



INGEN GROUP

FLOW ASSURANCE CAPABILITY STATEMENT

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**Flow Assurance Capability Statement
Ingen Group**

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1 INTRODUCTION

1.1 Ingen

Ingen, established in 2000, is an independent oil and gas engineering consultancy specialising in field development & project decision support.

Ingen currently has a staff base of over 50 engineers, primarily in Process, Petroleum and Reservoir disciplines, working within integrated project teams. We also call on specialists in other areas, such as Safety, Materials, and Piping & Layout.

Ingen is active in a number of locations around the world such as Dubai, Norway, Canada, America and the UK; supporting operators in Oil and Gas field developments with conceptual studies for new developments and optimisation studies for existing producing assets.

The company has developed enabling methodologies and tools to facilitate project execution, such as the integrated asset modeling package RAVE, which has been custom-developed to enable accurate, quick and consistent evaluation and screening of life of field development opportunities.

1.2 Flow Assurance Overview

The traditional perspective on Flow Assurance is that before embarking on the development of a pipeline development tied back to a host facility, knowledge is required of how the fluid will behave within the pipework and how this will vary through the producing life of the field. Developing this understanding and then ensuring facilities are designed and operate to meet the challenges is what flow assurance is all about.

For smaller subsea accumulations of hydrocarbons, where there is insufficient reserves to justify fixed facilities, subsea tiebacks are the natural means of development. The size of accumulation that can be successfully developed has reduced over time, whilst tie-back distances and maximum water depths have all increased.

Whilst Ingen agree in principle with this perspective we believe that this goal must be pursued within the context of developing the appropriate integrated conceptual solution where life of field reservoir understanding is incorporated within this design stage. This must access and respond to the subsurface teams view on what could be delivered to the production network and host facility that will produce the hydrocarbons. In this consideration should be given to how the potential production rates could be enhanced. This is where knowledge of the overall depletion strategy and the applicable artificial lift methods is required. It is our belief that these goals can only be truly realised if there is a strong subsurface understanding and ability to integrate this cross discipline expertise within the project and Ingen has this expertise.

In addition to determining what the production network looks like, flow assurance has a key role in determining the appropriate temperature management strategy for the system and also in setting design conditions for all the components. Flow assurance also considers the impact of the chemistry of the fluids in terms of material selection and defining any treatments that are required to maintain flow.

The field life, future plans, risks and opportunities play an important role in the decision making process.

2 INGEN FLOW ASSURANCE EXPERIENCE

What makes Ingen unique is our ability to integrate the subsurface and life of field understanding into our design process. In addition our ability to fit seamlessly into the overall project and deliver our services from concept to operation whilst at all times considering the project from the oil company perspective makes our approach particularly effective for delivering quality work.

Our flow assurance history in subsea tie-backs gives us an outstanding track record as shown in Figure 2.1. In all of these projects we have had a focus on operation from an early stage which has resulted in a proud record which shows no Ingen flow assurance project has ever required post design remedial work.

Figure 2.1 Ingen Flow Assurance Track Record

Client	Development	1st Oil/Gas	O = Oil G=Gas
Amerada Hess	East Telford	2002	O
Amerada Hess	Angus	2003	O
PetroCanada	Clapham	2003	O
Venture	Annabel	2004	G
DONG	Stine Segment-1	2004	O
PetroCanada	Pict	2005	O
Talisman	Blane Development	2007	O
Talisman	Enoch Development	2007	O
Talisman	Wood Development	2007	G
Talisman	Yme	2007	O
DES/BP	King	2007	O
Talisman	Fiddich	2007	G
Oilexco	Brenda	2007	O
Centrica	Seven Seas/Grove	2008	G
Silverstone	Victoria	2008	G
Granby	Tristan	2008	G
Ithaca	Athena	2008	O
Bridge Resources	Durango	2008	G
Talisman	Burghley	2010	O
Talisman	Auk North	2010	O
Lundin	Broom	2010	O
Endeavour	Rochelle	2011	G
Serica	Columbus	2011	G
Sterling	Breagh	2011	G

We work from the oil company perspective and understand the life of the field value drivers. We integrate tightly with the subsurface teams as we are aware of the impact of reservoir data and prediction on the design and selection. We fit seamlessly into the project delivery team.



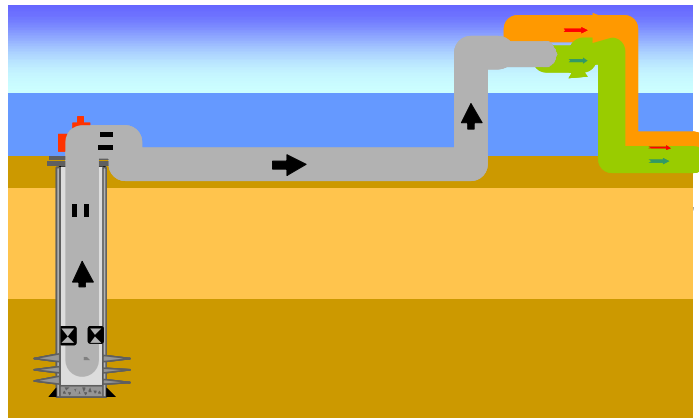
We have strong technical expertise in petroleum engineering, artificial lift and subsea engineering, flow assurance, facility design, production chemistry, material selection, corrosion and erosion.

We have delivered more than thirty subsea tie-back projects. We offer more than flow assurance. **We know what needs to be done when and to what level.** This is essential to control costs, protect schedule and ensure there is no wasted effort.

3 INGEN APPROACH

We believe that understanding the big picture barriers or challenges is the key to integrate production wells, subsea systems and topsides in the solution. We know how to make the development happen as we are clear where we fit into the development process.

Figure 3.1 Reservoir, Well, Subsea Systems and Topsides Integration



The approach we adopt addresses the following areas:

- Integration with Reservoir
- Artificial Lift and Subsea Engineering
- Line Sizing
- Temperature Management
- Assuring Continuity of Flow which includes material selection, production chemistry and managing flow regimes
- Commissioning/Operations support from conditioning for start up and starting flow to maintaining operability through field life

Finally, we calibrate our fields in production and any lessons learned are fed back into future projects.

3.1 Benefits to the Ingen Approach

Ingen’s approach to flow assurance is very targeted and ensures that adequate work is performed to deliver successful production without wasted time and effort. The approach and workflow is demonstrably quicker, more efficient and more robust than industry norms. Our inherent understanding of subsurface plus our tight integration in the project delivery team during execution ensures this.

3.2 Integration with Reservoir

Ingen has its own in-house subsurface expertise and as such, is able to communicate understanding with client sub-surface engineers on a peer to peer basis. This allows the full implications of reservoir engineering decisions to be fed seamlessly through the development without causing significant design iteration loops. We know that integration with the sub-surface team is vital and understand their issues and methodology. Subsurface provide the inputs for the flow assurance assessment. For instance:

- Initial conditions generally dictate the maximum design pressure/temperature.
- Water cut development dictates the thermal performance.
- Fluid compositional changes through field life impacts on production chemistry and material selection.
- Implementation of artificial lift impacts on thermal and hydraulic performance.

For oil fields, reservoir management strategies are key to the productivity of the system. Depending on which management strategy is chosen, a number of problems can occur later in field life. The artificial lift method and implications need to be understood as shown in Table 1. For example, a reservoir with strong aquifer support will gradually increase water cut and demand higher gas lift rates. Temperatures at the wellhead would also increase meaning these conditions must define the design case for upheaval buckling.

Table 1: Typical issues for an Oil Field

Reservoir Management Strategy	Behaviour Through Life	Typical issues
Depletion – no aquifer support	Peak flow early in life, steeply decreasing rates as water cut increases and reservoir pressure declines	Low temperatures later in field life Change flow regime with reducing rates Below bubble point production
Depletion – strong aquifer support	Flowrates gradually decline as water cut increases	Peak temperatures at intermediate point in life Gas Lift requirements increasing through life Flow regime changing because of gas lift
Pressure supported	Flowrates constant through field life	Peak temperatures late life Gas Lift gradually increases to meet increase in static head

A key aspect of subsurface performance for gas reservoirs is how water ingress into wells can negatively influence the performance of the system, in terms of the direct effects on the wellbore, pipeline hydraulics and the system thermal performance. In the worst case, extreme water ingress can kill the wellbore, but other less extreme problems can arise from moderate water ingress. Higher water content in the production fluid will increase both the hydraulic resistance and the specific heat capacity of the fluid, which means the fluid will be harder to transport around the system, and also that the FWHT of the production fluid will be higher. Ingen understand all the design implications of water ingress.

Sand production is a factor which can affect the productivity of a system. It can cause numerous problems, including restricted productivity, completion component erosion, obstruct access to the wellbore, can interfere with operation of downhole equipment and also presents significant disposal difficulties. Sand production occurs mainly when

reservoir rocks fall below their compressive strength, causing instability in the rock formation. This in turn leads to sand entering the production system. Sand screens can be used on the completion to prevent sand entering the well bore, but this has the adverse effect of limiting well productivity. Ingen has the understanding and expertise available to mitigate and manage the effects of sand production.

Additionally, we are also aware of when normal calculation techniques fall down and when more detailed analysis is required. For example in high pressure/high temperature reservoirs, the pressure conditions can be such that reverse Joule Thomson takes place – the gas heats up with a drop in pressure. This is exactly the opposite of what is intuitively expected. We know how to deal with this and what difference it makes to design.

3.3 Expertise in Artificial Lift and Subsea Processing

Ingen have expertise in all types of artificial lift applied to pipeline systems and wells. We understand the benefits associated with all lift mechanisms. We also recognise where their application may be limited. In addition to understanding the process benefits, we are aware of the hardware challenges associated with the technology – factors that are often underestimated.

Artificial lift technologies that Ingen have modelled in detail on projects include but are not limited to:

- Gas Lift
- ESP's
- HSP's
- Jet Pumps
- Venturi Pumps
- Velocity Strings in gas wells
- Multiphase Pumps – electrical and turbine driven

All of the above technologies have been applied to fields that are currently in production.

Ingen have expertise in modelling subsea separation and wet gas compression for a number of our international clients to demonstrate clearly the large future potential that these technologies provide and to enable our clients to evaluate and rank these options on a consistent basis.

4 TYPICAL PROJECT WORK FLOW

This section describes how projects can be developed using the Ingen approach. This approach has been adopted successfully many times. Initially, we determine a conceptual solution based on a well count and a host facility, with an associated tie-back distance. An artificial lift method and associated implications are evaluated, if necessary. New technologies like subsea processing could be proposed and evaluated.

Then we set the design conditions, i.e. maximum design pressure/temperature in the production pipeline.

After this we analyse the flow assurance behaviour through screening on the pipeline size/insulation. This is done by defining the hydraulic behaviour vs. line size and the thermal behaviour vs. level of pipeline insulation. We also provide production chemistry analysis of the production fluid for materials assessment and wax/hydrate management. It is during this phase we will also perform an erosion/corrosion analysis.

Once the basic system design and architecture are defined the Ingen focus shifts to demonstrating effective operability. Ingen will define an outline operating philosophy that describes how the system is intended to start up, operate normally and shut down. In doing this we will clearly identify the gaps in knowledge to be filled by transient analysis. A very targeted set of transient simulations will be defined and carried out to develop the appropriate understanding of the system. This approach allows the design to be finalised with respect to such issues as minimum design temperatures for connecting spools. The information will also be used to populate the operating philosophy for the system that will detail how the field will operate through field life.

At the start of the detailed design process we will develop a philosophy for commissioning and initial startup of production. This philosophy will act as a bridging document between the system being mechanically complete and handover to operations.

Both the operating and commissioning philosophy documents are designed to turn into the procedures to be adopted offshore and as such are created from the perspective of carrying out the operations and not as static project documents.

Once flow is established, we calibrate how the system has performed in comparison to the design predictions to ensure there are no potential future issues which have not been allowed for in the design.

4.1 Project Integration

From our extensive project experience we understand the needs and drivers of the various technical disciplines within the project. That means we deliver what's needed when it's needed. This approach saves considerable time and effort for the other parties involved in the project and ensures that often challenging schedules are protected. For example we provide:

- Maximum design pressure/temperature that kicks off the pipeline design,
- Line sizes that feeds back to subsurface team preparing FDP and allows pipeline design to proceed.
- Level of insulation which is based in the expected operating temperature that feeds into pipeline design

- Chemical injection requirements that supports the umbilical design
- Flow regime so topsides can be designed to accommodate slugging
- Transient analysis to facilitate the start up and production operations

4.2 Concept Selection

Ingen's concept screening process ensures that we can rapidly develop models that give a robust screening of all the available options and can incorporate uncertainty into the option analysis in an efficient manner and to the appropriate level of detail for the design stage. This is particularly useful to evaluate all the possible development alternatives in terms of well count, host facilities and tie-back distances, and artificial lift/subsea processing.

We set the maximum design conditions.

We determine the hydraulics which includes:

- range of line sizes, artificial lift and subsea processing options
- back check with subsurface teams to confirm viability

We determine the thermal performance. This determines the level of insulation that is appropriate for the development for the full life of field.

The outcome of concept selection sets the basis for start of FEED.

4.3 Conceptual Design into FEED

We deliver a flow assurance report that includes:

- selected artificial lift and/or subsea processing solution
- maximum design pressure
- maximum design temperature
- recommended pipeline sizes for all pipelines
- recommended level of insulation on production pipeline
- recommended production pipeline material
- recommended chemical injection strategy and core sizes
- expected steady state flow regime and slug sizes/frequencies

We integrate our findings with the project basis of design (BoD). It should be noted that Ingen can also produce the BoD document on behalf of the client in addition to the flow assurance work described within this document.

We define the plan moving forward into FEED. At FEED stage, we focus on operability.

At the early FEED stage, we will focus on developing the Operating and Commissioning Philosophies for the system. This is the stage of the project at which transient analysis would be carried out.

4.4 Inputs to Detailed Design

During detailed design, there is a need to provide the following inputs to the Subsea Engineering team:

- Maximum temperature profiles for upheaval buckling
- Densities for on bottom stability calculations

- Minimum design temperature
- Pressure and temperature measurements requirements

We provide the following inputs to the Topsides team:

- subsea P&IDs in process format
- Cause and effects for the subsea system
- Chemical injection system definition, i.e. supply pressure and storage requirements
- Slug impact loads for piping design

In addition to the services listed above we will actively participate in all safety assessments of the system and can provide a Chairman for these reviews. We will also provide input to environmental reviews and commercial negotiations on oil and gas valuations and tariffs. These activities are generally carried out concurrently with the development of the Operating and Commissioning procedures for the system.

4.5 Commissioning and Operation

As production becomes imminent, the focus will be on developing Operating and Commissioning Procedures for the system. Ingen has significant experience in successfully implementing these procedures offshore. This experience has successfully started up many of the fields that we have designed to date. This hands on practicality feeds back into the design process. As a result of carrying out this activity, we have also gained offshore experience in other areas which require subsea intervention and are explained in further detail in section 5.8.

4.6 Tools Used

Ingen have experience in the following software packages, and have utilised them in numerous flow assurance projects.

- Pipesim™ (Schlumberger)
- Hysys™ (AspenTech)
- OLGA™ (Scandpower)
- Prosper™/GAP™ (Petex)
- Pipephase™ (IPS)

Ingen have developed numerous engineering tools for calculations involved in flow assurance projects. These include;

1. Ingen Corrosion Calculator
2. Ingen Erosion Calculator
3. Ingen Gas Value Calculator
4. Ingen Hydrate Inhibition Strategy Tool
5. Ingen Chemical Injection Core Sizing Calculator
6. Ingen Water Injection Line Sizing Calculator
7. Ingen U Value Calculator

Ingen has proven the reliability of these tools by calibrating the performance of each tool against empirical data from live projects and against other software packages.

5 TECHNICAL EXPERTISE

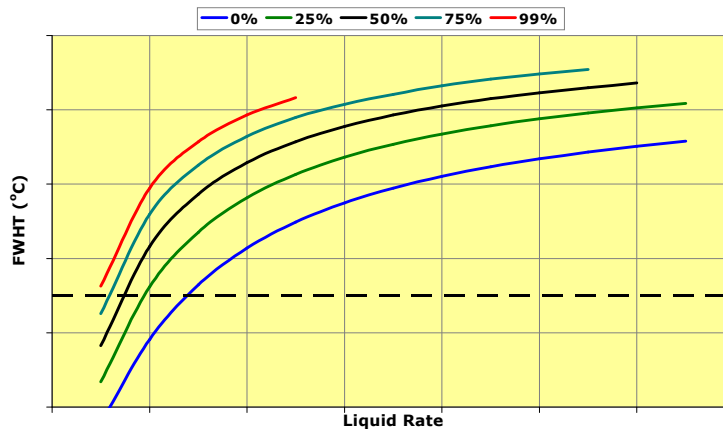
The following section outlines areas of technical expertise that Ingen provide.

5.1 Setting Maximum Design Pressure and Temperature

The maximum design pressure is set by the reservoir pressure and the artificial lift method. This is the gas lift design pressure or the ESP dead head pressure.

The maximum design temperature is linked to the depletion strategy as shown in Figure 5.1 Graph showing the effects of Water Cut on FHWT during field life. It has a major impact on pipeline and Xmas tree mechanical design.

Figure 5.1 Graph showing the effects of Water Cut on FHWT during field life.



5.2 Line Sizing

The determination of the appropriate line size for a subsea development is a value based decision and is one that is taken based on considering the incremental benefits of different line sizes versus what the reservoir can produce against the constraints of the host facility. This decision is driven by these overall considerations and is rarely driven by the pipeline hydraulics alone.

The role of flow assurance is to demonstrate the flowing pressures and temperatures in the system for a given network configuration and to be able to feed this information to the appropriate design teams for input into their calculations. The system hydraulics also feed into assessment of corrosion and erosion in the pipeline.

There are interactions between hydraulics and the type of artificial lift method. There are also considerations in terms of fluid behaviour that need to be taken into account. For example in heavy oils, the potential for emulsion formation can lead to higher pressure drops at intermediate water cuts than would be experienced at no or high water cut.

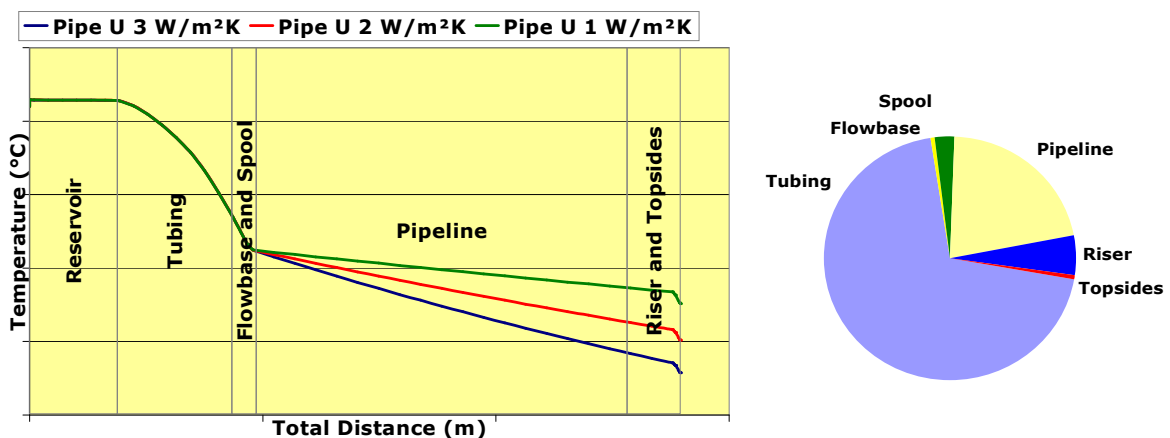
We size all the pipelines i.e. production, gas lift, water injection, chemical injection, service lines (e.g. for venting) and distinguish umbilical cores from e.g. MEG pipelines.

5.3 Thermal Performance

Ingen are experts in modelling thermal performance of oil field developments. This extends from the reservoir through to the host facility. We understand how fluid thermodynamics can influence thermal behaviour and we understand heat loss from the well bore all the way to the reception facility.

The steady state calculations define the U value requirement. This is generally dictated by the wax appearance temperature and the hydrate formation temperature at the operating pressure. The choices available in terms of insulation solution can be significantly different in terms of costs. We understand the step changes in cost (PIP vs. conventional insulation).

Figure 5.2 Understand Temperature Drop - Example



In addition to steady state considerations, Ingen also take into account shut down and start up. For prolonged shutdowns Ingen take into consideration the important issues such as, how long can a system survive without needing to be depressurised? For start up, how can low temperatures due to Joule Thomson cooling be managed? How long will it take for the system to be up at the operating temperature and what does this mean for the pipeline operation?

5.3.1 Well Thermal Performance

Ingen has particular expertise in the calibration of well thermal performance, having worked on numerous flow assurance projects on both oil and gas assets. This extensive project history has allowed Ingen to build up a vast and in depth understanding of how well thermal performance is sensitive to many factors. Key thermal sensitivities for gas wells are the variation of WGR (Water to Gas Ratio) and LGR (Liquid to Gas Ratio). These ratio's have a significant effect on the thermal performance of each well, due to the differing specific heat capacity values for each production fluid. The Flowing Wellhead Temperature [FWHT] of each well is also affected by the rate at which production fluids are flowing through the tubing. High FWHT are generally characterised by high flowrates in the well, and conversely low FWHT is generally characterised by low flowrates in the well. Other thermal factors include insulation levels in the tubing, reservoir temperature, pressure and depth, tubing material etc.

For gas wells, the maximum FWHT may occur at intermediate flowrates, as peak flowrates can give rise to acceleration losses in tubing. Designing the system for the peak rates can have the effect of missing an intermediate point that is hotter and underestimating the

maximum design temperature. The FWHT for gas wells also varies strongly with the flowing wellhead pressure (FWHP). Any assessment of the FWHT needs to take the likely range of FWHP into account. As well as correctly predicting the temperature at the wellhead, the impact of choking needs to be considered. The Joule Thomson effect at the wellhead generally introduces a temperature drop. The impact of this temperature drop on the pipeline downstream needs to be considered. Ingen has considerable experience in specifying maximum FHWT limits for any given system, in order to provide a satisfactory system design.

5.3.2 High Pressure/High Temperature Systems

From past experience on HP/HT fields, Ingen have recognised the importance of understanding fluid thermodynamics and the knock on impact on thermal behaviour. Additionally, we are also aware of when normal calculation techniques fall down and when more detailed analysis is required. For example in high pressure/high temperature reservoirs, the pressure conditions can be such that reverse Joule Thomson takes place – the gas heats up with a drop in pressure, which is typical of fluids such as retrograde gas. This is exactly the opposite of what engineers intuitively expect. This effect is not taken into account in black oil models which are used for the prediction of flowing wellhead temperature. We know how to deal with this and what difference it makes to design.

5.3.3 Pipeline Thermal Performance

The level of insulation required for the pipeline is dependant on the wax appearance temperature and the hydrate formation temperature. Ingen understands the importance of designing the system to avoid hydrate formation temperatures, and also keeping the system design temperature above the wax appearance temperature. The other option to control wax is continuous dosing, which can be used to minimise the appearance of wax in the system. The pipeline outlet temperature may also be determined by the topsides or export specifications, e.g. for efficient oil/gas separation.

Hydrate formation in a pipeline system can plug the pipelines, damage equipment and restrict flow, therefore it must be avoided. Many possibilities are available for the mitigation of hydrate formation. We have understanding of choosing the best hydrate inhibition strategies for a wide range of operational conditions.

We also have detailed experience in comparing the performance of numerous hydrate inhibitors. This level of expertise has recently been developed in flow assurance studies, which have compared the use of MEG and other hydrate inhibition options. We also appreciate the advantages of MEG alternatives such as low dosage inhibitors which consist of two alternate technologies; kinetic hydrate inhibitors (KHI) and anti-agglomerant inhibitors (AA). These methods achieve hydrate control at dosages which are orders of magnitude lower than those typically used for MEG/methanol.

5.3.4 Interaction with Pipeline Mechanical Design

In terms of pipeline flow assurance, Ingen has also developed a wide ranging understanding of how system temperatures affect the performance of pipelines. Upheaval buckling is caused by the thermal expansion of pipelines on the seabed, over the length of the tie-back. Ingen has experience in mitigating the effects of upheaval buckling by incorporating the effects of rock dump and back fill into its pipeline thermal performance calculations. Ingen has also accrued a depth of understanding in the area of upheaval

buckling prevention, which allows our clients to benefit from effective but economic system designs.

5.3.5 Active Heating

In areas such as deep water, there is a need to be able to add heat to the system and where active heating becomes applicable. Ingen personnel have experience in designing and testing active heating systems for subsea applications. There are numerous methods to add heat to the system, such as supply and return heating medium lines within a dry annulus, supply and return heating medium using the annulus of a pipe-in-pipe system, and electrical heating.

The challenge in the active heating system is to design a system which provides sufficient heat reliably to ensure that its primary purpose is met but also to ensure that it cannot overheat the system beyond design conditions. Modelling warm up can be particularly challenging, especially as the system is flowing. The challenge is to understand how the system responds to the addition of heat from the active heating system and from hotter fluids entering the system and how this interacts with the heat loss to the environment. It is essential that the designers have an understanding of the underlying heat transfer processes. Ingen have the ability to apply this understanding to active heating systems and are able to develop robust solutions that can be practically applied in the field.

5.3.6 Thermal Performance Calibration

Ingen have a large data base of calibrated well and pipeline performance and are able to call on that database and experience in determining expected flowing wellhead temperatures and comparing these to both predicted and measured values. Ingen regularly benchmarks the design predictions made during the project and has compared these with actual operating data supplied by clients. To date as a direct result of our ability to integrate the life of field and subsurface understanding none of our subsea tie-backs have fallen outside the range of temperatures and pressures specified during design. We believe this approach is a key factor which differentiates the Ingen approach with that of the company's competitors and which provides a unique advantage to our service in this area,

5.4 Flow Mapping

In steady state we determine the operating envelope in terms of multiphase flow regime, develop operating philosophy, and prepare guidelines for transient analysis simulations.

In transient analysis we cover the life of the field flow and water cut, steady operation, start up and shutdown.

Figure 5.3 Typical Flow Regime Map

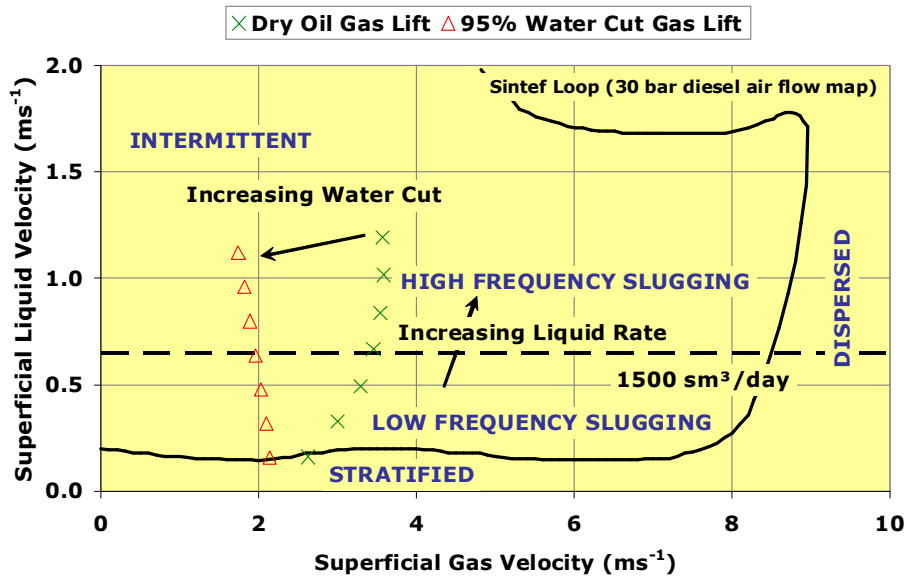
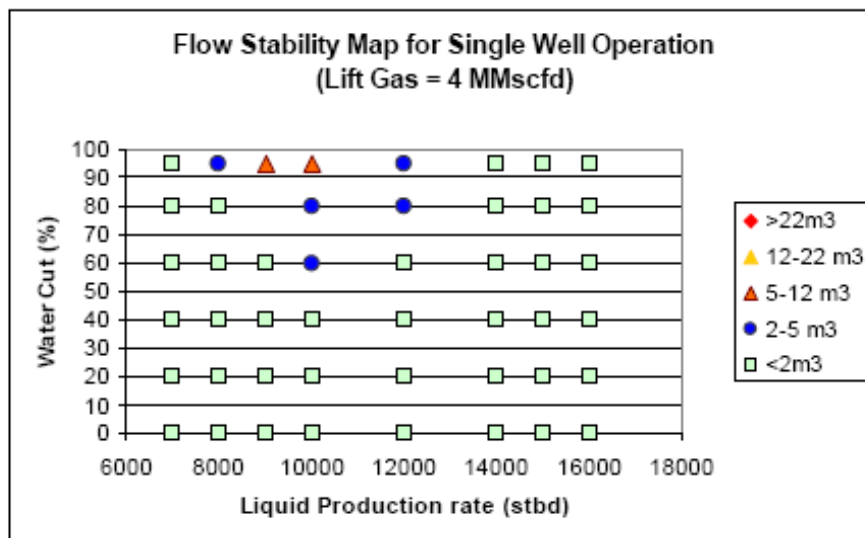


Figure 5.4 Typical Flow Stability Map



5.5 Material Selection

Material selection is very important for pipeline and topsides design. This is because poor choices in material selection could cause premature failures. We understand how to make the choices in terms of operating pressures and temperatures for selection. This is considering normal, start up and upset conditions. There are two main considerations for design – erosion and corrosion.

For corrosion, fluid contaminants such as CO₂ and H₂S, and water play an important role. We can predict corrosion rates for uninhibited and inhibited conditions. We have the

experience to recommend appropriate materials for the selected conditions and the appropriate testing to confirm viability.

Ingen's in-house corrosion calculation tool can predict erosion rates using both Norsok and Cassandra calculation basis and also takes into account corrosion inhibitor availability and efficiency. Having the ability to screen material selection at the conceptual stage identifies potential issues and how they can be resolved as early as possible in the project cycle.

Ingen have an in house erosion calculation tool that can predict erosion based on the full methodology from the University of Tulsa. If less information is available, simpler methods can be used.

5.6 Production Chemistry

Production chemistry provides necessary data to assess the flow assurance risks. The PVT properties of the reservoir fluid define phase behaviour. Contaminants (e.g. CO₂ and H₂S) are known to increase corrosion rates while potential flow inhibitors (scale, asphaltenes, wax, halite formation, hydrates) are known to be the principal causes of flow problems. Scale and halite formation can result in lower production rates, and therefore need to be mitigated against. Halite formation may occur on the sandface or the wellbore, while scale can occur anywhere in the pipeline. The effects of halites can only be diminished by wash water, while methods such as scale-inhibitor squeeze and pigging can be used to alleviate the problems caused by scale formation. Asphaltenes are caused by the accumulation of heavy oil fractions which can deposit anywhere in the pipeline system, the adverse effects of asphaltenes, wax and hydrates can be alleviated in a number of ways.

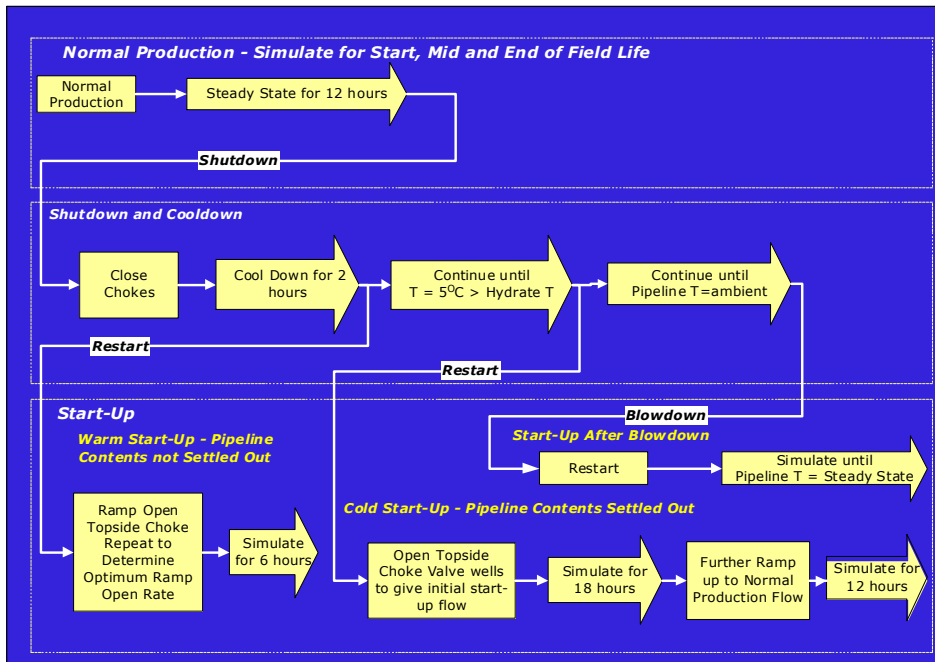
Ingen has extensive understanding of these problems and we provide effective production chemistry expertise to all our flow assurance projects. We integrate design and operating conditions. We recommend the chemical injection regime. We recommend sampling and testing when required.

5.7 Operability

Once a conceptual design is prepared and accepted, the focus of flow assurance design shifts to operability. The first stage in our process is to develop an outline operating philosophy. This philosophy will demonstrate how the system is intended to be operated. It will also highlight any areas where transient analysis is required. We define a route map for transient analysis as shown in Figure 5.5 below. We define what questions need to be answered and structure the analysis to answer these questions.

The transient analysis is used to confirm the remaining design issues, such as pipeline/spool minimum design temperature, and confirm the maximum design temperature.

Figure 5.5 Transient Analysis Route Map



The output from the transient analysis is used to develop the operating philosophy of the system. A typical output is shown in Figure 5.7 below:

Figure 5.6 Typical Liquid Hold Up and Temperatures on Shut Down

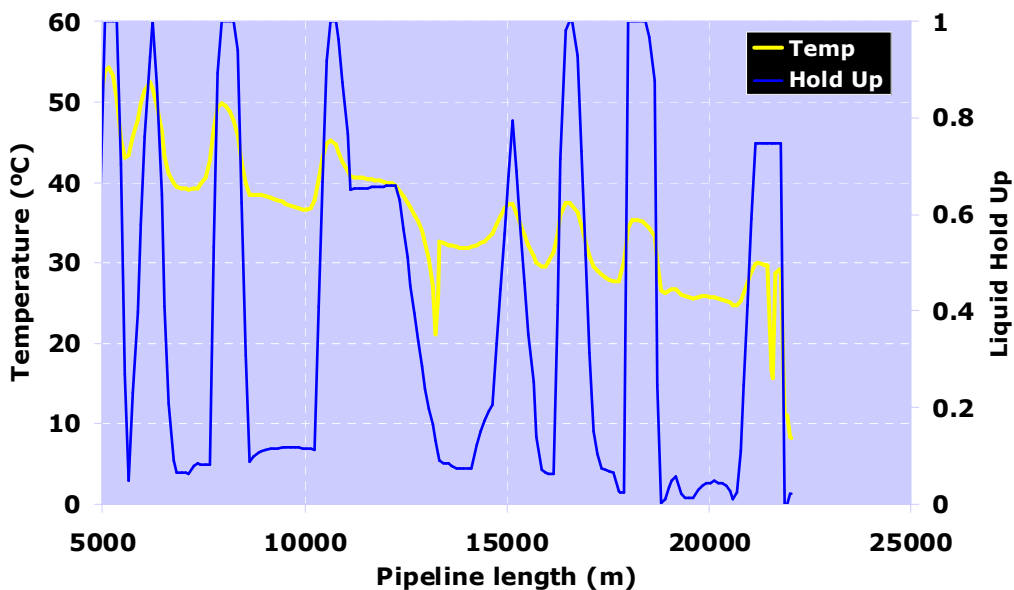
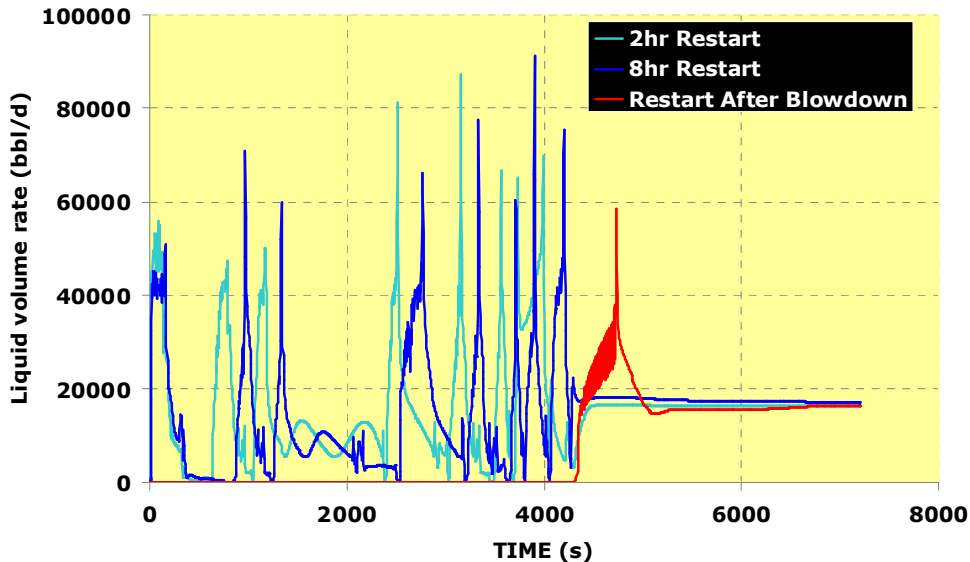


Figure 5.7 Transient Analysis Output – Start up Slugging



5.8 Operation

Ingen develops the operating philosophy for the system. We demonstrate how the system stays within design limits. We communicate to operations what is going to happen when production starts. This is the starting point for integration within existing procedures. In parallel, we develop a commissioning/start up philosophy report. This is a bridging document between mechanically complete and leak tested subsea to normal operating philosophy. We communicate start and end points for each activity. This is the starting point for a procedure.

Ingen also offer the following additional support to our clients during operation;

- Subsea Well Commissioning and Start Up
- Remediation of Process problems
- Remediation of Umbilical problems
- Barrier Testing/Well Operations Support

For all of these, Ingen would be involved from developing the procedure, through all risk assessments to successful implementation offshore.

These additional services will now be discussed in more detail:

5.8.1 Subsea Well Commissioning and Start Up

For starting up subsea wells, we start by developing a Commissioning/Start-Up Philosophy. This document describes the bridge between the system being mechanically complete, leak tested and function tested, through to the introduction of hydrocarbons into the system. This will identify what needs to be done prior to commencing the start up process. The sequence for start up will be defined and the appropriate sequence of events defined. For example, for carbon steel pipelines, dewatering the corrosion inhibitor line needs to happen prior to hydrocarbons being introduced into the system. Determining what is required here will also identify if the start up sequence could be optimised by use of temporary equipment. This philosophy will also identify the

materials required to carry out the start up operation. This will help the topsides understand the logistical requirements such as number of tote tanks required for start up.

The Commissioning/Start-Up Philosophy would be used as a basis for generating a detailed procedure. The procedure would then be safety reviewed and implemented offshore. We provide engineers to ensure the successful implementation offshore and act as the offshore representative for the subsea tie-back operator.

We have successfully started up more than 20 subsea wells in this manner.

5.8.2 Remediation of Process Problems

We support the remediation of process problems by first identifying the source of the problem and then by developing procedures to rectify the problem. Typically these would be caused by hydrates or blockages. Another area which Ingen offer expertise in is investigating adverse thermal behaviour in systems. If the operating temperatures are higher or lower than expected, we can determine the root cause and recommend appropriate remedial action. If required, we could support this through offshore visits. [what about leaks as in Venture or other problems]

5.8.3 Remediation of Umbilical problems

There are frequent problems encountered with umbilicals in terms of cores blocking or having much greater pressure drops than expected. We have identified and rectified numerous chemical injection problems. The starting point is the analysis of the system to determine what should be happening and comparing this to observed data. We will then model the system and determine what would need to happen to match the observed situation. We will then identify how to solve the operational problems and recommend how to implement this offshore. We will go on to develop the offshore implementation procedure. We can also provide offshore support to implement the recommended changes.

We have substantial experience in this area derived from Petro-Canada's subsea infrastructure tied back to the Triton FPSO. This comprises what is arguably the most complex subsea chemical injection system in the North Sea

5.8.4 Barrier Testing/Well Operations Support

We provide support in terms of determining the required barrier testing procedure to ensure diving operations can safely be achieved. In identifying the barriers, we will also demonstrate how they can be tested and the sequence of operations required in order to do this. We will also identify contingencies in the event of failure of the primary barriers. Having the contingency procedures in place prior to the subsea operation means that there would be no need for Management of Change during the offshore implementation phase – something that can save considerable time offshore. More importantly, this ensures that the contingencies are fully safety assessed using HAZID/HIRA as part of the development of the procedure. This type of barrier testing is typically required for operations such as scale squeeze on wells.

The procedures that Ingen develop would go from start to finish of the operation and would end when normal production is restored. Having a process engineer offshore on the producing facility for the duration of these operations is beneficial.

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