

Floating liquefaction nearshore

Adrian Finn,
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the commercial proposition
of LNG production on floating
vessels.

LNG production on floating vessels became a serious commercial proposition about a decade ago. Feasibility studies identified the expected capital costs of floating LNG production¹ and as the cost of onshore LNG plants escalated to over US\$1000/t of LNG, the economic case for floating LNG production became of real interest for the first time.

Offshore LNG production

Floating LNG (FLNG) was seen as a solution to monetising gas from offshore gas fields that were otherwise 'stranded', too far from land to consider a pipeline to shore. It was envisaged that as technology improved and design experience was gained then capital

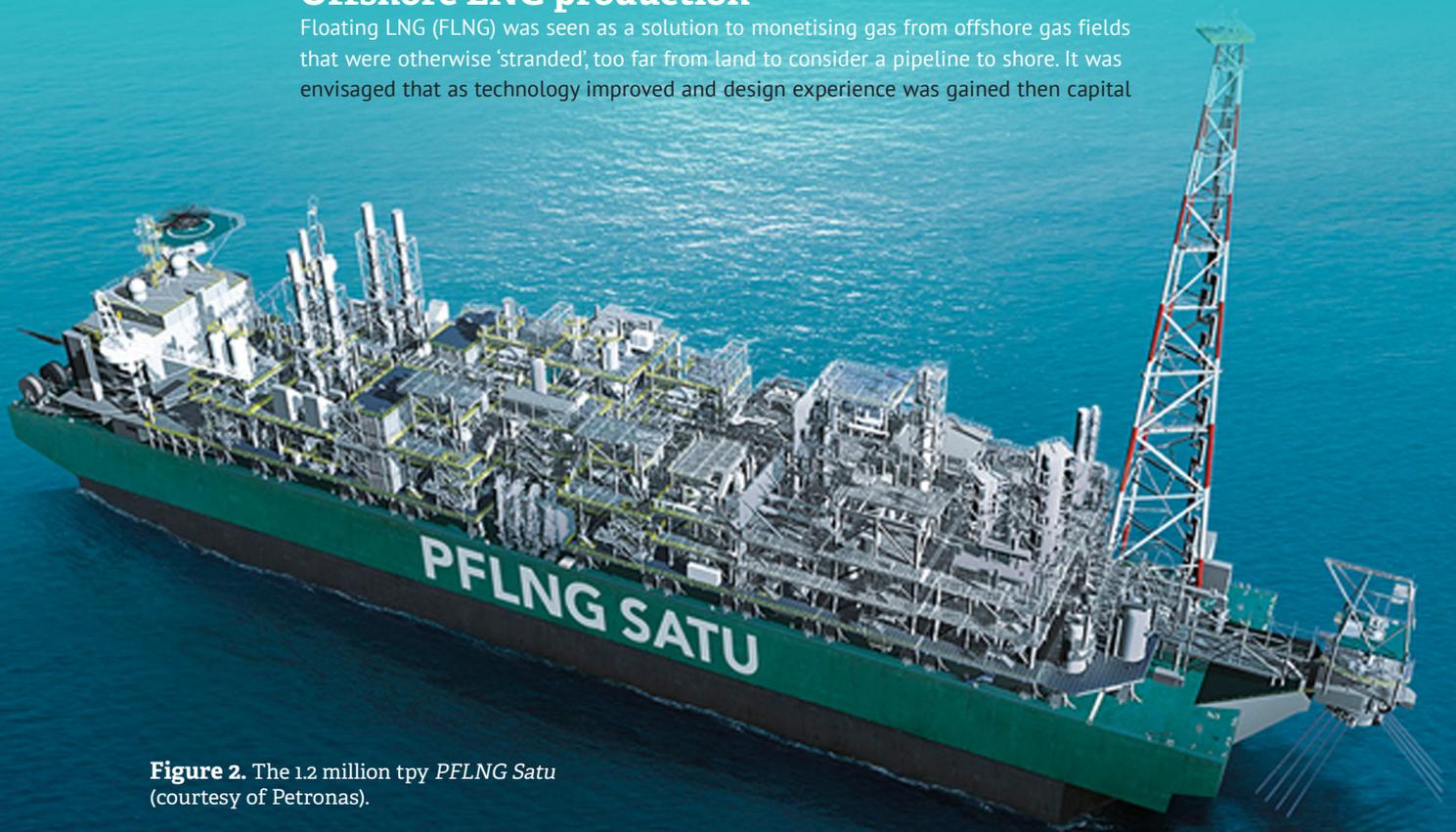


Figure 2. The 1.2 million tpy *PFLNG Satu*
(courtesy of Petronas).

costs would reduce and there would be clear commercial opportunities for LNG production many miles from shore.

Offshore LNG technology development focused on fully self-sufficient gas receiving, pretreatment, liquefaction and storage facilities. Many important technical issues were challenging. LNG storage systems would have to cater for partially filled tanks being subject to vessel motions and the associated sloshing effects. LNG transfer from the floating liquefaction vessel to an adjacent carrier would have to consider tandem LNG transfer, rather than side-by-side, again due to vessel motions. Gas pretreatment and liquefaction technology could be relatively conventional, but would have to consider impairment of operational performance by vessel motions and the safety concerns due to the restricted space and weight on an offshore vessel. By 2008, these challenges had been progressed sufficiently to launch the first topsides front end engineering design (FEED), by Kanfa Aragon, Norway and Costain, UK (Figure 1).

LNG investment decisions accelerated in 2011 and 2012, notably on major coal seam methane (CSM) fed LNG plants in Queensland, Australia and on the conversion of existing LNG import terminals in Texas and Louisiana for gas liquefaction for export. The first investment decisions were also made on FLNG production vessels – by Shell on the giant *Prelude* vessel for North West Australia and by Petronas for two smaller vessels, the first of which is shown in Figure 2.

The current worldwide LNG glut (and consequent low prices), arising from the completion of 25 million tpy of Australian capacity and from American plants coming on-stream, means few 'greenfield' LNG plants will now achieve final investment decision (FID) before the 2020s. The BP Tangguh plant extension is a recent exception, but benefits from relatively low investment costs by having existing infrastructure. The same applies to the US LNG production plants that are being converted from LNG regasification terminals and have low cost shale gas feedstock. Several FLNG projects have been cancelled or postponed including the 10 million tpy Lavaca Bay project in Texas and Shell's Browse project offshore North West Australia. Even the commissioning of Petronas's second vessel has been delayed.

So at a time of limited LNG plant FIDs, what is the future of FLNG?

Though Eni's Coral FLNG project, offshore Mozambique, may be an exception, it is unlikely FLNG will be used extensively to exploit stranded gas many miles from shore. This requires a turret and a complete gas processing facility atop an LNG storage vessel with all gas reception and



Figure 1. Flex LNG Producer, first floating LNG FEED.

pretreatment as well as liquefaction, all plant utilities, LNG storage, flare, accommodation, etc. An economic case for such a major venture may require LNG production of several million tpy. With project costs of up to several billion dollars and low gas prices, the return on investment (ROI) will normally be too low. Projects are also too technically complex for most.

However, could FLNG production nearshore, rather than many miles out to sea, compete with onshore LNG production?

Future LNG demand

In the mid to longer term, energy supply diversification, the need for 'greener' energy and delays in committing to new nuclear power plants all support increased natural gas use for power generation, especially in place of coal, and thus investment in LNG production.^{2 & 3} LNG imports are anticipated to grow in Europe, Asia and South America and surplus gas in the US and the Pacific will drive LNG supply opportunities,⁴ as shown in Figure 3.

An economic alternative is needed to onshore liquefaction as this can require huge infrastructure costs – for the feed gas pipeline, jetty and other marine costs, access roads and other infrastructure, construction personnel accommodation, etc. Construction costs can be excessive due to difficult terrain and/or shortages of local labour (which leads to high costs to bring in qualified resource). This has been ameliorated on recent LNG projects by pre-assembly of plant units off-site (in qualified fabrication yards) and delivery of the plant as modules. This modular approach, established in smaller scale natural gas processing and liquids extraction, can reduce construction costs and safety risks, but is not feasible for all locations.

Onshore plants increasingly face opposition on environmental grounds. Many environmental factors need evaluating in detail for planning consent. Obtaining planning permission can take years, especially if the proposed plant is located close to human habitation and/or areas of environmental sensitivity.

Nearshore LNG production

LNG plant costs and time to start-up can be less than for a conventional onshore plant by using a floating 'nearshore' moored barge, especially where the water depth is sufficient to avoid regular dredging and other location factors are favourable. This avoids the difficulties of extensive onshore construction by using a vessel and shop-fabricated topsides to totally avoid most site construction costs.

The economics of FLNG production are very much influenced by hull costs. With a dearth in recent orders for new LNG carriers, 'new build' hulls are available at competitive costs from established shipyards.

Benefits of pipeline gas

Nearshore LNG enables the use of transportation pipeline gas that has already been processed to meet water and hydrocarbon dew point specifications, maximum inerts (carbon dioxide and nitrogen) level and sulfur specifications, so the pretreatment for gas liquefaction is much less than normally required for an offshore location. This reduces the number of plant items, modules, plant space requirements, weight and cost.

The pipeline gas may have been processed to extract natural gas liquids (NGL) and be 'lean' in hydrocarbons heavier than ethane. If the gas contains much over 1 mol.% of nitrogen, this will require removal from LNG flash gas but cryogenic fractionation technology is well-proven for this.⁵ The carbon dioxide content of the gas needs reducing to 50 ppmv to avoid freeze-up during liquefaction. This is conventionally achieved in the acid gas removal unit (AGRU) by MDEA solution with an added reaction enhancer/activator. Physical solvent can be appropriate, especially on smaller facilities. Physical solvent may struggle to achieve 50 ppmv carbon dioxide in the treated gas, but the downstream molecular sieve dehydration system can be designed to remove any remaining carbon dioxide to meet the required 50 ppmv specification. As pipeline gas already meets hydrogen sulfide and total sulfur specifications, there should be no need to remove any (though vented carbon dioxide from the AGRU may need to be thermally incinerated as it will contain absorbed sulfur compounds).

Water removal via molecular sieve is always needed for liquefaction. An upstream TEG unit may be justified to remove the 'bulk' water from the treated gas from the AGRU, especially in warmer climates. The TEG unit could remove some heavier hydrocarbons from the gas, though there will still be a need to remove any heavier hydrocarbons that could freeze in the liquefaction section. This process duty is normally integrated with the liquefaction system and uses feed gas chilling. For very lean gas, an adsorbent system will likely be optimal, with removed heavier hydrocarbons used as fuel. Mercury removal will also be required.

A 'standardised' liquefaction plant design can be used for nearshore liquefaction as the feed gas is lean in heavier hydrocarbons and of a relatively constant (high methane) composition. This cost reduction approach is already gaining acceptance for smaller skid-mounted onshore LNG plants. The LNG production capacity would be determined for each project by process simulation based on the specific feed gas

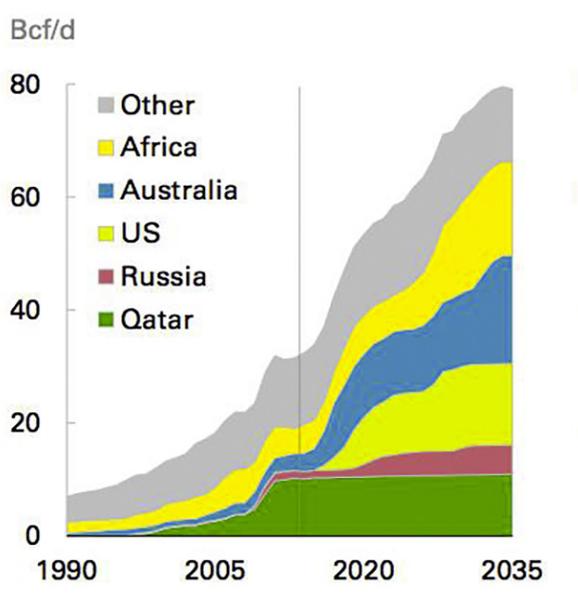


Figure 3. Global LNG Supply (source: BP Energy Outlook to 2035).

pressure and composition. The plant and refrigeration system design would essentially be 'standardised', thus considerably reducing engineering labour, time and capital cost. The plant layout, footprints and weights would be known early in the detailed design schedule. Plant items would be provided as modules for installation on the barge. Limited engineering, the use of proven 'standardised' equipment and an established 'procurement chain' would mean plants being operational much quicker than a conventional onshore LNG plant. Onshore plants can use the same approach to modular plant design, but cannot reduce plant start-up time due to the time required for construction.

As gas pretreatment is relatively modest, there is justification to locate the gas pretreatment equipment on the moored barge, as well as the liquefaction plant so as to further minimise onshore construction. The pretreatment plant can be 'standardised' to a great extent as most pipeline gas contains not more than about 3 mol.% of carbon dioxide, so this value could be used for AGRU design. For offshore FLNG plants, there has always been concern over the performance of the amine system regeneration column under vessel motions and, to a lesser extent, the amine system contactor. These concerns do not apply to a moored barge operating in calm seas nearshore.

Liquefaction

Onshore liquefaction usually relies on the principle of evaporating liquid to provide refrigeration and the necessary refrigerant components – ethylene and/or ethane, propane and butane (as a minimum) being readily available. Use offshore of such liquid hydrocarbon refrigerant (either in separate refrigeration cycles or in a multicomponent mixture) has always been a concern, for two key reasons:

- The effect of vessel motions on the distribution and effectiveness of the evaporating refrigerant can disrupt heat exchanger performance and therefore liquefaction plant performance and LNG production.
- The need for storage of hazardous flammable refrigerant on an integrated and confined topsides has either influenced the decision to use safer inert nitrogen refrigerant for liquefaction or has meant increased spacing distances and fire barriers so limiting overall plant size and LNG production.

These have led offshore liquefaction projects to propose and use nitrogen expansion technology as nitrogen is inherently safe. Nearshore LNG production on a barge located in calm waters does not incur severe vessel motions and if the hydrocarbon refrigerant can be stored onshore then LNG production is not limited as much by topsides space restrictions.

Refrigeration compressor drives

A 1.0 million tpy LNG plant requires approximately 40 MW of power to drive the refrigeration compressor(s) so an offshore plant either requires a significant electrical power generation system or the use of aeroderivative gas turbines as compressor drives (with a smaller power generation system for other electricity users). Aeroderivatives are proposed rather than the 'industrial' gas turbines used on virtually all major onshore liquefaction plants due to their higher thermal efficiency and lower weight. Electricity generation

incurs weight and significant space, but electric motor drives are much better established than aeroderivative gas turbines as direct compressor drives on process plant and/or refrigeration service. Direct drive compressors also need to be located away from the gas pretreatment and liquefaction plant so increasing piping runs and causing other engineering challenges.

Different LNG technology licensors, plant designers and operators have advised one driver option or the other on cost and performance grounds.⁶ If nearshore LNG could use imported electrical power, with no electrical infrastructure being needed on the barge itself, this would be the most energy efficient and environmentally favourable approach. Clearly, this is location dependant and in some locations the use of gas turbine drivers will be favoured based on overall cost and environmental effects.

Of course, nearshore LNG does not require any accommodation on the LNG production barge, which contains only gas pretreatment and liquefaction, so providing a significant saving in topsides weight and support steel.

Plant size

Nearshore liquefaction would be suitable for LNG production of up to 2.0 – 2.5 million tpy (and gas reserves of the order of 1 trillion ft³). The LNG industry has usually considered such plant capacities as small and uneconomic for traditional long-term (typically 20 year) take or pay type contracts. However, conventional LNG business models are changing and LNG buyers are looking to renegotiate long-term contracts. The use of a liquid 'spot market' for LNG, as with crude oil, is becoming more widespread. These developments could justify

more flexible commercial arrangements and smaller capacity, simpler LNG production projects which can be developed, taken to FID and executed more quickly than typical large LNG projects.

LNG plant prospects in Canada, West and East Africa and Papua New Guinea have all considered nearshore liquefaction to be relatively attractive.⁷

Conclusion

Nearshore liquefaction can lead to reduced costs and shorter time to LNG production than onshore liquefaction. It avoids construction works, a jetty, long gas pipelines and other major infrastructure, thus making it attractive for new liquefaction projects in locations where construction is especially difficult and/or costly. **LNG**

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