The benefits of a compositional thermal hydraulic integrated production model when investigating subsea processing

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ABSTRACT
Subsea processing has become a promising technology for the offshore upstream oil and gas industry, which could solve many current and future field development challenges. Some authors are predicting a fivefold increase in annual spending on subsea processing from 2013 to 2020. It is becoming more common for offshore field development planners to consider subsea processing during conceptual design. However, like most production technologies, it is not appropriate for all projects at all points in their field life and hence should be looked at thoroughly when being considered. In this paper it is argued that many of the simplifications made in traditional Integrated Production Models (IPM) can lead to errors in the production forecast, particularly for subsea processing systems. Worse still, simple IPM lead to the slowing down of the design process, such that many of the cost and operability advantages and disadvantages of subsea processing are not investigated until the concept has already been selected. This paper discusses the benefits of compositional, thermal hydraulic integrated production models for the evaluation of subsea processing, illustrating many of the points with two case studies based on real projects; a subsea separation and a subsea compression study.

1. INTRODUCTION

The emerging innovations in subsea technology have mainly been driven by the need to access some of the world's most remote locations and extreme environments, minimising costs by reducing the size and number of surface facilities, and reducing/eliminating the need for platform changes to accommodate additional equipment, such as separation, water-handling, and compression facilities (11). Furthermore, numerous production benefits are associated with subsea processing, which can include increased recovery factors, accelerated production, improved flow assurance, reduced CAPEX over use of conventional technology (e.g. second pipeline), phase investment and increased revenue, operational flexibility, longer tie-back distances, reduced OPEX, and HSE benefits (i.e. fewer offshore personnel, materials, emissions, less to decommission) (9,11). Some authors (17) are predicting subsea processing spend to be over $130 billion in 2020; five times higher than 2013 figures.

Subsea processing consists of a range of technologies for separation, pumping, and compression. Successful implementations of subsea pumping and/or compression have enabled new subsea field developments that were not economic with traditional production technologies. Subsea separation may be required with one of these subsea boosting options, though for the right development, it could be a preferred development concept on its own as it makes it possible to send gas and liquid to different locations with different processing capacities. Also, Subsea water treatment technology allows separated water to be injected in the reservoir for pressure maintenance (6).

Subsea processing is generally considered to include the following existing or developmental functional capabilities;

- For oil systems, subsea oil pressure boosting systems, subsea oil processing, bulk water separation, sales quality oil polishing, and subsea raw seawater injection for reservoir pressure support.
- For gas systems, subsea gas compression, bulk water removal, subsea gas dew pointing/dehydration, capabilities for flow assurance and for sales quality (1).

Subsea processing also covers the challenges in handling and treating produced water at the seabed between 1.5 and 2.5 km water depth (11). Table 1 summarises the technical status of the subsea processing technologies based on both completed development and qualification activities as well as on experiences from subsea applications (5).

Table 1 Technology maturity overview of the main subsea process technology alternatives (5).

Subsea Process	**Status**	**Experience**
Multiphase Boosting	Mature technology	Several successful applications
Gas-liquid separation and liquid boosting	High technical maturity level	Subsea operational experience
Bulk water separation	High technical maturity level	Subsea operational experience
Complete water separation	Some further technology maturing required	
Gas compression	Extensive further technology maturing required	

Some of the most recent subsea processing applications include the following developments;

- Hydrocarbon boosting on the Lufeng field offshore China;
- Separation at the Troll pilot project and separation and boosting at the Tordis project, both offshore Norway;
- Separation on Pazflor in Angola;
- Raw seawater injection at the Norwegian Tyrihans development; and
- Compression at the Gullfaks, Åsgard and Ormen Lange pilot project offshore Norway.

See References 9, 11, 15 and 18 for further details.

The expanding and diversifying global demand for energy is accelerating the multifaceted advancements in subsea processing technology. However, subsea processing is not without cost. Beyond the immediate costs of the hardware are the costs associated with the additional complexity of the system, which include operating expenses and potentially reduced uptime. In order to rate a subsea production technology against a conventional one, engineers must compare these costs against the additional benefits to production.

2. PREDICTING THE INCOME (PRODUCTION PROFILE)

The effect of hardware on a development's production profile (i.e. the rate of production through life) is best forecasted by an Integrated Production Model (IPM). These are typically models of the production system from reservoir to some point in the network where a constant arrival pressure can be assumed. Such models predict the flow rate as a function of the resistances in the network and the arrival and inlets (reservoir) pressures. As the reservoir pressure(s) and fluid composition changes through time, the resistances and hence flow rates change, subject to constraints imposed by the user to represent processing and reservoir management constraints.

Most of the resistances to flow in a tieback are usually the multiphase pressure drops. Typical IPM tools represent these multiphase resistances as lift curve tables; tables of inlet pressure versus flow rate for a range of gas/oil ratio and water/liquids ratios at stock tank conditions and arrival pressure. Such models assume that the compositional variations each branch in a tieback might see through life can be represented by the gas/oil ratio and watercut alone. This is not generally true, especially not in systems where fluids from multiple reservoirs are blended. To illustrate this, a simulation of a deepwater gas condensate tieback was performed for a range of compositions, all of which had the same condensate to gas ratio (CGR) and watercut (WC); 1stb/MMscf and 1%, respectively. The results are plotted in Figure 1, in terms of predicted flow rate for a range of pressure drops.

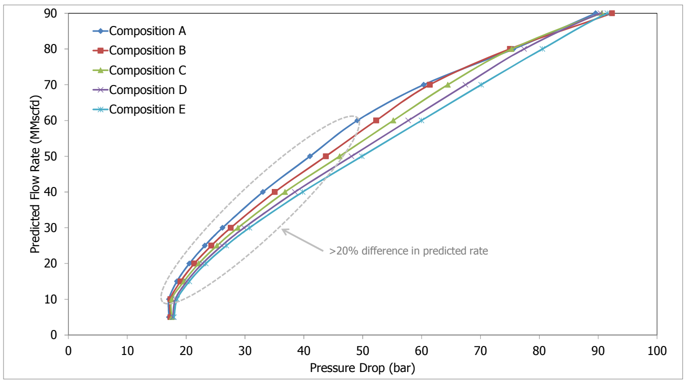

Figure 1 Rate vs pressure drop for a range of compositions with same CGR & WC

As can be seen, though each composition had the same CGR and WC, and all used the same three phase multiphase flow model, significantly different flow rates are predicted; a scatter of more than 20% in predicted flow rates at pressure drops of less than ~55bar.

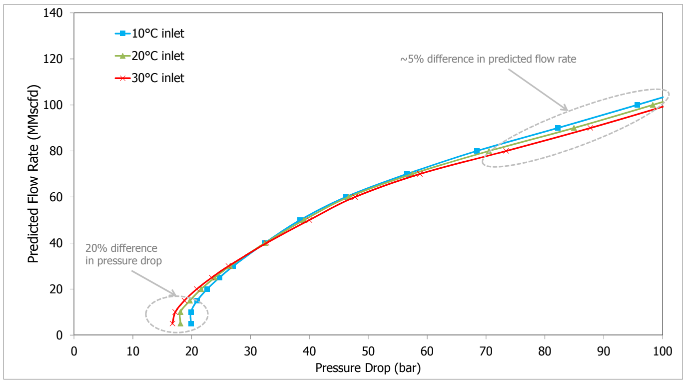

Figure 2 Rate vs pressure drop for a range of inlet temperatures

Similarly, such lift curve tables take no account of inlet temperature changes. Figure 2 plots the rate versus pressure drop curve for one of the compositions in Figure 1 for a range of inlet temperatures (10, 20 and 30°C). Though the change is more modest than the compositional error, it is still noticeable. Hence, even if the look-up tables are generated using the same three phase multiphase flow model, significant errors (>10%)

can creep into production forecasts based on lift curves. This is particularly true if the compositions and temperatures vary through field life, which is generally the case in multiple reservoir tiebacks.

For subsea processing examples, simplifications of the thermal hydraulics can cause greater errors in the forecast. Figure 3 plots the phase envelope of fluids entering the separator on one of the days of production. It should be noted that the hydrocarbon and water composition (hence phase envelope) of the fluids in this separator change through time as the reservoir pressure drops; this plot is just for illustration. Also show in the plot is the operating envelope predicted for the subsea separator through life by a thermal hydraulic and compositional IPM tool. As shown, the gas mass fraction in the separator (quality) varies significantly with both pressure and temperature. Getting the separator temperature wrong by 10°C would lead to an error in quality of ~1%, which assuming a constant separation efficiency, could mean an error in liquid carry over rate into the gas stream of 20 to 50%, depending on time in field life.

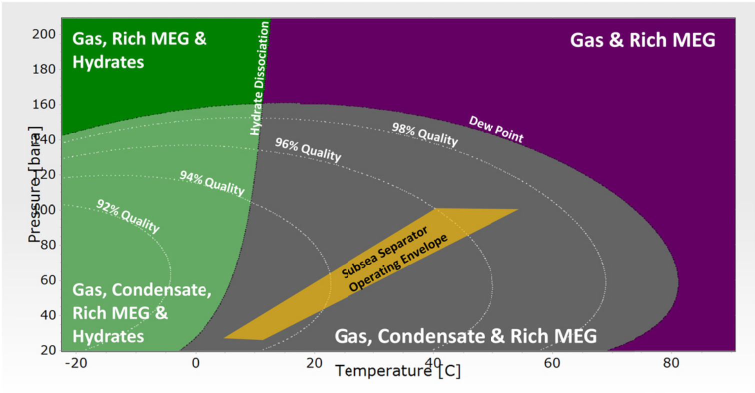

Figure 3 Phase envelope of the composition in a subsea separator

Such a large error in liquid carry over into the "wet gas" stream may or may not have a direct impact on the forecast estimate, though it depends on the system. Typically, it is the back pressure from the wet gas pipeline and the subsea compressor (if there is one) that determines the operating pressure of the subsea separator, the wellhead pressure and hence what flow rate can be achieved from the wells. However, if the separator has a reasonable efficiency, the mass flow rate of liquid will be relatively low (even +/-50%) and will generally have little impact on the pressure drop in the wet gas pipeline at high gas velocities. However, at low velocities, liquids can accumulate in the pipeline and create an additional back pressure on the wells. To illustrate this, the ~150km twin 36inch export pipeline system from Reference 21 was simulated using LedaPM 3 phase v1.2 in Maximus v4.14 for two different compositions; one with an LGR of 1stb/MMscf and another with an LGR of 1.5stb/MMscf. Figure 4 plots the total liquid content of the pipeline versus flow rate. The liquid content is increased by ~40% by the 50% increase in LGR throughout the range of operation (500 to 2000MMscfd), however at high flow rates the hold-up is relatively small and so the increase has little impact on pressure drop. At low flow rates, the liquid content dominates the pressure drop and how the pipeline is operated. It is typical to have a minimum operating rate for such pipelines, below which the pipeline will not be operated for fear of creating excessive surges on restart, ramp-up or even small changes in rate. To operate below this rate safely, the Operator may need to change operating procedures, such as regularly pig the line, drop the arrival pressure, abandonment or (in this case) switch from twin to single line production mode. Any of these operating modes will change the resistance to flow through the export pipeline and hence production profile. The value of this minimum flow rate depends on the liquid content in the pipeline, the surge volume in the slug catcher and the restart and ramp-up strategies. However, on a like for like basis (e.g. no more than 10,000m³ of liquid in the pipeline; dotted line in Figure 4) the decision to change operating mode would occur at ~100MMscfd higher rates with a 50% higher LGR.

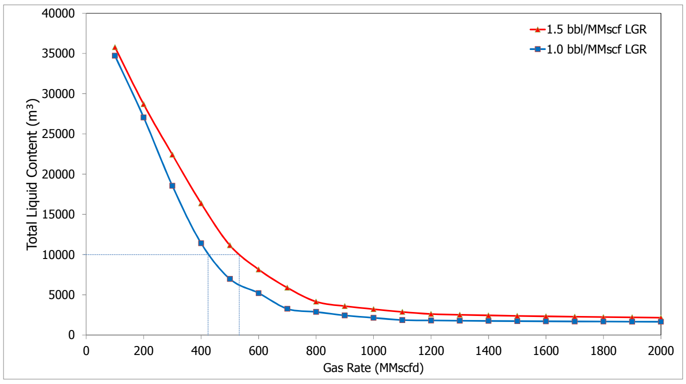

Figure 4 Sensitivity of the liquid content of a long distance wet gas trunkline to LGR

This is a typical problem of deepwater gas systems late in life and can be the reason why they drop off plateau sooner than predicted by simpler IPM tools.

Some engineers (3) have been so concerned by the errors associated with simple IPM tools (GAP, in their case) that they developed bespoke tools for some of their projects in order to tune their IPM to results from a more rigorous simulator (OLGA, in their case) during runtime. Figure 5 shows a flow diagram of how their bespoke "Integrated Flow Assurance Modelling Tool" worked. It is not reported how long it took to build such a system for each project, but it is not expected to be very practical for conceptual design of a multiple drill centre development, when a wide range of network configurations should be investigated. Other engineers (8, 19, 20 and 21) have developed commercially available IPM tools that can solve the molar and energy balance from reservoir to reception facility in one tool at the same time as the momentum (i.e. pressure) balance. This speeds up the model build and analysis time and reduces the likelihood of model build errors.

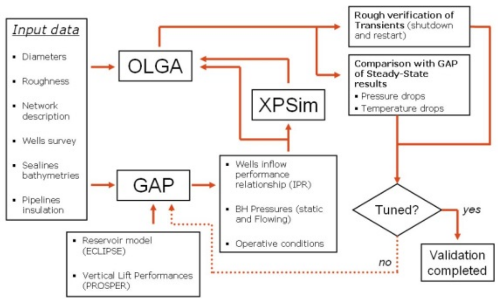

Figure 5 Schematic of a bespoke "Integrated Flow Assurance Modelling Tool" (3)

In most subsea processing systems, the performance of the subsea compressor (or the pump if there isn't a compressor) is the main constraint to the production rate for the majority of field life. Hence modelling the performance of such equipment is important when trying to predict the future revenues from such systems. Not only is the hydraulic performance of a compressor a strong function of composition, temperature and pressure, so is its operable range.

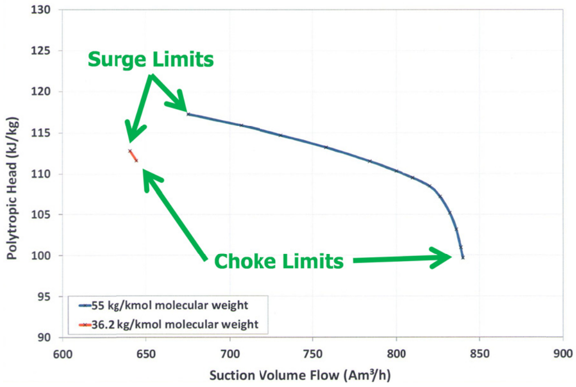

Figure 6 An example of how compressor limits change with composition (12)

For example, Figure 6 (12) is a plot of the operating envelop for a compressor with two different compositions (with average molecular weights of 55 and 36.2 kg/kmol). As can be seen, the performance curve for the leaner gas (36.2 kg/kmol) is significantly different from the other, but more importantly, the limits within which the compressor must operate (the surge and the choke limits) have shrunk so much that the compressor is almost inoperable with the leaner gas composition.

Clearly, if the production enhancing capabilities of a subsea (or topsides) compressor is to be properly estimated, the forecast must capture the effect of the changing composition throughout life, which might be significant if fluids vary significantly in hydrocarbon and carbon dioxide concentrations, for example.

3. MANAGING RESERVOIR RISKS

The case often made for simpler (i.e. lift curve) based IPM tools over more detailed simulators is that the errors associated with the simplistic assumptions are small compared to the economic uncertainties, such as reserves size and price of oil, etc. In the long run, it can be risky for the project to be over reliant on one assumed representation of the reservoirs during the design of the facilities. However, previous papers have described how rigorous thermal hydraulic IPM can be used to manage such risks (8,10) and investigate potential opportunities (Case Study 1; Ref 19) of different reservoir assumptions. As these papers show, rather than being an unnecessary level of detail that slows the process of optimising the system, if done correctly, rigorous IPM models can improve the workflow between engineering groups and help them understand and even quantify the subsurface risks to the facilities design.

Traditionally, facilities engineers try to stick to "design cases" for their studies and add margins before and after their work to cover unquantified uncertainties. The process of determining these design cases is arbitrary and can lead to snowballing of design margins between disciplines. This can lead to projects not knowing if a cheaper solution is possible or if their current solution is robust against reservoir uncertainties.

By modelling the reservoirs in the thermal hydraulic simulator, facilities engineers can do life of field sensitivity studies on the key uncertainties, such as “what if this reservoir was 10°F cooler?” or “what if the cold reservoir in this network ends up being much larger than currently thought” and see if these potential risks could change their opinion of the choice of insulation, etc.

4. PREDICTING THE COSTS

Rigorous thermal hydraulic IPM tools have a major advantage over lift curve based models when it comes to the assessment of the costs of a development. In deepwater tiebacks, subsea costs (wellheads to risers, umbilicals, etc) can be up to a third of the costs of the entire project (drilling, processing facility, etc). Though subsea processing can offer lower subsea CAPEX solutions, its greatest benefits are generally in terms of improved production, which may increase subsea costs such as additional kit, power and chemicals requirements, etc.

If the costs or savings of subsea processing are not adequately quantified in concept design, the project may enter Front End Engineering Design with a sub-optimal design that may necessitate costly “value enhancement” studies to change the concept, be it to or from a subsea processing solution. Late changes to concepts can cause delays in projects being sanctioned and hence “lost production”, as production from year 1 gets effectively delayed until several years later.

Whist a simple IPM tool could give an idea of the required diameter of a pipeline, they do not give reliable thermal hydraulic or compositional data (3). The total cost of the subsea tieback requires estimates of the pipeline diameters, wall thickness (including corrosion allowance), installation, insulation, umbilical and power cable requirements and remedial measures for any pipeline seabed stability or thermal expansion issues, etc. These require a significant amount of compositional and thermal hydraulic results (pressure, density and temperature profiles, carbon dioxide fugacities, phase velocities etc) throughout the production network and throughout time; as in general they vary significantly with the production profile.

Therefore, if the project has used a simple “lift curve” type IPM tool, a good understanding of the CAPEX of the system can only be determined once it has been re-modelled in a thermal hydraulic simulator. This creates an additional step between the revenue forecast and the CAPEX assessment and can slow down the progress of optimising the design. Economically marginal developments often require tens if not hundreds (20) of iterations between the forecast and facilities engineering team to find the right solution as they cannot afford to spend their way out of a technical problem such as using Corrosion Resistant Alloy pipes (19) or high performance insulation.

Given subsea processing capacity can be the main constraint to the production profile and (as discussed in Section 2) lift curve type IPM tools are expected to have greater errors in estimating the hydraulics of such systems; more iterations may be required between “flow assurance” and forecasting before a physically realistic solution is found.

With additional steps between “production” and “CAPEX” forecasts comes the risk of additional and unnecessary design margins to the design and cost estimate. For example, it is typical for thermal hydraulic simulations that following a simple IPM forecast to assume “conservative” flowing well head temperatures (FWHT) rather than simulating the well and Joule Thomson cooling effect across the choke. Choosing a conservative FWHT is not easy, especially as different engineering disciplines have different concepts of what is “conservative”. For example, engineers sizing the insulation to avoid wax deposition may consider low temperatures to be conservative, however as corrosion rate increases with temperature, corrosion engineers may consider that to be under conservative. Furthermore, in general the prediction of FWHT cannot be decoupled from the hydraulic calculation of the downstream and upstream system.

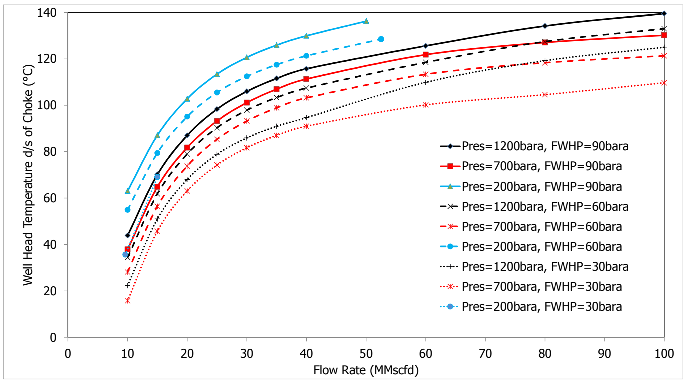

Figure 7 FWHT vs rate, reservoir pressure and FWHP

For example, Figure 7 is a plot of FWHT versus flow rate for a well with different reservoir pressures and flowing wellhead pressures (FWHP), covering the range that is typical throughout the life of a high pressure high temperature (HPHT) reservoir. As can be seen, the FWHT (i.e. the temperature into the pipeline) is a function of the back pressure from the pipeline (i.e. the WHFP) and hence to decouple the FWHT calculation from the pipeline thermal hydraulics would require iteration between a pipeline and a well simulator. Traditionally, engineers have a choice of picking a conservative design case from plots like Figure 6 or developing some sort of bespoke IPM simulator that uses spreadsheets, look-up tables, correlations and/or bespoke software such as that described in Reference 2, 3, 13 and 16 to ensure a reasonable FWHT is used. However, such bespoke methods are difficult to check and hence easy to make mistakes in.

5. FLOW ASSURANCE CASE STUDIES

The following case studies are simplified versions of real studies carried out by the authors. They help illustrate some of the typical flow assurance issues found in subsea processing systems and how they can be evaluated in a compositional, thermal hydraulic Integrated Production Model.

5.1 A Deepwater Oil Gas/Liquid Subsea Separation Systems

Subsea separation ranks as the most targeted technology for rapid development and application due to its huge potential for cost savings by moving some of the traditional topsides fluid processing to seabed (11). An overview of available technologies for gas/liquid separation in deep water is given in Reference 6. A summary of the subsea separation installations can be found in Reference 11. Some subsea separation concepts include water removal for reinjection into the reservoir to aid pressure support and to enable increased production to a water processing bottlenecked facility. However, subsea water removal was not considered for this project as the Operator's subsurface engineers were concerned about the effect of trace quantities of oil in the injection water reducing the injectivities of the water injection wells.

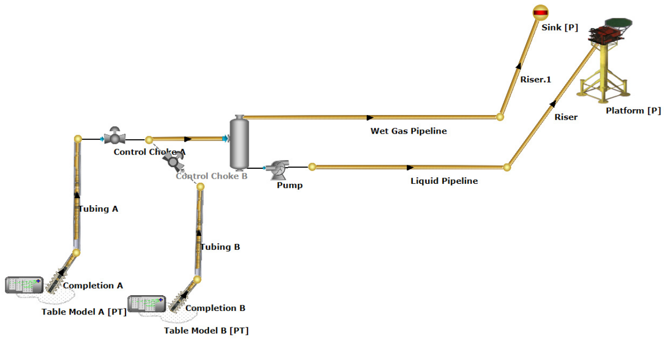

Figure 8 Typical system used for modelling two-phase separator life of field production profile forecasting simulation

Figure 8 shows a two well subsea separator system for illustrative purposes. The reservoirs were modelled as "Table Models"; which in this case are tables of reservoir pressure, completion productivity index, fluid GOR and watercut versus cumulative oil production. These curves were obtained from a reservoir simulation for a more simplified assumption of the network; in this case a fixed wellhead pressure. Such tables have their limitations and need to be updated if the production profile is grossly different from the one that generated the original table. However, they enable the facilities teams to have a representation of the reservoir whilst quickly investigating many hundreds of permutations of the subsea system. In later stages of design, when the concept has been selected and more time can be spent on each simulation, a dynamic link between the IPM and reservoir simulator may be more appropriate.

Also specified in the reservoirs is a base composition; in this case a characterised composition based on lab analysis of a sample. At each timestep, the IPM interfaces with a thermodynamic simulator (in this case InfoChem's Multiflash) to flash and recombine this base composition to achieve the GOR and watercut as specified by the table. This composition and Multiflash are then used to calculate the phase flow rates and transport properties for the thermal hydraulic simulation of the flow path to the seabed (marked Tubing in Figure 8). The energy balance in the thermal hydraulic simulation takes into account the heat loss to the environment, kinetic and gravitational energy gains to obtain an accurate flowing wellhead temperature. A molar balance determines the composition in the rest of the network and this composition is used (with Multiflash) to predict the thermal hydraulics of the rest of the network. As discussed earlier, the operating temperature of the separator can impact on the rates from each well and the split between the two outlets.

The separator model requires the user to input the separator efficiencies, i.e. what proportion of each phase goes to each outlet. These have been fixed, but can be made a function of flowing parameters based on information from subsea separator vendors.

In this case, the arrival pressure of the wet gas pipeline was fixed at a value commensurate with the stage of compression it was routed to on the topsides facilities, as was the liquids pipeline arrival pressure; which could be routed to a different stage of separation. The wet gas tieback and the liquids pipeline cannot both determine the separator operating pressure as they will not necessarily have the same inlet pressure; one must be choked or boosted to match the other. In this case, it was decided that the wet gas pipeline would determine the operating pressure and that this would be lower than the operating pressure of the liquids pipeline, requiring the liquids from the separator to be pumped into the liquids pipeline. The main alternative would be to operate the separator at the liquids pipeline inlet pressure and choking upstream of the wet gas pipeline; this would not require a subsea pump, but it was quickly shown that this cost saving was small compared to the lost production due to the increased back pressures on the wells. Hence, as described earlier, the subsea separator temperatures and pressures were uncontrolled and allowed to "float".

The main flow assurance concerns of this particular system were:

Issue 1. The back pressure on the wells, particularly in late life.
Issue 2. The size of pump required to achieve the preferred mode of operation.
Issue 3. The hydrate management strategy of the Wet Gas Pipeline (MEG injection).
Issue 4. The hydrate management of the liquids pipeline (insulation and blowdown).
Issue 5. Wax management in the liquids pipeline (insulation).
Issue 6. Wax management in the wet gas pipeline.
Issue 7. Restart, pigging and ramp-up surges in the wet gas pipeline (surge volume).
Issue 8. Restart, pigging and ramp-up surges in the liquids pipeline (operating above the bubble point plus surge volume for liquid/liquid surges).
Issue 9. Corrosion in the wet gas pipeline.
Issue 10. Corrosion in the liquids pipeline (corrosion inhibitor).

Issues 1, 3, 7 and 9 are typical issues for a wet gas pipeline that, as discussed earlier, benefit from an accurate thermal hydraulic and compositional simulation of the system. The added complexity here is that the system is conjoined to a liquids system via a separator with an unspecified pressure; hence pressure surges in one will affect the other. A quick study of the transient issues using steady state IPM results (using methods described in 4) concluded that both the wet gas and the liquids pipelines needed to be routed to the same slug catcher; meaning that the potential benefits of routing them to different stages of compression could not be exploited.

Issues 2, 4 and 8 required the oil and water flow in the liquids pipeline to be modelled accurately, in particular;

- The effect of the pump shear; type of dispersion formed, residence time taken to break and for slip to occur between the liquids, what is the effect of the choice of corrosion inhibitor (injected to solve issue 10) on this? What are the benefits of emulsion breakers?
- The water hold-up in the liquids pipeline if slip does occur between the liquid phases.

Issue 6 was investigated without selecting a separator vendor by investigating a range of separator efficiencies to determine the critical efficiency, above which negligible wax components are expected to enter the wet gas pipeline. This critical efficiency and life of field thermal hydraulic results can then be used as a sizing case for the separator manufacturer.

In this example, commercially available three phase flow models were used to simulate the pipelines (OLGAS 7.2 and LedaPM 1.2). It was found that OLGAS and LedaPM gave approximately the same resistances in the wells and wet gas pipelines for this particular system, which resulted in near identical production profiles. Figure 9 plots the calculated liquids pump power requirement for the first 10 years of production life. For reference, also plotted is a case called "Woelflin (1942)"; this is an identical model to the OLGAS 7.2 case except a homogeneous flow model is selected for the liquids pipeline and riser, using the Woelflin (1942) "loose emulsion" viscosity correlation (22).

As can be seen, though the separator pressure profiles and liquids rates were very similar between the three cases, the peak power requirement was highest for the OLGAS 7.2 case, closely followed by the Woelflin case. In this case, the OLGAS 3 phase model predicted homogeneous flow for the liquids pipeline throughout life, this explains why it matches the Woelflin case, which presumably has a similar effective viscosity correlation under these conditions. The phase inversion point for both models was set to 60% water volume fraction, which occurs in year 8.2 for both models.

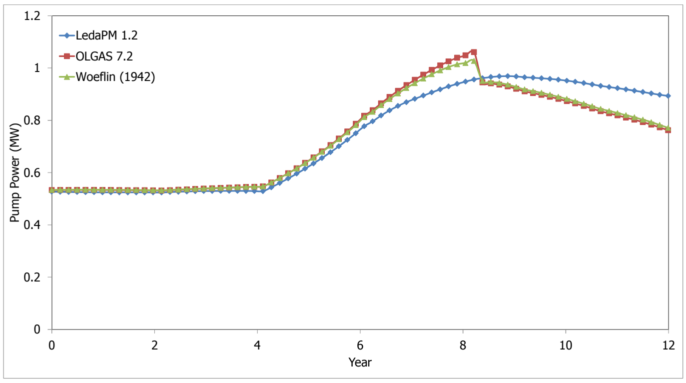

Figure 9 Pump Power Requirement

The LedaPM model predicts an oil/water slip ratio of up to 1.2 in the liquids line in early life (low watercuts) which gradually changes to 0.88 in late life, when the watercut is greater than 80%. LedaPM model predicts a slightly lower peak power requirement than the OLGA version (0.97 rather than 1.06MW) but this is considered to be well within the margin of error and hence are practically the same with regards pump sizing criteria. Power requirement can be a constraint to production; either at the supply, the power cables or the pump itself. Following such a study, the detailed results from this "unconstrained" pump can be discussed with Topsides Electrical Engineers as well as pump and subsea cable manufacturers to see if this is the case and whether or not such constraints need to be added to the model and if necessary, pump curves can be added in which the pump's expected efficiency and pressure gain can be made a function of the volumetric flow rates, fluid densities and viscosities based on tests done by the manufacturer.

The accuracy of liquid/liquid multiphase models was a concern and though lab work could be done to investigate emulsion viscosity and stability versus shear history, etc. They are usually at conditions significantly different to those expected in the liquids pipeline (i.e. small diameters, dead oil rather than live, etc.) and it is not obvious how they can best be extrapolated back to live conditions. As subsea gas/liquid separation takes off in larger developments of distributed drilling centres, networks of wet gas pipelines and liquid/liquid pipeline systems may become commonplace. Therefore, better mixing rules for liquid/liquid blends (of different watercuts and shear histories) will be required if these systems are to be properly sized and operable.

5.2 Subsea Compression System

One fast-growing technology for large fields requiring pressure boosting is subsea gas compression technology, which improves production and recovery from the reservoir by reducing back pressure on the wells. Subsea compression can be used to extend production from mature fields or provide initial support for production for remote fields with long tiebacks (14). Adding energy to the production fluid via compressors to produce more hydrocarbons, more quickly; enabling long distance gas tiebacks and avoiding topside facilities are the value drivers of this technology (6).

A screenshot of a greatly simplified version of a recent subsea compressor IPM study is shown in Figure 10. The performance of the reservoirs, wells and pipelines are modelled; the fluids leaving the reservoir are assumed to be saturated with water at bottom hole conditions; due to the shape of the water saturation curve, this means that the concentration in the produced fluids increases as the reservoir pressure drops. This is simulated with the CPA model in InfoChem’s Multiflash, as was the process of the hydrocarbon composition becoming more “lean” through time as the reservoir pressure declines into the two phase region and the heavier liquid hydrocarbons are left in the reservoir (21).

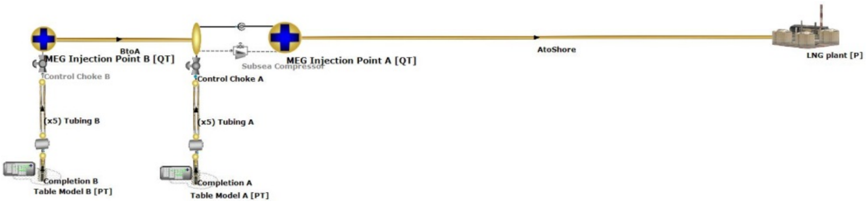

Figure 10 Subsea gas compression modelling system

The compressor can be bypassed, act as a conventional gas/liquid separation and compression system (with the liquids either rejected downstream of the compressor or pumped into another pipeline) or act as a wet gas compressor (7).

The key flow assurance issues of this system were:

- **Issue 1**. When the subsea compressor was required.
- **Issue 2**. Hydrate avoidance in the export pipelines. MEG injection was chosen.
- **Issue 3**. Top of well erosion due to low suction pressures into the compressor.
- **Issue 4**. Top of line corrosion due to high inlet temperatures into the uninsulated wet gas pipeline. Cooling spools were selected.
- **Issue 5**. Restart, pigging and ramp-up surges in the wet gas pipeline. LNG plant surge volume requirement.

To assess items 1 and 5 throughout life requires a three phase simulator and as discussed above, such models are only being used properly when the correct phase flow rates and properties are being used (i.e. a compositional simulation). Item 2, 4 and 5 require knowledge of the composition from the reservoir (particularly water content) and the thermal hydraulics of the pipelines to predict the water condensation rates throughout the network throughout field life. Item 4 is affected by the discharge temperature from the compressor and the MEG injection rate, which typically increases the water flow rate by ~50wt%. Hence to some extent many of the first four items are interdependent; i.e. may require numerous iterations to find a solution for all issues. With a compositional and thermal hydraulic IPM, the speed at which these issues are solved increases and some can be done simultaneously within the tool. For example, on a typical subsea compression study with such a tool, the above flow assurance issues are addressed like this;

- **Issue 1**; Determine the date when compression was required, by adding events to the model to bypass the compressor until the system was about to drop off plateau.
- **Issue 2;** Add logic to control the rate from wellhead MEG injection points (see Figure 10) to track the condensed water rates in the flowlines through time to ensure the fluids were sufficiently dosed to avoid hydrates (see Figure 11 as example results).

Issue 3; As API 14E RP was not deemed to be sufficient for this case, erosion was monitored by exporting fluid velocity and density results to a more detailed erosion simulator. Though this could have led to many iterations between the erosion and IPM disciplines, in this, like many other projects, it concluded with a maximum gas velocity which was added to logic in the IPM to trigger events (such as reducing the compressor speed) in order to avoid the problem.

Issue 4; Similarly, top of line corrosion was modelled offline using results from an IPM, though this quickly concluded with a maximum condensation rate per unit length. This was not used to trigger events, but as a measure of whether the cooling spool was of sufficient length that could be seen during runtime. A few iterations of the IPM ensured that the cooling spool was sufficiently long throughout life.

Issue 5; Life of field liquid steady state hold-up results at normal operating and turndown scenarios from the IPM can be used to estimate surge volumes (4). This is generally sufficient for conceptual design; proving that such transient operations are possible within a reasonable time frame and can be used to focus transient multiphase simulator studies in later stages of design; potentially reducing the number of transient simulations required by an order of magnitude or more.

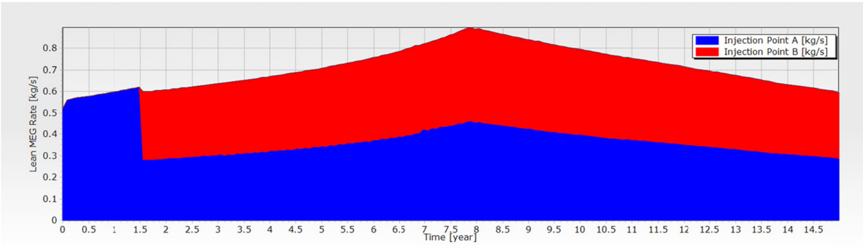

Figure 11 MEG injection rate through time for the subsea gas compression example

6. CONCLUSIONS

Representing the key resistances to flow in the system between the reservoir and the point of sale in one model (i.e. an Integrated Production Model) is an efficient way of managing the interdependency of the hydraulic modelling of the subsurface and surface facilities. However, most integrated production modelling tools do not model systems to sufficient detail that they can generate trustworthy estimates of temperatures and hence the system needs to be remodelled in a more detailed simulator. This slows the process of optimising the design of a system with respect to revenue and CAPEX. This is particularly pertinent to economically marginal developments where there may need to be multiple iterations between the production forecast and CAPEX estimation to find an economic solution. It is also argued that the simple methods in many IPM tools can lead to significant errors in the production forecast, particularly in gas condensate systems, multiple reservoirs networks with different compositions and/or subsea processing applications. In most subsea processing applications, at some critical point in life the subsea processing kit (separator and/or compressor and/or pump) is the main constraint to production and hence if not represented properly can lead to a false estimate of the forecast. The performance of processing equipment is strongly dependent on composition and inlet temperatures and pressures. Worse still, poor IPM modelling of subsea processing can lead to a false understanding of the operability of the system, including many key flow assurance issues. If these are not resolved early in design, they can lead to a re-evaluation of the CAPEX of a subsea processing project, or worse, a change of concept later in design. The paper gave two case studies based on real projects to show

how a compositional, thermal hydraulic Integrated Production Model can be used to get a much better picture of the feasibility of a subsea concept. With such a tool, conclusions of the techno-economic feasibility of a subsea processing concept can be drawn much earlier in design, leaving fewer surprises for later stages of design.

If subsea processing is to take off as expected, liquid/liquid pipelines will become more common place in upstream production. The accuracy of commercially available three phase models in liquid/liquid systems is unknown to the authors. However, it is expected that more will be expected of liquid/liquid hydraulic models in the near future. Better mixing rules for liquid/liquid blends (of different watercuts and shear histories) will be required if networks of subsea separation systems are to be properly sized.

7. NOMENCLATURE

CAPEX	Capital Expenditure
CGR	Condensate Gas Ratio at stock tank conditions
CPA	Cubic Plus Association
FWHP	Flowing Wellhead Pressure
FWHT	Flowing Wellhead Temperature
GOR	Gas Oil Ratio at stock tank conditions
HSE	Health and Safety Essentials
IPM	Integrated Production Modelling
LedaPM	Steady State Multiphase flow model from Kongsberg
LGR	Liquid Gas Ratio at stock tank conditions
LNG	Liquefied Natural Gas
MEG	Mono Ethylene Glycol
MMscf	Million Standard Cubic Feet
MMscfd	Million Standard Cubic Feet per day
Mstb/d	Thousands of stock tank barrels per day
MW	Mega Watts
OLGAS	Steady State Multiphase flow model from Schlumberger
OPEX	Operational Expenditure
stb	Stock tank barrel
WC	Watercut

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