INNOVATION IN THE LNG INDUSTRY: SHELL’S APPROACH

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Introduction

The LNG markets have enjoyed a rapid growth over the last 40 years and Shell has played a leading role in this development both as an equity shareholder and as a technical innovator. Currently, Shell advised and equity share projects make up a significant portion of the LNG industry, counting for some 40% in terms of global capacity. Plants advised by us are in operation at six locations worldwide, with new construction underway and other projects at various stages of development. However, in order to remain competitive in today’s environment, the current challenges facing the energy industry as a whole must be taken into consideration. These can be summarised in the following three points:

1. Global energy demand is continuing to grow
2. The growth rate of supplies of “easy oil and gas” will struggle to keep up with the growing energy demand
3. Increased use of coal, plus the overall dominance of fossil fuels, will cause higher carbon dioxide (CO₂) emissions, and strongly increase environmental stresses.

Natural gas, being the fuel with the lowest carbon intensity, will play an increasing role in the future of energy supplies, and demand for LNG has been forecasted to grow at seven percent per annum until 2020[1]. Project requirements will become ever more demanding due to increasing project sizes, difficult gasses and remote locations. Stakeholders will have higher expectations in particular in terms of a plant’s environmental impact. Considering all this along with the above three points, it is clear that continued technology innovation and flexibility of designs are required to suit industry needs.

This paper will present an overview of innovation across the LNG value chain from LNG export to LNG import, including how success is achieved through operational excellence, maintaining a diverse portfolio, integrated solutions and excellence in asset management and safe operability.

History of Shell’s LNG Involvement

Shell helped pioneer the LNG sector, providing the technology for the world’s first commercial liquefaction plant at Arzew, Algeria, in 1964. Since then, we have participated in, and provided the technical advice for projects that count for 40% of today’s global production (see Figure 1). The LNG industry has seen successful LNG plant development from the early steam turbine driven plants in Brunei and Malaysia Satu, through the application of Frame 5, 6 and 7 gas turbines to the large Frame 9 gas turbines employed in Qatargas4 (as designed by APCI).

The Brunei LNG plant has never missed a contractual delivery since being commissioned in 1972 and now, after rejuvenation, operates at 150% of its original design capacity. The Qalhat plant in Oman, completed in 2005, has one of the lowest unit costs of any liquefaction facility yet built. There has been a continued effort to improve the technology behind LNG over the years and with four decades of experience in production and transportation of LNG, Shell remains a pacesetter in the industry.
Innovation

Innovation is much more than research performed in laboratories on molecules. It is also about finding opportunities to enhance value and achieve business objectives in a quicker, cheaper, simpler and more efficient manner. Crucially, the innovation process is complete only when it has created customer value.

Innovation is encouraged in all business areas. Improved products; advantaged feed-stocks; more efficient and reliable manufacturing processes and equipment; more effective business processes; new business models; and ways of retaining and sharing knowledge are all within Shell’s scope. Initiatives exist to explore ways of reducing the capital cost of major projects, with contracting strategies, project management practices and information exchange techniques all coming under the microscope. This is particularly relevant in today’s engineering, procurement and contracting market where the price of steel, concrete, labour and equipment fluctuate so much.

On-going research and development (R&D) and operational and project experience is used to advance designs and project implementation. Practicable innovations resulting from R&D are released for implementation after an in-depth review in the form of a development release and networking is promoted between LNG operating sites in order to exchange best practices. In this way, a cycle of continuous improvement is achieved, as seen in Figure 2.

Along side incremental improvements, step-out innovation is also encouraged. The launch of the GAMECHANGER* initiative has lead to the generation of more novel and creative ideas. A company wide LNG Game Changer project resulted in a generic basis of design for a single train development with twin parallel refrigerant loops based on the proprietary double mixed refrigerant (DMR) process.

Shell’s excellence in research, technology and innovation has also gained independent industry recognition. A biological gas desulphurisation technology jointly developed with Paques B.V. was the winner of the Institution of Chemical Engineers (IchemE) Awards, Sellafield Award for Engineering Excellence in 2007.
Gas Treating

The first step in the liquefaction process is gas treating, a process of significant importance in view of future developments of increasingly contaminated gas reserves. In spite of the relative abundance of gas resources, “easy” fields with low levels of contamination are becoming increasingly scarce. Considering this along with the growing world demand for gas and the fact that approximately one-third (500 trillion cubic feet) of the world’s gas fields are highly contaminated, there is an increasing interest to develop these more “difficult” resources. The major contaminants that need to be dealt with in the LNG industry are carbon dioxide (CO₂), hydrogen sulphide (H₂S) and other sulphur-containing species (mercaptans and COS).

Figure 3 below provides an overview of the front end of the gas / LNG value chain. Gas development projects have evolved from relatively simple exploitation of sweet gas reserves that were directly routed into domestic and industrial supply networks to exploitation of contaminated and remote gas deposits through liquefaction, marine transport and regasification. This results in increased complexity, often requiring multiple process combinations and is further complicated by the tightening of product specifications both for sales gas and LNG, as well as stricter environmental emission standards.

Ample scope exists for simplification of the process line-ups, through technology development as well as smart integration of the different process steps. Innovations here are targeted at increasing the value of contaminated reserves and focus on developing and applying safe and sustainable solutions for the disposal or utilisation of the acid gas contaminants. A key unit in these line-ups is the acid-gas removal unit (AGRU), which traditionally relies on amine-based solvent absorption.

Shell’s early gas treating technologies included application of the ADIP-D (di-isopropanolamine - DIPA) and ADIP-M (methyl di-ethanolamine - MDEA) processes for H₂S removal. The CO₂ removal challenge was met with the development of the hybrid solvent Sulfinol-D, which combined an organic solvent (sulfolane) with an aqueous amine, leading to an improved physical solubility of the H₂S and CO₂ in the solvent. Changing the formulation to Sulfinol-M (combining MDEA with sulfolane) allowed for an increase in selectivity of H₂S separation over CO₂. At that time, these technologies were step changes enabling value to be accessed from contaminated resources previously considered un-processable. Many of the early LNG and gas processing projects benefited from the use of SULFINOL® technology, with greater than 200 applications currently in operation worldwide. Figure 4 shows some of the applications of Shell technology used to access high H₂S containing gas reserves.
Amine absorption technology has continued to develop and includes the development of accelerated MDEA solvents, where the chemical stability and CO$_2$ loading capacity of MDEA has been enhanced through the addition of fast reacting components like piperazine. Shell’s version of accelerated MDEA technology is called ADIP-X. This technology is well suited for the efficient and deep removal of CO$_2$ and H$_2$S from natural gasses upstream of LNG plants.

Based on proven design practices with these hybrid and accelerated solvents, as well as long-term operational experience, Shell recently developed a second-generation hybrid solvent Sulfinol-X which is ideally suited for the treatment of hard-to-handle gasses$^4$. The new technology can be considered for revamps (solvent swaps) in existing plants to increase gas throughput capacity and for the design of new plants. For new plants, it has been shown that simplicity and reliability can be achieved by employing Sulfinol-X, while significantly reducing capital expenditure (CAPEX) when compared with traditional accelerated MDEA line-ups for highly contaminated gasses. Commercial facilities currently utilising Sulfinol-X indicate that the demonstrated advantages and lasting stability are proven.

The advantages this solvent brings include separation of H$_2$S, CO$_2$, COS and mercaptans within a single processing step, rather than having to remove those components via molecular sieves and a separate solvent unit. The addition of the sulfolane, replacing part of the water content of the solvent also improves resistance to foaming due to the presence of liquid hydrocarbons in the acid gas removal unit (AGRU).
We have been a pioneer in separation column internals design with calming section and SHELL HIFI* tray designs and significant contributions in packing developments. This development continues with work on SHELL CONSEP* X trays which include cyclonic separators integrated with the contacting trays to allow increased column capacities and smaller, cheaper and lower weight designs.

After separation of the acid gases and other contaminants, the contaminant species need to be utilised to limit their impact on the environment. In the case of H$_2$S the typical route is conversion to elemental sulphur, as the alternative of acid gas injection. CO$_2$ has historically been vented, but increasingly climate change concerns are driving the industry to develop solutions to keep the CO$_2$ out of the atmosphere.

Typically H$_2$S is removed via Claus and Shell Claus Off-gas Treating (SCOT*) processes. With this Claus-SCOT process, an overall sulphur recovery efficiency of more than 99.8% can be achieved. This standard line up can be enhanced to meet the increasingly more stringent environmental requirements: a hydrogen sulphide specification of 10 ppmv in the SCOT vent gas can be achieved by using a low concentration of an additive in the solvent. There are more than 180 SCOT units in operation worldwide, including at Caroline, Yellowhammer and Emmen. Despite their maturity, step changes are still foreseen to cope, for example, with low H$_2$S/CO$_2$ ratios and the impact of aromatics and mercaptans. In view of the very large H$_2$S volumes in some fields, novel sulphur recovery concepts are currently in development with the aim to reduce costs significantly, while still meeting product and emission specifications.

For post-combustion applications, Shell offers a state of the art amine based technology that achieves bulk CO$_2$ removal. The CANSOLV* CO$_2$ capture process uses an absorbent which is tolerant to SO$_2$ and generates a high purity CO$_2$ gas, with minimal effluents, low solvent degradation and low heat consumption compared to traditional amines.

An alternative means for the removal of H$_2$S is the biological desulphurisation process jointly developed with Paques B.V., which integrates gas processing with sulphur recovery in the same process unit. The simple two-step process (as seen in Figure 5 below), involving the contacting of gas with an aqueous solution containing sulphur bacteria in an absorber column, can remove over 99.8% of the H$_2$S. Depending on the pressure, less than 4 parts per million (ppm) H$_2$S is possible in the treated gas. Since virtually all the H$_2$S is turned into elemental sulphur (up to 80 to 100 tonnes per day), there is no need for flaring or incineration of H$_2$S containing off-gasses. This technology, applicable for small natural gas fields, syn gas, smaller refinery gas streams and debottlenecking sulphur recovery units (SRUs), avoids many of the challenges associated with redox chemistry through the non-fouling or hydrophilic nature of the bio-sulphur produced. Utilising reactor units in parallel would lend the process also to treating larger gas streams with a moderate H$_2$S content. The bio-sulphur can then be used directly, without the need for further processing, as a soil improver. The well-proven process, in operation since 2002, has been designed to be easy to operate with limited maintenance requirements and a high on-stream time. Direct treatment of high-pressure-gas can lead to significant operator cost savings. This biological desulphurisation process is another example of step change technology. Incremental developments of this technology focus on increasing the single unit capacity beyond the current limit of 80 to 100 t/d by making improvements to the bioreactor design.

![Figure 5: Simplified flow scheme of the biological desulphurisation process and scanning electron microscopy (SEM) image of a sulphur bacterium.](image-url)
Alongside the already operational techniques, work is done on future step change technologies for efficient contaminant separation. Examples of these technologies include:

- **Cryogenic solutions:**
  - CRYCELL**, removing CO$_2$ as a solid
  - Condensed Contaminant Centrifugal Separation (C3Sep), removing CO$_2$ as a liquid
- **Membrane separations:**
  - Molecular sieve membrane (SAPO-34, a stable crystalline inorganic membrane)
  - Carbon membranes.

These new technologies being developed are aimed at separating in different regions of the phase envelope. The C3Sep technology operates in the vapour-liquid region. The CryoCell technology is designed to operate in the vapour-liquid-solid region and the SAPO membranes operate in the vapour region. The application envelope for Cryocell, C3Sep and SAPO technologies is seen in Figure 8.

![Figure 8: Application envelope for Cryocell, C3Sep and SAPO technologies.](image)

Increasingly efficient technologies allow the development of contaminated hydrocarbon resources within the tightening economic and environmental constraints of our industry. These technologies are developed through:

- Continuously pushing the limits of existing technologies such as ADIP*, Sulfinol, SCOT and biological desulphurisation processes.
- The constant exploitation of synergies through clever process integration.
- The development of step out innovative concepts to provide the next suite of differentiating technologies.

**Portfolio Development**

Since providing the technology for the world’s first commercial liquefaction plant in Algeria in 1964, the portfolio of Shell’s liquefaction technologies has seen continuous development and growth[8]. The current portfolio of liquefaction technologies is seen in Figure 9 below.
Typically, LNG train capacities have increased over time in order to capture the advantages of economies of scale. In the “mega train” range of over 6 million tonnes per annum (mtpa), Shell has developed the next generation of LNG technology: a parallel mixed refrigerant (PMR) liquefaction process based on propane mixed refrigerant (C3-MR) or DMR technology which is fully scalable between 6 and 11 mtpa. With PMR, gas flows through two simultaneous, parallel cooling cycles that can boost the maximum capacity of a single processing unit up to 11 mtpa depending on the choice of gas turbine drivers. These technologies are based on well proven spool-wound heat exchangers in pre-cool and liquefaction cycles, combined with proven rotating equipment without requiring further scale-up. Three General Electric (GE) Frame 7 machines (or equivalent) can be installed to produce up to 8.5 mtpa; a step-up to three GE Frame 9 machines (or equivalent) can be employed to produce up to 11 mtpa. The parallel line-up improves the overall reliability and availability of the train, further lowering the technology risk. Production can continue at 60 percent capacity if one of the parallel cycles is shut down.

With the world now calling for more energy and less carbon dioxide, the implication of emerging carbon markets on the gas industry and the push for the greener designs is obvious. The PMR process achieves a high liquefaction efficiency through the use of two very efficient refrigeration cycles. The parallel line-up also reduces the pressure drop in the system, which further helps improve efficiency. Another advantage is the absence of a third cycle (typically present in other mega-scale designs) with associated efficiency losses due to temperature approaches in the cooling of the third cycle refrigerant. The PMR design incorporates the full utilisation of waste heat from the gas turbine exhausts which increases plant efficiency and reduces the specific CO$_2$ emissions with respect to a conventional LNG plant design. Comparison of different mega-train processes for similar conditions and design premises has shown that the Shell PMR process has an efficiency that is up to 10% better than alternative processes.

Building on the mega LNG train development and considering the 163 presently discovered gas fields between 5-50 trillion cubic feet (tcf), suitable for 3 to 6 mtpa designs, we have developed a next generation large LNG train design in this size range based on its well-established C3-MR liquefaction process, the current workhorse of the industry. Around 20 different refrigeration compressor drivers and heat and power co-generation options were compared and contrasted based on costs, CO$_2$ emissions, project and technology risk, simplicity and operational flexibility. The effect of main equipment constraints on the design efficiency and the capacity has been studied and the merits of using heavy-duty gas turbines versus aeroderivative gas turbines as mechanical drive have been evaluated. The new LNG train design offers simplicity, high efficiency and low CO$_2$ emissions at competitive cost whilst the concept remains fully scalable between 3 to 6 mtpa.

By applying two well established heavy duty gas turbines (e.g. Frame 7s or Frame 9s) as the propane and mixed refrigerant compressor drivers in combination with waste heat recovery steam generators (HRSGs) to produce steam for (shaft) power generation, increases the efficiency of a plant considerably. The integration of the liquefaction and the utilities means that the electrical power plant can be kept to a minimum size and no gas turbine generators (GTGs) are required in the power plant, only steam turbine generators (STGs). This reduced the installed spare power generation equipment significantly.

A move away from traditional heavy-duty gas turbines could be to employ aeroderivative gas turbines as the compressor drivers. Aeroderivative machines have a higher fuel efficiency than heavy-duty machines and
therefore no steam systems are required to achieve good CO₂ performance. In addition, the power plant can be run on aeroderivative gas turbines, further improving the efficiency of the plant. However, the power output of aeroderivative machines is more sensitive to ambient temperature swings than for heavy-duty gas turbines. This results in a significant drop in LNG production at high ambient temperatures. Moreover, the shaft power drop of the gas turbine can be so much that the propane compressor can run off its operating curve during large ambient temperature swings (the compressor is too large for the remaining gas turbine power available). A way to compensate for this effect is to oversize the gas turbine driver for the propane compressor (undersize the propane compressor) at average ambient conditions. The excess power can then be used at hot ambient conditions. Another way to compensate for this effect is by employing inlet air chilling of the gas turbine/s by using a chilled water/glycol loop.

These energy efficient options give approximately a 25 to 30% reduction in CO₂ emissions from fuel per ton of LNG compared with currently installed and running designs (open cycle, heavy duty configurations). CO₂ emissions from fuel from open cycle heavy duty configurations can be improved by approximately 8 to 9% by simply applying more efficient aeroderivative gas turbines in the power plant.

Shell’s single mixed refrigerant (SMR) process is based around one gas turbine and compressor with multiple spool wound (or plate-fin) heat exchangers. The single mixed refrigerant is used at two or more different pressure levels both for the pre-cooling as well as liquefaction of natural gas. Scaling the process with production capacities ranging from 0.5 to 3.3 mtpa can be realised easily by selection of the appropriate gas turbine. The smaller scale concept is of course driving against the economy of scale rules, but has a lower market acceptance threshold.

Flexibility in Location and a Project of “Firsts”– Sakhalin II

The Sakhalin II development has been hailed as the pride of the energy industry. Not only is it a world-class export-oriented integrated oil and gas project, the sub-Arctic conditions lead to one of the most complex and challenging engineering feats ever attempted. The Sakhalin II team pioneered many new technologies and business solutions to overcome those obstacles, and along the way, a number of engineering records were broken.

At the heart of the Sakhalin II development is Russia’s first LNG production plant (shown in Figure 10), consisting of two LNG trains, together capable of processing gas to produce a total of 9.6 mtpa of LNG and the offshore export terminal. Indeed Sakhalin can be considered to be a project of many “firsts”, not just in terms of Russia’s first LNG plant. The offshore oil platform Molikpaq was the first to be installed on the Russian shelf – and has just completed its ninth production season. The Lunskoye-A and Piltun-Astokhoye-B (PA-B) platforms are also the first of their type to be installed on the shelf. Another “first” was the opportunity for customers in the Asia-Pacific markets to access Russian gas.

Figure 10: LNG Export Facility at Sakhalin.
Photo courtesy of SEIC.
Shell developed the proprietary DMR process, a two-stage liquefaction process, specifically to help cope with and even exploit the varying ambient temperature of Sakhalin. The swing from negative 25 to positive 25 °C between the winter and summer months required a liquefaction technology that could be seasonally optimised and adjusted. Increasing the proportion of propane creates a heavier refrigerant mix for the first cycle in the summer months, which cools gas to -40°C, while adding ethane yields a lighter mix for winter, cooling gas to -65°C. Traditional C3-MR pre-cooling cannot be adjusted in this way and is best suited to large-scale plants in equatorial conditions. Sakhalin II uses 6% less energy than similar facilities based on C3-MR technology in the Middle East and 9% less energy than a C3-MR plant in the Far East. The DMR process hence reduces the amount of natural gas used to run gas turbines by taking advantage of low ambient temperatures for cooling, and the “saved” gas can be processed into more LNG. Additionally, waste heat generated by the liquefaction process is used as a heat source in the gas-treating unit. This integrated approach minimises CO₂ emissions and improves energy efficiency.

Prior to shipping the LNG, it is run down and stored in two insulated storage tanks. The sub-Arctic conditions required the installation of electrical heating elements beneath the tanks to warm the ground in order to prevent freezing. The two tanks were also designed not to collapse or leak even in the case of an earthquake measuring 7.5 on the Richter Scale. The tanks are fixed to their reinforced concrete foundations to limit motion. The first LNG train started up in March 2009. Shell’s “FLAWLESS* Start-Up Initiative” (FSI) was employed, resulting in no unplanned production trips in the first five weeks of operation. The FSI process is based on early identification of potential flaws in plant and equipment during start-up and putting tools and activities in place to help mitigate the numbers and effects of those flaws. It is a rigorous quality execution programme that ensures a project delivers in a number of identified critical success areas by meeting or exceeding agreed Key Performance Indicators (KPIs). KPIs might include ‘clean’, ‘dry’, ‘integrity and operability’. Between 1999 and 2009, fifteen LNG trains were started up using the Flawless initiative.

Practically all of the LNG from Sakhalin II has been sold under long-term contracts of twenty years or more to supply customers in the Asia-Pacific region and North America. The first LNG cargo left the Prigorodnoye port in March bound for the Sodegaura terminal in Tokyo Bay.

The project, which brought together Russian and international expertise to overcome the formidable challenges, provides a potential model for similar collaboration in unlocking much needed reserves in Arctic regions.

Offshore LNG Production

Floating LNG solutions support our strategic ambition to maintain or grow market share in the LNG business. They are particularly well suited to tap into difficult-to-reach or smaller scale reserves to monetise gas from offshore and close-to-shore fields. As such, they are complementary to conventional on shore LNG.

For Shell’s generic Floating LNG (gFLNG), which is generally more suitable for distant offshore fields, challenges posed by variable met-ocean conditions and the dynamic motion environment had to be surmounted. The key dimensions of Shell’s gFLNG concept are approximately 450 metres x 75 metres, with about 3.5 mtpa LNG capacity plus associated LPG and condensate production, taking total liquid production potential to around 5 mtpa. Shell’s philosophy of “design one, build many” makes gFLNG suitable for a wide range of feed compositions and metocean conditions.

In addition to designing a floating unit capable of receiving, processing and liquefying natural gas, a suitable LNG transfer system allowing for LNG off-loading must be incorporated. The concept depicted in Figure 11 shows the current, proven side-by-side offloading solution. A future innovation in transfer technology could result from work being undertaken closely with joint industry partners on the feasibility of tandem off-loading systems. In harsh dynamic motion environments, tandem off-loading could result in increased availability.

Complementing the gFLNG, we have a solution for customers who are holders of more modest gas reserves. The Shell Floating, Liquefaction, Storage and Off-loading (FLSO*), which is best suited for smaller LNG production rates of around 2 mtpa, is unique and proprietary to Shell. FLSO creates synergies with existing onshore infrastructure and allows domestic gas supplies in addition to LNG exports. The portfolio of gas monetisation solutions can either co-exist with LNG from inception, or the mix can be changed flexibly as domestic and international gas markets evolve. Also, FLSO is adaptable to a changing gas resource base and can be redeployed to respond flexibly to future options.
Next to design and construction, a plant is supposed to be operated safely and profitably over its entire lifetime. In order to manage those risks we have developed a framework to provide integrated best practices in asset management in gas and LNG plants by aligning processes, people and tools. It is called Gas-GAME\textsuperscript{[14]}, which stands for Global Asset Management Excellence for Gas sites. The gas-GAME business modules are:

- Maintenance Execution (ME)
- Reliability Centered Maintenance (RCM)
- Equipment Integrity (EI)
- Instrumented Protective Functions (IPF)
- Ensure Safe Production (ESP)*
- Turnarounds (TA)
- Contracting & Procurement (CP)
- Strategy and Asset Information Management (SAIM)
- Competency Management (CF)
- Site Management Systems (SMS)
- Process Safety (PS)

Each of these modules consists of further modules with specific purposes. Fig 12 shows the next level of the ESP (Ensure Safe Production) module. An example of implementation of the ESP module is at one particular Shell advised site that was experiencing a high number of operating alarms on its control system. Panel operators were consequently drowned in regular alarm floods, which sometimes made it difficult to recognise critical alarms and define a proper response. Initial results have shown that the operating window is much better defined; a 40 to 90\% alarm reduction in the utilities area; and that communication during shift handover has been improved.

The programme is aligned across various operating companies and has now been rolled out globally across LNG and NGL plants both internally within Shell as well as across Shell-advised plants. The benefits arise from standardised and simplified business processes and are realised through increased process safety, increased reliability and availability (improved margins) and cost reduction.
Another area where development is done in support of operational excellence is automation. One example is a new technology for the automated cool-down of the main cryogenic heat exchanger (MCHE). The technology addresses the problem of bundle tube leaks in MCHEs and reduces the risk of leak formation during cool-down by automatically cooling down the MCHE in a controlled way and at the most efficient average rate. It leads to rapid start-up and less flaring or venting, while operating closer to performance limits. Therefore, it increases reliability and availability of the LNG train.

At another Shell advised plant, the process resulted in a 60% reduction in the severity of excursions outside the recommended ranges for the rate of temperature change and the temperature difference, which lessened the likelihood of tube leaks caused by temperature shocks. The automated cool-down was also two to three hours faster than the manual procedure (as shown in Figure 13) so LNG production was faster and, consequently, the amount of venting during the shut-down period was reduced.

**Conclusions**

Successful innovation in LNG requires a thorough understanding of the value chain from gas production to market delivery and of the project development phases from identification through to operation, rejuvenation and finally retirement. This understanding allows clear identification and prioritisation of challenges that can be overcome by innovation. Through the identify, develop, deploy and operate cycle, innovation continues to add benefit to our industry. Shell is involved in all parts of the LNG Value chain and has contributed to step change and incremental innovation over the industry’s 45 year history. The structured approach applied to developing innovative solutions to LNG’s current challenges means the LNG industry will continue to benefit from innovation as it evolves to meet the energy needs of future generations.
References


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