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The Growth of Australia's LNG Industry and the Decline in Greenhouse Gas Emission Standards

Increased Emissions Have Offset Any Gains From Renewables' Rise in Electricity Generation

Executive Summary

Greenhouse gas (GHG) emissions from the fast-expanding Australian liquefied natural gas (LNG) industry since 2014 have grown from 13 to 60 million tonnes per annum (Mtpa) in just five years, offsetting the reduction in emissions from the electricity generating industry over the same period.

Electricity emissions have declined due to the expansion of renewables for generation and the declining supply from coal-fired generators.

But the 360% expansion of LNG production since 2014 has been accompanied by a likely 460% growth in the industry's domestic greenhouse gas emissions.

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New (and old) plants are developing reservoirs with increasingly higher levels of CO2, or using coal seam gas, far from the plants.

Measurement and reporting of emissions from the LNG industry is made opaque by the classifications used by the Department of Environment and Energy.

Market factors in 2019 and again in early 2020 with the COVID-19 event and the Saudi-Russian oil war have reduced prices, margins and operating rates for the Australian LNG industry, and GHG emissions have reduced accordingly. Future higher polluting LNG industry developments have also been impacted.

Nonetheless, this paper describes the worrying increase in GHG emissions that need to be noted as the industry ramps up again into the future, and the reasons for it.

History

Since 2014 Australia's LNG industry has undergone a huge boom in investment and growth in exports. Australia now rivals Qatar as the world's largest exporter of LNG.

Back in 2014, LNG plants in Australia produced and exported about 24 million tonnes (Mt) of LNG and emitted about 13 million tonnes of CO2 equivalent (MtCO2e) on Australian territory (offshore and onshore). That is, 0.54 tCO2e was emitted to produce each tonne of LNG. This can be called the 'specific emissions in production', or SEP as shown in the first column in Table 1 below. Note that this does not include emissions arising when that LNG is burnt in power stations or industries overseas or in transit to overseas markets.

Australia's GHG emissions are reported and projections are made by the Department of Environment and Energy[1] in eight sectors. For some unknown (or perhaps no good) reason, these sectors do not align with the UN Environment Department[2] reports which show seven sectors. Five of these sectors appear to correspond by their simple descriptions, but the detail of the classifications is beyond the scope of this paper.

In any case, Australian LNG industry emissions are reported under three sectors' categories (Electricity, Direct Combustion, and Fugitives) but might also be included in the 'Industrial Processes' sector. This confusion illustrates the difficulty in identifying and tracking this important industry's emissions in the public domain. It would be an improvement for public and global scrutiny if they were counted as one sub-category under 'Industrial Processes'.

By 2019 the industry had more than tripled its output capacity and quadrupled its emissions. It had capacity to produce 86 Mtpa of LNG together with estimated GHG emissions of about 60 MtCO2e/y, based on company and regulators' EIS reports, announced modifications and private estimates. This brings the specific emissions in production (SEP) to 0.70 tCO2e/tLNG, which is a 30% increase on the SEP of 0.54 t/t five years ago.

The 'boom-built' LNG plants alone seem to have an average SEP of 0.76t/t which is 41% higher than the plants operating in 2014. So, are they less efficient?

Table 1: Increases in LNG Production and Emissions Over 2014-19

		2014	New	2019
LNG Production	MtLNG/y	24	62	86
CO2 Emissions	MtCO2/y	13	47	60
Specific Emissions in Production (SEP)	tCO2/tLNG	0.54	0.76	0.70

Source: Estimates by John Robert.

LNG market factors in 2019 caused Australian LNG plants to run at rates lower than capacity through much of the year. Some reports indicate that only 75% of nameplate capacity was achieved for the year, which would have increased the unit cost of production and reduced revenues and margins for the operators. Capital-

[1] Australian Government Department of the Environment and Energy. Australia's emissions projections 2019. December 2019.
[2] UNEP. Emissions Gap Report 2018.

intensive processing plants like LNG plants normally run at 95% of capacity or higher if they can. The good news in this (for some) is that actual emissions would have reduced nearly proportionately from the levels quoted above.

In early 2020, the impact of COVID-19 on demand for LNG in manufacturing industries in China, Korea and Japan reduced prices further. And more recently again, the Saudi-Russian oil price war which commenced in February has again deepened that trend since most LNG contracts are linked to the oil price. It is therefore likely that production and emission rates will be lower again than in 2019.

With this new scenario in play, it was no surprise to learn in February 2020 that some operators have announced 'holds' on two of the potentially most polluting proposed new developments described below. This could be good news for global warming, if not for the operators and others like them. Interestingly, the lead partner and then operator of one of these developments sold its share of the project (at what some analysts said was a bargain price) in late 2019.

Important Technical Aspects of the LNG Industry

Before looking for the reasons behind the surprising trend, there are a few technical points which need to be made:

- The percentages of CO2 in various gas fields discussed below and (rarely) quoted in the gas business generally are percentages on a volume basis, not weight. But when it is the mass (or weight) of the LNG which is important for sales, and the mass of CO2 is what matters for the atmosphere, the weight percent is very important. The conversion from volume % to weight % is a bit complicated but for example, nine volume percent CO2 (9 vol%) in a typical conventional gas mixture is actually about 20 weight %, so an increase in reservoir gas CO2 content from 3 vol% to 9 vol % is very significant for the mass of CO2 emitted.

- The vented CO2 emissions from the LNG industry are commonly, and I believe erroneously, described or classified as 'fugitive emissions' in government and other reports on emissions. Inadvertent or unintended emissions of methane could correctly be called fugitive, but they are generally very small in the conventional LNG industry compared to both necessary and deliberate CO2 venting (AGRU vents – see below) from LNG plants and some domestic gas treatment plants.

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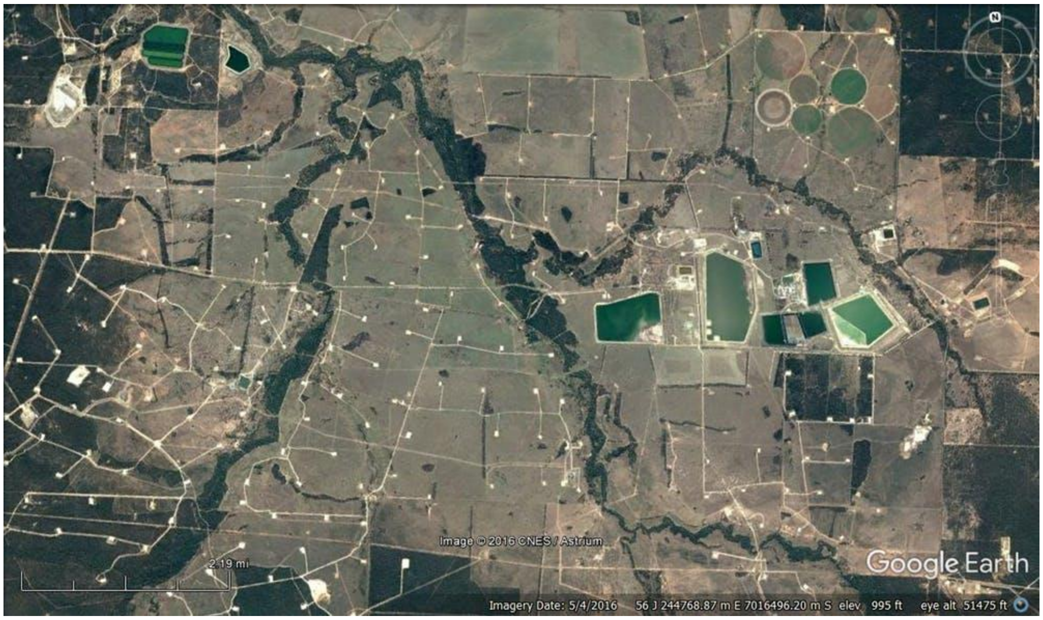
- The exception to this is where coal seam gas (CSG) resources are produced for LNG, as they are in Queensland and nowhere else in the global LNG industry. CSG is produced from thousands of wells at low pressure and require complex systems of gas gathering and compression equipment to send the gas to the LNG plants about 400km away at Gladstone. This can lead to significant leakage of methane from the tens or hundreds of thousands of joints, seals and unlit flares in the remote and widespread production and pipeline system.



Pictured: CSG wells near Chinchilla, Queensland.

- It is estimated there may be 4,000-5,000 wells already drilled and that ultimately 40,000 wells may be drilled to supply gas to the LNG plants in Gladstone. The magnitude of these methane emissions has been investigated in various studies in recent years and been found to be extremely difficult to measure accurately, but significantly larger than stated by gas operators and accepted by regulators.[3]

- All LNG plants emit diluted CO2 (8-12 v%) from the exhausts of gas turbines (electricity generators and compressor drives) and steam boiler stacks. Around 8% of the gas reaching an LNG plant is diverted to electricity generation or direct energy to process and liquefy the gas, and to provide electricity for all systems on the plant and export facilities (e.g. loading pumps).

- LNG plants also emit a concentrated stream of CO2. At the very low temperature at which methane (the main component of conventional gas and LNG) is liquefied, CO2 is a solid, so it must be removed before the actual cooling process begins. Removal is performed in an Acid Gas Removal Unit (AGRU), from which CO2 is emitted in concentrated form (99+%) from vents directly to the atmosphere or via a 'thermal oxidiser' if there are also sulphur compounds in the reservoir gas. The amount vented from this source varies directly with the CO2 content of the gas reservoir. At low reservoir CO2 levels like the 3v% in the

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[3] Melbourne Energy Institute. A review of current and future methane emissions from Australian unconventional oil and gas production. 2016.

original plants in the north of Western Australia (Rankin and Goodwyn fields), this is about one quarter to one third of the total emissions from the LNG plant.

- For reference, there are currently 10 LNG operations in Australia, all owned by consortia and managed by one of their owners as operator. Each comprises a gas-gathering system, one or more LNG production units (or trains), storage tanks, utility systems and ship loading facilities. All of these operations are supplied from offshore gas reserves except for the three plants in Gladstone which gather coal seam gas from the Surat Basin and other resources in the inland of Queensland.

- The first plant (with three trains) was built near Karratha in the northwest of Western Australia, started shipping in 1989 and is operated by Woodside for the NWS consortium. Since then, two more trains have been added to this plant. The second, Darwin LNG, began production with its single train in 2006. The operator was Conoco-Phillips until late 2019 when operatorship passed to Santos as CP exited the joint venture. Then Pluto's single train started up in 2012 adjacent to the NWS plants near Karratha but with different ownership and also operated by Woodside. This was the situation in 2014: three plants operating seven trains of various capacities averaging 3.4 Mtpa.

- The 'boom built' plants in Gladstone, Queensland are QCLNG, GLNG and APLNG. They are operated by Shell, Santos and Conoco respectively. Each plant has two trains and the six together average 3.9 Mtpa capacity. In Western Australia the new plants are Gorgon and Wheatstone, both operated by Chevron, and Prelude, the world's first floating LNG plant, is operated by Shell with six trains all up, averaging 4.5Mtpa. In the Northern Territory the Ichthys plant has two trains of 4.5Mtpa and is operated by INPEX.

Why Have Emissions Grown So Fast Over the Past Five Years?

Emissions grew faster than LNG production through this short but dramatic expansion phase of the industry, mostly due to **four factors**:

First, three out of the four new LNG plants in WA and NT - Gorgon, Pluto and Ichthys - source their raw gas from gas reservoirs containing 9 v%CO2, which is about three times the CO2 content of the reservoirs which supplied the LNG plants operating in 2014. This means the AGRUs in the new plants must have three times the capacity of the earlier plants with the same LNG capacity and three times the mass of concentrated CO2 emissions.

The energy required to process the gas through the AGRU also increases, so the electricity generation must increase to pump, heat and cool three times more solvent around that unit. The electricity to do this extra processing is generated by raw conventional gas carrying three times as much CO2 as an inert 'passenger' through to the exhaust stacks as before. In other words, the emissions do not rise in proportion to the CO2 content of the incoming gas, but on a rising trend as CO2 v%

content in the reservoir gas rises. The capital cost of that part of the processing plant rises also.

In the case of the new Ichthys Darwin plant the gas also has to be piped from the Ichthys field in the Browse basin 900 km away offshore Western Australia, and this requires compression, causing further emissions.

Second, the three new plants at Gladstone, Queensland process coal seam gas (CSG) resources. These may have a low CO2 content but are produced in the extensive gas fields at very low pressure and from thousands of low-productivity wells. In contrast, conventional gas is found at much greater depth and pressure and so may supply a typical LNG plant with only 5-15 wells.

Consequently, CSG has to be gathered and compressed in many small and inefficient compression units over several stages to transport the gas so it is delivered at high pressure at the LNG plants in Gladstone, some 400 to 500 km away. Most of the energy for this complex compression system is supplied by grid electricity which is mostly coal-fired, thus causing high emissions per unit of gas as delivered to the LNG plants. The result is that the advantage of starting with low CO2 reservoir gas is lost and the specific emissions (SEPs) of the Gladstone plants are about as high as the new WA units.

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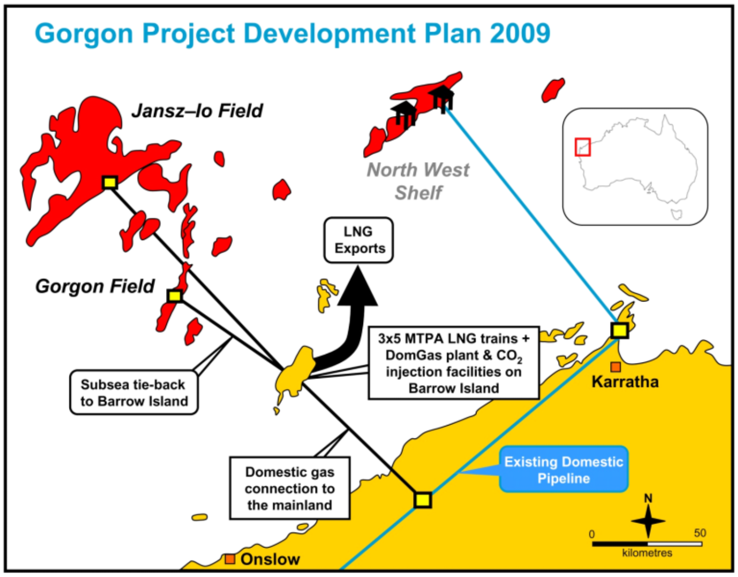
Third, the largest Australian LNG plant (Chevron's Gorgon 15.6Mtpa project on Barrow Island - layout and picture below) failed to commission its required CO2 re-injection system until August 2019, about 2½ years behind schedule since the first of its three 'trains' were commissioned in 2016. This caused about 4 MtCO2 to be vented above its permitted quantity.



The Gorgon project Joint Venture operates two main fields with very different CO2 contents (Gorgon 16 v% and Jansz 1 v%) and planned to balance flows from each so as to operate the LNG plant with an average 9 v%CO2 feed stream. When the Gorgon JV was seeking environmental approval for the project it was required to investigate and then install a very large CO2 re-injection system which would be twice the size of the only other operating large-scale reinjection scheme.

Curiously, two other LNG projects now operating with 9 v%CO2 (Prelude and Ichthys), but approved a year or two later, were not required to install CO2 re-injection systems.

Fourth (and most concerning), between 1989, when the first LNG was shipped from the NWS (North West Shelf) consortium's plants on the Burrup Peninsula near Karratha WA and 2014, the original gas reservoirs lost pressure through depletion. The operators have countered this by developing nearby offshore gas fields and later by adding compression facilities on offshore platforms (e.g. the North Rankin B compression platform commissioned in late 2013 – pictured below). This has increased the effective emissions of the existing plants although their LNG capacity has not increased.

When reservoirs are further depleted, new sources may be brought into production by the operators. It is a profitable strategy for the operators to initially develop the reservoirs containing the most associated liquids (condensate, LPG) and the lowest CO2 content. By now most of the closest to shore and 'best' reservoirs have already been consumed. When depletion occurs, this will typically lead to processing higher-CO2 content gas, leading to significant increases in their emissions.

As a second example of depletion resulting in higher emissions, the Darwin LNG plant operated by ConocoPhillips (and lately by Santos) has been supplied with gas from the Bayu-Undan field in the Timor Sea since 2006 and this field is now almost fully depleted. The operators' published plan is that the plant will shut down in 2022 and wait for two years until gas from another field is available following field development. During that time the LNG plant will be maintained and upgraded.

The likely new 'backfill' gas reservoir to be developed for Darwin LNG is the Barossa field which contains 18 v%CO2 and also significant gas liquids. The development will require the liquids to be removed, stored and exported from a new floating processing facility (FPSO) located near the field 350km offshore. The FPSO will also reduce the gas CO2 content to 6 v%, re-compress and pipe it to the Darwin LNG plant.

The total project could become a CO2 venting factory with an LNG by-product.

The upgrade of the LNG plant will include modifications to handle feed gas containing 6 v% CO2. This will increase the SEP of this plant (despite some possible efficiency improvements) because the Bayu-Undan field contains only 2-3 v%CO2.

The CO2 removed on the FPSO will be vented and certainly should not be considered merely 'fugitive'. Between the new FPSO and the upgraded LNG plant, the total emissions might rise 4-6 times, thus increasing this development's SEP from 0.6 t/t in 2015 to between 2.4 and 3.6 tCO2e/t LNG. In other words, the total project could become a CO2 venting factory with an LNG by-product.

A further, similar steep increase in emissions is likely to be repeated when the five original NWS plants finally deplete their currently producing reservoirs and gas is piped (as foreshadowed by Woodside) from the Browse area 900km away. Those fields are reported to contain 10-16 v%CO2 and in combination with compression for the long pipeline, this development is likely to then also have a very high SEP.

Conclusion

In summary, the older plants have already (or will soon have) depleted their initial gas reservoirs and are using or planning to develop reservoirs with higher CO2 gas contents. The new (and planned) plants are developing gas reservoirs with increasingly higher levels of CO2 or using low pressure CSG resources far from the plants.

All LNG exporting nations other than Australia (including Qatar, PNG, USA, Trinidad, Indonesia, Malaysia) either have national oil companies and/or administrative regimes which have powers to licence energy exports. They are thus able to extract substantial and equitable returns to the national estate on behalf of its citizens. Several of these authorities also take an active national interest role in the planning of LNG plants.

By contrast, the extreme 'laissez-faire' regime in Australia has not served the nation's interests in either financial returns or in clarity about controlling their emissions.

We now have greater public awareness of the global hazards of such significant emissions. In the interests of reducing CO2 emissions, maintaining a social licence to operate and compensating for past opportunities lost, it should be possible to implement some changes to improve this situation. At the very least those emissions which are already captured and concentrated, such as from the AGRU vents, should be stored and dealt with appropriately.

The poor LNG market conditions in 2019 and 2020 should provide a window of opportunity to re-evaluate some planned (and approved) projects that would make the Australian LNG industry even more polluting - just when the need for urgent emissions reductions is becoming more apparent to many more people here and around the world.

About IEEFA

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John Robert is a Process Engineer and Industrial Economist with more than 40 years of experience including directly developing and/or managing estimates for capital and operating costs for LNG plants, along with benchmark comparisons for export competitiveness and reviewing the potential impact of emissions trading schemes such as Australia's proposed Carbon Pollution Reduction Scheme (CPRS) on LNG projects. From graduation John spent almost eight years in engineering and operations management roles with Exxon in the Australian petrochemicals industry, followed by a similar period as an Australian Government Trade Commissioner in Europe and the Middle East. John then became a business development manager and technical / economic consultant with Davy McKee (later Aker Kvaerner) for some twenty years, with clients including multinational energy and chemicals companies, and Australian and state/territory governments. John then took up a role as engineering manager with MEO Australia Limited, covering all aspects of innovative offshore methanol and LNG projects in the Timor Sea, and was responsible for the engineering development of the Timor Sea LNG Project (TSLNGP) since its inception in early 2002.