 1 and 2 GHG emissions intensities in Australia were 4.77 kt CO_2-e/PJ and 2.58 kt CO_2-e/PJ, respectively (MRIO). The combined scope 1 (direct), 2 (indirect) and 3 (external) GHG emissions intensity for this company were 7.63 kt CO_2-e/PJ (MRIO) and 10.30 kt CO_2-e/PJ (LCA).

The primary activities contributing to these emissions in Australia were electricity use on-site for CSG extraction and natural gas combustion to electricity for use in LNG production.

Outside Australia, the primary activities contributing to emissions were combustion of natural gas which represented 83% of total emissions when all processes from well head through liquefaction, shipping, regasification and combustion are considered.

Scope 1 GHG emissions within Australia, calculated through consideration of activities and processes in the MRIO and LCA analyses including CSG production, compression, dehydration, water treatment and liquefaction, represented 0.90% of methane generated in the Surat Basin for domestic gas and for feedstock for LNG production at the assumed future production scenario of 576 PJ.

When Scope 2 and 3 emissions are included, this proportion increases to 1.44% of LNG production.

A comparison of GHG emissions from electricity production in Australia from Queensland thermal coal or natural gas derived from Surat Basin CSG showed a reduction in emissions of 31% (open cycle gas turbine; OCGT) and 50% (closed cycle gas turbine; CCGT) because domestic gas use avoided GHG emissions associated with liquefaction, shipping and regasification in Asia, activities which represented 9.9% of total life-cycle GHG emissions.

1 Introduction

Methane is a colourless, odourless, non-toxic gas. It is also the primary constituent of liquefied natural gas (LNG), is a potent radiatively active ’greenhouse’ gas and has a global warming potential (GWP) approximately 28 times that of carbon dioxide (based on a 100-year climate horizon as used in the IPCC Fifth Assessment Report; Saunois et al. 2016; IPCC, 2014). As a result, losses of methane from the onshore petroleum sector to the atmosphere (referred to as ‘fugitive emissions’) as well as overall GHG emissions from this sector are of potential climatic concern particularly where natural gas is used as a replacement fuel for other fossil fuels such as coal. Fugitive emissions are those released in connection with, or as a consequence of, the extraction, processing, storage or delivery of natural gas, and include flaring, venting and leaks, associated with exploration, production, processing, transmission and distribution of gas. Currently, limited information exists on methane emissions from the coal seam gas (CSG) industry in Australia generating potentially high uncertainties in emission estimates.

Globally, 558 Mt of methane is released into the atmosphere annually from anthropogenic and natural sources but considerable uncertainty exists in the magnitude of anthropogenic sources and sinks (Saunois et al. 2016). About 16% of natural sources are seeps from coal seams, hydrocarbons in sedimentary basins and other geological processes in landscapes. A further 29% of methane flux to the atmosphere is derived from fossil fuels (Kirschke et al 2014) which have increased by 15 Mt y^{-1} between 2006 and 2014 (Thompson et al. 2018). Despite these increases, methane emissions from natural gas as a fraction of global production have declined from approximately 8% to 2% over the past three decades (Schwietzke et al 2016). This has probably been due to a combination of rising economic value of natural gas and improved leak control leading to reductions in the release of light hydrocarbons globally into the atmosphere (Aydin et al 2011). Ongoing reductions in fugitive emissions from oil and gas production is critical to reducing any potential climate related risks.

The United States Environmental Protection Agency’s Greenhouse Gas (GHG) Inventory estimates 6.5 Mt CH_4 y^{-1} losses by the onshore oil and gas industry (equivalent to 164 Mt CO_2) representing 1.4% of gas produced and transported in the US (USEPA 2018, page 3-79). Considerable debate has ensued regarding consistent underestimation of fugitive emissions in the ‘bottom-up’ US inventories possibly due to presence of infrequent but large sources of methane from infrastructure (referred to as ‘super-emitters’). Attempts to reconcile inventory estimates of methane emissions with ‘top-down’ observations of atmospheric methane concentrations made from aircraft and towers appeared initially to confirm this underestimation in gas industry sources (Miller et al 2013). However, more recent detailed studies have demonstrated that short duration top-down measurements do not compare well with bottom-up estimates for three reasons: (1) failure to account for coincidence in timing of intermittent work-related emissions events; (2) inaccuracies in emissions factors associated with high flow events; and (3) under-representation of high emitting sources (Vaughn et al 2018). Thus, careful comparisons in time and space between bottom-up and top-down estimates of fugitive emissions are required to understand what actual emissions are (Zavala-Araiza et al., 2015; Alvarez et al., 2018).

In Australia, the Queensland Government estimates that about 110,000 tonnes of fugitive emissions (3 Mt carbon dioxide equivalent; CO_2-e) were emitted by the CSG industry in 2014 representing 12% of all state-wide fugitive emissions. CSG from these sources provides some gas for domestic consumption on Australia’s East Coast but the majority is transported by pipeline to Curtis Island, Queensland, for export to industrial customers in Japan and China. The value of Australia’s LNG exports increased from $17 billion in 2015–16 to $30.8 billion (59.7 Mt) in 2017-18 and is projected to increase to $42 billion in 2021–22 (Resources and Energy Quarterly, 2018). The majority of the

LNG export will be sold to Japan, China and Korea and with a small amount going to India. CSIRO has undertaken a comprehensive examination of fugitive emissions from upstream CSG production fields in the Surat Basin (Day et al., 2012; Day et al., 2013; Day et al., 2014; Day et al., 2015; Day et al., 2016a; Day et al., 2016b; Luhar et al 2018) utilizing ground based mobile survey, remote sensing, bottom-up inventory and top-down atmospheric transport model inversion techniques.

The work undertaken in this study identifies and quantifies 'Scope 1', 'Scope 2', and 'Scope 3' emissions (WRI 2004; BSI 2008; BSI 2011) for upstream CSG and downstream LNG operations of a single company in the Surat Basin, Queensland. **Scope 1** ('direct') refers to emissions directly due to activities within the company during production of CSG and LNG. **Scope 2** ('indirect') emissions are indirect and includes all emissions in the generation and transmission of electricity used by the company to produce CSG and LNG. **Scope 3** ('external') emissions are also indirect and refer to all other emissions – these are generally emissions associated with the production of goods and services that the company has purchased and used in the manufacture of CSG and LNG. For this study, downstream combustion or other uses of gas are not included in the scope 3 emissions calculations. They are reported separately as emissions from combustion in Asia and Australia.

Accurate estimation of emissions from the oil and gas industry requires detailed measurements at a range of time and space scales. This study uses two approaches to estimate Scope 1, 2 and 3 emissions for a Surat Basin, Queensland, coal seam gas (CSG) to LNG project. These are:

1. a multi-regional input output (MRIO) analysis; and,
2. a life-cycle assessment (LCA)

The MRIO was used to estimate total direct and indirect greenhouse gas (GHG) emissions from the company's operations and produces a Scope 1, 2 and 3 assessments (WRI 2004; BSI 2008; BSI 2011). The approach of MRIO is comprehensive and mathematically complete in assessing all upstream CSG and downstream LNG plant contributions to carbon dioxide emissions. The LCA generates data on all upstream and downstream GHG emissions associated with exploitation of Australian gas reserves using a life-cycle assessment (LCA) methodology.

The LCA provides a sound method for determining and comparing environmental impacts of a particular product over its lifetime and identifying points of high emissions to provide opportunities in reducing overall GHG impacts. LCA allows for a complete evaluation of GHG emissions from extraction, processing, through to end-use. The process of LCA typically involves four stages – (1) goal and scope definition, (2) methodology & inventory analysis, (3) impact assessment and, (4) interpretation. Impact analysis allows for conversion of raw inventory data obtained from industry and other literature into GHG 'intensity' (i.e. t CO_2-e per unit product; where 'product' is either LNG, electricity generation or on an energy units basis). Both methods incorporate GHG emissions from upstream CSG production at the well head through compression, dehydration, and liquefaction. The LCA method includes also an estimate of GHG emissions from regassification, transport of gas to destination and combustion.

By analyzing GHG emissions using both MRIO and LCA techniques, this study provides estimates of comparative GHG emissions and emissions intensity over the entire production chain from upstream CSG production to downstream LNG processing, transportation and combustion for a single CSG-LNG project in the Surat Basin, Queensland, Australia. These comparative GHG emissions and emissions intensity values reflect operation under a realistic future output scenario.

2 Methods

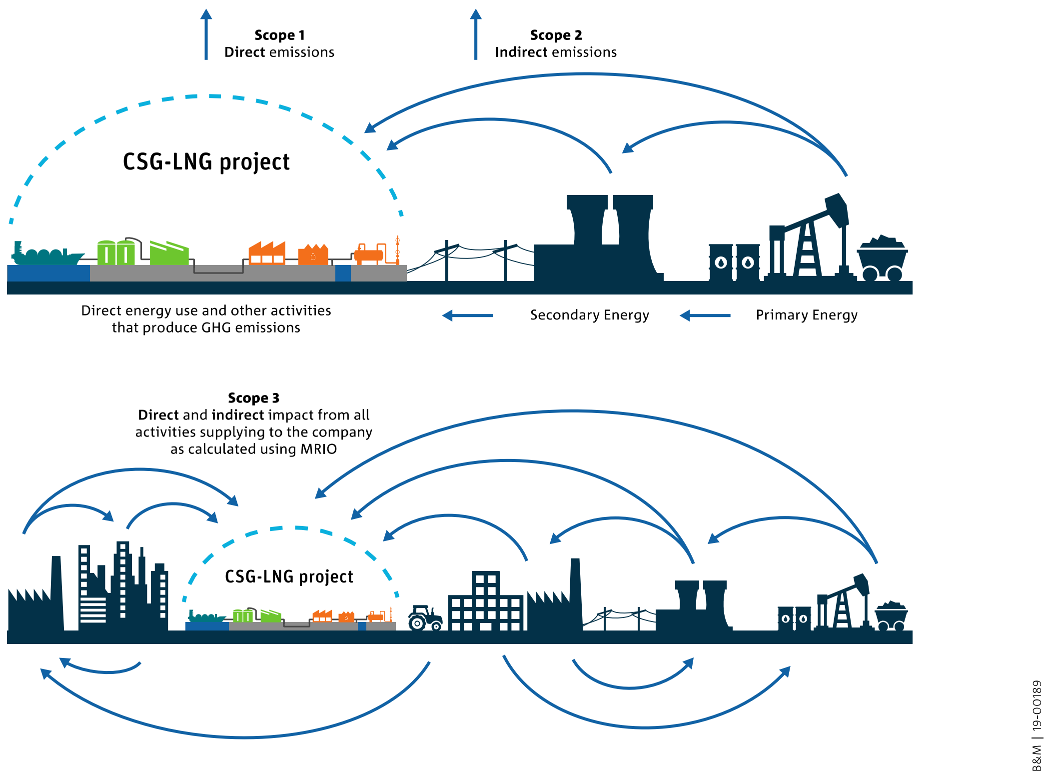
2.1 MRIO methods

Multi-regional input-output analysis (MRIO) is an established method for obtaining a comprehensive account of carbon emissions and attributing them to the consumption of goods and services (BSI 2008; ISO 2018). With a record of the company's expenses and revenue for 2016, we were able to attribute carbon emissions to purchases of products and generate a complete assessment of the impact of the company's activities on GHG emissions and intensity. The Input-Output analysis generates a vector of expenses by the company to calculate the embodied emissions of products in the supply chain.

Emissions calculations are connected to expenditure accounts of the company and from the relative contribution of each product, GHG emissions intensity is calculated, usually with respect to output in dollar value terms. The direct and total GHG emissions were calculated by applying input-output analysis to the company's expenditure and revenue data from 2015-2016.

As our data collection occurred over a period when CSG and LNG production was ramping up to move into the first phase of LNG transportation and trading (ie between 2015 and 2017), we have used account expenditure data to calculate separate intensities per Petajoule (PJ) of CSG and LNG production (where CSG is the feedstock for LNG). These intensities were then scaled to a future output scenario of the LNG trains at an annual total production that represents the most probable sales volume of natural gas to domestic customers and LNG to international customers.

Figure 1: Scope 1, 2 and 3 GHG Emissions associated with the present whole of life GHG emissions for a CSG to LNG gas project in the Surat Basin, Queensland Australia. Arrows indicate physical and /or value flows to production that have associated GHG emissions illustrating the feedbacks inherent in the complex economy surrounding and supporting the company's activities.



MRIO calculations in this report were carried out in the Australian Industrial Ecology Virtual Laboratory (IELab). The IELab is a cloud-computing environment that enables construction of customised input-output tables, which can then be used for undertaking emissions assessments.

The IO table for year 2015-2016 was coupled with data on carbon emissions for 344 sectors of the Australian economy. This model was then used for calculating both the direct and indirect carbon dioxide emissions (Wood and Lenzen 2003; Lenzen et al. 2014a; Malik et al. 2014; Fry et al. 2015; Baynes et al. 2018).

The Scope 1, 2 and 3 emissions (Figure 1) are expressed in terms of direct and indirect GHG emissions (kilotonne CO_2-e /year) and GHG emissions intensities (kilotonne CO_2-e/PJ or kilotonne CO_2-e/$AUS million in 2016 dollars where the $-value in the denominator includes the value of all output locally consumed CSG and exported LNG).

2.2 MRIO Data Sources

The IELab database is a compilation of two types of data: monetary transactions from the Australian Bureau of Statistics (ABS) National Accounts for 2015/16 and a set of corresponding 'satellite accounts' that detail the social, environmental and economic inputs to production by sectors of the Australian economy (Lenzen et al. 2014a; ABS 2018). The IELab has been used with a set of 344 sector and product classifications, to which we added the data from this company. The total energy value of production by this company was 576 PJ/year at full capacity (100 PJ of CSG being used domestically and 476 of LNG being exported).

We were granted access to commercial-in-confidence financial, production and GHG emissions information owned by the company on their actual or budgeted annual expenses pertaining to the CSG and LNG businesses, respectively. This was combined with production reports and reports on domestic sales and exports for 2015/16 and 2016/17. We have used direct data on expenses, revenue and the quantities available in quarterly and year-to-date production reports to obtain intensities that ultimately enabled us to estimate future GHG emissions through a scenario of forecast production of LNG for export and Australian consumption of CSG. These were standardized and applied to forecast future LNG production to estimate GHG emissions during operations (referred to here as 'future output scenario').

From an analytical and reporting perspective, this MRIO is reporting the CSG and LNG production as a single entity; although input data was obtained and prepared separately for each side of the business. Since data availability for upstream and downstream parts of the businesses was in different years, we adjusted changes in prices between years and combined the intensity data (e.g. $output/PJ, or $expenses/PJ) for the different operations in a consistent way so that data between the two years were compatible (refer to the data harmonisation steps shown in Table 1). Production and emissions data from ramp-up of a second LNG train commissioned during 2016/17 were excluded from the calculations of GHG intensities for the LNG operations because this period involved unusual emissions. Hence, the results of this work should be interpreted as emissions from a standard year's plant function for the future output scenario.

Table 1: **Data harmonisation of production and expense data from CSG and LNG operations for different financial years to obtain GHG intensities ($/PJ) in 2015/2016. Changes in prices and Consumer Price Index (CPI) are used to adjust LNG expense data for 2016/17 so that GHG emissions under future output scenario can be calculated.**

CSG Expenses 2015/16	CSG Production 2015/16	CSG Intensity 2015/16		Intensity 2015/16		LNG intensity 2015/16		LNG production 2016/17	LNG Expenses 2016/17
$	PJ →	$/PJ	→	$/PJ	←	$/PJ	← CPI, price	← PJ	$

2.3 CSG Production and Sales

From company data, we determined production and destination of CSG over 2015/16. Average prices for domestically sold CSG, and exported LNG over that same financial year enabled us to estimate the value of sales production specifically from the Surat Basin.

The future output scenario of LNG production is based on a contracted export flows of LNG added to the domestic supply of natural gas (100 PJ/year) which includes 24 PJ of natural gas to domestic electricity generation (CCGT). The scenario of domestic natural gas sales flows of 100PJ/year is an approximate annualized average over the project lifetime considering long-term gas contracts to 2040 and observed total domestic sales volumes of ~500PJ to date.

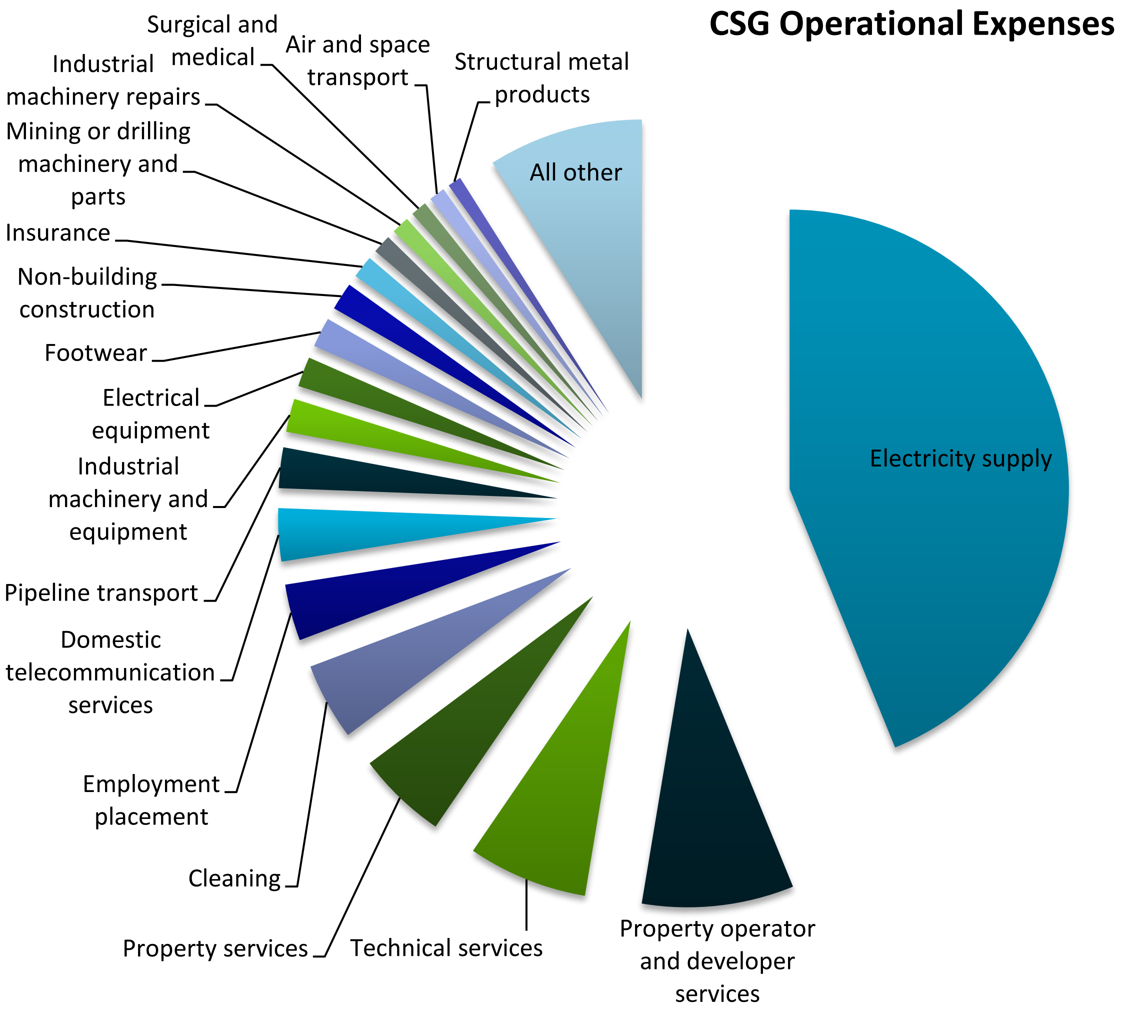
2.4 CSG Business Operations Expenses

From company data on the expenses for upstream CSG operations, a sample of 65,000 individual expenses from the company's general ledger were used to estimate the profile of annual expenditure on activities across 135 classes of goods and services. These were mapped to the 344 'ISAPC' product classifications used in the IELab (see also Lenzen (2008) for use of the ISAPC) to derive GHG emissions estimates. A selection of the most significant products is shown in Table 2. Total of the estimated expenses were corroborated with the company's publicly disclosed expenditure data in the 'Full Year Results' Director's Report by the company.

Table 2: Operational expense profile of the 'upstream" CSG extraction, gathering and pipeline distribution for 2015/16 (excluding all labour expenses and including dehydration and water treatment operations). Table shows the 18 most significant items.

Expense Category	Proportion of total 2015/16 expenses
Electricity use	44%
Property operator and developer services	9%
Technical services	7%
Property services	5%
Cleaning	4%
Employment placement	3%
Domestic telecommunication services	3%
Pipeline transport	2%
Industrial machinery and equipment	2%
Electrical equipment	2%
Footwear	2%
Non-building construction	2%
Insurance	1%
Mining or drilling machinery and parts	1%
Industrial machinery repairs	1%
Air and space transport	1%
Structural metal products	1%
All other	10%

Figure 2: proportion of non-labour CSG operational expenses in the ISAPC product classification. Expenses on grid electricity were cross-checked with reported consumption of 1,267GWhr (4.56 PJ) in 2015/16.



2.5 LNG Production and Sales

Total production of LNG for the 2016/17 financial year was 388 PJ. No produced LNG was sold to domestic customers (for electricity or otherwise). The value of this production used 2015/16 prices in order to combine with the data on CSG. Note that we are careful to distinguish between production of CSG for consumption as natural gas and CSG as feedstock to LNG. With the latter, we only count the value of the gas sold as tonnes of LNG.

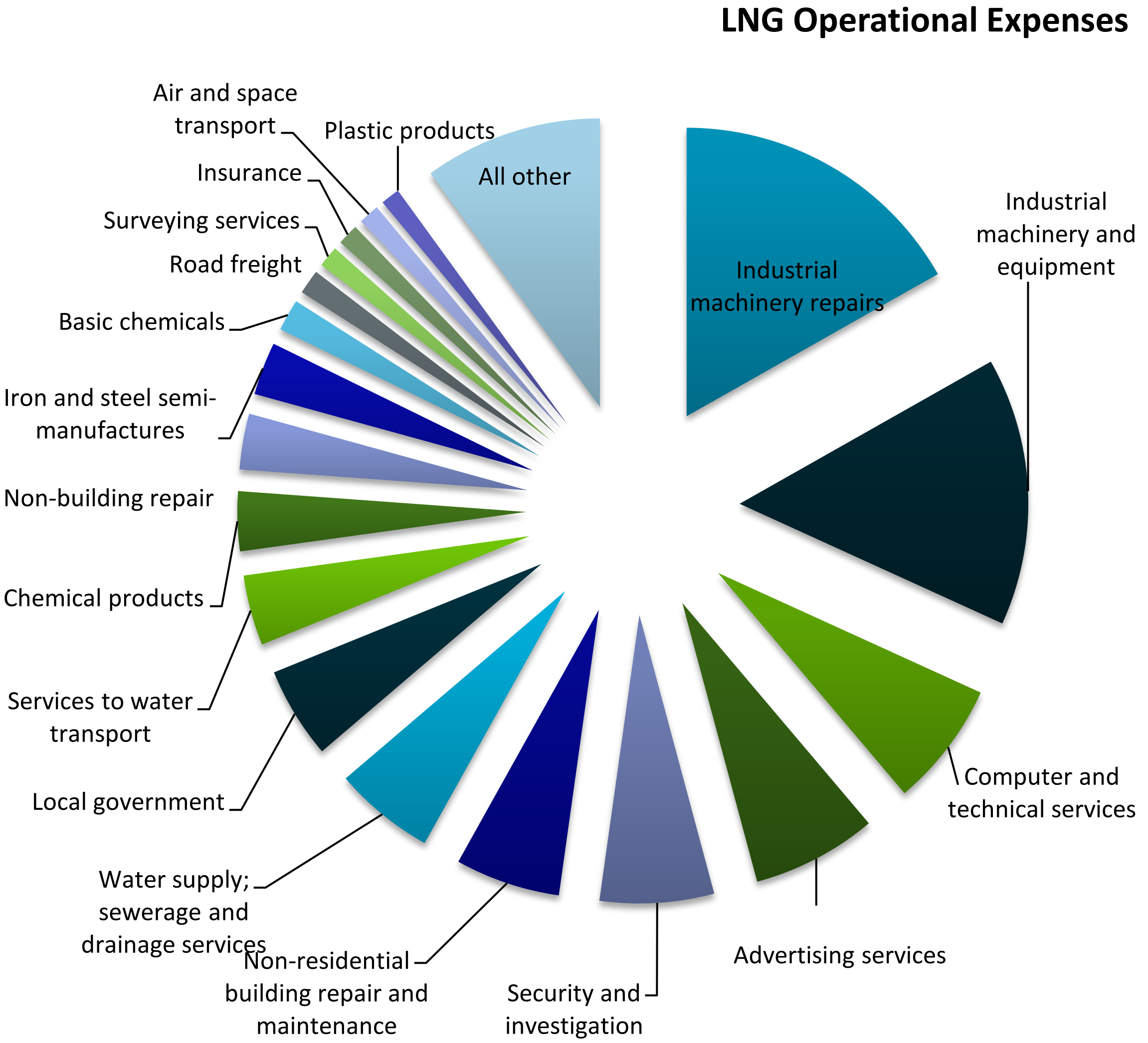
2.6 LNG Business Operations Expenses

Using company data on the budget for 'downstream' LNG production, we itemized the budget for 2016/17 financial year as a proxy for actual expense data for the operations of the LNG plant. These data were then mapped to the ISAPC product classifications used in the IELab and divided by total expenditure for 2016/17 to obtain the proportions shown in Table 3.

Table 3: Operational expense profile of the 'downstream' LNG operations for 2016/17 (excluding all labour expenses), showing 18 most significant items.

Expense Category	Proportion of total 2016/17 expenses
Industrial machinery repairs	17%
Industrial machinery and equipment	15%
Computer and technical services	7%
Advertising services	7%
Security and investigation	6%
Non-residential building repair and maintenance	6%
Water supply; sewerage and drainage services	6%
Local government	5%
Services to water transport	4%
Chemical products	3%
Non-building repair	3%
Iron and steel semi-manufactures	3%
Basic chemicals	2%
Road freight	1%
Surveying services	1%
Insurance	1%
Air and space transport	1%
Plastic products	1%
All Other	10%

Figure 3: proportion of non-labour LNG operational expenses in the ISAPC product classification.



Expenses for LNG operations are more varied than for CSG, involving purchase of materials and services for repair and maintenance, and do not involve the purchase of grid electricity. Any electricity used is generated on-site from natural gas and emissions arising from this generation are counted in Scope 1 direct emissions. For the LNG business there are no Scope 2 emissions.

2.7 Summary of Company Operations Expenses

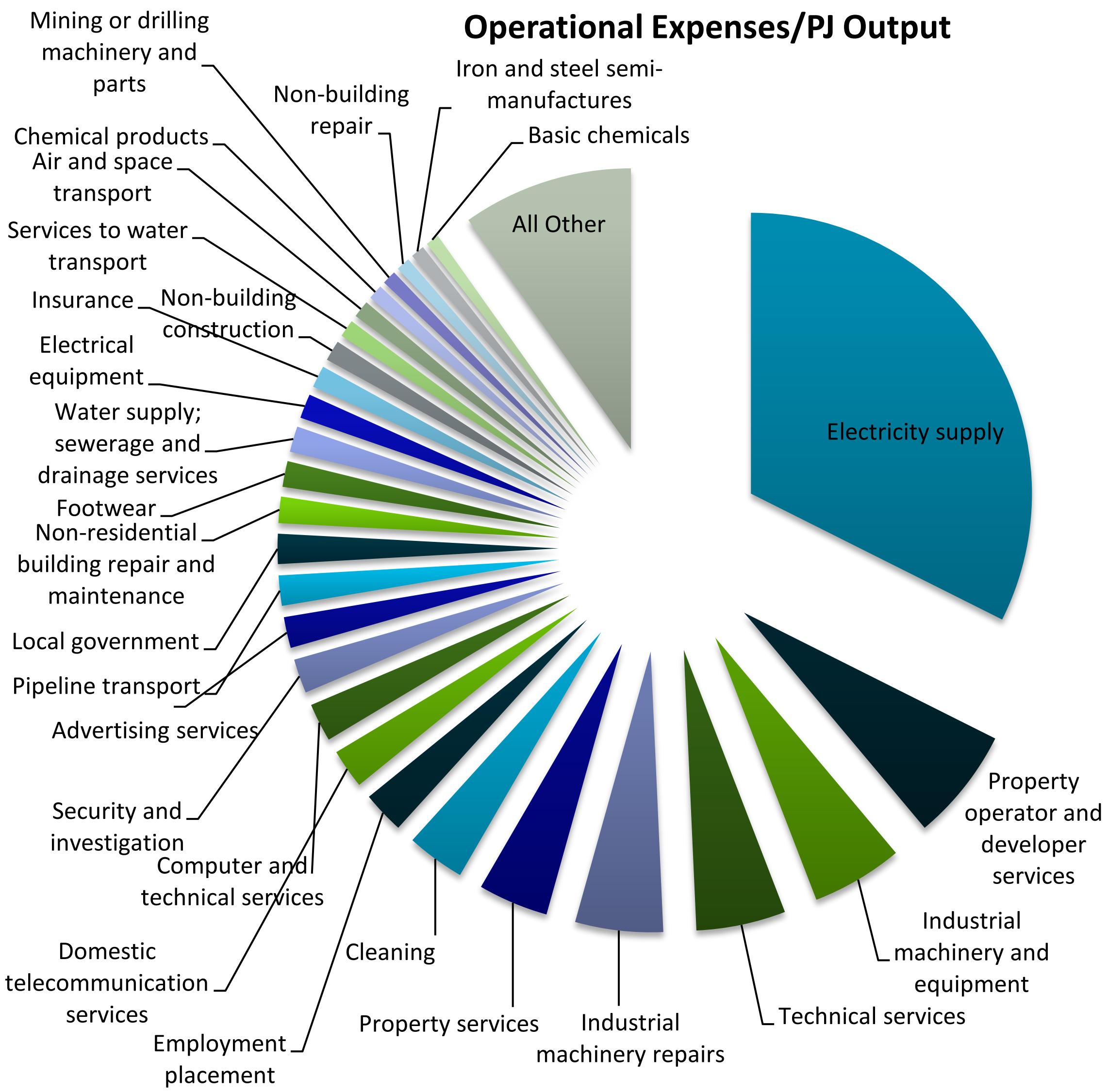
Using the schema in Table 1, we combined data on CSG and LNG business operations expenses (above) with annual production flows and corresponding revenue from LNG operations to obtain the non-labour 'expense intensities' for production by the whole company. These are also applied to a future output scenario of LNG production.

Expense intensities, as shown in Table 4, are purchases of goods and services over one year to produce 1 Petajoule of sales output by the company ($/PJ). This is a useful intermediate measure to multiply with the flow volumes for a future output scenario. That product is effectively the expense vector (in 2015/16 prices) used to represent the company data in the MRIO.

Table 4: Relative proportion of operational expense intensities for a future output scenario of production (excluding all labour expenses). CSG operations expenses were divided by only CSG sales volumes (PJ), and LNG operations expenses were divided by only LNG sales flows (PJ), before combining to obtain the intensities shown.

Expense Category (not including Labour)	Proportion of Estimated Expenditure future output scenario ($/PJ)
Electricity supply	32%
Property operator and developer services	6%
Industrial machinery and equipment	5%
Technical services	5%
Industrial machinery repairs	5%
Property services	4%
Cleaning	3%
Employment placement	2%
Domestic telecommunication services	2%
Computer and technical services	2%
Security and investigation	2%
Advertising services	2%
Pipeline transport	2%
Local government	2%
Non-residential building repair and maintenance	2%
Footwear	1%
Water supply; sewerage and drainage services	1%
Electrical equipment	1%
All other	17%

Figure 4: proportion of non-labour operational expenses for every PJ of sales volume output (i.e. both CSG and LNG). The top 25 expense categories (by ISAPC product classes) are shown.



2.8 LCA methods

An LCA was also carried out for all upstream CSG and downstream LNG phases of processing in relation to CSG and LNG production. Company data were obtained on energy use, water treatment, blowdowns and workovers, dehydration and flare emissions. Upstream processes considered in the LCA include all gas related extraction, processing, compression, dehydration, and water treatment. Downstream processes include liquefaction to the point where it is ready for loading onboard an LNG carrier for transportation to Asia. Further downstream processes of shipping, regasification and combustion stages in Asia are also considered in this analysis with appropriate assumptions regarding transport distances, destination, regasification process and end-use of LNG. GHG emissions associated with exploration are not incorporated into this study. During each stage, all emissions relating to energy use during construction, transportation, venting, flaring and fugitives were considered.

Through the creation of detailed process flowsheets, mass and energy balances were conducted over each unit stage involved in the process with data being supplied by the company. Data involving CSG production, losses and gas use are detailed at each stage, with inputs and outputs being defined for each unit process. Energy use over each stage and major pieces of equipment were accounted for, utilising both gas field data (obtained from the gas company) and emissions factors obtained from Clark et al. (2011).

Mass and energy data, involving all upstream and downstream stages and their respective inputs and outputs were entered into SimaPro Software.

For reliable and accurate data, with subsequent analysis and comparisons, exports to China for electricity production were considered in this study taking into account transport and shipping distances.

Fugitive emissions (flaring, venting and leaks) were prescribed in this analysis along with well head, gas processing facility and pipeline emissions at a value of 1.5% of production based on results of the MRIO study (above). In the MRIO analysis, no *a priori* upstream fugitive emissions were assumed and so the upstream Scope 1 emissions from the MRIO are applied in the LCA analysis (see Discussion).

2.9 CSG Infrastructure Construction and Transport

The diesel required for construction of upstream operations (wellheads, gas processing, pipeline, LNG facility) were included as data inputs using emissions factors from Clark et al. (2011). Emissions factors were also included for the diesel required for transport of raw materials and other associated transport emissions in the upstream process. However, emissions related to the construction of regasification plants and power stations and the transport of materials for construction were not included for the downstream stages in China.

2.10 CSG Energy Use in Operations

Electricity from the grid and gas use for the purpose of CSG-LNG activities during both upstream and downstream processes were calculated over each unit from extraction to end use combustion using industry data and emissions factors from Clark et al., (2011).

2.11 CSG Electricity Production

Natural gas power plants use either open cycle gas turbine (OCGT) or closed cycle gas turbine (CCGT) technology to produce electricity. CCGT technology is predominantly used for intermediate and based load power production and is built with a heat recovery system to make them more efficient than OCGT systems. OCGT systems are designed to work with peak loads and respond to adverse changes in demand but are less efficient (Seebregts, 2010). In the LCA method, an electricity generation efficiency of 39% was assumed for OCGT and 53% for CCGT (Clark et al., 2011).

2.12 CSG Life-Cycle Stages of CSG-LNG Production

The unit processes for CSG – LNG production considered in the LCA and the source of information are listed in Table 5.

Table 5: Stages of CSG-LNG production and data sources for the LCA analysis.

Stage	Process Description	Mass & Energy Inclusions
Extraction	The extraction of CSG from underground reservoirs with the use of gas wells and wellhead separators to effectively collect CSG to be processed. Natural gas is sent to gas processing facilities and water used and separated in process is sent to water treatment facility.	• Fugitive, blowdown (Industry Data) • Water treatment (Industry Data) • Diesel for construction (Clark et al., 2011) • Energy – gas use (Company Data)
Gas processing	The processing of CSG from wells include, removal of impurities and gas compression for transport to pipeline.	• Fugitive, flare (Industry Data) • Diesel for transport (Clark et al., 2011) • Energy – gas use (Company Data)
Dehydration	Excess water is removed from CSG before it is sent to pipeline for transport to LNG facility.	• Flare (Industry Data) • Water removal (Company Data) • Energy – gas use (Company Data)
Water treatment plant	Water from extraction and dehydration facilities is treated and purified to remove salts and other organic and inorganic compounds through a series of filtration systems and reverse osmosis.	• Water from extraction & dehydration (Industry Data) • Energy – gas use (Company Data)
Pipeline compression	Utilising in-line compression for CSG, pumping and transporting extracted gas to LNG production plant on QLD coast.	• Flare, solids, blowdown (Industry Data) • Diesel for construction (Clark et al., 2011) • Energy – gas use (Company Data)
LNG plant	CSG is cooled -160°C undergoing liquefaction, compressed into LNG.	• Fugitive (Company Data) • Diesel for construction (Clark et al., 2011) • Energy – gas use (Clark et al., 2011)
Shipping	The LNG is loaded for transport on LNG carriers, where it is transported to its destination in China, Japan, Korea.	• Assume no CSG loss at either port or during transportation • Diesel for shipping (Clark et al., 2011)
Regasification	The LNG is unloaded from the ships and transported to a regasification plant where the product is able to flow through a range of heat exchangers to successfully convert the LNG back into natural gas.	• Assume no CSG mass loss • Assume 3% gas use for energy (Clark et al., 2011)

Combustion	Natural gas is sent for combustion. Thermal heat drives turbines to generate electricity.	• Assume no CSG mass loss • Assume 55.42 GJ/tonne thermal produced from LNG • Turbine efficiencies; Assume OCGT – 39% Assume CGGT – 53%

2.13 Coal

Data for GHG emissions associated with the production of Queensland thermal coal in Australia was sourced from *SimaPro* LCA software using the Australian Life Cycle Inventory (AusLCI) database and analysed in comparison with emissions from CSG data in Australia.

2.14 GHG Emissions Impact Assessment

The main focus of life cycle emissions analysis being conducted for this study was that of GHG emissions coming from a CSG to LNG project expressed as tonne carbon dioxide equivalent (t CO_2-e). With a detailed inventory analysis conducted over unit operations of the CSG-LNG production process, utilising CO_2 breakdowns provided by SimaPro, a case comparison was also made between end use of gas for electricity generation using OCGT and CCGT turbines in Australia through combustion of CSG for electricity generation. This assessment provides a straightforward comparison of potential GHG emissions reductions under assumptions that CSG is used to displace coal fired electricity generation domestically in Queensland.

For MRIO method:

- Scope 1 includes emissions from all upstream activities (wells, pumps, compressors, gas and water processing). At the LNG Facility it includes all emissions from refrigeration and compression including all gas used to generate electricity on site (Curtis Island).
- Scope 2 is defined by the grid electricity purchased to operate upstream processes. There is no grid electricity purchased at the LNG Facility on Curtis Island hence no scope 2 emissions.
- Scope 3 includes ONLY emissions for processes upstream of CSG and LNG production typically as embedded products such as clothing, steel and administrative services. No downstream use of gas is incorporated in scope 3 (these would be included in scope 1 emissions under gas end-user)

For LCA method:

- Scope 1 emissions includes all processes for upstream activities and an incorrect assumption that electricity used was generated by gas at upstream sites for CSG production. At the LNG Facility scope 1 emissions are for all refrigeration and compression processes including gas used to generate electricity at Curtis Island.
- Scope 2 emissions therefore do not appear; yet are incorporated into scope 1 calculations because of the incorrect assumption at the time that onsite electricity is generated by gas. Regardless, this calculation

- Scope 3 includes ONLY upstream processes of CSG and LNG production. No downstream use of gas is incorporated in scope 3.

Because of the differences in the MRIO and LCA methods, only MRIO is reported for Scope 1 emissions on their own. Both studies are reported for scope 1 + scope 2 because these can be compared between the two studies. Scope 3 does not include combustion in either case.

3 Results

3.1 Scope 1 Direct GHG Emissions (MRIO)

In addition to company CSG/LNG production and financial data, we also obtained (1) detailed data on the direct GHG emissions used to report to the National Greenhouse and Energy Reporting Scheme (NGER) for sites in Surat Basin; and (2) company data on monthly emissions from operations at the Curtis Island liquefaction plant for 2016/17 (noting months where train two was entering commission and when regular outage periods occurred). These data were built into the aggregated numbers of Table 6 noting that direct emissions intensity excluded LNG train two commissioning and ramp up period. The data we have used to calculate GHG emissions and emissions intensities are as close to the measured emissions and physical output as possible given the resolution of a unit process in this study.

Table 6: Direct Scope 1 GHG emissions (kt CO_2-e/year) and emissions intensities (kt CO_2-e/PJ), and totals from the CSG and LNG operations at 2015/16 and a future output scenario for production. GHG emissions and intensities refer to upstream activities, pipeline transport and liquefaction (i.e. do not include shipping, regasification or combustion).

	Company
Direct GHG intensity kt CO_2-e/PJ	2.67 (2015/16) 4.77 (future output scenario)
Total for 2015/16 kt CO_2-e/PJ	1036.3
Total at future output scenario kt CO_2-e/year	2746.5

The expense profile for company operations is a weighted combination of separate expense intensities for CSG and LNG operations. These weightings use respective sales volumes of CSG and LNG for a future output scenario of the LNG trains. As sales volume of CSG in the domestic market is proportionally (and in total) much less in the future output scenario compared to the actual 2015/16 flows of gas, there is proportionally less consumption of electricity per PJ total output (or per dollar value of output) in Figure 4 than for 2015/16 production of CSG in Figure 2.

For the future output scenario, Scope 1 GHG emissions from upstream CSG operations (excluding liquefaction, regasification and combustion) were 0.86 Mt CO_2-e/year. Liquefaction emissions were 1.88 Mt CO_2-e/year giving a total GHG emissions of 2.75 Mt CO2-e/year (Table 6). In total across CSG-LNG operations the GHG emissions intensity for Scope 1 emissions was 4.77 kt CO_2-e/PJ.

The result for the future output scenario LNG production may be compared with the original Scope 1 emissions for CSG and LNG operations anticipated in the company's environmental impact statement (EIS) of (not including construction):

- 3,110 kt CO_2-e/year for the CSG operations.
- 2,800 kt CO_2-e/year for the LNG facility.

Note that these EIS figures are for the year of expected maximum production (2023) of 9 Mt LNG/year, equivalent to 499 PJ. In the original estimations of the company's Environmental Impact Statement, it was also expected that nearly 1Mt CO_2-e/year would be emitted from CSG combustion for power generation in the gas fields. In this study, power consumption in the gas field was derived from grid electricity. Thus, these emissions would not appear in the Scope 1 account but are, rather, captured in Scope 2 emissions.

The upstream CSG operations and downstream LNG production Scope 1 emissions (MRIO) from wells, gas processing, water treatment, dehydration, pipeline transport and liquefaction equates to 0.90% of CSG produced (i.e. 576 PJ).

3.2 Scope 2 GHG Emissions from Grid Electricity (MRIO)

In addition to direct emissions from activities entirely within the physical boundaries of the company's operations, there are also Scope 2 emissions arising from the purchase of grid electricity outside these boundaries. Purchased grid-sourced electricity in Queensland has a Scope 2 (GHG) emissions factor of 0.79 tonnes CO_2-e/MWh (Department of Environment and Energy 2017b), because 72% of generation of this electricity comes from coal.

Upstream CSG operations purchased 1267 GWh of grid electricity in 2015/16 resulted in 1001 kt CO_2-e Scope 2 emissions in 2015/16, or 2.58 kt CO_2-e/PJ of CSG sold (see Table 7). Since all of the liquefaction operations at Curtis Island are powered directly or indirectly by CSG on-site, LNG production involves no Scope 2 emissions from grid electricity.

When this GHG intensity is applied to the future scenario of 576 PJ CSG per year, the overall Scope 2 component GHG emissions (for upstream wells, water treatment, dehydration, pipeline transport and liquefaction) is 1486 kt CO_2-e/year (see Table 7). These Scope 2 emissions equate to 0.49% of gas entering the LNG trains on Curtis Island. Onsite operations and purchase of grid electricity dominate Scope 1 and 2 emissions in the supply chain for production of LNG.

Table 7: Scope 2 GHG emissions and emissions intensity for CSG - LNG output at 2015/16 production levels and future output scenario. Note that emissions from grid electricity in Queensland uses the Scope 2 emissions factor of 0.79tons CO_2-e/MWh (Department of Environment and Energy 2017b)

	Company
Purchased grid electricity GWhr	1267
Scope 2 GHG emissions kt $CO_{2\text{-}e}$ in 2015/16	1001
Scope 2 GHG intensity kt $CO_{2\text{-}e}$/PJ	2.58
Scope 2 GHG emissions for future output scenario kt $CO_{2\text{-}e}$/year	1486

3.3 Scope 3 Indirect Greenhouse Gas Emissions (MRIO)

Scope 3 emissions intensity and total annual emissions are derived from expense and revenue data for the combined CSG and LNG businesses. As such, we cannot report a breakdown of the Scope 3 emissions by different operations; rather we report here CSG-LNG combined Scope 3 emissions. In Table 8 we report on the company’s Scope 1, 2 and 3 emissions noting that Scope 2 is really a specific case of Scope 3 emissions pertaining to the purchase of grid electricity and Scope 3 emissions includes indirect emissions associated with production activities outside the companies owned assets (not including purchased electricity) under the future output scenario of production.

Table 8: Direct and total impacts of production activities for CSG – LNG, as GHG emissions intensity (kt CO_2-e /PJ) and total GHG emissions (kt CO_2-e /year) for the full production scenario of production (not including shipping, regasification and final combustion).

Scope	Emissions Intensity (kt CO_2e/PJ)	Total Emissions CO_2 equivalent (kt CO_2e/year)
Scope 1	4.77	2746
Scope 2	2.58	1486
Scope 3	0.28	149
Total	7.63	4381

When Scope 1, 2 and 3 emissions are combined for CSG – LNG operations (Table 9) this total equates to 1.44% of CSG produced and either entering the LNG trains on Curtis Island, Queensland, or used domestically (i.e. 576 PJ).

Table 9: Proportional contributions and totals of annual Scope 1, 2 and 3 emissions from CSG – LNG operations (Scope 3 emissions are broken out into component emissions from row 3 onwards). Last (shaded) column shows proportional contribution to total Scope 3 emissions (i.e. excluding Scope 1 and 2).

Source of Emissions	% contribution to scope 1, 2 & 3 emissions	GHG emissions (kt CO_{2-e}/year)	% contribution to Scope 3 emissions *(excluding Scope 1 and Scope 2)*
CSG – LNG Operations (Scope 1)	65%	2747	
Electricity, Gas and Water (Scope 2)	32%	1486	
Electrical and Machinery	0.62%	29	*20%*
Transport	0.59%	28	*19%*
Agriculture	0.56%	26	*18%*
Financial and Business Activities	0.34%	16	*11%*
Petroleum, Chemical and Non-Metallic Mineral Products	0.22%	10	*7%*
Wood and Paper	0.13%	6.2	*4%*
Metal Products	0.11%	5.1	*3%*
Textiles and Wearing Apparel	0.09%	4.4	*3%*
Post and Telecommunications	0.08%	3.8	*3%*
Maintenance and Repair	0.08%	3.6	*2%*
Construction	0.08%	3.6	*2%*
Food & Beverages	0.07%	3.5	*2%*
Public Administration	0.07%	3.4	*2%*
Other	0.12%	5.5	
Total	**100%**	**4381**	

3.4 Comparison with Australian Black Thermal Coal (MRIO)

Using IELab data combined with this input-output analysis, we have calculated the overall Scope 1, 2 and 3 GHG emissions intensity of CSG-LNG production to be 7.63 kt CO_2e/PJ, excluding combustion. Using the exact same method and scope, we calculate Scope 1, 2 and 3 emissions and intensities relating to production from the Black Coal sector in Australia for comparison.

Total Scope 1, 2 and 3 emissions intensity associated with coal production for 2015/16 was 4.28 kt CO_2-e/PJ. Note that these GHG emissions intensities do not include final combustion of coal for electricity generation, which is where more than 90% of black coal emissions are generated. Note also that liquefaction contributes significantly to the Scope 1 ('direct') emissions of CSG-LNG production but gas generated electricity in Australia does not require liquefaction.

From Table 4.1 of the Australian Energy Update (Department of Environment and Energy 2017a), total production of black coal in Australia for 2015/16 was 12,157PJ or approximately 405 Mt. The former figure is used as the divisor to compute intensities in Table 10, below.

Table 10: Direct and total impacts of production activities by the 'Black Coal' sector in Australia, as an intensity (kt CO_2-e /PJ) and total (kt CO_2-e /year) for 2015/16 production (including black coal destined for exports and electricity generation but not including final combustion).

Scope	Emissions Intensity (kt CO_2e/PJ)	Total Emissions (kt CO_2e/year)
Scope 1	4.26	51,776
Scope 2	0.00056	6.86
Scope 3	0.02	13.10
Total Scope 1, 2 & 3	4.28	51,796

Our calculated Scope 1, 2 and 3 emissions intensity per unit mass of black coal output is 0.12 t CO_2-e/t production (not combustion) which is similar to 0.15 t CO_2-e/t black coal reported by Clark et al. (2011). According to data in IELab and 2016 export sales, black coal has a GHG intensity of 1.22kt CO_2-e/$million (not including combustion).

3.5 GHG Emissions on a Unit Mass Production Basis (LCA)

Table 11 shows total GHG emissions intensities (t CO_2-e per unit LNG) and their distribution among unit processes in the CSG-LNG production process from upstream production at well heads in the Surat Basin to combustion of regasified LNG in Asia based on the life-cycle analysis. The results indicate that 4.9 t CO_2/t LNG of GHG emissions were produced with combustion contributing 3.5 t CO_2-e /t LNG (i.e. 80%) of these emissions. Liquefaction also had a significant contribution to GHG emissions, yielding 0.26 t CO_2-e /t LNG, with most of this stage's emissions arising from energy use associated with cooling and pressurising the gas. Dehydration and wastewater treatment components of the process have much lower GHG emissions contributing much less than 0.1% of emissions.

Table 11: **GHG emissions intensity for whole life-cycle of CSG – LNG production and combustion in Asia for electricity generation in units kg CO_2/t LNG taking account of the 1.50% loss (on a production basis) of methane due to fugitive emissions from upstream operations.**

Unit Process	CSG – LNG	Clark et al. (2011)
Total	**4222**	**4270**
Well head	85	-
Gas processing facility	88	582.2
Water treatment	0.8	-
Gas dehydration	0.3	-
Pipeline transport	129	6.8
Liquefaction	257	370.5
Shipping transport	51	93.7
Regasification	108	76.9
Electricity generation	3502	3138

Wellhead, upstream gas processing, gas pipeline and liquefaction components of the production chain contributed most GHG emissions with 85, 88, 129 and 257 kg CO_2/ t LNG. These values correspond to 5.9, 6.1, 9.0 and 17.8 kg CO_2/MWh and 1.56, 1.61, 2.38 and 4.72 kg CO_2/GJ, respectively. The upstream emission components include fugitive and flaring emissions.

CO_2 emissions reproduced from the Clark et al., (2011) LCA study are also shown in Table 11 for comparison (noting that Clarke et al., 2011, was commissioned prior to the gas production phase of operations in the Surat Basin). While overall emissions of 4.2 t CO_2/ t LNG (this study) and 4.3 t CO_2/ t LNG (Clark et al., 2011) are comparable (due to majority emissions from gas combustion for electricity generation), the distribution of GHG emissions among upstream unit processes (such as well head, gas processing water treatment, dehydration and pipeline emissions) are very different.

For example, in Clark et al (2011) emissions estimates were more than 6.5-times greater than estimated in this study because the former study based emissions on assumptions in the environmental impact statement that appear to have overestimated predicted emissions relative to actual emissions from the LNG facilities. Furthermore, Clark et al (2011) appear to have underestimated emissions contributions from pipeline operations (< 0.1% of non-combustion emissions); whereas, in the present study, these emissions make up ~18% of non-combustion emissions.

Total upstream (well head to end of pipeline) emissions in the LCA study were 304 kg CO_2/ t LNG compared with 589 kg CO_2/ t LNG in Clark et al (2011). When comparing the rest of the stages of liquefaction, shipping, regasification and combustion values found for both these studies were more similar (a total of 3918 kg CO_2/ t LNG for this LCA c.f. 3679 kg CO_2/ t LNG in Clark et al., 2011, for these unit processes). Comparing the two methods used in this study (LCA and MRIO), emissions for well head, gas processing water treatment, dehydration, and pipeline emissions were 5.6 kt CO_2-e/PJ (LCA) and 4.1 kt CO_2-e/PJ (MRIO); a 37% difference between the two methods.

Table 12 shows that combustion of gas in Asia for electricity production made up 83% of all GHG emissions along the entire production chain and that liquefaction and pipeline contribute 6.1% and 3.1%, respectively. Well head and gas processing contributed 2.0% and 2.1 %, respectively to GHG emissions. Water treatment and dehydration phases contributed <0.1% of GHG emissions.

Table 12: Proportion GHG emissions by unit process

Unit Process	Proportion GHG emissions
Well head	2.02%
Gas processing facility	2.09%
Water treatment	0.02%
Gas dehydration	0.01%
Pipeline transport	3.07%
Liquefaction	6.09%
Shipping transport	1.21%
Regasification	2.57%
Electricity generation	82.94%

3.6 GHG Emissions on an Electricity Production Basis (LCA)

GHG emissions calculated on an electricity generation basis in Asia (i.e. incorporating all shipping, regasification and combustion emissions) utilising OCGT and CCGT technology, with an assumed 39% and 53% electricity efficiency, respectively, generated 6 MWh/t LNG and 8.16 MWh/t LNG with associated GHG emissions intensity of at 0.73 and 0.53 t CO_2-e/MWh (Table 13).

Table 13: GHG emissions intensity of electricity production for open cycle gas turbine (OCGT), and closed cycle gas turbine (CCGT): units t CO_2-e/MWh.

Unit Process	OCGT	CCGT
Total	0.73	0.53
Well head	0.014	0.010
Gas processing facility	0.015	0.011
Water treatment	0.000	0.000
Gas dehydration	0.000	0.000
Pipeline transport	0.022	0.016
Liquefaction	0.043	0.031
Shipping transport	0.008	0.006
Regasification	0.018	0.013
Electricity generation	0.583	0.429

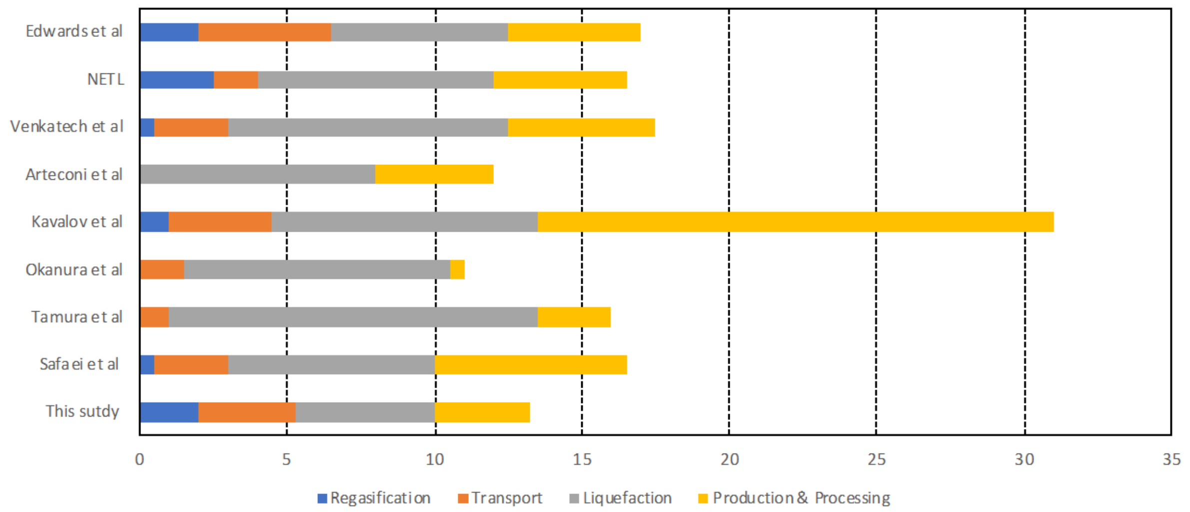
3.7 GHG Emissions on a Thermal Heat Production Basis (LCA)

GHG emissions intensity were also calculated on an energy units basis for combustion of each energy source (GJ) using SimaPro emissions factors for combustion of LNG. Results for GHG Emissions intensity from this study when compared with National Greenhouse Accounts Emissions Factors (Commonwealth Government 2018) show that production of upstream CSG, and liquefaction, transport, regasification and combustion of LNG produced a GHG emissions intensity of 77.6 kg CO2/GJ.

This study calculates a GHG intensity of 70.0 kg CO2/GJ (combustion alone = 64.4 kg CO2/GJ) from well head production, gas processing, water treatment, dehydration, pipeline, and CSG combustion within Australia. Note, the above calculations are greater than National Greenhouse Accounts Emissions Factor of 51.4 kg CO2/GJ (Commonwealth of Australia (2018)) because this study has used a comprehensive life-cycle approach. That is, emissions intensity reported for this study incorporates all emissions including construction costs, in-line gas pipeline compression, and other components not accounted for in the national GHG accounts.

Figure 5 compares results from this study with other life-cycle analyses examining coal bed methane (Safaei et al., 2015). The values range from as little as 10 kg CO2/GJ to over 30 kg CO2/GJ (Tagliaferri et al., 2017). The overall GHG intensity value (excluding combustion during end-use) was 13.23 kg CO2/GJ, consistent with other published studies for LCA of natural gas. Of note is the lower liquefaction emissions in the present study due to increased efficiency of the liquefaction process on Curtis Island. The figure also shows the general trend of liquefaction, production and processing to be the major components of GHG emissions intensity from gas production. It is important to note that comparisons among these different studies show variation in GHG intensity of gas production due to differences in scope and boundary among studies, the units and values of inputs used by researchers and assumptions made in the calculations of GHG emissions.

Figure 5. Comparison among studies of GHG emissions intensity of unit processes (units kg CO2/GJ) based on Tagliaferri et al. (2017).



4 Discussion

This study has used two contrasting approaches (MRIO and LCA) to develop an estimate of Scope 1 (direct), 2 (indirect) and 3 (external) GHG emissions from CSG - LNG production for a single company operating in the Surat Basin, Queensland, from upstream production at the well head, through transport and storage to liquefaction. The LCA analysis also estimates GHG emissions associated with eventual regasification and combustion in Asia for the generation of electricity. The two methods utilised company data to formulate accurate estimates of unit process activity making up the supply and production chain of CSG – LNG within Australia. The study also provides a comparison of the potential climate change benefit of the use of CSG in displacing coal fired electricity generation within Queensland, Australia.

Established relationships between GHG emissions and production processes contained within the IELab database were used to develop a comprehensive account of overall emissions in the MRIO. The SimaPro LCA software using the Australian Life Cycle Inventory (AusLCI) database incorporated information on GHG emissions by unit processes associated with all phases of LNG production. Aggregation of company data and comparison with publicly available financial accounts ensured that activity data for operations considered in this analysis was complete. This discussion provides a synthesis of the two methods in terms of the GHG emissions and emissions intensity for the upstream and downstream CSG – LNG components of the supply chain.

Comparison with emissions from coal fired electricity generation alone was undertaken because climate benefits of natural gas only exist where gas displaces coal as the source of fossil fuel emissions (McJeon et al., 2014; Gilbert and Sovacool 2018). Where natural gas displaces renewable forms of electricity generation rather than coal, such as where market conditions prioritise natural gas over solar, wind or nuclear energy sources, potential climate benefits are reduced and possibly reversed.

4.1 GHG Emissions

Based on our dataset, company expectation of exports for a future output scenario for two LNG trains and the MRIO and LCA analyses, we estimated that production of CSG (including feedstock to LNG) would be, on average, 576 PJ/year yielding revenue of $3.7 billion/year. These production figures generate a total of Scope 1 (direct), 2 (indirect) and 3 (external) GHG emissions intensity for this company within Australia (i.e. not including shipping, LNG regasification & combustion) of 7.63 kt CO_2-e/PJ (MRIO; equivalent to 1.17 kt CO_2-e/$million) or 10.30 kt CO_2-e/PJ (LCA). For comparison, Clark et al. (2011) reported on GHG emissions from CSG to LNG production (i.e. not including shipment, regasification and combustion) as 0.95 t CO_2-e/t LNG (16.0 kt CO_2-e/PJ). Equivalent MRIO Scope 1 (direct) and 2 (indirect) emissions in this study were 4.77 kt CO_2-e/PJ and 2.58 kt CO_2-e/PJ, respectively, yielding a total of 7.35 kt CO_2-e/PJ. The lower GHG emissions intensity of the present study is because of the use of actual company activity data based on accounts which indicate GHG emissions efficiencies over what was initially estimated in the company's environmental impact statement.

For the future output scenario of CSG – LNG production (576 PJ), the two analyses generated estimates of total GHG emissions of 4.38 Mt CO_2-e/yr (MRIO) and 5.94 Mt CO_2-e/yr (LCA). These totals include upstream production of CSG and liquefaction to LNG at Curtis Island, Queensland (ie. including well head, gas processing, water treatment, dehydration, pipeline transport, and liquefaction). Furthermore, the LCA analysis estimated that another 38.76 Mt CO_2-e/yr emissions were generated from LNG shipping, regasification and combustion in Asia for electricity production.

The primary activities contributing to these emissions within Australia were due to use of gas on-site at the LNG facility for refrigeration compression turbines; use of gas and/or electricity for stationary equipment operations in gas production fields; and, on-site fugitive emissions in gas production fields. The primary activity contributing to emissions outside of Australia was combustion of natural gas. Other elements in the supply chain contributed <3% of the overall operational carbon emissions.

4.2 Upstream GHG Emissions

Significant interest has focused on upstream fugitive emissions from natural gas production in the United States arising from perceived climate benefits of natural gas as an energy source for electricity generation (Howarth et al 2011; Cathles 2012; Miller et al 2013; Allen et al 2013; Brandt et al 2014; Zavala-Araiza et al 2015; Littlefield et al 2017; Alvarez et al 2018; Vaughn et al 2018). A general consensus has emerged from these studies that climate benefits of natural gas replacing coal are lost where fugitive emissions from all upstream operations are greater than 3% of total production (Alvarez et al 2012; Zavala-Araiza et al 2015). However, while simple 'rules-of-thumb' are useful, climate benefits/dis-benefits of fuel-switching from coal to natural gas are more complicated than a simple cap on upstream fugitive emissions (see 'Comparison with Coal Fired Electricity Generation' below). Nevertheless, it is worthwhile examining upstream fugitive emissions of the CSG - LNG operations of this company as a proportion of total natural gas production (i.e. that gas entering LNG trains on Curtis Island and diverted to domestic market; *viz*. 576 PJ).

The US Environmental Protection Agency has estimated that fugitive emissions from gas production, gathering, processing, transmission and storage, local distribution and oil refining/transportation amounts to 1.4% of gross national natural gas production (Alvarez et al 2018). However, alternative estimates based on attempts to reconcile 'top-down' and 'bottom-up' inventories indicate that this figure may be as high as 2.30 - 2.85% of US gross national gas production (Zavala-Araiza et al, 2015; Alvarez et al 2018). In the present study, Scope 1 and 2 upstream and downstream emissions in Australia (i.e. including CSG production, compression, dehydration, water treatment and liquefaction) represent 0.90% and 0.49%, respectively, of methane generated in the Surat Basin and transported as feedstock for LNG production (based on the future output scenario operation of LNG trains). Scope 1 (direct), 2 (indirect) and 3 (external) emissions in total for LNG production in Australia equate to 1.44% of LNG production. These estimates do not include shipping, regasification and combustion which occur outside Australia's borders. Day *et al* (2014) examined *in situ* leaks from well heads and casings over 43 wells in the Surat Basin and found that mean emission rate was about 7 m^3/day (maximum <100 m^3/day) compared to mean gas production per well of 29,600 m^3/day, suggesting that fugitive GHG emissions directly from CSG wells and casings in the Surat Basin, even at a maximum rate, is <0.34% of production. 'Top down' atmospheric inversion of methane concentration data in central Surat Bains (Luhar et al. 2018) coupled with a 'bottom-up' inventory of methane sources for the same region suggests that CSG fugitive emissions due to venting and leaks were between 13.9 and 15.0 kt CO_2/year from approximately 4600 gas wells, compressor stations, water treatment plants and gathering pipelines within the 'footprint' of the measurement stations. Extrapolating this figure to 18,500 production wells suggests that fugitive methane emissions from upstream gas production infrastructure is <0.5% of maximum capacity CSG – LNG production in the Surat Basin. Flaring of gas, however, adds significant GHG emissions to upstream emissions (Table 11) but as carbon dioxide rather than methane emissions. In this study, when including flaring, total GHG emissions intensity over the entire LNG production chain was 4.4 t CO_2/t LNG (LCA) with 0.09 t CO_2/t LNG, or 2%, arising as total (i.e. CO_2 and CH_4) emissions from well heads with flaring included.

4.3 Regional industry wide GHG Emissions

We have extrapolated GHG emissions for this company to the whole Surat Basin by considering the company's 2P reserves (as at June 2015) in proportion to the remaining three companies operating in this region (Towler et al 2016). Using the proportion of 2P reserves and assuming the future output scenario for operation of LNG trains, we calculate that under a whole-of-industry production scenario of 1400 PJ/yr of LNG export from Curtis Island, 12.8 Mt CO_2-e/yr of fugitive emissions would be generated. LNG production, by this company in 2016/17 was running at 81.4% of maximum capacity and so the industry wide upstream component of these Scope 1 (direct), 2 (indirect) and 3 (external) GHG emissions (i.e. from CSG gas production, water treatment, and liquefaction of LNG) represents 1.73% of LNG production.

Crude oil and natural gas fugitive emissions in Australia are currently 8.9 Mt CO_2-e/yr with total fugitive emissions (including coal) accounting for 11% of Australia's National Greenhouse Gas Inventory (Commonwealth of Australia 2018). In the first quarter of 2018, overall fugitive emissions increased 2.2% as a result of increasing natural gas production, but this increase was partially offset by decreases in fugitive emissions from coal production. From this study, the 2015/16 industry estimated Surat Basin GHG emissions (based on extrapolation, above, using the 2P proportions by companies in the basin) was 1.70 Mt CO_2-e/yr. Commonwealth National GHG Inventory gives national crude oil and natural gas fugitive emissions as 4 Mt CO_2-e for June 2016. This suggests that 43% of total fugitive emissions in the National GHG Inventory were originating from the Surat Basin.

Environmental Impact Statement (EIS) documents from the company provided estimates of expected future GHG emissions prior to commissioning of LNG trains in 2016. These records show that expected Scope 1 and 2 emissions were 3.11 kt CO_2-e/yr compared with the present study of 2.35 kt CO_2-e/yr. The company expected that 8.2% of total production CO_2-equivalent emissions (whole of production chain) would arise from flaring and 0.9% from CSG leaks, fugitive emissions and venting to yield a total expected 'well head' emissions of 537 kt CO_2-e/yr. The equivalent actual emissions estimated by this study were 85 kt CO_2-e/yr based on actual production data; 84% lower than the original estimate within the EIS.

4.4 Comparison with coal fired electricity generation

The climate implications of alternate choices of fuel sources, such as natural gas, coal, renewables and nuclear, are not straightforward and depend on a complex interaction between government policy, incentives and market signals influencing the energy mix. The global LNG market is impacted by supply and demand for natural gas as a fuel and the effect of this supply and demand on market prices of gas relative to other fuels and generation technologies. For example, McJeon et al (2014) demonstrated that gas substitution for coal in energy generation would lead to a decrease in global GHG emissions of between -0.1% and -5.9% by 2050 (assuming in this case that fugitive emissions were maintained between 2% and 3% of gross production). These estimates were derived from five 'integrated assessment models' that simulated both the global economy and associated effects of gas use on the future energy mix, GHG emissions trajectories and global warming. They showed that where fugitive emissions were 8% of production, enhanced climate warming by up to 5% by 2050 would occur over the five integrated assessment models. Furthermore, climate benefits or dis-benefits of natural gas depend on whether displacement of renewable sources of energy by gas occurs; such as under scenarios where cheap abundant natural gas displaced more expensive renewable and nuclear electricity generation (Gilbert and Sovacool 2018). However, considerable climate benefits are possible where natural gas replaced coal for electricity generation; particularly in developing countries.

In the present study, we cannot calculate directly the GHG emissions reduction of LNG exports from Curtis Island, Queensland, relative to coal-fired electricity generation in Asia because we do not know the proportion of gas used to displace what would have been produced from coal. However, we have estimated the efficiency of electricity production by natural gas based on Scope 1 unit processes from gas production in Australia as 6.0 MWh/tonne LNG and 8.16 MWh/tonne LNG for Open Cycle Gas Turbine (OCGT) and Closed Cycle Gas Turbine (CCGT) generation, respectively. These generation rates produced GHG intensities of 0.73 t CO_2-e/MWh (OCGT) and 0.53 t CO_2-e/MWh (CCGT). In Australia, if Surat Basin natural gas was used to displace domestic coal fired electricity generation, GHG emissions intensities would be 0.66 t CO_2-e/MWh (OCGT) or 0.48 t CO_2-e/MWh (CCGT) representing a reduction in emission compared with coal of 31% and 50%, respectively. These GHG emissions reductions following domestic use of natural gas occur because emissions associated with liquefaction, shipping and regasification are avoided (representing 9.9% of total life-cycle emission of electricity generation in Asia). It is clear from these results that ensuring high efficiency electricity generation (e.g. via CCGT technology) is important in realising the potential climate benefits of natural gas where it replaces coal fired electricity generation.

The Australian National Greenhouse Accounts (Commonwealth of Australia 2018) publishes emissions factors for consumption of a range of fuel types (e.g. natural gas). For pipeline distributed natural gas in the domestic market, the emissions factor for gas is 51.4 kg CO_2-e/GJ (Commonwealth Government 2018) and should be interpreted as an average value relevant across all applications in which natural gas is distributed to various facilities and combusted to generate heat. In this study, the emissions factor for commercial gas production at the well head (including flaring), gas processing facility, water treatment facility, gas dehydration, pipeline transmission and combustion for electricity production was 65.55 kg CO_2-e/GJ. The difference in emissions factors between this study and the National Greenhouse Accounts reflects differences in the way commercial gas is produced, compressed and transported in pipelines to Curtis Island LNG plant compared to other uses of natural gas in Australia. The Commonwealth Government's emissions factor is a sector-wide average value over all gas utilization (i.e. combustion) in distribution pipelines to other industry sectors. Note that the climate benefits of natural gas use as a replacement fuel for domestic thermal coal electricity generation are preserved even at the higher gas emissions factors determined in this study.

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