FLOATING LNG: THE CHALLENGES OF PRODUCTION SYSTEMS AND WELL FLUID MANAGEMENT

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ABSTRACT

Floating Liquefied Natural Gas (FLNG) units combine gas pre-treatment to tight specifications and natural gas liquefaction that are new to offshore with traditional production systems that are commonly found on oil Floating Production Storage and Offloading (FPSO) vessels. Attention is often focused on the new units, sometimes forgetting that successful operation of the Liquefied Natural Gas (LNG) section requires properly designed inlet facilities and well fluid management. The challenges are greater still in deepwater and harsh environments.

Technip has recently completed several front end engineering designs for FLNG projects. There have been many engineering challenges in the inlet facilities and well fluid management systems to ensure smooth delivery of gas to liquefaction. Chemicals injected in the production piping for hydrate or corrosion prevention, produced water and hydrocarbon condensate must all be removed and treated.

Although this paper will describe floating LNG projects, it will focus on the challenges in the production systems that must be mastered to ensure proper and reliable operation of the FLNG. In particular, it will present challenges in the inlet facilities including gas, condensate and water handling and treatment.

INTRODUCTION

For several years, the offshore industry has been evolving from shallow water fixed platforms to deepwater field developments with floating facilities. Several technology gaps have been successfully filled, one of them being the transfer of industrial gas liquefaction from an onshore to an offshore environment. For a FLNG project development, both liquefaction and upstream production approaches shall be combined to maintain the proper operation of the floating liquefaction unit.

Traditionally, offshore gas field developments linked to LNG include production facilities, a pipeline to receiving facilities at shore, and liquefaction plant onshore with large marine facilities (port, jetties, breakwater, etc.). What FLNG technology brings to the industry is a combination of all these into a same location, including also a combination of all the constraints previously independently managed.

In an offshore environment, topsides weight is a key project driver whatever the support (from fixed platform to floating vessels). Weight affects directly the support size, project cost and stability of floating structures.

Today a state-of-the-art large oil producing FPSO has the following characteristics:

- Hull Dimensions = 310 m x 60 m
- Topsides Weight > 40000 t
- Production capacity is close to 200 000 bopd.
- Flow from wells ~2000 t/h
FLNG is quite different due to the complexity of processing.

- Length > 1.5 x Oil FPSO
- Weight > 1.5 x Oil FPSO
- Production > 0.5 x FPSO

These differences are due to the increase complexity of topsides, to different product storage philosophies and logistics, and to the nature of the feedstock: whereas FPSO feedstocks are characterised by low Gas Oil Ratio (GOR), from 50 to 300, FLNG’s are treating inlet feedstocks with high GOR above 50000 leading to larger equipment size.

**FLNG Typical Architecture**

![Figure 1. FLNG typical architecture](image)

An FLNG field development has the following main blocks:
- Subsea equipment including wellheads, jumpers, manifolds and flowlines
- Risers and umbilicals for the seabed / surface interfaces
- Turret / Mooring for vessel anchoring and weathermaning
- Hull including storage
- Topsides

These blocks are interconnected and are designed using assumptions that may impact weight and space: the key drivers of cost estimation.
Although liquefaction represents the core and characteristic process of a floating LNG, other process operations and units are necessary to ensure the proper operation of liquefaction.

In outline, an FLNG includes:

- Receiving Facilities
- Condensate Production
- Produced water treatment
- Gas treatment
- Liquefaction
- Storage and Export
- Utilities

Receiving facilities provide the interface between subsea systems (wellheads, flowlines, and risers) and the topside units. Condensate stabilization ensures the product specification for export and produced water unit reduces contamination to an acceptable level for environment disposal. Gas treatment units remove natural gas contaminants (CO2, water and heavy hydrocarbons) before liquefaction.

These units are supported by utilities and product storage and export systems. Receiving facilities, condensate production systems and produced water units, ensuring the management of well fluids are regrouped within the Upstream Facilities that are the subject of this paper.

Comparing these entities in term of weight is a good way to appreciate their importance in an FLNG design.
Figure 3. Typical Unit weight repartition on a FLNG

On a weight basis, liquefaction represents less than 25% of topsides systems or as much as the upstream facilities. Gas treatment and utilities represent between 25-30% each.

Another reading is that for an FLNG, 75% of topsides weight is related to units other than liquefaction. This means three quarters of topsides equipment are designed to facilitate liquefaction.

Almost 20 to 25% of weight covers the upstream facilities.

Whereas upstream facilities and liquefaction units were previously independently managed, they are for FLNG strongly interconnected and respective design and operational constraints must be reconciled.

FLNG Operational Constraints

For FLNG, process design has to consider interactions between the production systems and liquefaction that do not exist in a standard LNG chain with units at several locations. Common operational constraints are:

For liquefaction:

- Stability of operating parameters at liquefaction inlet
- The option of extended shutdown
- Minimization of restart time

For upstream facilities:

- Reservoir dependency and the evolution of wellhead conditions with time.
- Uncertainties of the wellstream composition.
- Instabilities from multiphase flow, and during restart.

Special attention shall be paid to ensure that the instabilities inherent in the upstream facilities remain under control avoiding unmanageable disturbances to the liquefaction unit.

This paper considers well fluids management as a key issue for floating LNG and how the upstream facilities design shall be oriented to ensure successful gas liquefaction.
DESIGN CHALLENGES OF WELL FLUID MANAGEMENT

Well fluids are characterised by the uncertainties:

- Reservoir depletion over time leads to modification of pressure, temperature and composition
- Water break-through
- Reservoir geology and drilling activities may cause pollution (sand, salts, completions fluids, radioactive material, tracers, etc.)

In addition process parameters can be modified by phenomena generated within the subsea architecture:

- Seasonal cycles (seawater temperature)
- Start-up or shutdown of wells
- Flow regime in flowlines and risers

By combining all uncertainties, design must consider a wide range of inlet stream variation in terms of:

- Well fluid composition and production flowrate
- Topsides arrival temperature
- Topsides arrival pressure
- Presence of solids

At the same time, natural gas pressure, temperature, flow and composition must be stable when entering liquefaction unit to maximise LNG production and keep steady operation.Upstream facilities are designed to transform unstable well fluid parameters to produce a stable feed stock for liquefaction. Each of these parameters will be subject to specific design and control operations to cope with this main objective.

Production and Composition Profile

Variations in terms of flowrate, pressure, temperature are expected throughout field life.

These variations are linked to reservoir depletion, number of wells in operation and production ramp-up.

Associated to these production profiles, composition may also vary during the year. The impact on liquefaction should be evaluated for Lean / Rich compositions for example. In upstream oil and gas production, GOR and Light / Heavy fluids define the variation of fluid composition during field life. In both cases, this defines the future range of operation for all the FLNG units.

![Figure 4. Composition profile](image-url)
Not considering these production profiles may lead to an underestimation of the design flowrate per phase, for example the water content that generally increases at the end of life.

Production profiles, linked with composition profiles are key parameters for design of upstream facilities as they provide input for flow rate evolution during field life, water breakthrough on reservoir which conducts to design parameter for produced water unit. They allow also designers to envisage optimization and phasing of FLNG design.

Upstream facilities process design is oriented to manage these uncertainties and instabilities and this is particularly true for FLNG.

![Figure 5. Overall LNG field architecture](image)

By carefully combining production profiles from reservoir engineering, field architecture selection by subsea engineering and flow assurance expertise, the definition of well fluid parameters at the topsides battery limit can be done with a more narrow range of uncertainty.

Flow assurance refers to ensuring successful and economical flow of hydrocarbons from the reservoir to the point of sale. Through flow assurance simulation, engineers are able to specify operating procedures linked with field architecture to reduce the large slug catcher (1000 to 5000 m$^3$) commonly installed upstream of onshore liquefaction units to a more reasonable size on floating vessels (10 to 100 m$^3$).

This implies that well location, flowline and riser type and well fluids data are defined in the Process Design Basis documentation.

Once this data is available, each process parameter impacting the upstream facilities design can be evaluated and the design adjusted to maintain smooth operation of liquefaction by avoiding shutdown, unstable process conditions and allowing ramp-up or down of well production without downstream shutdown. For FLNG these are well fluid management and production systems main objectives.

**Operational Temperature Range**

The arrival temperature is a resultant of reservoir temperature, reservoir pressure, subsea production field architecture (type, length of flowline, buried or aerial, choke valve position, dry or wet well, etc.) and FLNG arrival pressure. It is therefore not possible to control all these parameters to ensure a constant fluid arrival temperature at the FLNG topsides during all the field life.
Upstream facilities need to be consequently designed to operate with a large operating range of temperature including seasonal variation and Start or End of Life operating year conditions (SOR / EOR). For process stability, a set of coolers and/or heaters are often installed to avoid transmission of this wide range to downstream units.

One other important point regarding the arrival temperature is the problem of hydrate formation. Generally, well fluids are water saturated and in some conditions may form hydrates on in the subsea lines or on the deck. This is particularly true for:

- Deepwater fields with long tie backs
- High pressure reservoirs when low temperatures are expected downstream of choke valves due to Joule-Thomson effect

For deepwater fields, seawater seabed temperature is usually within a 0.5 to 4°C range. At this temperature hydrate formation may occur in most water saturated well fluids operating above 20 barg.

Flow assurance calculations are therefore required to ensure that the flowlines and risers have been properly designed to avoid blockage of subsea equipment and receiving facilities. The same flow assurance calculations also define the mitigation measures to be implemented to avoid hydrate formation.

![Figure 6. Typical flow assurance result for Temperature profile along subsea pipeline / riser](image)

Several mitigation measures exist:

- Injection of hydrate inhibitor
- Use of active heating technology
- Operation at a lower pressure (LP Mode operation)

Operating at lower pressure is not cost-effective as pressure is the driving force for the liquefaction process and the pressure level to avoid hydrate plug should be lower than 10 barg. In that case additional compression may be required. This option is never considered for FLNG.

Active heating technology such as the ETH-Pipe-in-Pipe or Flexible IPB riser developed by Technip represents a good hydrate mitigation measure. It works by maintaining the production fluid above its hydrate temperature during production or during shutdown and it avoids equipment on the FLNG.

A standard practice is to inject hydrate inhibitor when process conditions indicate a risk of hydrate formation.
Several hydrate inhibitors can be used:

- Glycol (generally Mono-Ethylene Glycol (MEG))
- Methanol
- Low Dosage Hydrate Inhibitor (LDHI).

The choice of inhibitor is made considering volatility, freezing point, product instability, offshore supply chain, environment behavior or potential regeneration.

Whatever the option selected, the impact on a FLNG is not negligible:

- Additional compression when LP operation is used
- Additional emergency power supply for subsea equipment preservation when ETH-PIP, IPB and heat tracing are used
- When permanent hydrate inhibitor injection occurs, either the product is lost in the produced water or it is regenerated. For both cases, the following facilities are required:
  - Storage
  - Injection with flow control
  - When regeneration occurs, impact on FLNG system is even higher:
    - A regeneration module (up to 20x20x40 m module size) including salt reclaiming
    - Hydrate inhibitor buffer tank to avoid shutdown of overall
    - Salts offloading for onshore treatment

**Operational Pressure Range**

FLNG arrival pressure also depends on reservoir characteristics (Well Head Shut-In Pressure (WHSIP)), reservoir depletion and subsea architecture. Variation of pressure may be experienced also due to start and stop of wells.

Pressure range which is specific to each project, will change with time and may vary with well operations. Design has to cope with these three issues.

First, upstream facilities should be designed to cope with the maximum well pressure meaning direct impact on the following equipment:

- Emergency Shutdown valves
- Risers / Flowlines
- Piping manifolds when several risers are installed
- Separators
- Pig launcher / receiver

Inlet pressure has also an impact on the subsea/surface riser connection, especially when a turret is used.

A turret is a device which allows the mooring of the FLNG in harsh environment, when fixed mooring is not applicable. In the turret, several swivels route fluids. However, sealing of these swivels leads to technical limitations regarding pressure and flow. That means that inlet pressure may have to be reduced to cope with these mechanical constraints.

Secondly, upstream facilities should ensure that the pressure variations are not transferred to downstream units. This implies a robust and flexible design in terms of control and specific stabilization schemes.

Finally, even if maximum well pressure (WHSIP) will determine topsides design inlet facilities, end of life pressure may determine size of equipment.
Inlet facilities should anticipate end of life operation with low well flowing pressure due to reservoir depletion. For example, for end of life operation, pressure levels can be so low that for the FLNG liquefaction unit, a depletion compressor is required. Depletion compression has an impact as it represents one additional topsides module (from hundreds up to thousands tons).

This additional module may be envisaged as future offshore retrofitting. This point can be anticipated at an early stage of FLNG development if production profiles are available.

**Well Completion Fluids / Solid content**

Apart from the process parameters, oil reservoirs are also characterized by their geology. Oil & gas reservoirs are a subsurface pool of hydrocarbons contained in a porous or fractured rock formation overlaying by a lower permeability layers on top and often aquifer on bottom.

Therefore, due to the reservoir porosity and the suction forces created by well operations, elements from the reservoir and/or drilling operations can be expected in the well fluids. Topside equipment need to be designed for:

- Sand / Gravel
- Salts

**Sand / Gravel**

Sand is often found in production fluids entering topsides equipment. It enters the well stream due to fluid suction forces on the well and the quantity depends on reservoir porosity.

When sand is expected, material selection for valves and piping should resist erosion.

Sand will potentially depose on any vessel or drums where fluid velocity is reduced. When sand accumulation is expected, a sand removal and treatment unit should be installed.

**Salts**

Salts arrive dissolved in water and condensate phases. They may create problems in the gas phase by salt deposition on compressor wheels following carry over of salty liquid droplets, but this phenomenon is rare and minimized by correct separation design.

In the liquid phase, the main risk is salt deposition when heaters and/or reboilers are used.

When sand content raise issues with regard to commercial specification or operation constraints, desalting system will have to be installed.

**Produced Water**

Once water is segregated from condensate, produced water treatment provides additional separation to reach very low oil content values in water for disposal.

Generally, hydrocyclone technology associated with compact floatation units are sufficient to reach standard Oil In Water (OIW) content

Stringent specifications can sometimes be requested for pollutant like Benzene, Toluene, Ethylbenzene and Xylene (BTEX) or oxygenates. Additional treatment is then required with a non negligible impact on FLNG.
PRODUCTION SYSTEM DESIGN

When well fluids and operations are correctly defined, challenges remain to ensure the smoothest possible operation of the liquefaction section.

There is mutual dependency with liquefaction. Thus, on an FLNG, the production system design should address the following questions:

- If an upset occurs: how does the process need to react to maximize protection for the liquefaction unit?
- How can the well fluids be safely disposed of when an upset occurs in liquefaction?
- In terms of operation, what is the most simple and robust process scheme to ensure smooth operation (meaning stable process parameters at the LNG unit inlet)?

Reception Facilities – Control Strategies

The purpose of inlet unit control systems is to recover the stability required by the LNG units following any perturbation.

Equipment design and control strategies include:

- Liquid accumulation in separators to provide retention time for smooth control
- Route for safe disposal of gas
- Pressure control on the inlet separator which releases gas to flare.
- Route for safe disposal of off-specification condensate.

Shutdown of liquefaction units has to be avoided so sparing and robustness of upstream equipment has to be carefully studied.

Nevertheless if shutdown occurs, sequences of shutdown and re-start have to be reviewed overall taking into account LNG and well fluid preservation constraints. Two different challenges have to be met: issues linked to cryogenic equipment (MCHE thermal stress, shutdown duration before depressurization, depressurization time) and preservation of well fluids.

What is preservation? When shutdown occurs, hydrate formation may plug the subsea pipelines. Preservation consists in depressurizing and replacing the well fluid with “clean” product: generally stabilized dehydrated condensate or diesel. For risers and flowlines, depressurization is performed over a long period of several hours to avoid very low temperatures that impact material selection.

The combination of two (LNG and upstream units) sets of requirements (depressurization time and time delay before depressurization) may then bring operational issue for the FLNG.

This may lead to frequent depressurization of equipment and a loss of gas inventory.

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To solve the above, a good understanding of liquefaction and production systems is necessary as all points are interrelated.
Production System: What For?

For an FLNG, the feed stream is mainly gas. However, even if the amount of liquid is low, it must be properly treated because:

- Associated condensate or produced water cannot be released directly to the environment
- Associated condensate has a high commercial value
- Condensate is difficult to use as fuel on an FLNG

Process production system should be installed to treat condensate to commercial specifications and water to environment disposal specifications.

Typical specifications are within the range of:

<table>
<thead>
<tr>
<th>Condensate Export Specifications</th>
<th>Water Disposal Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>RVP &lt; 6 to 12 psi</td>
<td>OIW content &lt; 5 to 30 ppm</td>
</tr>
<tr>
<td>BSW &lt; 0.5 to 2%</td>
<td></td>
</tr>
<tr>
<td>Salt content &lt; 15 to 60 mg/l</td>
<td></td>
</tr>
<tr>
<td>H2S content &lt; 1 to 10 ppm</td>
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</tr>
</tbody>
</table>

These ranges of values are typical and may vary with project location and product final destination.

Condensate Production Systems

For condensate, production system treatment consists of:

- Separation of hydrocarbons and water to reach Base Sediment Water (BSW) specification
- Heating and separation to reach Reid Vapor Pressure (RVP) specification on condensate product
- Washing and purification to obtain H2S or Salt content

Process operations required to obtain the specification of condensate are separation, compression associated with gas separated from condensate and heating or cooling.

When stringent specifications are defined, additional separation or high performance technology are available.

Arrangement of these process operations is mainly dependant of the fluid composition and the specification to be reached. Two main schemes are commonly used: multi-stage separation or a stabilization column.

Figure 8. Multi stage and Stabilization column arrangement schemes for production system
The most simple and robust production scheme is the multistage separation as only vessels and heat exchangers are installed. This set of equipment is suitable to achieve standard vapor pressure and BSW specifications.

When more stringent specification like H2S or very low water content is requested, a stabilization column scheme is preferred.

However, as with any distillation column, control can be difficult and may be subject to disturbances from upstream (salts, chemicals, chloride) and to ship motions.

For tight specification on water content, additional equipment to standard separator should be added. Coalescing element or electrostatic dehydrator technology is providing high outlet specification, but this requires additional separation stages.

When stable emulsion or foaming occurs during water/condensate separation, the hold-up time required for separation is considerably increased. Tendency to foaming behavior and stable emulsion creation depends on well fluid composition and mainly when heavy products are present. For floating LNG, this tendency is limited as only condensate is expected.

In conclusion, recommendations for FLNG production process scheme are flexibility and simplicity, high robustness and smooth stabilization of process parameters for downstream units.

Good sparing philosophy is a key way to solve instability and improve robustness. Associated costs should be evaluated.

CONCLUSION

For the successful operation of a FLNG vessel, it is most important to design the process from the wellhead to the liquefaction unit. This implies the following:

- Good understanding of reservoir characteristics over the entire life of the field
- Good understanding of fluid behaviour from wellhead to topsides, meaning that flow assurance studies are mandatory for all cases
- Simple, robust, flexible designs and easy to operate upstream facilities to avoid unplanned shutdowns of the liquefaction unit
- Smooth control of upstream facilities to stabilize process parameters upstream of liquefaction unit.

Respecting these main principles will bring success to the development and operation of FLNG.

Therefore, well characteristics should be carefully detailed in the process design basis when projects come into development to allow the engineering company to anticipate and adapt the FLNG design issues related to well fluid management.