Use of Dynamic Simulation To Assist Commissioning and Operating a 65-km-Subsea-Tieback Gas Lift System

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Summary

The Penguins field comprises of a cluster of reservoirs in the northern North Sea. The need for gas lift was foreseen during the early stages of field-development planning. Five oil wells were completed for gas lift service. A 65-km 4-in. gas lift line was laid in 2006, running alongside the production line and tied into the drill centers by flexible 2-in. jumpers.

Because of the unconventionally long distance of the field from the platform, it was necessary to carry out transient modeling of the full commissioning and gas lift startup process. Particular attention was required, both in design and operating procedure, to avoid hydrates and excessive velocities in the high-pressure, low-temperature system.

Dynamic simulation with the industry-renowned transient software package (OLGA v5.1 2006) has proved to be valuable for the commissioning of this gas lift system. It also explained discrepancies between anticipated behavior of the shear orifice valve and the actual behavior seen in the field.

The overall project outcome was a success, with excellent improvements in field stability and production. The project was justified on the basis of kickoff capability only, but continuous gas lift is required to maintain stable flow from all of the wells.

Introduction/Field Background

The Penguins field was discovered in 1974. Several exploration wells were drilled until 1991 to understand the field and acreage.

Numerous field-development options were considered. It was concluded that a 65-km subsea tieback to the Brent Charlie platform was the most economical option. The key technical justifications for this choice were that processing capacity was available, product evacuation routes were established, and the availability of an unused gas-injection compressor was suitable for redesign as a gas lift compressor.

The reservoir fluids range from black oil in the north at Penguin A to retrograde condensate in the south at Penguin E. To date, nine development wells (A1, A2, C1, C2, C3, D1, D2, D3, and E1) have been drilled, with a spread across the fields. The field has been developed with four drill centers, starting with DC2 at Penguin A and extending to DC5 at Penguin D/E **(Fig. 1).** The field is located 50 to 65 km north of the Brent Charlie platform and is produced by a single 14-in. commingled flowline. The field produced naturally from 2003 to 2007, from which time a few wells now require artificial lift.

Various artificial-lift methods were evaluated, but gas lift was selected as the best option for this high-gas/oil-ration (GOR) field on depletion drive. Reliability was a key decision factor because of the high intervention costs. However, justification of gas lift in a 65-km tieback was not straightforward, because other examples and industry experience would suggest that gas lifting a tieback field further than 25 km could become unbeneficial because of the backpressure effects from friction (Øverland and Ramstad 2001). Uncertainties in reserves estimates required a phased development plan where the five oil wells were equipped for gas lift, but provision of lift gas to the field was left open until a later date.

The Penguin A and Penguin C reservoirs are both black-oil systems. It was foreseen in the development plan that artificial lift would be required to ensure ultimate recovery, and wells in these reservoirs were completed with a single gas lift mandrel (GLM) with a shear orifice valve preinstalled. The five A and C wells have varying reservoir pressures, flow rates, and pressure/volume/temperature (PVT) properties. The remaining four wells, in the Penguin D and Penguin E clusters, are light-oil/condensate systems.

Initial production-system optimization was relatively simple because of the high GOR and overpressurised nature of the Penguin wells. All wells had the ability to operate at high pipeline/drill-center pressures (up to 65 barg), and the landing pressure at the Brent Charlie platform was required to be 24 barg or higher. However, as the wells have depleted over the years, the black-oil wells started to struggle to flow to the point were the gassier condensate wells had to be choked back severely to avoid killing the black-oil wells. Eventually, one well (C2) ceased production at any point when another well was flowing. The other wells were also having kickoff problems and required the pipeline to be bled to below normal operating pressure (35 to 40 barg) to allow them to restart. Hence, optimization of the field production became increasingly complex over time.

In 2005, the gas lift project was approved, using a 4-in. supply line from the Brent Charlie platform and modifying an existing injection compressor to provide the required rate of 500 Km^3/d (18 MMscf/D) of lift gas at pressures up to 280 barg (4,000 psi).

As the project on-stream date came closer, it was realized that the commissioning phase posed some challenges and required detailed planning. Commissioning challenges that were evaluated are discussed in this paper and include

- Avoiding hydrates or other temperature-related integrity limits because of Joule-Thomson effects through various valves in the system.
- Staying within velocity limits of orifice valves in the side-pocket mandrels.
- Minimizing risk of slugging wells and/or pipeline during commissioning and steady-state flow, which may result in a platform trip at Brent Charlie.
- Minimizing time taken for the commissioning process and hence production deferment.
- Determining measurable indicators as to when the gas lift line, jumpers, and annuli were cleared/unloaded.

Following the commissioning phase, challenges that existed in field operations evaluated were

- Managing liquid slugs during future startup of the system.
- Maintaining stability of the wells under conditions of continuous gas lift.

Engineering assessments and achieving the desired targets were primarily carried out by using both transient (OLGA v5.1 2006) and steady-state modeling techniques (Petroleum Experts 2009).

System Description

Following project approval, a 65-km 4-in. flexible pipeline was later laid to provide gas lift from Brent Charlie to the Penguin Field. Lift gas is supplied from the Brent Charlie gas-export system

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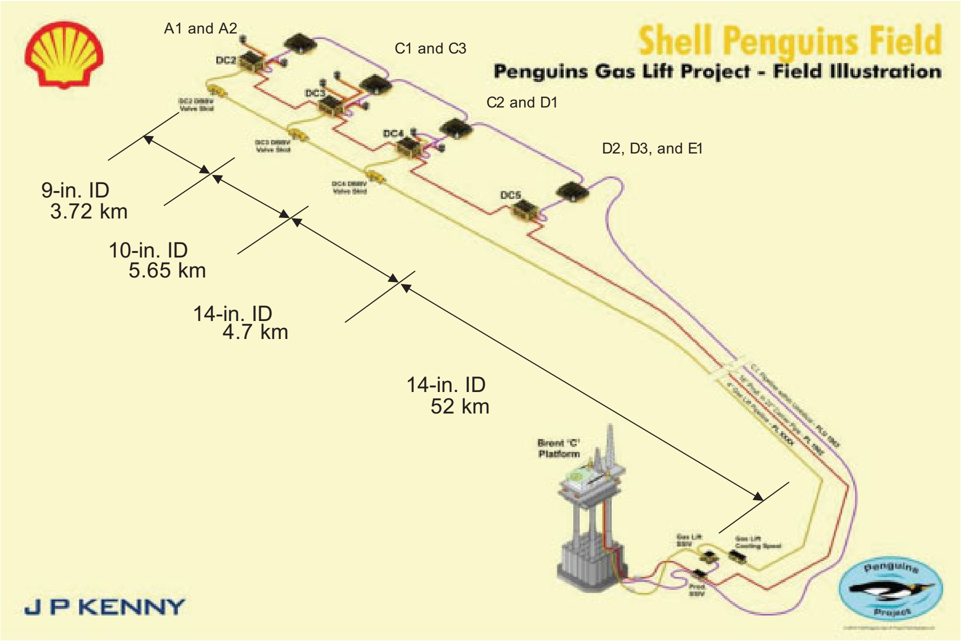

Fig. 1—Penguins field subsea configuration.

and is further compressed by a modified reciprocating compressor, previously used for gas-injection purposes. The system is capable of delivering gas lift rates of up to 500 Km^3/d (18 MMscf/D) and pressures up to 280 barg (4,000 psig) at the Brent Charlie platform and is selectively controlled by flow or pressure. Cooling for the gas lift compression system is provided by a newly installed printed circuit heat exchanger (PCHE) cooled by recirculating platform cooling medium. The configuration on the platform is shown in **Fig. 2.**

The gas lift line configuration is a single 4-in. line feeding to each of the farthest three drill centers DC2, DC3, and DC4. Before commissioning, the gas lift line was filled with monoethylene glycol (MEG). In addition to Fig. 1, **Fig. 3** shows the layout of the line. Gas lift injection rate into each well is a function of the topside compressor gas input into the gas lift line, and the output of gas from the line into each well is controlled by the gas choke-valve settings.

All gas lifted wells are similar in design and encompass a 5 ½-in. completion with 4 ½-in. TCP guns hung off from the tailpipe. The design has a single GLM with a shear orifice valve preinstalled. The shear orifice contains a drawbar with a rating of 70-barg dp from casing to tubing pressure. All wells were completed in base oil, and hence this was left in the A-annulus since the completion was installed.

Produced fluids arrive at the platform from the production flowline and flow into the Slug Suppression System (S^3). This is a Shell proprietary unit installed at the top of the riser to mitigate against the phenomenon of slugging and to provide a smoother delivery of both gas and liquid flow into the processing train. The S^3 device also acts to crudely separate, meter, and control independent gas and liquid streams.

Challenges During Commissioning Process

The Penguins gas lift system was commissioned in two stages. The first stage involved commissioning of the 4-in. gas lift pipeline, and the second stage involved the commissioning of the gas lift system for each individual well.

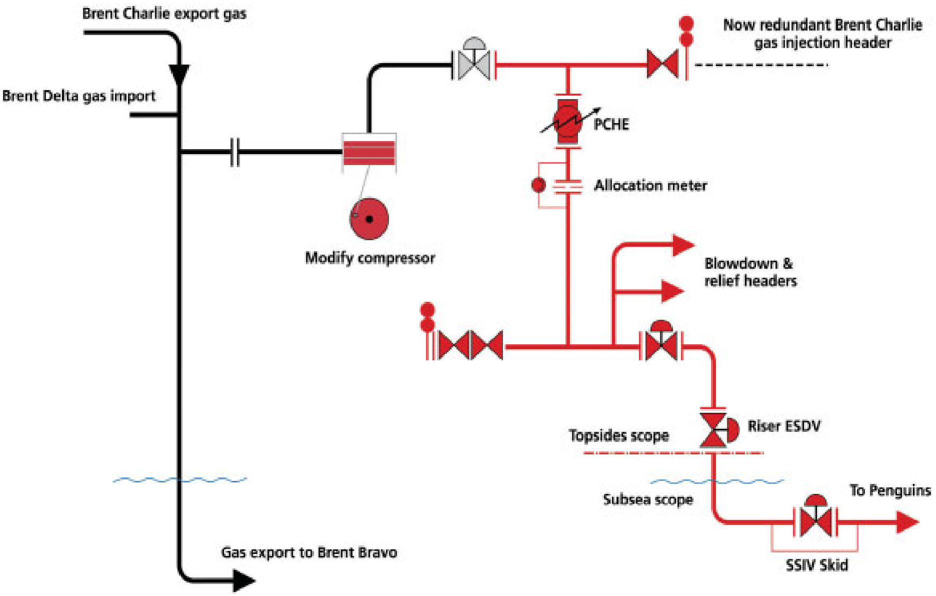

Fig. 2—Topside gas lift compression configuration.

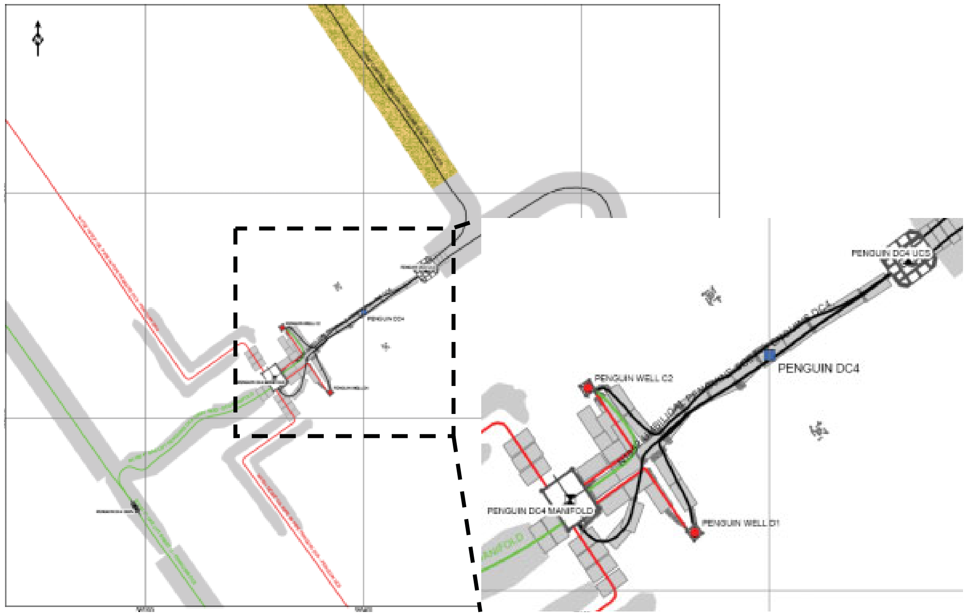

Fig. 3—An example of a drill center configuration.

For the commissioning of the 4-in. gas lift pipeline, the main objective was to clear the entire pipeline of MEG. This was to be done by flushing the MEG from the gas lift line through to the production pipeline by a crossover connection for one of the wells using gas lift supplied at the Brent Charlie platform.

The commissioning of the gas lift system for each individual well involved the clearing of MEG from the well jumpers connecting the drill-center manifolds to the wellheads and the clearing of base oil from the well annuli. This was also to be done using gas lift from the Brent Charlie platform.

The commissioning of the system had to be controlled within the system limitations, including pressure, temperature, and velocity limits. To predict the transient effects of this process and to optimize the commissioning process, a transient modeling package (OLGA v5.1 2006) was used. The specific challenges are described in the following sections.

Hydrates. There is a high risk of hydrate formation in gas systems operating at high pressures and low temperatures. Gas quality is therefore highly critical, and measures have to be in place to mitigate the risks. This includes improved drier gas quality as well as the facility to allow injection of methanol.

Multiphase fluids arriving from the Penguin field are commingled with Brent Charlie production in the production separator. The gas is dehydrated by contact with triethylene glycol (TEG) and compressed to export-delivery pressure. Furthermore, the gas-dehydration process has been improved through the addition of stripping gas in the TEG regeneration process. This further reduces the water dewpoint of export gas used for gas lift to –29.4°C. This higher specification of lift gas is required to assist in avoiding hydrate formation as the lift gas cools down to a seabed temperature of approximately 5°C, before being exposed to Joule-Thomson cooling resulting from large pressure drops during dynamic phases of the commissioning process.

Therefore two pumps have been installed as part of the gas lift modifications to provide methanol injection directly into the gas lift pipeline, further protecting the system from the risk of hydrates.

In addition to the hydrate risk from low temperatures, various sections of equipment in the system have low-temperature limits, such as the gas lift and production jumpers. The low-temperature limits of these components vary from –29 to –46°C.

Erosional Limits. Because of the drawbar in the gas lift orifice valves, it was unknown what the initial velocity would be through the orifice. The standard practice in the North Sea for gas lift operations is to limit the liquid velocities through the valve to 1 bbl/min to avoid flow-cutting the port and to check assembly in the orifice valve. The challenge in this case was to understand if this limit would be exceeded, and if so to minimize the exposure time.

Slugging. The production flow from the Penguins field is susceptible to pipeline slugging upon arrival at the Brent Charlie platform. This is because of the size of the flowline (14-in.), the terrain, and the fluid characteristics. An S^3 has been installed at the Brent Charlie side of the riser and acts to provide a smoother delivery of both gas and liquids. The system is capable of handling foreseeable startup slugs generated under rapid well-opening conditions and serves to produce the slug at a controlled rate rather than eliminate the phenomena entirely. On the occasion that a size or pace of generated slug can overcome the S^3, the platform would most likely encounter a rapidly fluctuating flow of gas and liquid, the likely result of which would be a compressor trip because of short-term starvation of gas for compression. Because of the turndown experienced by the field, the production separator is sufficiently oversized to capture liquid fluctuations.

Commissioning Time. It was desired to reduce the overall commissioning time to allow gas lift to be used on the field as soon as possible to obtain the production benefits.

Determining Measurable Indicators. Some phases of the commissioning program required defined parameters to indicate when the objective was met. This was particularly important for the clearing of the gas lift line. Because the system was still in production during the commissioning, it was not possible to determine what volume of fluid received at the platform was MEG that was circulated through the lines.

Gas break-out at the production choke of A2 was the first indication of a milestone in the process. After that, however, there was no way to know what volume of MEG still remained in the line. Here the transient modeling package (OLGA v5.1 2006) was used to advise the time and flow rate required for circulation following gas break-out at A2 to fully clear the MEG from the gas lift line.

OLGA Model Description and Predicted Results

Model Description. Since the inception of multiphase-flow modeling in the oil and gas industry, there have been many developments in modeling capabilities (Lopez et al. 1997; Norris et al. 1985;

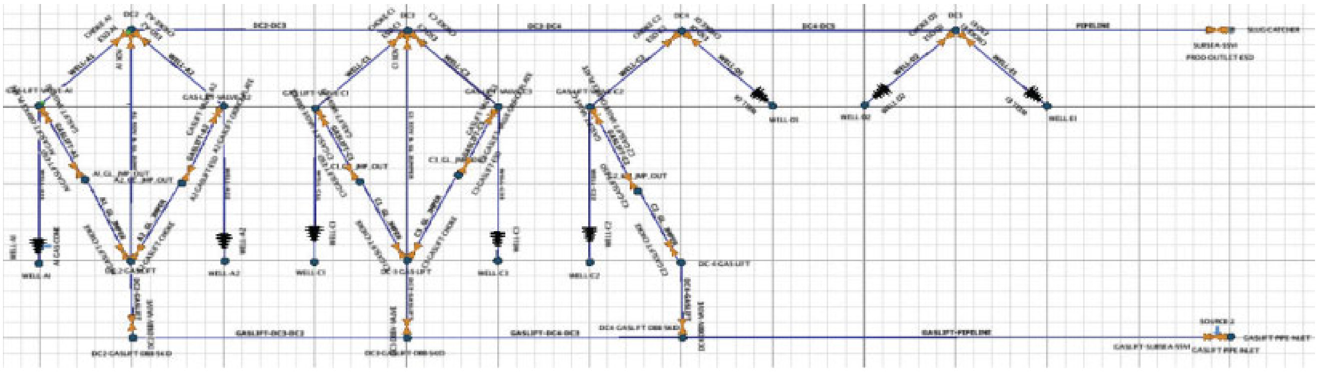

Fig. 4—Complete OLGA model for the Penguins production and gas lift system.

Nossen et al. 2001; Mantecon 2007), particularly in the area of transient simulations. This is providing increased confidence in the results of dynamic multiphase-flow simulators. An industry-renowned transient modeling software package (OLGA v5.1 2006) was selected because it has proved to be reliable and robust with advanced modeling capabilities that are maintained and validated in joint industry projects (JIP) (Nossen and Rasmussen 2001) of which Shell is a participant.

The main objective of the studies carried out using transient simulations for the Penguins field is to provide high-level guidance and procedures for the various operational aspects of interest for the gas lift system. Other engineers have also approached the problem in a similar manner (Hyllseth and Cameron 2003). In order to obtain an all-purpose model, the complete Penguins system, including the wells, the 14-in. production pipeline, and the 4-in. gas lift pipeline, was built as shown in **Fig. 4.** For each of the wells, the inflow and outflow were modeled using parameters including reservoir pressure, productivity index (PI), and fluid PVT. Separate pipes were used to model the gas lift annuli for the different wells. This model was validated against field data and was determined to be representative of the Penguins system.

In the interest of computational expense and time, subsequent simulation work was performed using simplified models **(Fig. 5)** reduced from the full-system model. The full-system model includes not only both the production and gas lift lines but also all the wells, gas lift annuli, and jumpers. Typical run times were reduced from a scale of days to hours.

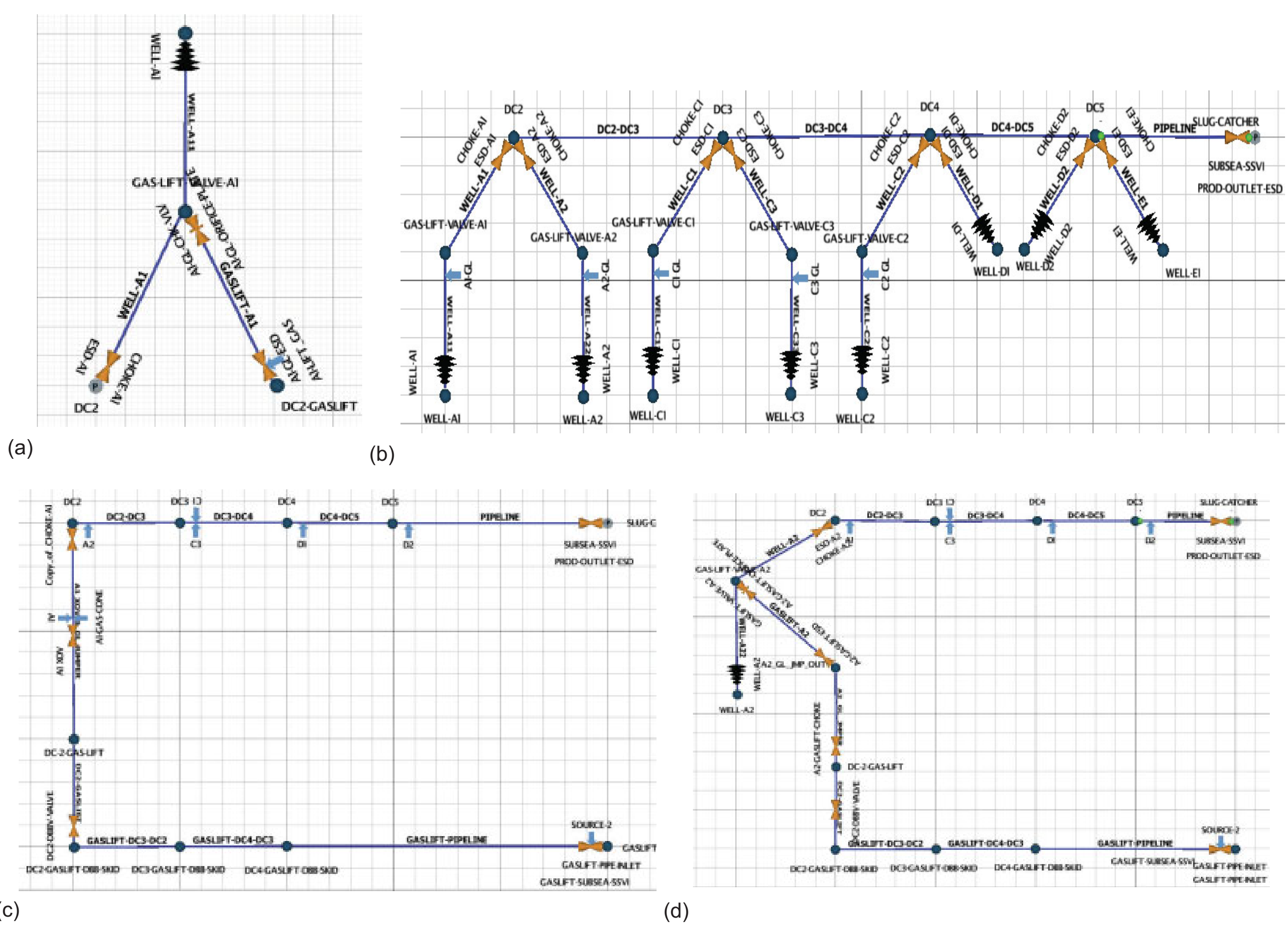

Fig. 5—Simplified OLGA models of the Penguins system for various gas lift studies. (a) Model used to study stability of Well A1 under conditions of continuous gas lift. (b) Model used to provide guidance for liquids management during the startup of wells. (c) Model used to provide guidance and procedures for first commissioning of main gas lift pipeline. (d) Model used to study the kickoff of Well A2 using gas lift.

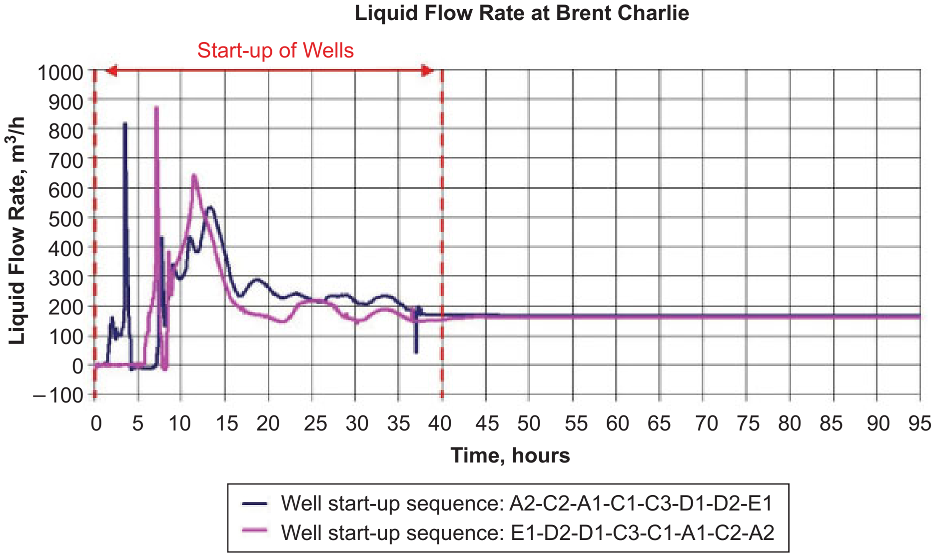

Fig. 6—Arrival of liquid rates at the Brent Charlie platform.

Modeling of Commissioning Phases. The phases of clearing MEG from the gas lift line and crossovers and the unloading of the base oil from the annuli were modeled in an iterative fashion to determine the best procedures. Many different runs were required to develop the procedures and limits that would comfortably safeguard the system with respect to the risks mentioned in the preceding sections.

The main step requiring iteration was the shearing of the gas lift valve in each well. Initial runs of the model resulted in velocities across the orifice that far exceeded the 1-bbl/min limitation and also showed temperatures at the gas lift choke that reached –30°C. The process control for this step was to reduce the gas lift pressure in the line available when the gas lift choke was first opened. It would therefore be required to depressurize the line to a certain value before the shearing step on each well. However, it was desired not to depressurize too much because this would require additional time for the depressurization and subsequent repressurization required for the unloading step. Iterations were run on each well to find a balance that allowed the process to stay comfortably within the system limits of temperature and velocity, while minimizing overall time for commissioning.

The resulting procedures for the commissioning of the wells and expected process parameters are compared in detail against the actual parameters during commissioning in the next section.

Liquids Management During Well Startup

Further to the initial commissioning, subsequent field-startup guidelines were derived from transient simulation. Scenarios developed for analysis were based on attempts to generate the largest perceivable slug sizes arriving at the Brent Charlie facilities. These were established with the most aggressive startup scenarios foreseeable under the limits of operation, involving startup with a filled pipeline, rapid well openings in quick succession, and startup with liquid wells having priority. **Fig. 6** illustrates the simulated arrivals flow rates for two well sequences. Both sequences generate liquid arrival rates within the handling capacity of the platform facilities.

Well Stability. Well stability is of a concern because this may cause undesired interruptions in production. Following Hu and Golan (2003), transient simulation has been used to investigate stability for each of the gas lifted wells under conditions of continuous gas lift. The model of each well was isolated (Fig. 5a), and the stability of individual wells was investigated for different backpressures and gas lift rates. The results of the dynamic simulations have been used to create stability maps whereby regions of unstable well production have been identified **(Fig. 7).** Well instability is defined here as when the well sees a limit cycle in production that oscillates by more than 10 kg/s.

Comparison of Transient Modeling to Actual Data During Commissioning

The transient-modeling results for the commissioning phase have been compared directly against data recorded during the actual process for the following phases of commissioning:

1. Displacing MEG from the gas lift line
2. Unloading of Well A2 (comparison to field measurements described in detail)
3. Sequentially unloading of the respective wells A1, C3, C1, and C2. Comparison of model and field results will be discussed for Well C3.

The clearing of the gas lift line was a fairly straightforward process and presented no unforeseen circumstances. Gas breakout at the choke of A2 was predicted to occur within 19 hours of introducing the gas into the line, while in practice the gas break-out was observed approximately 7 hours after the introduction of gas. Because there were no measurable parameters to indicate when the liquid was completely removed following the gas break-out, the predicted time from the model was used to circulate out the remaining liquids for the following 51 hours. The main reason for the discrepancy in the time to observe gas break-out at the A2 choke is most likely the gas rate being ramped up quicker in practice than what was modeled. Transient modeling predicted a lowest temperature of –5°C during the gas lift line commissioning, but a temperature of –4.9°C was measured. This low temperature is a clear demonstration of why high specification of gas lift quality is required, and hence low-temperature dewpoint is required to avoid hydrates.

The commissioning of Well A2 has been studied in detail and is discussed with conclusions and observations noted. **Fig. 8** shows pressures and temperatures during the entire A2 well-commissioning process and compares transient-modeling predictions to measurements obtained by PI Datalink. These graphs are overlaid on top of each other with matching start points. The main differences seen are

- Transient modeling predicted that the orifice valve drawbar would shear as soon as the A-annulus is exposed to the gas lift line pressure (79 barg) present at the start of the step. In reality, the orifice valve drawbar did not shear until 7.5 hours after exposure to the gas lift line pressure.
- Transient modeling predicted that the orifice valve drawbar would shear at a CHP of 71 barg. In reality, the orifice valve did not shear until the CHP reached 140 barg.
- Transient modeling predicted that the maximum CHP would be 160 barg, but the maximum CHP reached was approximately 140 barg.

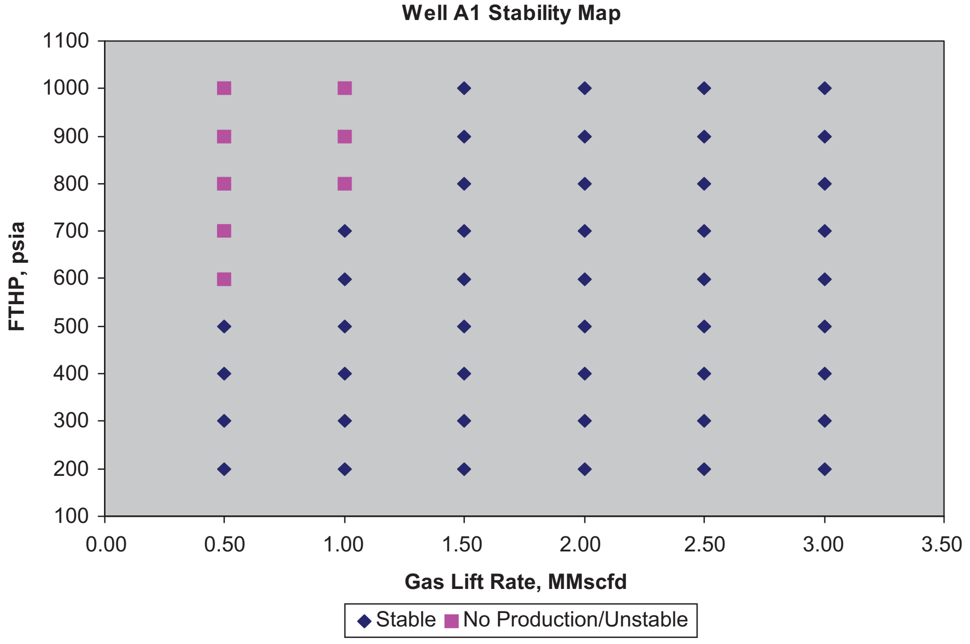

Fig. 7—Stability map for Well A1.

• Transient modeling predicted that the total time to unload the A-annulus would be 19 hours. The actual time to unload the A-annulus was 7 hours.

Some of the differences between transient modeling and the measurements are highlighted in Fig. 8. The major differences can be explained by either one of the two scenarios below:

Scenario 1: Because the time taken for the annulus IB pressure (CHP) to reach the OB pressure (pipeline pressure) was 40 minutes, it suggests that the casing was not liquid filled to surface. It is possible that over the years the base oil has leaked into the tubing by the nonsheared orifice valve and the new level is approximately 2,914 ft below the wellhead. The orifice-valve drawbar is set to shear at 70-barg differential; hence, if the annulus is not liquid filled, more pressure is required at surface than predicted by the model. Secondly, with the assumed liquid level at 2,914 ft, the average rate of unloading is only slightly more than the OLGA-predicted value of approximately 0.5 bbl/min and actually is 0.75 bbl/min. According to this scenario, the average leak rate was approximately 20 to 30 L/d over the life of the well.

Scenario 2: Should the annulus still be full of base oil, the shear value of the drawbar would have to be 132 barg. Also, in this case, the average rate of unloading is more than the prediction of approximately 0.5 bbl/min and actually is as high as 1.35 bbl/min.

Scenario 1 is accepted as the most likely explanation for the differences observed between the modeling and the actual results. The primary piece of evidence for this is the 40 minutes required to equalize the pipeline pressure and the CHP. This can be explained only by the presence of an incompressible fluid in part of the annulus. In addition, subsequent discussions with the supplier of the orifice valves offer the following points:

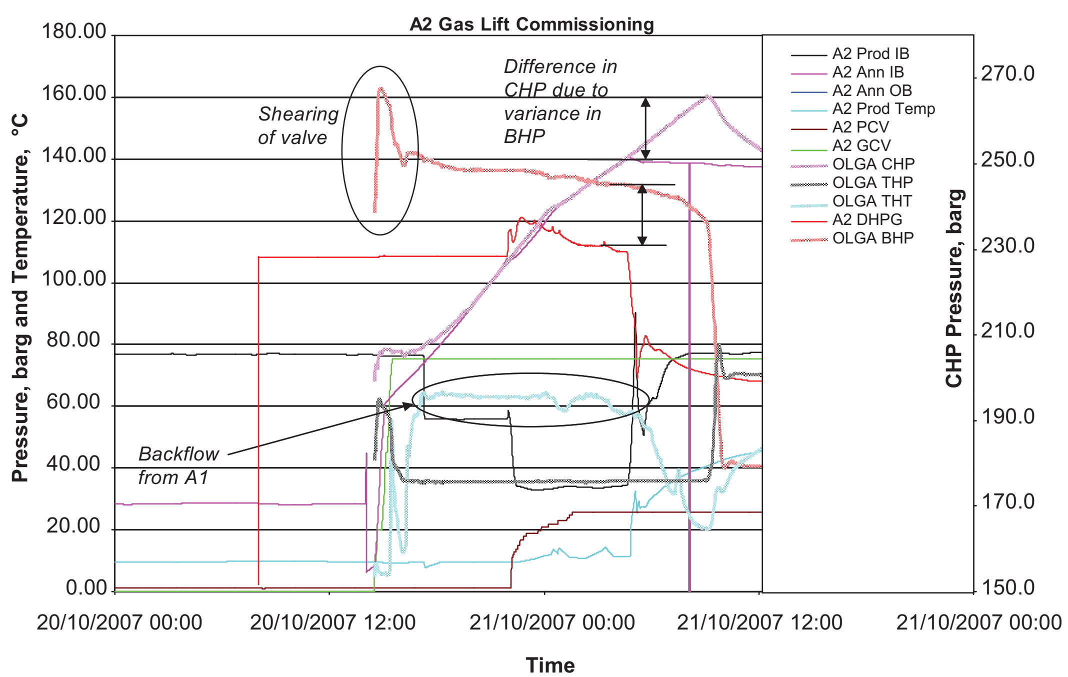

Fig. 8—Comparison of A2 OLGA simulation to real data during commissioning.

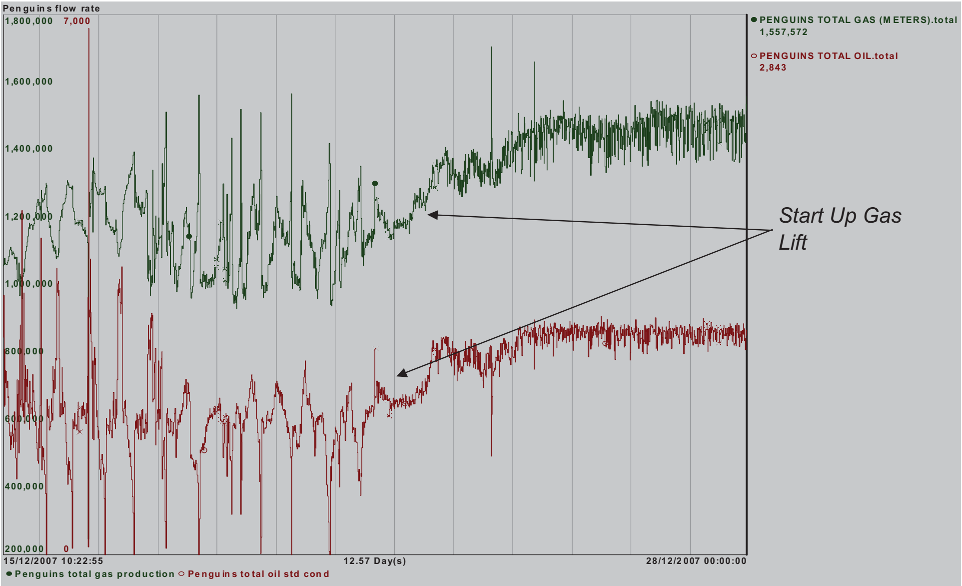

Fig. 9—Impact of startup of gas lift on Penguins production.

• The orifice shear valve used is not specified as "bubble-tight" in the direction of the flow preshear by the manufacturer. Leakage is therefore possible over time.

• The drawbar shear value is rigorously tested by the manufacturer and is unlikely to be approximately 90% higher than specified.

A similar analysis was carried out on Well C3, and this revealed very similar results and conclusions. A quick look at the maximum CHP during commissioning of the remaining three wells also revealed the same phenomenon.

In summary, commissioning of the gas lift line and the five wells was executed efficiently and successfully as a result of the good planning and guidance provided by transient modeling. After commissioning, the production-optimization process was carried out using empirical means because there were few or no production data on some of the wells that now had gas lift available to them. Initial analysis before commissioning suggested that two, or at most three, wells would benefit from continuous gas lift. However, the reality was that as more wells were gas lifted, the increase in pipeline pressure was sufficient to kill off the other oil wells. This resulted in all five oil wells requiring continuous gas lift. **Figs. 9 and 10** show the effect of gas lift on the field stability and a 25% increase in production, as well as the stability of individual wells.

The results of the field-startup simulation showed that despite the introduction of gas lift, the S^3 was capable of addressing the anticipated volumes, and this was also demonstrated in practice. Also evident was the ability of the model to correctly predict the pressure profile and arrival temperatures on the Brent Charlie platform.

Conclusions

The overall project outcome was a success, with excellent improvements to field stability and an initial increase in oil production of

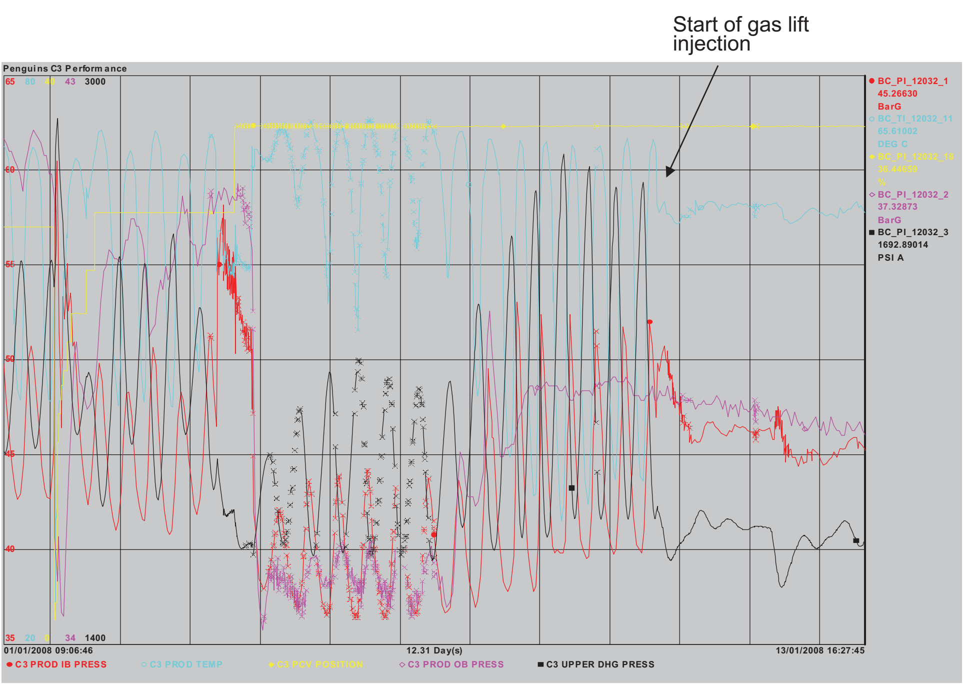

Fig. 10—Example of well-stability improvement with gas lift.

approximately 25%. The following conclusions can be drawn from the evaluations discussed in this paper:

- Dynamic simulations using a transient modeling package (OLGA v5.1 2006) were of great benefit in providing guidance and procedures for the commissioning process, predicting pressure, temperature, velocity transients, and the associated integrity risks.
- Shear orifice valves are evidently not leak-tight. Liquid from the annulus may leak into the tubing before shearing the orifice valve, thus creating a vacuum/void in the annulus. Care should be taken when designing the drawbar to ensure that sufficient differential pressure is available to shear the valve. Consideration should also be given to any integrity implications of not having a fluid-filled annulus.

Other useful learnings that have been demonstrated that were not the focus of the paper are

- Gas lifting at extremely long distances (65 km) is possible and beneficial.
- The Penguins project is a good demonstration of successful field-development planning where the wells were prepared and completed for gas lift use, long before it was actually required.
- Maintaining a simple-single mandrel gas lift design may require higher compression requirements. However the benefits of this far out weight the downside (i.e., simpler unloading process, fewer potential leak paths, no risk of inefficient lifting because of multipointing).
- Lift gas quality is of primary importance to avoid flow-assurance (hydrate) problems in a high-pressure, low-temperature gas lift system like Penguins.

Nomenclature

BHP = bottomhole pressure
CHP = casinghead pressure
DBBV = double block & bleed valve
DCx = drill center followed by the number of the specific drill center
DHPG = downhole permanent gauge
ESDV = emergency-shutdown valve
GAP = Petroleum Experts Ltd. General Allocation Program for steady-state-system modeling
GCV = gas choke valve
GLM = gas lift mandrel
GOR = gas/oil ratio
IB = inbore (upstream of PCV for production side and downstream of GCV for gas side)
Km^3/d = thousand cubic meters per day
MEG = monoethylene glycol
MMscf/D = million standard cubic feet per day
OB = outbore (downstream of PCV for production side and upstream of GCV for gas side)
OLGA = Scandpower transient modeling software
OLGA BHP = OLGA model calculated BHP
OLGA CHP = OLGA model calculated CHP
OLGA THP = OLGA model calculated THP
OLGA THT = OLGA model calculated THT
PCHE = printed circuit heat exchanger
PCV = production choke valve
PI = productivity index
PI Datalink = real-time and archived data system
Prosper = Petroleum Experts Ltd. software for steady-state well modeling
PVT = pressure/volume/temperature relationship
SSIV = subsea isolation valve
S^3 = slug-suppression system
TCP = tubing-conveyed perforating
TEG = Triethylene glycol
THP = tubinghead pressure
THT = tubinghead temperature
UCS = umbilical control structure

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