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Deepwater Chemical Injection Systems: The Balance between Conservatism and Flexibility

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Abstract

The chemical dosing requirements of any deepwater subsea tieback are always difficult to define. Well bore samples are rarely representative of the oil in place so there is a need for the design of the chemical injection system to be conservative. The system must be adaptable to any potential technical hurdles that may arise. This, combined with the need to define and then stay within a budget, makes for a dilemma that will neither lay down nor go away. Insight is presented into mixing new and proven technology to achieve a comprehensive solution.

The paper covers the challenges of extrapolating the data samples, which indicated the presence of asphaltenes, paraffins and hydrates in the oil, and determining the types of chemical inhibitors required. It details the lessons learned from the K2 project during and following the design of the delivery systems used for the chemicals, including the umbilical design, tube materials, and specialist valves.

The innovative method for controlling the dosing rates of chemicals, using the new technology of multiphase flowmeters to measure the oil volumes, combined with the unique use of a mathematical model of the flowline to determine the potential for deposition, is a first for the Gulf of Mexico.

Introduction

One of the objectives of the K2 development operated by ENI Petroleum was to optimize the chemicals used for the mitigation of flow assurance concerns. The conventional solution for chemical dosing is to add the chemicals into the system based on the data collected at the topside facility. Due to the time delay in obtaining results, more chemicals are added than necessary.

The K2 Project hoped to achieve a system that would use a mixture of conventional measuring devices combined with newer technologies to produce a control system that could dose chemicals and monitor the total flowline system in order to identify potential problems to the operators.

The chemical injection system was made up of a number of different elements:

(i) Mechanical Equipment
- Chemical injection skid
- Umbilical
- Subsea umbilical termination units
- Flying leads
- Chemical metering valves
- Valves for chemical isolation downhole
- Downhole tubing
- Injection mandrels

(ii) Measuring Instrumentation
- Flowmeters for total chemical
- Flowmeters at chemical metering valves
- Multiphase flowmeters for total oil/gas/water
- System instrumentaion

(iii) Control System
- A mathematical model of the whole system

The chemical injection system was fault tolerant as far as was technically possible, but equipment reliability is still a challenge.

Oil Samples

Prior to production sample acquisition there is a lot of planning for the analysis of the fluid samples. The planning also determines the amount of sampling attempted and the priority of obtaining the reservoir samples. The planning includes the Pressure, Volume, Temperature (PVT) analysis for the oil characterization required for project sanctioning to the flow assurance analysis for the production and chemical injection issues. Project sanctioning is in the critical path and consumes a large amount of the samples and there is always competition for clean reservoir samples but adequate samples were acquired in the formation evaluation phase of the project. Samples were collected under extremely difficult conditions with the maximum pressure differentials (difference between the hydrostatic and reservoir pressure) at 5,600 – 6,000 psi.

This was the limit of the formation sampling tools. The formation pressures were in excess of 15,000 psi and at a depth of 23,000 to 27,000 feet. The samples that were collected at great expense had varying amounts of synthetic based mud (SBM) contamination. The sample contamination ranged from 1.9 % to 45 % SBM. Forty samples were acquired and PVT analysis was run on the samples with less than 18.5 % SBM contamination. The PVT analyses were corrected using the equation of state (EOS) - Peng-Robinson-Perleoux. PVT analyses were also run on the drilling fluid and the EOS results were used to correct for the SBM contamination. Once contamination correction factors were applied to the samples, the most representative were used for project sanctioning and flow assurance work. Additional sample quality studies selected the best samples on the basis of variability in CO_2 or N_2 levels, length of restoration time, opening pressure and contamination. These samples were then used in the chemical inhibitor testing.
Initial testing showed that there were three potential areas of concern as is typical of most subsea oil tie-backs:

(i) Asphaltene deposition
(ii) Hydrate formation
(iii) Paraffin wax deposition

It was possible to run a number of different tests to measure the amount of material deposited and assess whether dosing was required, but because of the small sample size and the amount of contamination the results could not have been used with confidence. Hence the decision was taken to build sufficient chemical treatment facilities to dose chemicals into the oil for all three contaminants. If in the future it was found to be unnecessary, the dosing could be turned off. This was not the most cost effective solution but could be justified to ensure that first oil dates were achieved and to give a level of flexibility to enable operations to deal with any problems arising in the future. Each of the three concerns is dealt with in turn below.

Asphaltene Deposition
The likelihood of asphaltenes being deposited can be shown in Figure 1: de Boer Plot. From this data it can be seen that the K2 oils (M14 and M20 reservoirs) were likely to deposit asphaltenes. Asphaltene instability/deposition was measured using a near infra-red device together with high pressure microscopy and particle size analysis. Using these measurements with specialist prediction models it was possible to forecast at what pressure the asphaltenes would precipitate. It was found that asphaltene deposition occurs around the bubble point, where vaporization takes place, which is the peak of the curve in Figure 2: Asphaltene Precipitation. Understanding this allows the chemical injection to be used only when needed.

The following results were then obtained:

	M14	M20B	M20C/D
Bubble Point (psi)	2900	4000	3000
Asphaltene instability (psi)	3200	7500	5000

These results showed that asphaltenes would deposit in the riser at early field life and in the well bore towards the end of field life. The problem is not that asphaltenes are deposited, but that they might stick to themselves or to the pipe wall, eventually causing a flowline restriction. The “stickiness factor” is governed by the ratio of the asphaltenes to other resins as given in Figure 3: Asphaltene Resins Ratio Plot. These figures showed that the M14 oil would be the most likely to produce “sticky” deposits therefore asphaltene inhibitors would have to be used. At the time of writing, the M14 oil does precipitate asphaltenes but they are not sticking to the flowline or to the topsides vessels - the M20 wells are not yet operational.

Hydrate Formation
Black oil hydrates are well known in the laboratory but not commonly seen in practice. However as hydrate formation can have a large negative impact it needs to be mitigated. The normal pipeline operating pressure is 3000 psi which gives a hydrate formation temperature of 76 ^oF (see Figure 4: Topside Arrival Temperature to Prevent Paraffin Wax Deposition or Hydrate Formation), therefore it was considered prudent to provide a treatment method to protect the flowline system. The two methods of protection that were considered were methanol and/or Low Dosage Hydrate Inhibitor (LDHI).
The initial plan was to use only methanol for treatment but it was subsequently decided to use LDHI as the main inhibitor and methanol as a backup system for the following reasons:

(i) Impact on crude value, as it causes catalyst poisoning in the refineries
(ii) Good laboratory results with the use of LDHI
(iii) The costs for LDHI were lower on a per barrel oil produced basis
(iv) Topside storage volume was insufficient

The selected LDHI inhibitor is an anti-agglomerate type that lets hydrate crystals form but prevents them from agglomerating and forming a blockage. The un-agglomerated crystals are then carried off in the oil phase. The injection of LDHI before shutdown would allow the system to be fully protected during any long-term shut-in condition. Methanol would be used for well startup and for balancing the pressure across the downhole safety valve when it is being opened.

Paraffin wax Deposition
Steady-state thermal hydraulic analyses showed that the normal operating flowrates would be sufficient to keep the flowline temperature above the predicted paraffin wax appearance temperature (WAT) of 125°F for the M20 oils and 120°F for the M14 oils and hence avoid paraffin wax deposition - see
Figure 4: Topside Arrival Temperature to Prevent Paraffin Wax Deposition or Hydrate Formation. At shutdown, pipe-in-pipe flowlines and insulated risers were required to keep the oil warm and so provide operations with sufficient time to undertake repairs before flushing with inhibited oil. At startup, it is necessary to inject paraffin wax inhibitor to prevent paraffin wax formation while the flowrates are low and the temperature is below the WAT. Once the flowline

temperature is greater than the WAT the paraffin wax inhibitor is stopped. For each well, a flowrate of greater than 5000 barrels per day of produced fluid (oil & water) will keep the wellhead temperature higher than the WAT so that paraffin wax deposition will not occur.

Chemical Inhibitors

Having chosen to use chemical inhibitors to modify the behavior of the oil, it was necessary to select the chemicals, the vendors, the injection points and the method of delivery.
The one outstanding question was corrosion control and how this was to be handled. It was decided this could only be assessed once there was some information on the formation water as no true samples were available. It was clear however that the facilities would have to be designed to allow the corrosion inhibitor to be mixed with one of the other inhibitors during the mid to late life of the field once water breakthrough had occurred.

Chemical Inhibitor Types

The types of chemical inhibitors to be used were defined as:

(i) Asphaltene inhibitor
(ii) Hydrate inhibitor
(iii) Paraffin wax inhibitor

The corrosion inhibitor will be mixed with one of the other inhibitors once additional data on the formation water is available.

Vendors

A review was undertaken to identify potential vendors to supply the chemicals suitable for use in deepwater. The two with the most experience were selected as potential suppliers. The chemical types were reviewed and it was found they were very similar in cost and effectiveness. A contract was awarded to the supplier who was already supplying chemicals to Marco Polo to minimize logistics and improve operational synergies.

Injection Points

Having selected the chemicals, it was necessary to decide how they would be injected into the oil stream. The well bore consists of two deep-set chemical injection mandrels located at 200ft above the production packer, which in turn is approximately 18,000ft below the mud line at a sea level of 4200ft and one shallow-set mandrel located at 50 ft above the downhole safety valve which is 3900ft below the mud line. The deep-set mandrels are used for asphaltene and paraffin wax inhibitor injection because the inhibitors are required to protect the well bore, as well as the pipeline. They are connected to the umbilical via a chemical metering valve located at the tree to control flowrate. The hydrate inhibitor is used to protect the flowline; hence it was decided to inject LDHI downhole at the shallow-set mandrel for better mixing and methanol at the tree injection point between the wing and the master valve for startup only. The injection points are shown diagrammatically in Figure 5: Tree P&ID.

Inhibitor Physical Properties

While testing the chemical metering valve it was found that the asphaltene inhibitors changed viscosity both under pressure and temperature. The formation pressures required that the inhibitor be injected at 15,000 psi. After calculating the pressure in the umbilical it was found that the viscosity was so high at seabed temperatures that the inhibitor could not be pumped along the umbilical. After discussion with the chemicals supplier the fluid was modified to lower the viscosity and this solved the problem as shown in Figure 6: Inhibitor Viscosity.

Method of Delivery

The choices for the method of delivery of the chemicals were to use either single tubes to each of the three wells, which was complex at a 15,000 psi pressure rating, or to use a manifold type system. The concern with the manifold solution was that different pressures at each well would cause different back pressures at the manifold, but this was solved by the use of a chemical metering valve which allows fixed flowrates independent of back pressure. The distance from the Marco Polo TLP to the subsea trees is 5.2 miles to the South Fault Block and an additional 1.7 miles to the North Fault Block. A cost estimate for both solutions was prepared and the manifold system was 30% lower in cost with acceptable reliability, hence this system was adopted.

Umbilical Design

The electro-hydraulic control umbilical connects the platform based subsea control system to the subsea umbilical termination units with a single umbilical containing all electrics, hydraulics and chemicals. There are three different sections of the umbilical: a dynamic section from the TLP to the seabed; a static section to the South Fault Block; and an infield section to the North Fault Block. Figure 7: Umbilical Cross Section shows the lay-up of the super duplex steel tubes and the electrical cable quads. Table 1: Umbilical Hydraulic & Chemical Lines shows the sizes of all the tubes. The only difference between the three sections is that there are additional strengthening members in the dynamic section so that it can withstand the loads caused by the currents.
Between the South Fault Block and North Fault Block there is a remote operated vehicle (ROV) removable routing plate to allow the functions of the umbilical tubes to be changed in the event of a blockage.
From the umbilical termination unit, a flying lead connects all the services to each of the tree mounted control module mounting bases. The chemical tubes by-pass the control module and are tubed directly from the mounting base to valves located on the tree.

Chemical Isolation Downhole (CID)Valves

The remote operated valves were designed to isolate any well from the umbilical. They were designed to be used during initial startup and workover. The valves supplied as part of the tree were qualified to operate at 15,000 psi and in water depths in excess of 5000 ft. Due to a manufacturing tolerance problem they were found to be unreliable once deployed. They have had to be ROV operated to a fixed position and are being replaced using a special ROV installable CID valve module.

Chemical Metering Valve

The chemical metering valve is an electrically operated flow regulator used to meter the inhibitors to the deep-set chemical injection mandrels. A graphical representation is shown in Figure 8: Chemical Metering Valve. Transducers in the valve module provide flow and pressure data to the operator. This chemical metering valve design allows the valve to maintain constant flow regardless of the changes in back pressure by governing the pressure drop across a fixed fluid restriction, internal to the valve. Figure 9: Chemical Metering Valve Internal Mechanism shows a spring-balanced piston connected to a ceramic throttling point that maintains even regulation. An indication of the size of the valve is shown in Figure 10: Chemical Metering Valve being Installed. This unit has two flow cores for both asphaltene and paraffin wax in a single housing.

Topsides Chemical Injection Skid

The topsides chemical injection skid is a series of six variable speed pumps with a secondary spill-back method to allow a large turndown ratio. The cleanliness of the chemicals and their handling is essential for subsea operations. The initial work practices of the platform operators caused contamination of the fluids but this problem was overcome by the application of rigorous procedures and regular testing of the fluids.

Multiphase Flowmeters

The use of multiphase flowmeters (MPFMs) in the Gulf of Mexico is becoming more common. ENI Petroleum had had success with MPFMs on another project in the Gulf of Mexico and was keen to go forward with this technology. Originally the K2 project team proposed subsea MPFMs but the cost was high and the maintainability difficult. A market survey of twenty-three vendors found that in reality only one vendor could measure the K2 oil. As a result of these factors MPFMs were installed topsides for maintenance access and a third party consultant was commissioned to assist with technical support throughout this project and into the operational and maintenance phases.

Chemical injection depends primarily on the production flowrates of oil and water from a well to optimize chemical usage. In order to measure these flowrates, combinations of different technologies were implemented:

(i) MPFMs
(ii) A mathematical model of the system - a virtual flowmeter (VFM).
(iii) Downhole pressure and temperature gauges

MPFM Technology

Two Phase Watcher Vx MPFMs were installed and commissioned on the Marco Polo TLP downstream of the boarding valve and upstream of the allocation separator. The MPFM skid was installed such that flow from either flowline could be routed through either MPFM. The mass flowrate of the fluid mixture is calculated using previously measured fluid properties with the differential pressure measurement across the venturi, as can be seen in Figure 11: Cross Section Representation of the Phase Watcher Vx MPFM. The fraction of each phase is determined from the attenuation of a dual-energy gamma source (Barium 133). Three phase fractions, namely, gas, oil and water are determined using the gamma densitometer. Thus, the volumetric flow rates for each phase at operating conditions can be determined.

MPFM Operation

The following input parameters are required to attain minimal uncertainty results using the Phase Watcher Vx meter:

(i) Density or specific gravity of gas, oil and water;
(ii) Fluid composition of gas including non-hydrocarbons such as nitrogen, carbon dioxide;
(iii) Sulphur content of the oil;
(iv) Salinity of produced water;
(v) Viscosity of the oil.

The MPFM uses either a “Black Oil” model or measured fluid properties to calculate the parameters at operating conditions, which are then used in the system to obtain volumetric flow rate and calculated phase fractions. Using the fluid properties, the mass attenuation of each phase is obtained i.e. gas, oil and water. The mass attenuations at high energy and low energy are the end points of the measurement triangle shown in Figure 12: Phase Fractions and the Measurement Triangle. The mixture of gas, oil and water produced from the reservoir is always expected to remain inside the triangle. The point (0,0) represents the mass attenuation of a vacuum.

The measurement for the Phase Watcher Vx meter is independent of the flow regime through the MPFM. The use of laboratory-measured fluid properties improves the results significantly and a slip model is used to determine the gas fraction from the measured gas holdup using the dual-energy gamma data. It should also be noted that the use of chemicals in small quantities (ppm levels) does not affect the bulk measurements. The presence of solids such as paraffin wax, scale, sand, etc. will affect the measurements. Figure 13: A Comparison of MPFM’S versus the Allocation Separator on Marco Polo TLP shows that a variation of less than 2% for gas and liquid has been achieved. Because the allocation separator is a two-phase vessel the figures for combined liquids were used.

Virtual Flowmeter

The virtual flowmeter (VFM) is a mathematical model of the system from the reservoir to the topside separators. This model is a first in the Gulf of Mexico where its primary function is to predict the oil, gas and water flowrates from each well. As Marco Polo has no test separator and the main separators are two-phase units, this is the only way to allocate well production and so help the reservoir management. The mathematical model can also be used to predict solids deposition allowing the operators to know when and where hydrates, asphaltenes or paraffin waxes are going to be deposited in the flowlines. Figure 14: Overview Screen provides the operator with information on the location of solids deposition.

VFM Technology

The total flow from the three wells through the two flowlines is measured using the two topside MPFMs. The VFM collects pressure, temperature and position readings from all of the available instruments, including downhole sensors, high-resolution tree sensors, choke position indicators and separator sensors. The VFM uses previously measured fluid properties and a rigorous multiphase flow model of the wells and flowlines to infer well rates in real time and provide key flow assurance information for the flowlines. The model is tuned to the flow measurements from the MPFMs as well as historical flow data to reduce differences between the model and the physical measurement. Once the model is tuned to represent field behavior, it provides accurate estimation of multiphase flow rates per well and pipeline status information in real-time. The VFM generates a database showing flows, temperatures and pressures at all points along the flowlines. This data is generated once per minute and can be both trended and then alarmed if the variables go outside predetermined limits. The VFM model is capable of predicting the phase behavior of the produced fluid in the flowlines. These predictions are then used to evaluate solids deposition risks for asphaltene, paraffin wax and hydrate. The measurements can then be used both to optimize the chemical injection rates of asphaltene, paraffin wax and hydrate inhibitors during steady state flow and to provide flow regime information for slugging calculations. Figure 15: Chemical Dosing Screen shows the operator interface for this dosing.

VFM System

The VFM system is in two parts - one offshore and one onshore. They are identical, both using the same data in real time. The offshore unit is used by the operators; the onshore unit is used to check the model and data inputs and to predict the well production. The ability to check the model has been essential during the start-up phase because the transfer of data from the different systems to the model has not been as robust as the design would have indicated. Figure 16: Topsides Facilities is one of the key screens indicating that all of the measurements and predictions are operating correctly.

Conclusion

To achieve the flexibility required in the chemical dosing system a degree of complexity was inevitable. In the design phase, system flexibility is essential as the system has to be developed with uncertain information. Once a clear philosophy has been set, the system must collect all the data possible and give the operations staff a method to optimize the flow of chemicals into the system.

The combination of the MPFMs, the VFM and the downhole instruments gave the operational staff enhanced measurements that allowed them to make better decisions.

The chemical metering valves, in combination with the topsides chemical injection skid, provide the operators with the ability to vary the dosage rates from gallons per hour to gallons per minute.

The mechanical design of the umbilical with its redirectable routing plate has allowed a safety net in the event of a tube blockage.

Due to redundant measuring points instrument failures do not compromise the system. Moreover, the VFM allows faulty instruments to be identified and then excluded from the VFM calculations until they are repaired.

The combination of MPFMs and the VFM has provided the operational staff with significant insight into the fluid behavior along the flowlines.

The VFM originally justified on a cost basis for measuring individual well production, has provided a number of additional features that added value to the overall project.

Currently the information on the fluid flow is used to manually optimize the chemical inhibition. In the future it is planned to turn this into an automatic feedback loop.

The experience gained using these tools will allow the volume of chemicals to be decreased in a consistent way avoiding line blockages or production holdups.

Nomenclature

PVT – Pressure Volume Temperature
LDHI – Low Dosage Hydrate inhibitor
WAT – Wax Appearance Temperature
EOS – Equation of State
TLP – Tension Leg Platform
ROV – remote operated vehicle
MPFM – Multiphase flowmeter
VFM – virtual flowmeter

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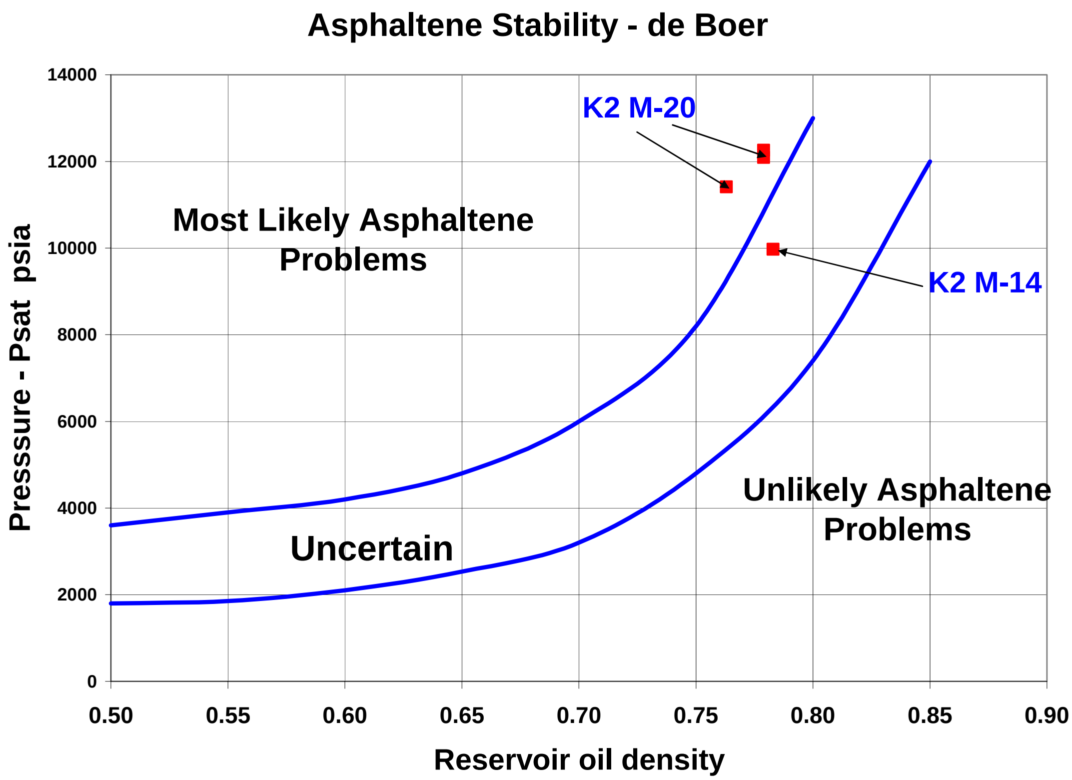

Figure 1: de Boer Plot

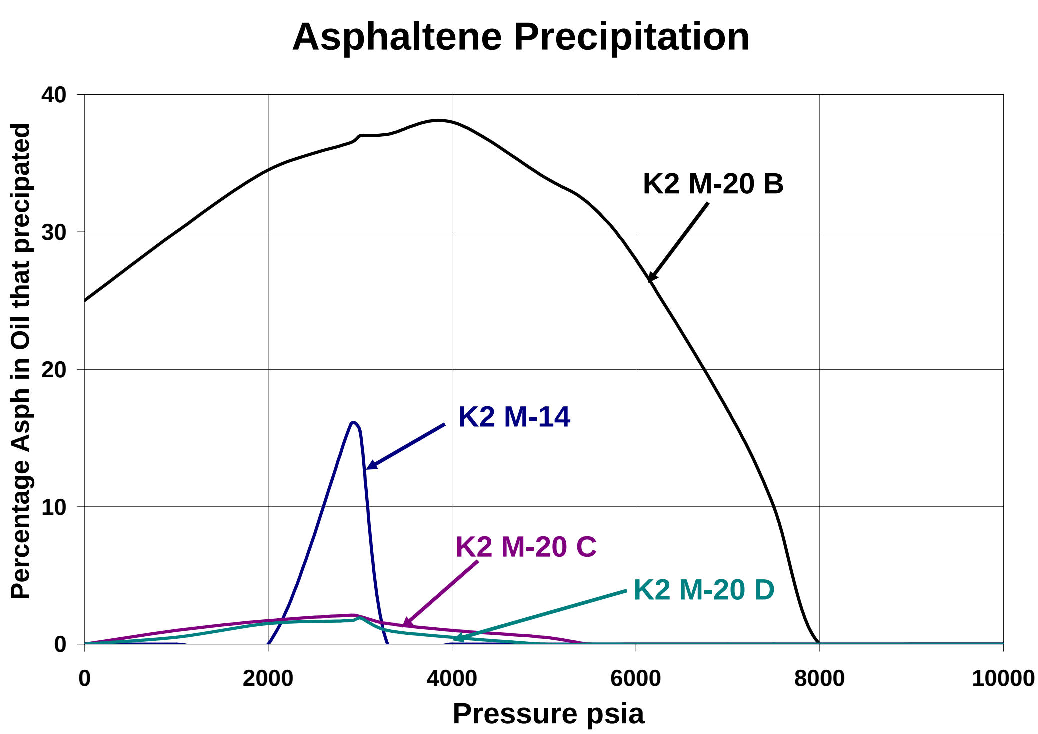

Figure 2: Asphaltene Precipitation

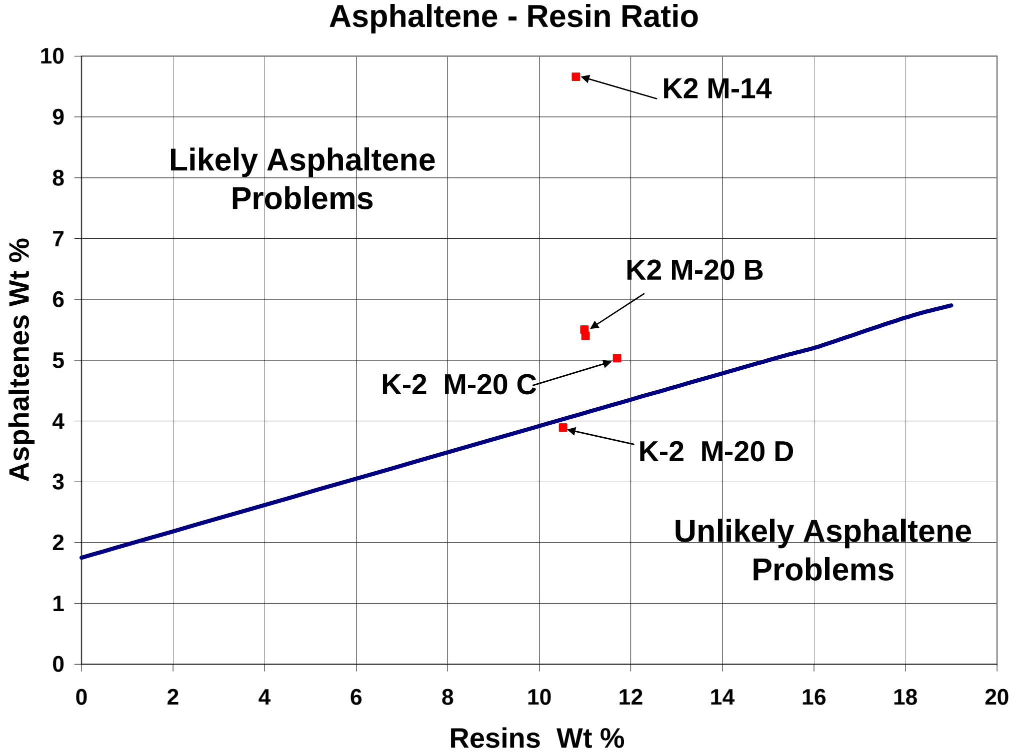

Figure 3: Asphaltene Resins Ratio Plot

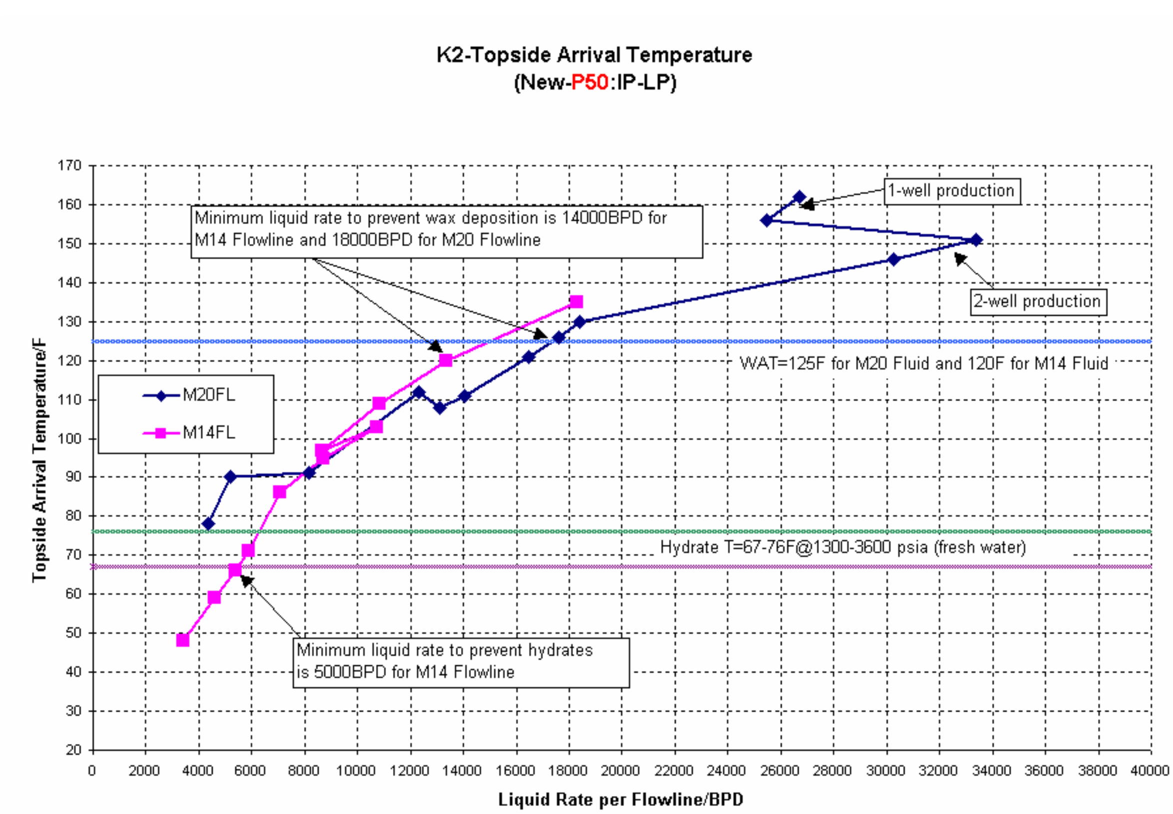

Figure 4: Topside Arrival Temperature to Prevent Paraffin Wax Deposition or Hydrate Formation

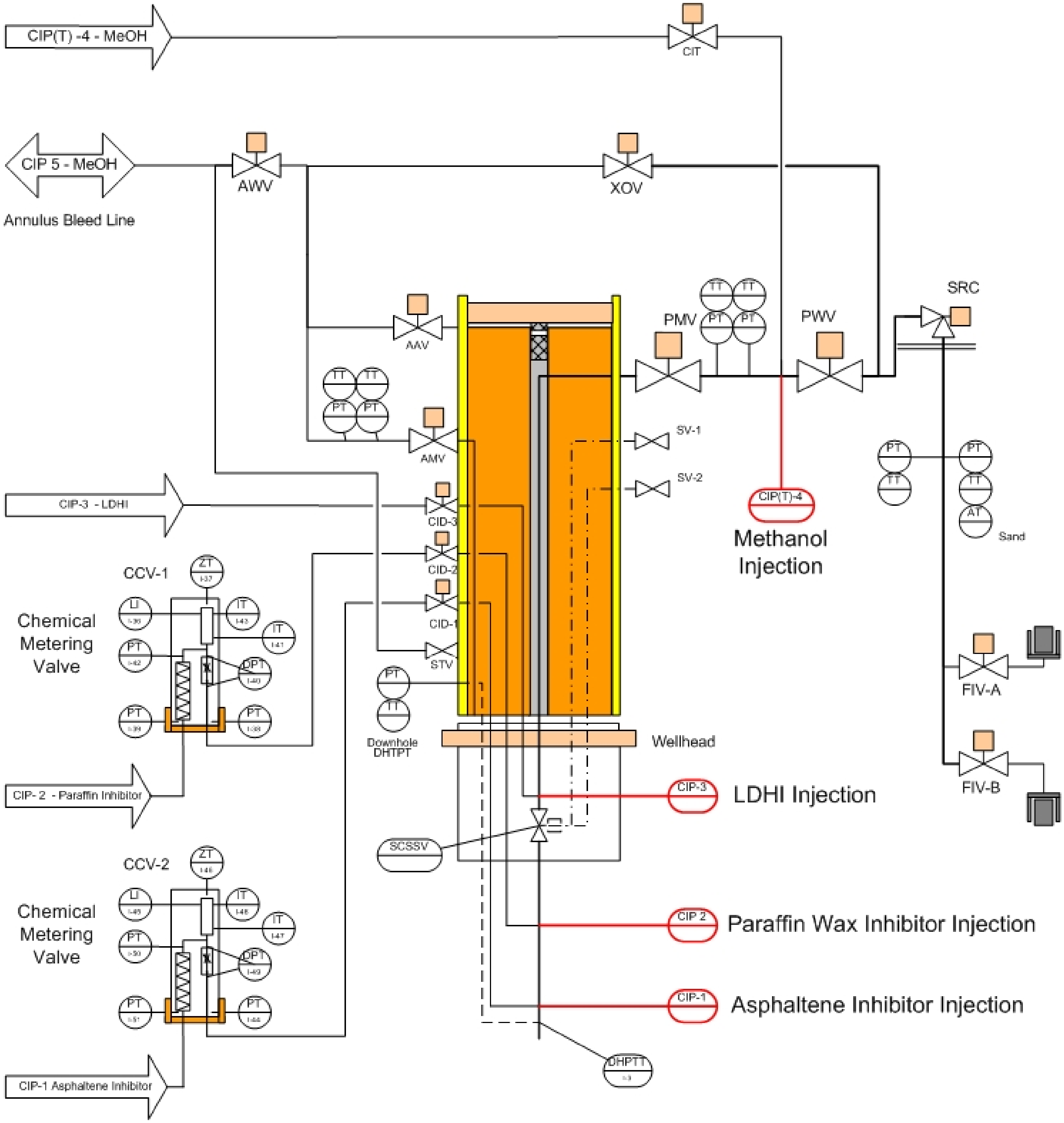

Figure 5: Tree P&ID

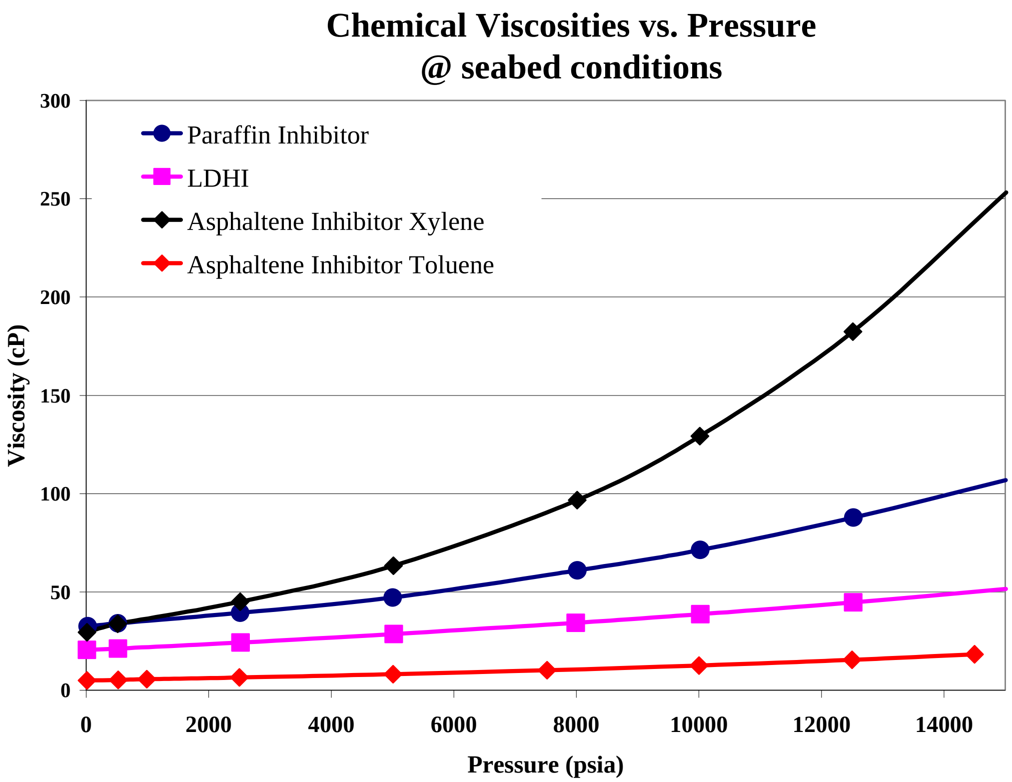

Figure 6: Inhibitor Viscosity

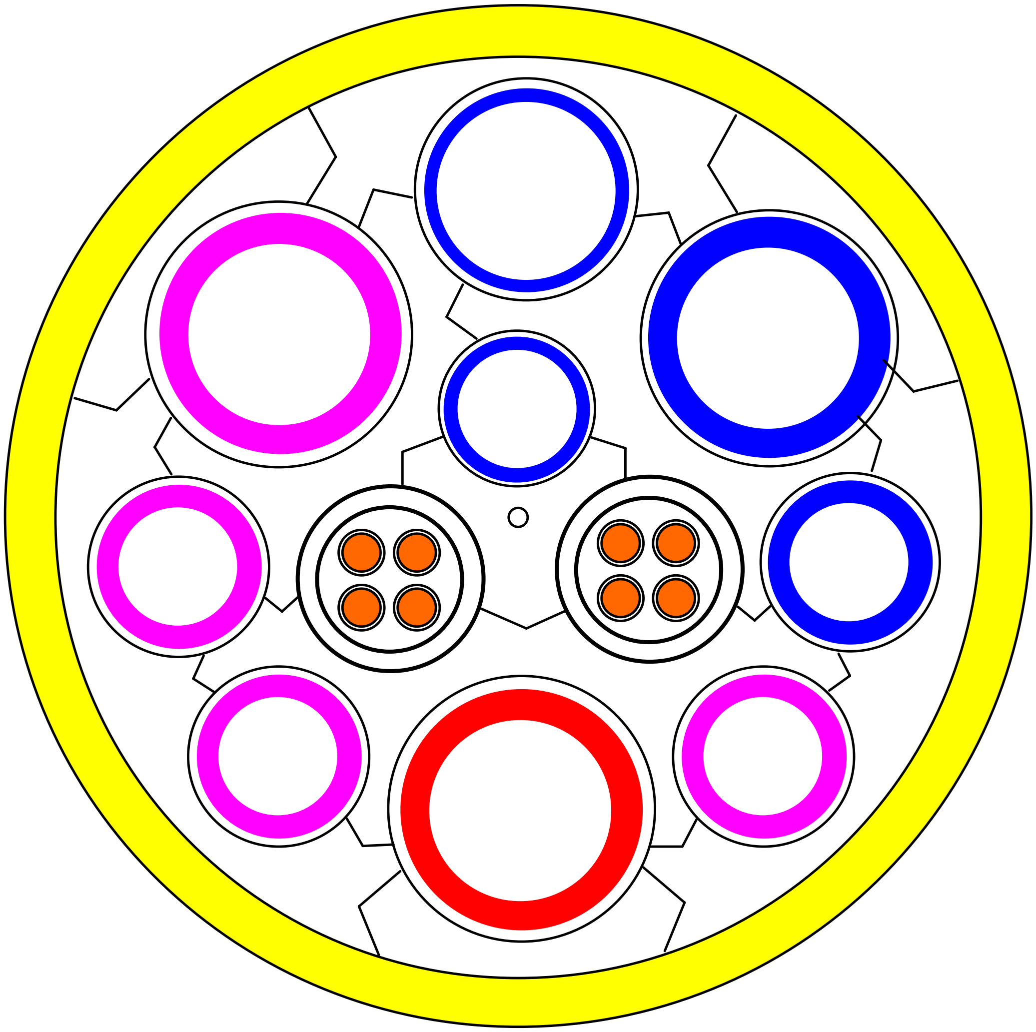

Figure 7: Umbilical Cross Section

#	Tube Type	Tube Size (ID)	Max Press - psi	Line Function
1	SDSS	½"	10,000	HP "A"
2	SDSS	¾ "	5,000	LP "A"
3	SDSS	¾ "	15,000	LP "B" / Spare
4	SDSS	½"	15,000	HP "B" / Spare
5	SDSS	½"	15,000	Asphaltenes Inhibitor
6	SDSS	¾ "	15,000	Annulus Access Line
7	SDSS	½"	15,000	LDHI
8	SDSS	½"	15,000	Paraffin wax
9	SDSS	¾ "	15,000	Methanol Line
A				Power / Signal Cable
B				Power / Signal Cable

Table 1: Umbilical Hydraulic & Chemical Lines

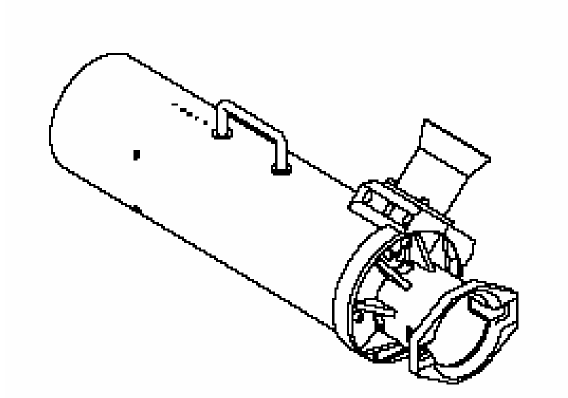

Figure 8: Chemical Metering Valve

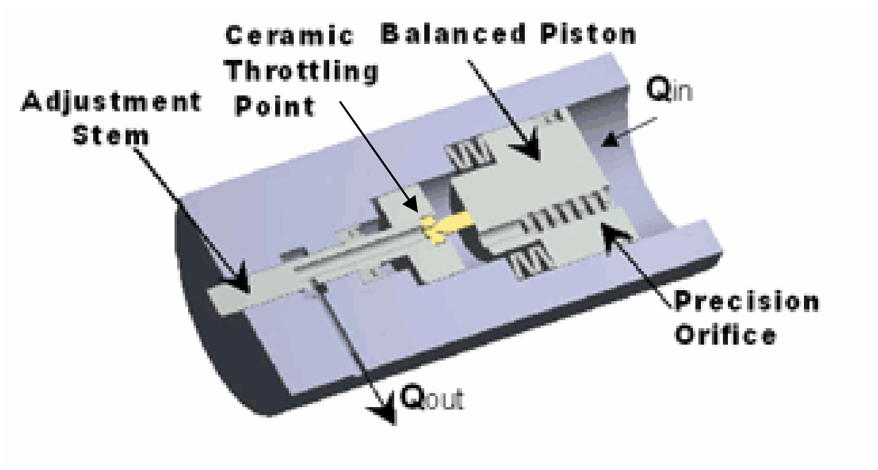

Figure 9: Chemical Metering Valve Internal Mechanism

Figure 10: Chemical Metering Valve being Installed

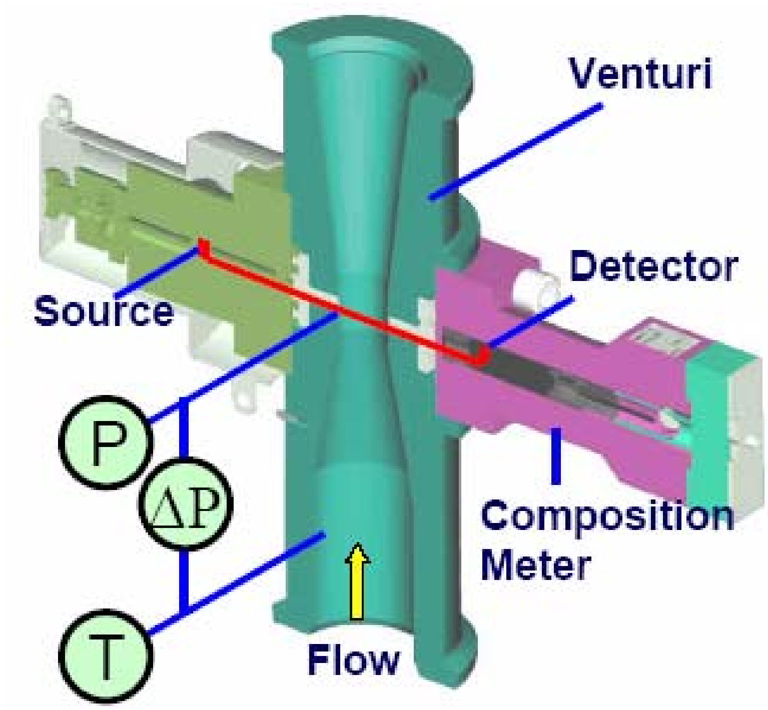

Figure 11: Cross Section Representation of the Phase Watcher Vx MPFM

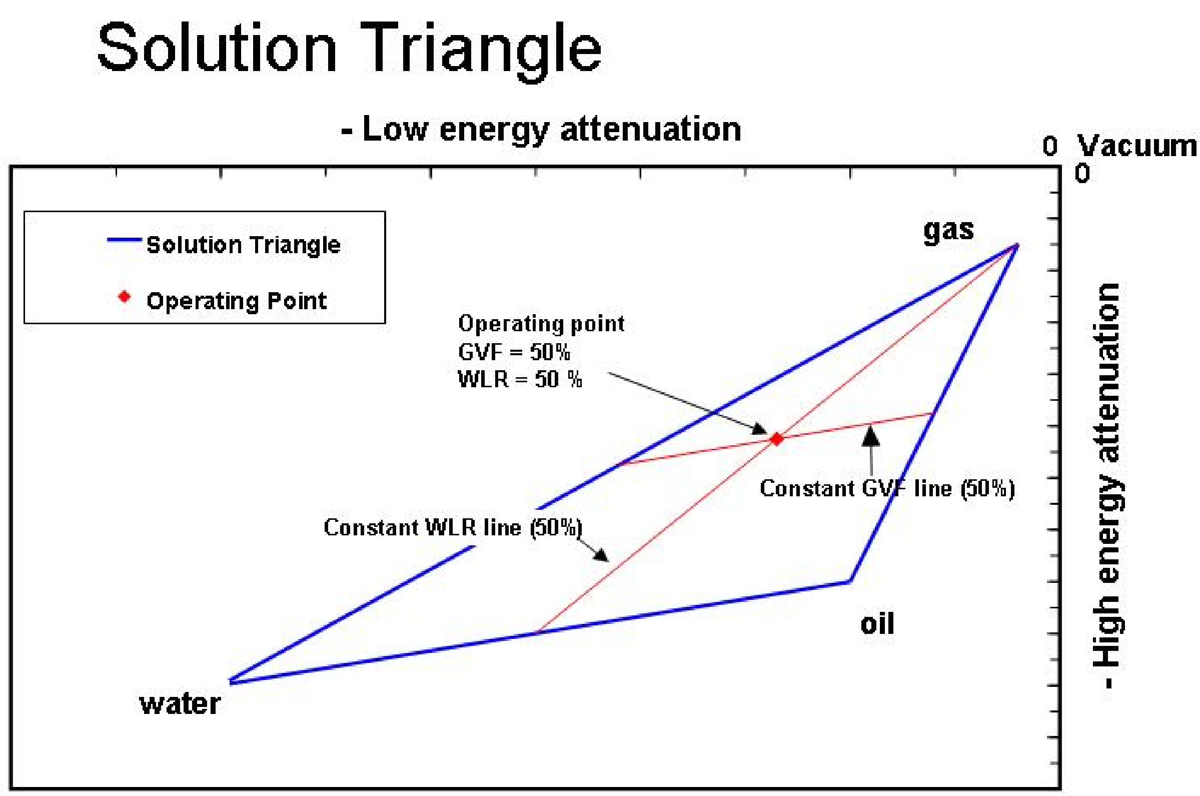

Figure 12: Phase Fractions and the Measurement Triangle

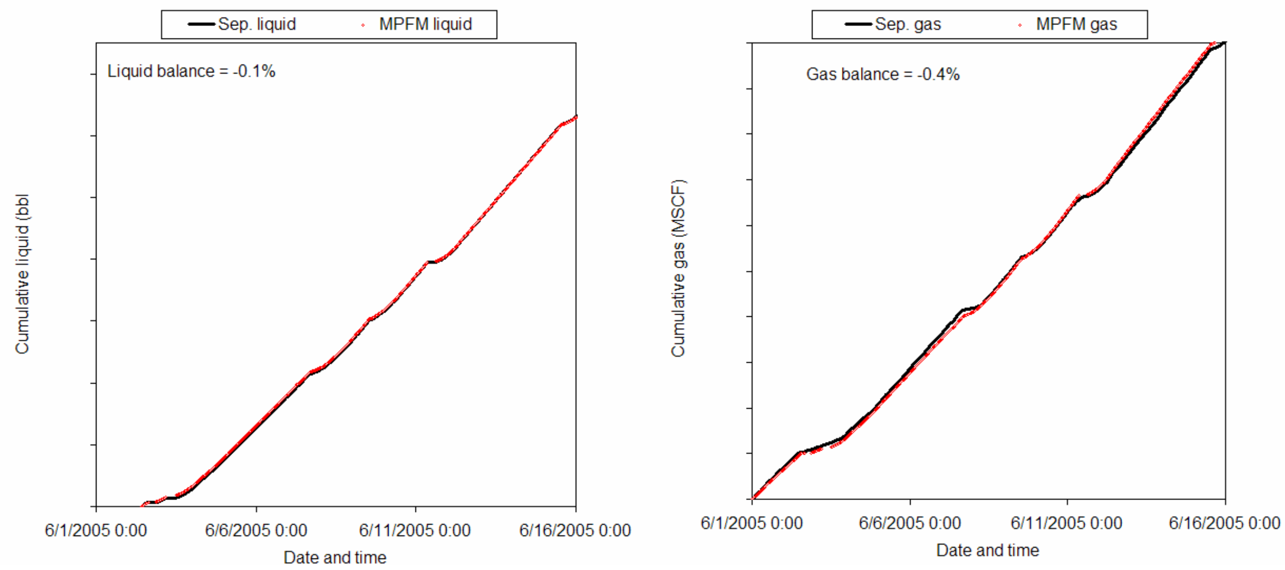

Figure 13: A Comparison of MPFM'S versus the Allocation Separator on Marco Polo TLP

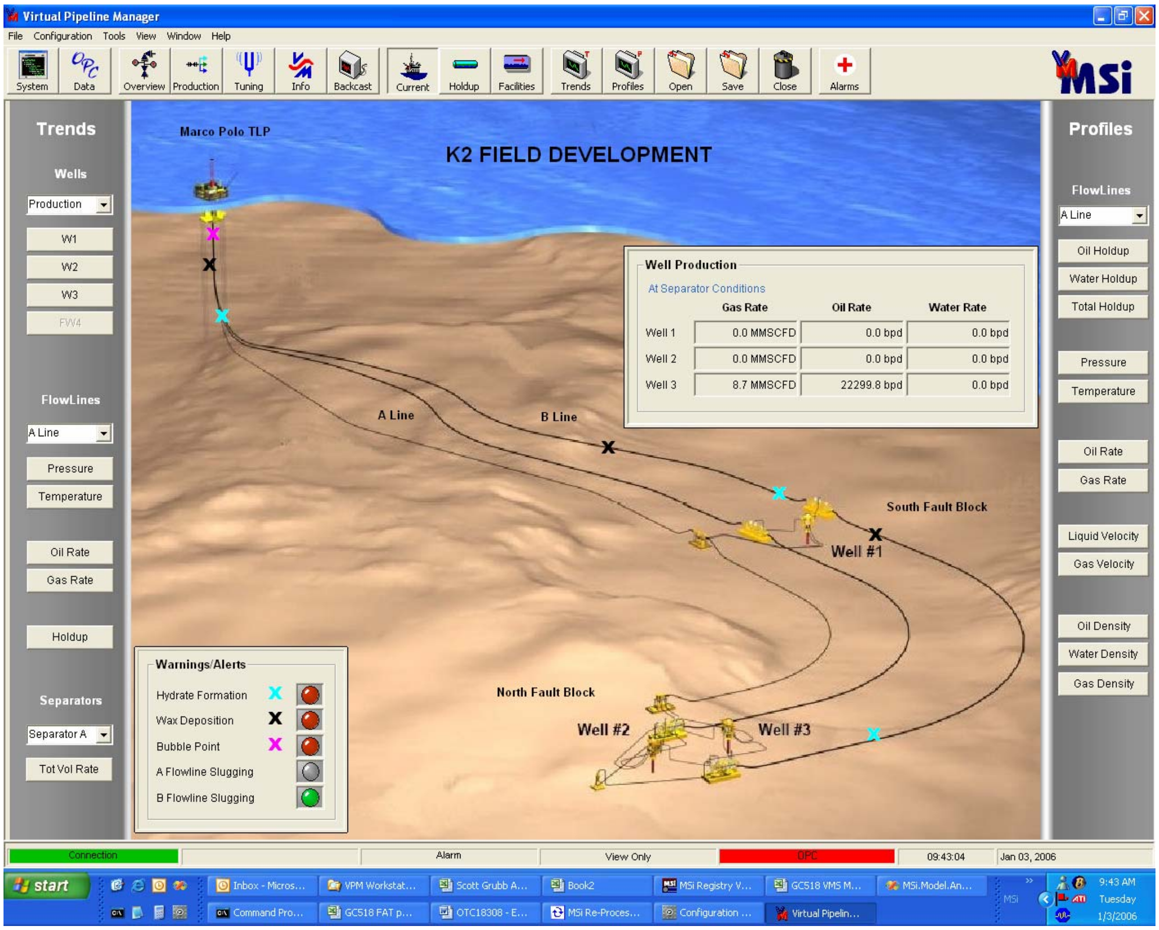

Figure 14: Overview Screen

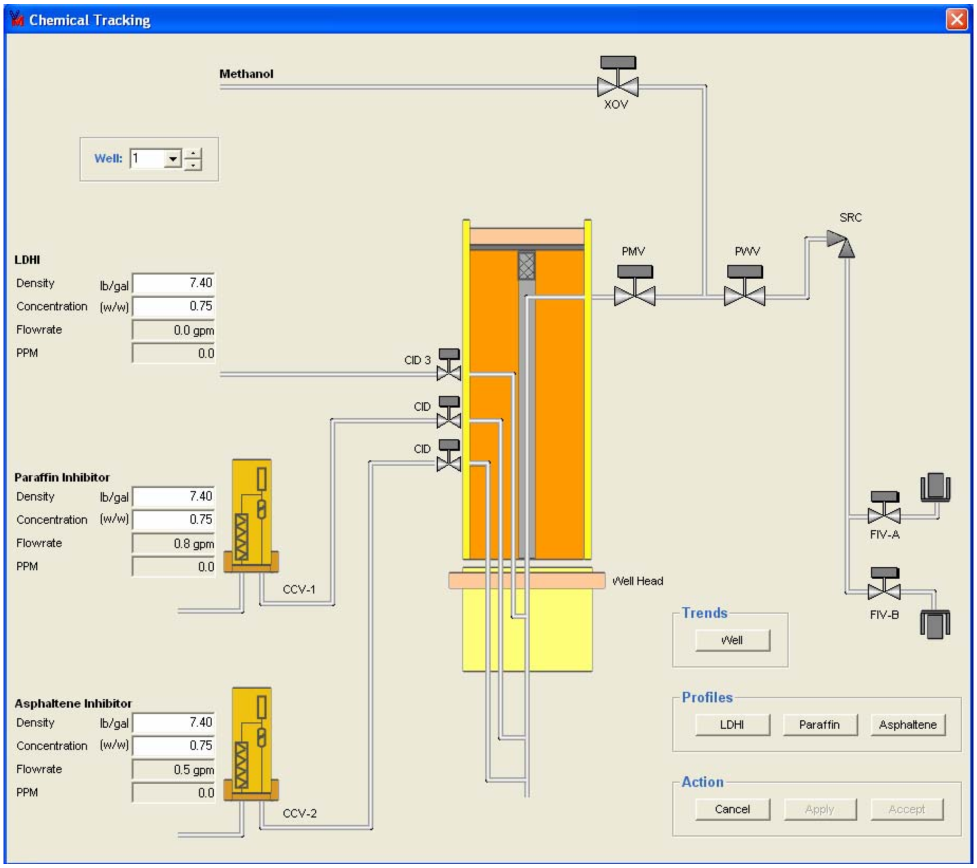

Figure 15: Chemical Dosing Screen

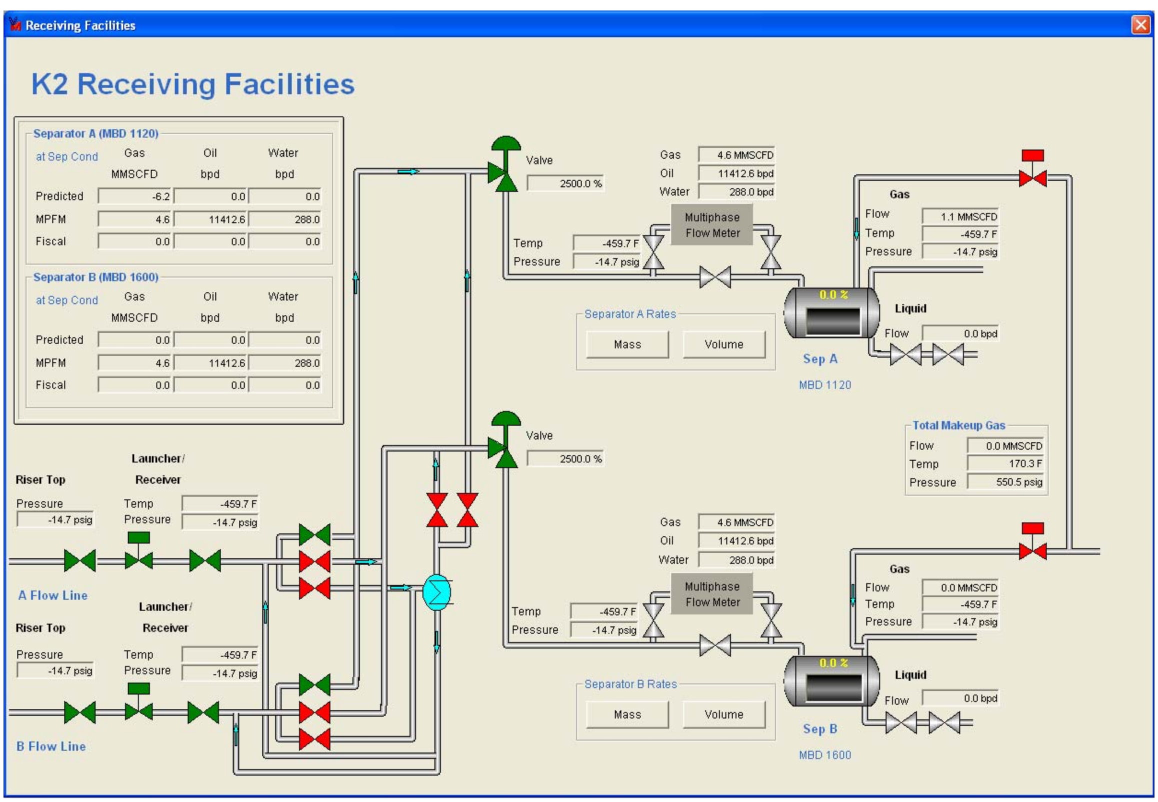

Figure 16: Topsides Facilities