

# Guidelines for Managing Wax Deposition and Gelling in Production Systems

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by

G. Broze

Contributors: George Broze, Menno van Dijk, Nancy Utech, Klaus Weispfennig, Scott Wierzchowski, Karthik Ramanathan, Kees Lagers, Michel Ondo Ella, Stuart McGregor, Bill Davidson, Wade Schoppa and Leonid Dykhno

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**Document History**

Date	Issue	Reason for Change	Author	Approved by

## Executive Summary

This document summarizes Shell's current state of wax management for flow assurance. The purpose of this document is to describe

- (i) The kinds of wax problems that can occur.
- (ii) The measurement and modeling techniques that are used to predict these problems.
- (iii) The development of strategies to manage wax.
- (iv) Surveillance techniques to detect incipient wax problems.
- (v) Remediation techniques to correct management failures.

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## 1. Introduction

### 1.1 The Problem

Waxes, also known as paraffins, are high-molecular-weight saturated hydrocarbons. They are a production problem for many crude oils because of their tendency to precipitate in the bulk fluids and/or deposit on pipe walls. Wax is one of a number of solids and flow problems, such as asphaltenes, hydrates, scale, emulsions, and multiphase slugging, that can cause significant production problems. The subject area that deals with these problems collectively has come to be known as Flow Assurance.

#### 1.1.1 Wax Deposition

Wax deposition occurs when the surface temperature of the well tubing, flowline, pipeline or vessel falls below the critical wax deposition temperature. The classical understanding of the process is that a temperature differential between the bulk fluid and the surface establishes a liquid-phase wax concentration gradient, which drives the transport of dissolved wax to the wall, where it crystallizes to form a solid deposit. This deposit will decrease the open cross-sectional area of the flow path (and usually increase surface roughness), which will increase the flowing pressure drop in the system. It is possible, but not common, for the deposit to block the flow path altogether.

#### 1.1.2 Wax Gelling

In many cases, the precipitated wax crystals form connected networks. The wax crystals are typically needle or platelet shaped such that a relatively small volume of wax suffices to build such a network. This network, essentially a porous structure of wax, filled with oil, may attain mechanical strength at sufficient subcooling. If this happens in a flowline (or in a transport carrier!) one may have a problem. If the strength of this gel is sufficient, such a flowline can no longer be forced to flow (restart), simply because the required pressure would be larger than the mechanical specifications of the flowline allow.

## 1.2 Purpose of the Document

The purpose of this document is to describe

- (i) The kinds of wax problems that can occur,
- (ii) The measurement and modeling techniques that are used to predict these problems,
- (iii) The development of strategies to manage wax,
- (iv) Surveillance techniques to detect incipient wax problems and
- (v) Remediation techniques to correct management failures.

The guidelines are divided into the following sections: §2 is an overview of wax management strategies; §3 is a description of the design work process; §4 covers the measurement and modeling tools; §5 contains details of wax management options, and §6 contains surveillance and operations support.

## 2. Overview of Wax Management Strategies

### 2.1 Opportunity Realization Process

Shell's ORP is shown in Figure 2.1; most readers will be familiar with this and it will not be described further here.

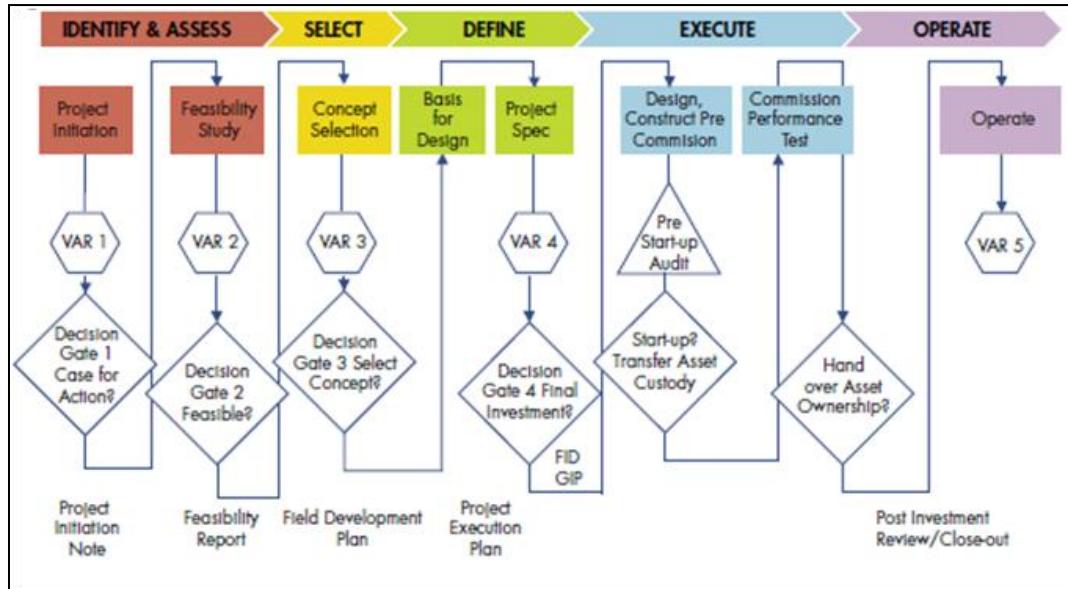


Figure 2.1: Opportunity Realization Process.

Shell has adopted a framework for Technical Assurance that is called DCAF (Discipline Controls and Assurance Framework). This framework standardizes Quality Control and Quality Assurance across all disciplines, in all ORP phases. In DCAF, there are three main elements: Discipline Standards, Discipline Authority Manual and Project/ Asset Controls & Assurance Plan. Details can be found at the following website.

<http://sww.shell.com/pt/projects/dcaf/index.html>

DCAF goes hand in hand with Operational Readiness and Assurance (OR&A). DCAF is the assurance control and OR&A are the elements that are delivered within that control. The OR&A prescribes the key steps to be taken in the opportunity and project development phases to ensure that:

- The project design takes into account the lifecycle safety, production and integrity critical requirements of the host Asset
- “Right first time” commissioning and “flawless start up” are achieved
- The project is ready for handover of ownership from the project to the operations team

#### 2.1.1 Discipline Standards

High quality decisions and deliverables are needed during all ORP phases to ensure the value of an opportunity, project or asset. As a result, all decisions made and deliverables produced, confirm and proof the appropriate way of working, as set in the Discipline Standards. These are

set by the ‘Global Discipline Heads’ as part of their Assurance role. In DCAF these decisions and deliverables are called Controls and their sign-off is done within the project line. The Discipline Standards also contain the required authority-level for sign-off of a specific Control.

### 2.1.2 Discipline Authority Manual

This sign-off of the Controls is conducted by qualified individuals. As part of their Assurance role, Senior Discipline staff will identify these individuals and their respective Authority Level. This list is called the Discipline Authority Manual.

### 2.1.3 Project/Asset Controls and Assurance Plan and Schedule

DCAF also provides two key tools that translate the Discipline Standards into a work plan/ schedule relevant for a particular asset or project. These are called Project/Asset Controls & Assurance Plan and Project/Asset Controls & Assurance Schedule.

### 2.1.4 Flow Assurance

Flow Assurance is a sub-discipline within the engineering discipline of Pipelines, Flow Assurance, and Subsea Systems (PFAS). Flow Assurance plays a Technical Assurance role, with a specifically defined subset of responsibilities and authorities, in each ORP phase.

## 2.2 Flow Assurance Strategies

For every development project, a large number of systems must be designed to manage flow assurance risks. Several major steps must be taken. First, risks must be identified and assessed. Second, means to control these risks must be designed and implemented for all expected field life phases. Finally, the system is handed off to production, which operates the system in a way to mitigate these risks.

Figure 2.1 shows a flowchart of the workflow and interfaces for Flow Assurance. This description is intended to provide a conceptual workflow rather than the actual framework and authority matrix. Further, this is largely based on experience with Upstream Major Projects.

This process requires interactions between 4 main groups:

- a. **FEAST** (or equivalent group responsible for exploration/appraisal fluid properties),
- b. **Flow Assurance specialists**,
- c. **Project Development Team** and
- d. **Production/Surveillance** teams in the operating unit.

At the risk of oversimplification, the functions can be briefly described as follows: **FEAST** obtains the necessary fluids and property measurements; **Flow Assurance specialists** identify and assess the risks and possible solutions based on the fluid properties and proposed systems; **Project Flow Assurance Engineering** develops the overall FA strategy and embeds it into the system design; and **Production/Surveillance** implements the strategy in the field.

### 2.2.1 FEAST (Fluid Evaluation and Sampling Technology)

This group is responsible for assessing the fluid sample needs at the exploration and appraisal phases of a project. They recommend the location, type and quantity of samples required for Flow Assurance, geochemistry and reservoir modeling. They also select, validate and manage all tests for these purposes. FEAST is not utilized in all development projects, but in all cases there should be a person or team responsible for this function. As of 2010, this group resides in PTU/DF: Projects & Technology\Shell Global Solutions Upstream\Expertise & Deployment\ Basins & Modeling.

### 2.2.2 Flow Assurance Subject Matter Specialists

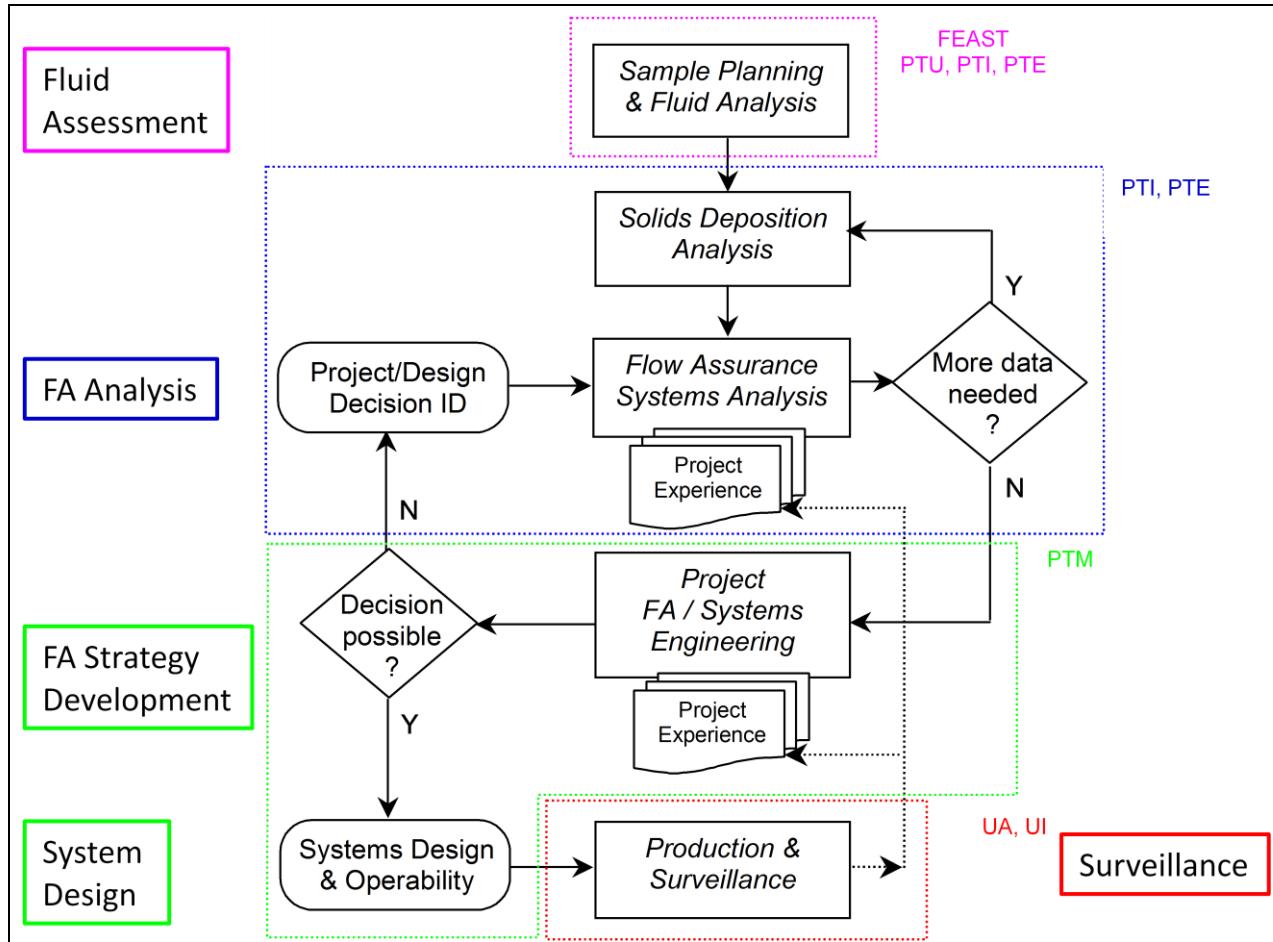
- a. Specialists in solids (hydrates, wax, asphaltenes, scale) formation and deposition, rheology, interfacial phenomena (emulsions and foam) and certain aspects of production chemistry. Reside in PTE\\_PFA: P&T\Projects and Engineering Services\Engineering (3 regions)\ Pipelines & Flow Assurance Systems
- b. Specialists in Flow Assurance Systems, including the thermal/hydraulic performance of the system under steady-state and transient conditions, design methodology for thermal/hydraulic FA management, and FA operability. Reside in PTI/WD: P&T\Innovation R&D\Wells and Facilities\Deepwater Technology\Flow Assurance

### 2.2.3 Project Flow Assurance/Systems Engineering

Each Project Development Team can draw upon the expertise of the FA/S team within Projects. These engineers are responsible for ensuring that the *strategy, design and operability* are in place to manage the Flow Assurance risks. As of 2010, in the Americas they reside in the regional projects organizations under PTM\MASUR: P&T\Upstream Major Projects\Subsea Design. There is no direct equivalent in PTM in the other regions.

### 2.2.4 Production and Operations Surveillance

This group is responsible for carrying out the Flow Assurance management strategies in the operating unit. Depending on the complexity of the development and the nature/difficulty of the Flow Assurance problems, this may require few or many people. As an example, the Subsea Surveillance Team in SEPCO-Upstream Americas has approximately 20 members, including engineers in subsea, surveillance, production and flow assurance specialties. Their team lies in Upstream Americas\Deepwater\Surveillance and Tech Support\Subsea Surveillance. In other Upstream organizations, these functions may be embedded or distributed in other ways.



**Figure 2.2: Conceptual workflow and interfaces for FA design.**

## 2.3 Risk Assessment

In order to develop a strategy, it is necessary to understand the risks posed by wax and ways to prevent or mitigate them.

### 2.3.1 Flow Assurance Risk Management

A research program (“FARMS”) on a risk-based approach to Flow Assurance was undertaken through EPT-R in 2006-09. Details of that approach are documented in [1]. The key shift in thinking in the FARMS approach is to consider probabilities and risks more quantitatively than in the usual project design process. This approach is in the pilot stage, and it is unknown the extent to which it will be adopted. However, several points stand out when working through this process. First, avoidance of all risk, if possible, is usually too expensive to be economic; risks are to be managed, not completely avoided. Second, the technology gaps are often not in tools for prevention or remediation but rather in our ability to put quantitative bounds on the risks and consequences. Third, the overall strategy should be considered, not a single solution.

### 2.3.2 HEMP Analogy

One conceptual tool to understanding Flow Assurance risk assessment is an analogy to the Hazard Effects and Management Process (HEMP) shown in Figure 2.3. In that process, we identify the risks and place barriers to prevent the undesired event. Should the undesired event occur, we need to have remediation methods available to recover from it.

**Wax Risks:** The risks are deposition, blockage and gelling.

**Prevention:** For every proposed system (e.g., dry trees, subsea trees, single flowline or dual flowlines), different prevention methods are available. For example, a subsea system with dual flowlines can employ hot-oiling or round-trip pigging for wax maintenance, while a single-flowline system could not hot-oil and would require subsea launchers for a pigging strategy. Therefore, the prevention strategy goes hand in hand with the production system.

**Undesirable Event:** For wax, these events are (a) deposits causing reduced production, (b) deposits causing blocked production and (c) gelling causing blocked production.

**Remediation Methods:** These are any techniques used to restore the production system to full functionality. They are thought of as extraordinary measures beyond prevention/ maintenance activities.

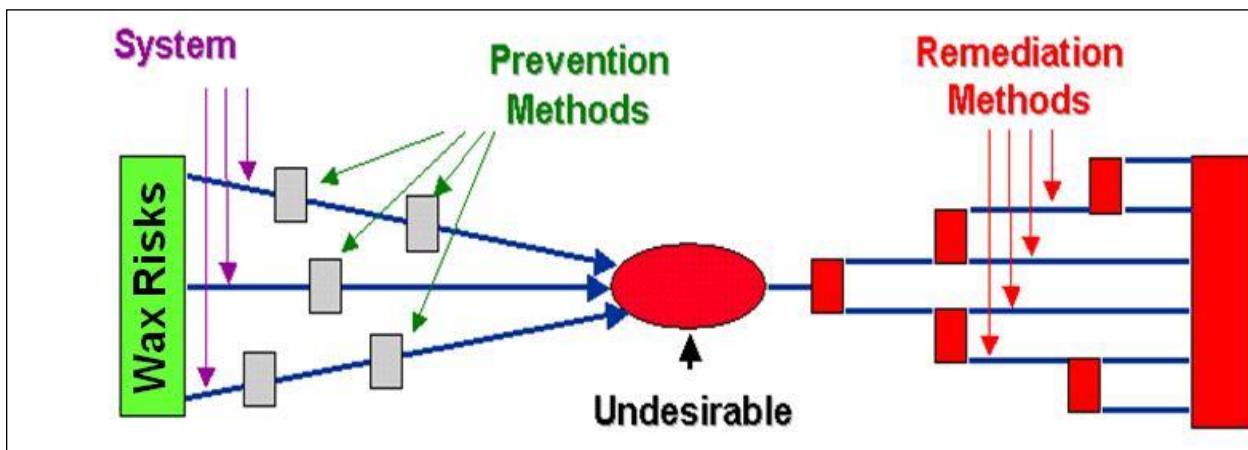


Figure 2.3: HEMP Analogy to FA Risk Assessment.

### 2.4 Wax Management Strategies

To develop a strategy properly, there are many factors that need to be understood: fluid properties, production system architecture (both subsea and topsides), production profiles and associated P and T conditions. Both steady-state production conditions as well as transient conditions/events must be understood in order to determine the feasibility and operability requirements of the strategy components.

#### 2.4.1 Example Strategy

Figure 2.4 provides an example strategy for wax management [2] provided by Bill Davidson of Shell Expro. There are 3 main inputs to the process: fluid properties, system architecture and production profiles. Note that these inputs are assumed to have some flexibility; if the cost-

benefit analysis appears to be suboptimal, these bases can be varied to improve the results. With these inputs, various wax management strategies are evaluated

- **Fluid Properties:** These are discussed in more detail in § 4.1-4.3.
- **System Architecture:** There is a direct interplay between FA strategies and system architecture, with architecture dictating available strategies, and strategies in many cases forcing changes to architecture. Critical components include single or dual flowlines, insulation, chemical injection systems, pigging systems, piping configuration that permits or prevents mechanical interventions.
- **Production Conditions:** Wax is controlled largely by temperature and only secondarily by pressure. Temperature is controlled by insulation, line length, and liquid/gas flow rates. Since rates vary significantly over the life of field, it is necessary to evaluate all life stages and weigh the risks accordingly.

From these inputs, the flowchart describes a process to develop a strategy. The first risk investigated is gelling. A series of barriers to successful restart are evaluated: cooldown time to avoid gelling, available pressure to break gel and finally flushing the system with a non-gelling fluid. Another option not shown is the use of a pour point depressant, which might reduce the gel point below ambient temperature. If the answer to all of these options is no, then the only options are to change to the system architecture or to live with unmitigated risks.

The second risk investigated is deposition. A combination of insulation, pigging, chemicals and hot flushing (oil or possibly water) are evaluated to determine feasibility and costs. These results are fed into a cost benefit analysis to determine life-cycle costs. Some optimization may be possible by changing the design basis re: architecture and turndown. From this process, a wax management strategy is derived.

Finally, the wax strategy must be reconciled with the management strategies for other Flow Assurance problems such as hydrates, asphaltenes and corrosion.

There are numerous variations to the flowchart in Figure 2.4. For example, rather than to develop a detailed strategy for one FA risk (wax) for one system architecture, a series of systems could be proposed from the outset. These systems could be screened at a high level against all flow assurance risks to identify obvious showstoppers before the detailed strategy is developed for individual FAS risks. Another possibility is to put novel technology on the table alongside accepted methods such as chemicals and pigging. To make an objective assessment of novel technologies, their risks and costs must be known from the outset. This is the goal of the FARMS risk management approach, to identify step changes in system selection at a sufficiently early project phase to realize their value.

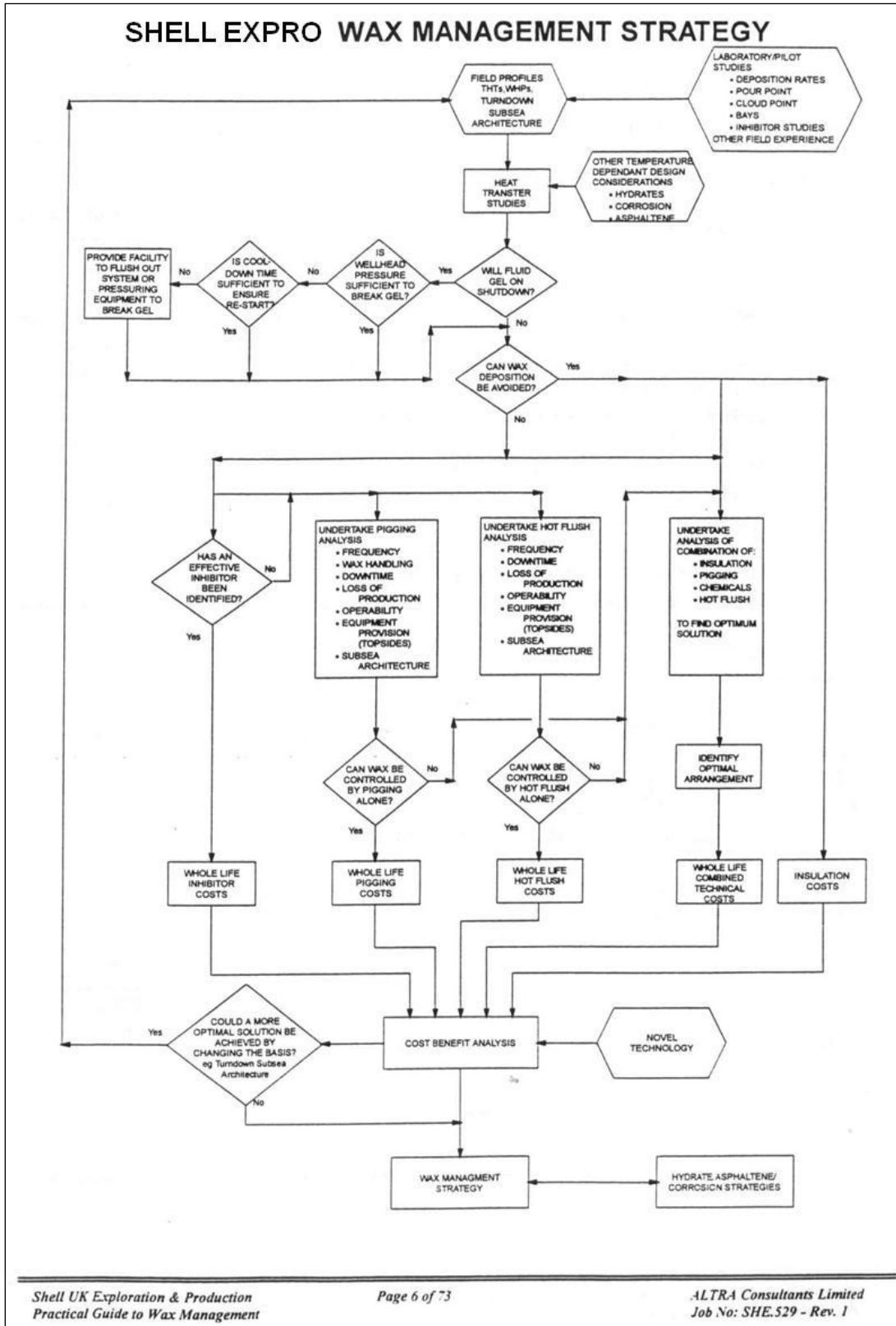


Figure 2.4: Example Wax Management Strategy from Shell Expro.

### 3. Work Process for Wax Management Design

The work described in this section corresponds to Figure 2.1, primarily in the FA analysis and strategy development sections. By the end of the fluid assessment phase, a set of basic wax related properties are available: pour point, cloud point and CWDT curve (§4.1-4.2).

#### 3.1 Define Systems

At the Concept Select phase, the Project Development Team evaluates a number of production concepts such as host type (TLP, FPSO, spar, etc.), dry trees vs. wet trees and tieback options. Flow Assurance concerns can play a role at this phase, but only at a feasibility/showstopper level. For example, a long tieback might be rejected as infeasible if there was no way to manage gel risks, e.g., the yield stress is too high to restart the line after a long shut-in.

Otherwise, Flow Assurance plays its biggest role in the System Select phase. First, the PDT defines a set of system options to be evaluated. This will include single or dual flowlines, insulation types and line topography. In addition, production forecasts must be provided, including rates for the life of field, water cuts and possible changes in fluid properties (e.g., reaching dew point pressure in a gas reservoir, producing an oil rim from a gas reservoir). Once these data are provided, the Flow Assurance specialists can evaluate the risks for the proposed systems.

#### 3.2 Define Risks

Since wax risks are largely governed by temperature, an initial set of thermal/hydraulic calculations must be done for each system option. These results are screened against the wax properties.

- For deposition, the criterion is lowest steady state temperature compared to CWDT. If the fluid remains above CWDT over the life of the field, there is no deposition risk.
- For gelling, the criterion is pour point temperature. If the pour point is below ambient, there is no gelling risk.

For systems that fail these screens, additional work is required.

##### 3.2.1 Assess Wax Deposition

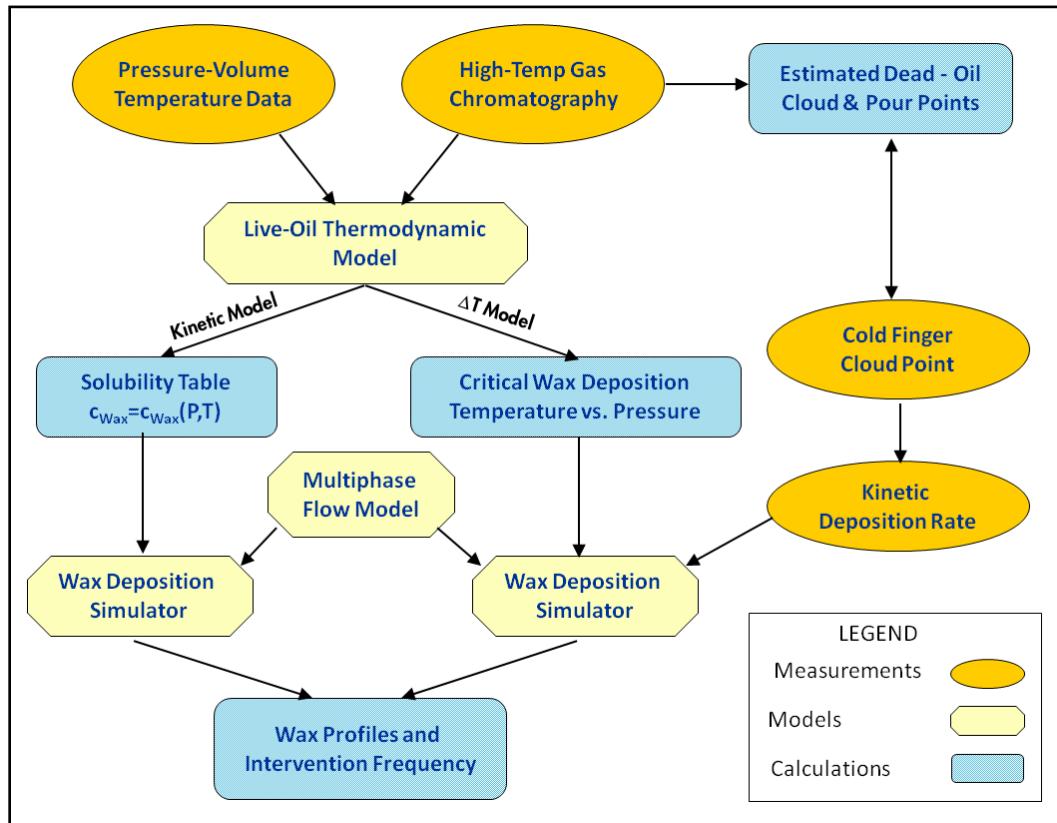
Figure 3.1 is a flowchart for estimating wax deposition. The PVT, HTGC, CWDT and cloud point work is all done in the fluid assessment phase. If the screen says deposition is a risk, then the following steps are taken:

Deposition rates are measured by one of the methods described in §4.3. The standard approach has been coldfinger deposition tests.

Data are interpreted and a rate equation is developed for use in a simulator. Shell deposition models have been implemented in UniSim using either the  $\Delta T$  power-law or a kinetic approach (§4.4).

A flow simulation model is developed (usually one that was used in the thermal/hydraulic screening) and deposition model parameters are input.

For various field life stages, deposition is simulated and maintenance options are evaluated. Most often, pigging intervals are estimated based on deposit volume (standard pig) or maximum thickness (bypass pig). If other maintenance options are considered, these are evaluated separately. For example, hot-oiling can be evaluated by using a mass-transfer based wax removal model using as inputs the wax deposit profile, deposit composition, and transient thermal flow calculations based on various hot-oiling flow/temperature scenarios (§5.2.3.3).



**Figure 3.1: Wax deposition work process.**

### 3.2.2 Assess Gel Risks

If the ambient temperature is above the pour point, then gelling risk must be assessed for shutdown conditions. To do this, gel strength must be measured (§4.5) and restart modeling must be performed. There are various levels of complexity to the measurements and the modeling (§4.6), depending on the level of risk. In the end, a strategy must be selected where the pressure to restart the gelled line must not exceed (i) the pipeline/flowline design pressure or (ii) the pressure capabilities of the well or pump.

## 3.3 Assess Management Strategies

Once the risks have been quantified for all of the systems considered, the PDT Flow Assurance engineer must incorporate these results into the system selection process by evaluating the degree of risk, mitigation options and recovery methods (as in Figure 2.2) should a restriction or blockage occur. This process is iterative (and, one hopes, convergent) as shown in Figure 2.1. Finally, as described in Figure 2.3, a strategy is developed which incorporates all Flow Assurance risks into a functional system.

## 4. Measurement and Modeling Tools

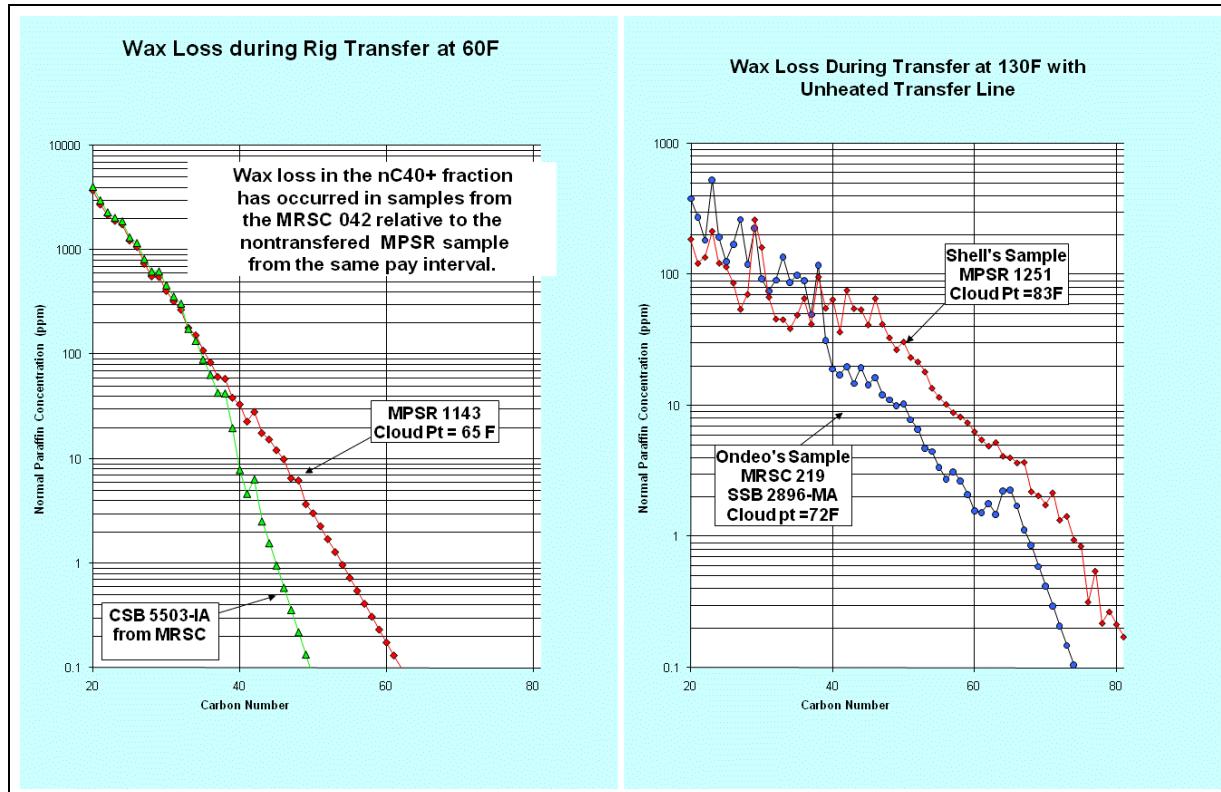
### 4.1 Fluid Property Measurements

Wax-related fluid properties can be altered by sample handling methods. Understanding the origin and transfer conditions of fluids is thus critical in assessing the quality of fluids for wax property determination. A review of the current methodology employed for sampling as outlined by FEAST (Fluid Evaluation and Sampling Technology) team is discussed. Once representative fluids are available, wax-related properties are determined from several in-house analytical measurements. These data are used as inputs and consistency checks to our thermodynamic and transportation models for wax deposition in flowlines and wells. A description of these measurements is provided along with the volume requirements. And finally, controls on wax-related fluid properties in both black oil and gas-condensate systems are discussed.

#### 4.1.1 FEAST Process

Sample handling procedures for the collection of high quality downhole and DST fluids are provided through FEAST (Fluid Evaluation and Sampling Technology) team. The purpose of the FEAST team is to provide technical support on pressure testing, fluid sampling and fluid evaluation of critical exploration and appraisal wells. It is the responsibility of the FEAST project lead (PL) to insure that the asset and area teams get the right support during the pressure testing and fluid sampling operations and that analytical programs are carried out according to Shell's best practices and HSE standards. The PL coordinates the involvement of subject matter experts from the extended FEAST network as needed including petrophysical engineers, geo-chemists, PVT experts, flow assurance specialists, and production engineers. Current Shell guidelines for sampling are available in EP2007-3186 [3]. Note that report EP2007-3186 supersedes EP2000-9021 [4], TIR BTC-3540 [5], EP92-0980 [6] and EP05-0758 [7] with regard to sampling procedures.

In downhole sampling, samples for wax analyses should be from DOT approved cylinders that are not transferred at well site (e.g. MPSRs). If only rig transferred cylinders are available, then standard restoration procedures of heating to 130F while rocking are required. In addition, heated line transfers are recommended. The current restoration temperature of 130F and the need for heated transfer lines were direct results of Shell's observation of wax lost from rig transferred samples due to low restoration temperatures and/or cold transfer lines (Figure 4.1). Changes in normal paraffin distribution and cloud point temperatures due to wax loss during rig transfer are shown in Figure 4.1. Note that documentation of field transfer conditions should always be provided by vendor.



**Figure 4.1: Wax loss due to improper rig transfer conditions.**

Surface samples, ideally, should be collected above the critical wax deposition temperature (CWDT). In cases where this is not possible, sample collection should occur at the highest temperature conditions available in order to minimize potential wax loss. Sampling should be close to mainstream fluid flow in order to avoid potential sinks of precipitated wax. In all cases, PT conditions at time of sampling and sampling location should be noted [8].

Restoration of live cylinders is required prior to standard flash for wax work [3]. Standard Shell procedures consist of equilibrating subsurface samples to reservoir temperature and pressure through the use of external heating jackets. During the heating, samples are continuously rocked for 5 days to ensure sample homogeneity. Note that sample restoration time can be reduced to 48 hours in gas-condensate systems where asphaltene stability is not an issue.

Flow Assurance procedures require that stock tank oil samples be heated to 140F and homogenized when subsampling for wax work. Current practice in Geochemistry for subsampling consists of sample agitation with no heating in order to minimize light hydrocarbon loss. Due to difference in sub-sampling procedures, flow assurance fluids (particularly condensates) may not be suitable for geochemical analyses and geochemical aliquots may exhibit wax loss.

#### 4.1.2 Analytical Tools

Standard analyses used to assess wax-related fluid properties are listed below (Table 4.1). A single-sourced fluid sample of 130 to 210cc is recommended for initial wax-related property determination. Deposition testing, requiring 300cc, is performed if potential flow conditions fall below critical wax deposition temperatures (CWDT). In the case of down hole samples, one MPSR cylinder is typically used for initial wax property testing and a second MPSR cylinder is reserved

for potential deposition testing. Note that API gravity and moisture content are used as quality checks on the received fluids. Descriptions of cloud point, pour point, HTGC, and HTSD analyses used by Shell are provided below. These techniques serve as inputs and control checks on our thermodynamic and deposition models.

**Table 4.1: Wax Analyses Used to Determine Wax-Related Fluid Properties**

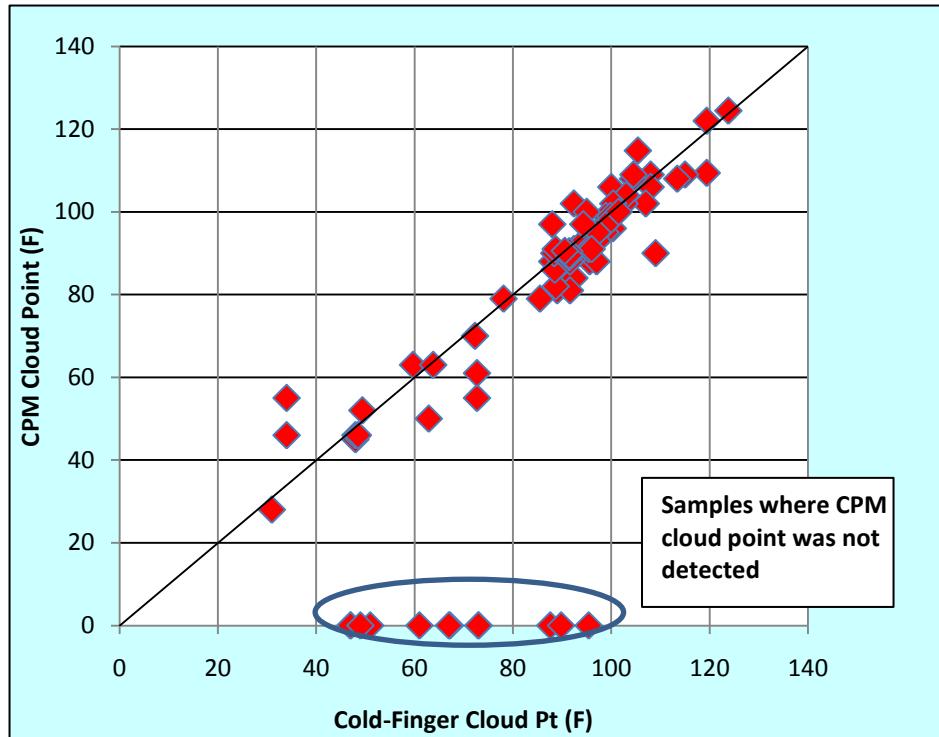
Analysis	Method	Volume (cc)	Recommended
API Gravity	ASTM D5002	3	X
% Moisture content	ASTM D4377	1	X
Wax Content	UOP-46	10	X
Wax Congealing Point	ASTM D938		
Cloud point temperature by Coldfinger	Shell	50	X
Cloud point temperature by CPM	AMS 259-1	1	X
Pour point temperature standard	ASTM D5853	100	X
Pour point temperature mini	mod ASTM D97	20	
HTGC - standard	Shell	5	
HTGC - extended	Shell	40	X
HTSD		1	x-on deposits
Deposition testing	Shell	300	if flow below CWDT
<b>Initial wax-related property assessment</b>		<b>210</b>	<b>complete</b>
		<b>130</b>	<b>substitute mini pour pt</b>

#### 4.1.2.1 Cloud Point

Cloud point is the temperature at which wax/paraffin particles first precipitate from solution. It also is referred to as the wax appearance temperature. Although, there are many different ways to measure the cloud point, the Shell preferred method is the coldfinger technique developed at WTC [9]. An advantage of this analysis is that it directly measured the temperature at which wax deposits begin to form on a cooled surface exposed to warm, flowing petroleum. The coldfinger apparatus is a small metal cylinder that is immersed in a well-mixed oil sample with bulk temperature initially above the cloud point. The finger and the oil can be maintained at independent temperatures. Deposits on the finger are identified visually on the coldfinger surfaces. In a “standard” test the finger remains in the oil for 2 hours. Extended testing from 24 to 72 hours has been run in select fluids which appear naturally inhibited with respect to wax deposition. Coldfinger cloud points correlate well with cloud points using cross-polar microscopy (CPM) (Figure 2.2).

Current recommendations are that both CPM and coldfinger be run to determine cloud point temperature. Though both techniques provide a cloud point temperature, the methodologies differ. CPM provides the temperature at which crystallization first occurs whereas coldfinger indicates the temperature at which a deposit forms. Numerous examples have been encoun-

tered where CPM was unable to detect wax crystallization, possibly due to contamination interference and/or low wax content, but deposits were seen in coldfinger analysis (Figure 4.2).



**Figure 4.2: Comparison of cloud point temperatures from coldfinger versus CPM analyses.**

Other techniques besides Coldfinger and CPM are used in the industry to determine cloud point temperature. ASTM D2500 can be used for semi-transparent crudes with cloud point less than 49C. Other methods include Differential Scanning Calorimeter (DSC) where cloud point is determined by an increase in heat flow, Fourier Transform Infrared Spectroscopy (FT-IR), viscometer where cloud point is determined by a change in the slope of the viscosity versus temperature curve, and light transmission techniques. The Shell coldfinger analysis was benchmarked against the majority of these techniques in a round-robin study funded by the Deepstar joint industry project for developing deepwater technology [10].

Note that cold point temperatures are also calculated from HTGC normal paraffin concentrations using Shell proprietary correlations as well as calculated from Shell's thermodynamic model.

#### 4.1.2.2 Pour Point

The gel point is the highest temperature at which a crude takes on solid properties, *i.e.* it does not flow under a shear force exerted by gravity. This is usually caused by wax precipitation and the formation of crystal networks. By convention, the pour point is the lowest multiple of 3°C or 5°F at which the oil still flows (therefore no more than 3°C above the gel point). Pour point is typically measured using ASTM techniques (D5853 or D97). ASTM D97 is an older oil-products pour-point protocol that requires heating to a prescribed temperature (60 °C) and cooling in a series of baths until the oil gels or solidifies. When sample volume is limited, a "mini" pour point can be run using 20 ml of sample. ASTM D5853 is designed specifically for crude oils and re-

cognizes the potentially strong effect of thermal history on the oil gelling temperature. Two separate heating and cooling protocols are used in order to see the effects of two substantially different thermal histories. The test results in a “minimum” and “maximum” pour point. The D97 pour point is usually close to or the same as the D5853 upper pour point. D97 pour point can also be estimated from HTGC data based on Shell proprietary correlations.

Most petroleum found in deepwater settings exhibit pour points less than the seabed temperature of 40°F (4°C), indicating that gelling should not be an issue during production and/or shut in conditions. There are surface environments where the ambient conditions can fall well below 40°F, such as the Arctic and the Caspian. There are also warm regions where the ambient falls below pour point, such as Gabon or Thailand. Deepwater regions where pour points are in excess of 40°F include shelf area of GoM, near deltaic environments such as Ram Powell-GoM, Angola, Nigeria, and the Asia Pacific. Note that even condensates can have pour points above 40°F, such as NAM G16 in the North Sea and Brecknock, Calliance and Torosa offshore Australia (40 - 70°F).

#### 4.1.2.3 High Temperature Gas Chromatography

Quantitative High Temperature Gas Chromatography (HTGC) is used to measure the concentrations of individual normal paraffins in ppm on a whole-oil stock tank basis [11]. This method yields absolute concentrations of normal paraffins above  $n\text{-C}_{20}$ . A standard analysis can typically quantify normal paraffin concentrations to approximately  $n\text{-C}_{60}$ . A “wax cut”, *i.e.* separation of a wax fraction at a temperature below cloud point, can be performed to extend the measurement to higher carbon numbers. The wax cut is a gravimetric method that determines the amount of solid precipitated at a given temperature. The solid precipitate, or “wax cut”, is analyzed by HTGC thus extending the range of the “standard” HTGC analysis. Cloud points and pour points can be estimated from HTGC data with proprietary correlations based on normal paraffin abundance [12]. Correlations have a 95% confidence limit of  $\pm 12\text{F}$  for cloud point and  $\pm 20\text{F}$  for pour point. Data are typically displayed in a semi log distribution plot of normal paraffins concentrations in the  $n\text{-C}_{20}$  to  $n\text{-C}_{80}$  range. Note that the HTGC data are critical input to Shell’s proprietary modeling programs for predicting wax deposition in live-oil systems (*e.g.* well bores and flow-lines).

#### 4.1.2.4 HTSD

High Temperature Simulated Distillation (HTSD) is a gas chromatographic (GC) technique which separates individual hydrocarbon components in the order of their boiling points, and is used to simulate the time-consuming laboratory-scale physical distillation procedure known as true boiling point (TBP) distillation. The separation is accomplished with a non-polar chromatography column using a gas chromatograph equipped with an oven and injector that can be temperature programmed. The result of HTSD analysis provides a quantitative percent mass yield as a function of boiling point of the hydrocarbon components of the sample.

HTSD is typically used in the analysis of deposits. A comparison of HTSD distributions between oils and deposits is done to determine the amounts of occluded oil and wax in the deposit.

### 4.1.3 Controls on Wax-Related Properties for Black Oil Systems

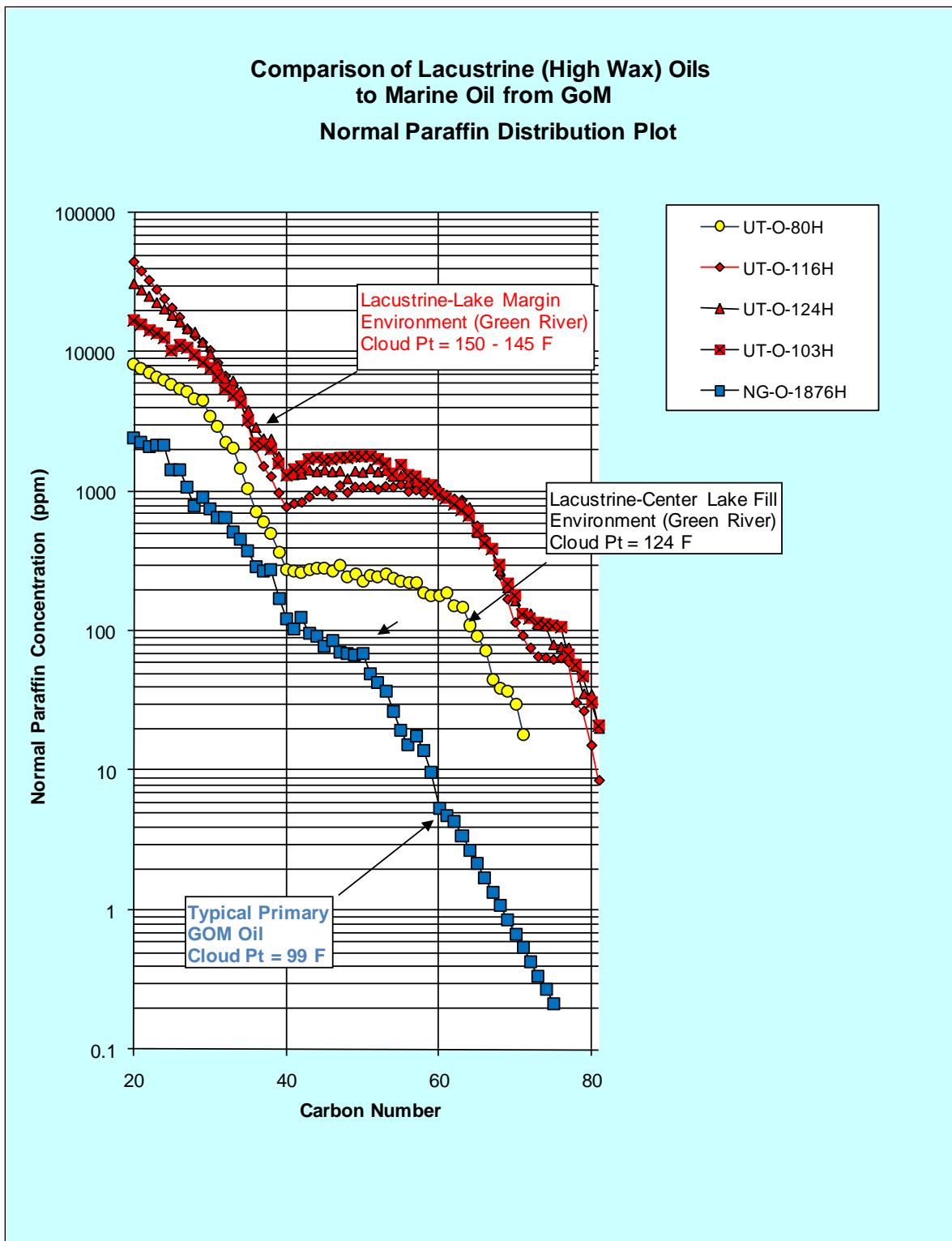
Numerous studies, both external [13] and internal [12; 14-15] have shown that wax-related fluid properties are primarily controlled by the concentration and distribution of high molecular weight

normal paraffins (HMWNPs). Variations seen in HMWNPs in black oil systems are attributed to the source of the oil and any secondary processes which could have altered the original oil composition.

Source refers to the source rock or kerogen composition from which the petroleum was expelled [16]. Two general types of kerogen are recognized in petroleum generating source rocks. Kerogen containing a significant contribution of terrestrial-derived material, such as found in deltaic and/or lacustrine environments, can exhibit high HMWNP content due to the incorporation of waxy plant remains and marine organic matter consisting of algal and planktonic remains thought to contain lower amounts of organic matter capable of producing HMWNPs. Comparison of normal paraffin distributions for lacustrine sourced fluids versus a typical marine oil from the GoM is provided in Figure 4.3. Note that even a single source rock can exhibit lateral variations in its organic assemblage and thus variations in HMWNPs due to facies changes at the time of deposition. For example, at a given point in time, deposition can occur in a near shore lagoon to nearby deltaic environment to deep water marine sedimentation. The same source unit can thus exhibit high wax properties close to the original coast to marine wax properties in the far offshore environment. In the case of the lacustrine Green River fluids, HMWNP is greater in the near shore sourced petroleum relative to the fluids derived from the center lake fill (Figure 4.3). In deepwater settings, organic composition of the source as well as geologic age is determined by geochemical analyses of the petroleum.

Hydrocarbon generation from a given source occurs over a period of time resulting in maturity variations. As a source rock matures, the expelled oil changes composition, increasing in GOR, API and decreasing in heavier components such as asphaltene content, sulfur, and metals [16]. Initial investigations into the effects of maturity on HMWNPs from a single source suggest little to no change in wax-related fluid properties occurs in black oil systems with maturity. If source maturity is not a significant factor in oil HMWNP content, then primary oils, (oils which have not been altered by secondary processes) exhibit HMWNP concentrations and thus wax-related fluid properties inherited from their source. Charge system analysis, including source rock mapping and hydrocarbon generation/migration evaluations coupled with analog studies from flow assurance are recommended in order to accurately assess primary wax-related fluid properties in untested regions.

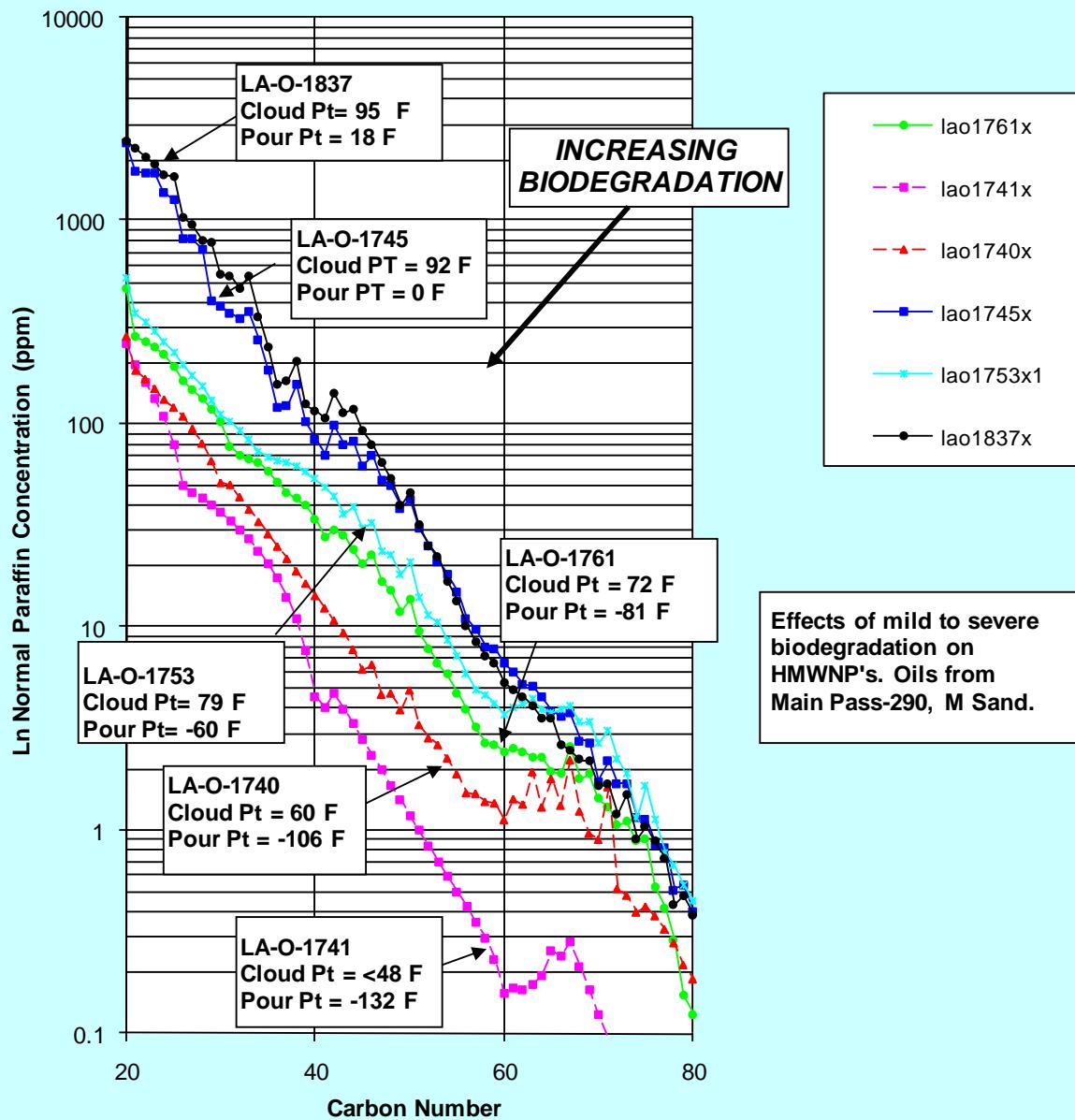
Secondary processes such as water washing, gas washing, biodegradation, hybridization, and potentially migration below CWDT can alter the composition of the primary oil. These processes can occur during migration and/or in the reservoir. The best documented of these processes with respect to effects on wax-related fluid properties is biodegradation [14]. Biodegradation, or the bacterial decomposition of petroleum, is a low-temperature phenomenon commonly seen in shallow reservoirs. During biodegradation, the lower molecular weight normal paraffins are most readily degraded. With increasing biodegradation, heavier normal paraffins are removed sequentially. Both cloud and pour point temperatures of black oils systematically decrease with increasing levels of biodegradation. During light-to-moderate levels of biodegradation, pour points decrease more dramatically than cloud points. Significant decreases in cloud points occur only after more extensive biodegradation. The effects of varying levels of biodegradation on HMWNPs and the associated cloud and pour points are shown in Figure 4.4. Biodegradation generally affects oil in relative shallow/cool reservoirs, while oil in deeper sands remains unaltered. In addition, gradients in HMWNP concentrations and therefore cloud point temperatures can develop in some reservoirs since biodegradation occurs only near the oil/water contact. Significant variations in critical wax-related fluid properties seen in a given field and/or reservoir are generally associated with varying levels of biodegradation [14].



**Figure 4.3: Comparison of lacustrine oil to GoM marine oil.**

## EFFECTS OF BIODEGRADATION ON HMWNP'S MAIN PASS 290 - CALIBRATION SET

**Normal Paraffin Distribution Plot**



**Figure 4.4: Effects of biodegradation on normal paraffin distributions.**

#### 4.1.4 Controls on Wax-Related Properties for Condensate Systems

The controls on wax-related properties in gas-condensate systems differ from those seen in black oils. Both source and secondary processes play a role, but wax-related properties of condensates are primarily controlled by pressure and temperature of the reservoir and the HMWNP composition of any associated oil phase [12]. In general, these variables control the solubility and partitioning of heavy normal paraffins in the gas phase under reservoir conditions. At low pressure and temperature conditions, significant concentrations of HMWNPs cannot thermodynamically partition into the gas phase, resulting in low wax-related fluid properties. With increasing pressure and temperatures, the potential exists for increasing levels of HMWNP to be incorporated into the gas-condensate. At high enough PT conditions, a given condensate can exhibit wax-related fluid properties similar to those seen oil systems. Changes in HMWNP content and cloud point temperature for GoM condensates from varying PT reservoirs are provided in Figure 4.5.

Based on an internal condensate calibration set from the GoM, a number of empirical correlations have been established for determining the standard cloud point of condensates based on either reservoir temperature and pressure alone, or reservoir temperature, pressure, and CGR [12]. For both cases, two trends are fit to the data. One trend is a fit to the data points for reservoirs that are at/near saturation (i.e. reservoir pressure is approximately equal to the dew point pressure). The other trend is a fit to all of the data points, including the undersaturated gas reservoirs. In general terms, values determined using the “saturated” trends are considered maximum values and have error bars of about 6-7°C, and values determined using the “all data” trends are considered more accurate but have significantly larger error bars (11-17°C). These errors are for 95% confidence limits. These correlations are used to estimate bounds on cloud points when no other data are available.

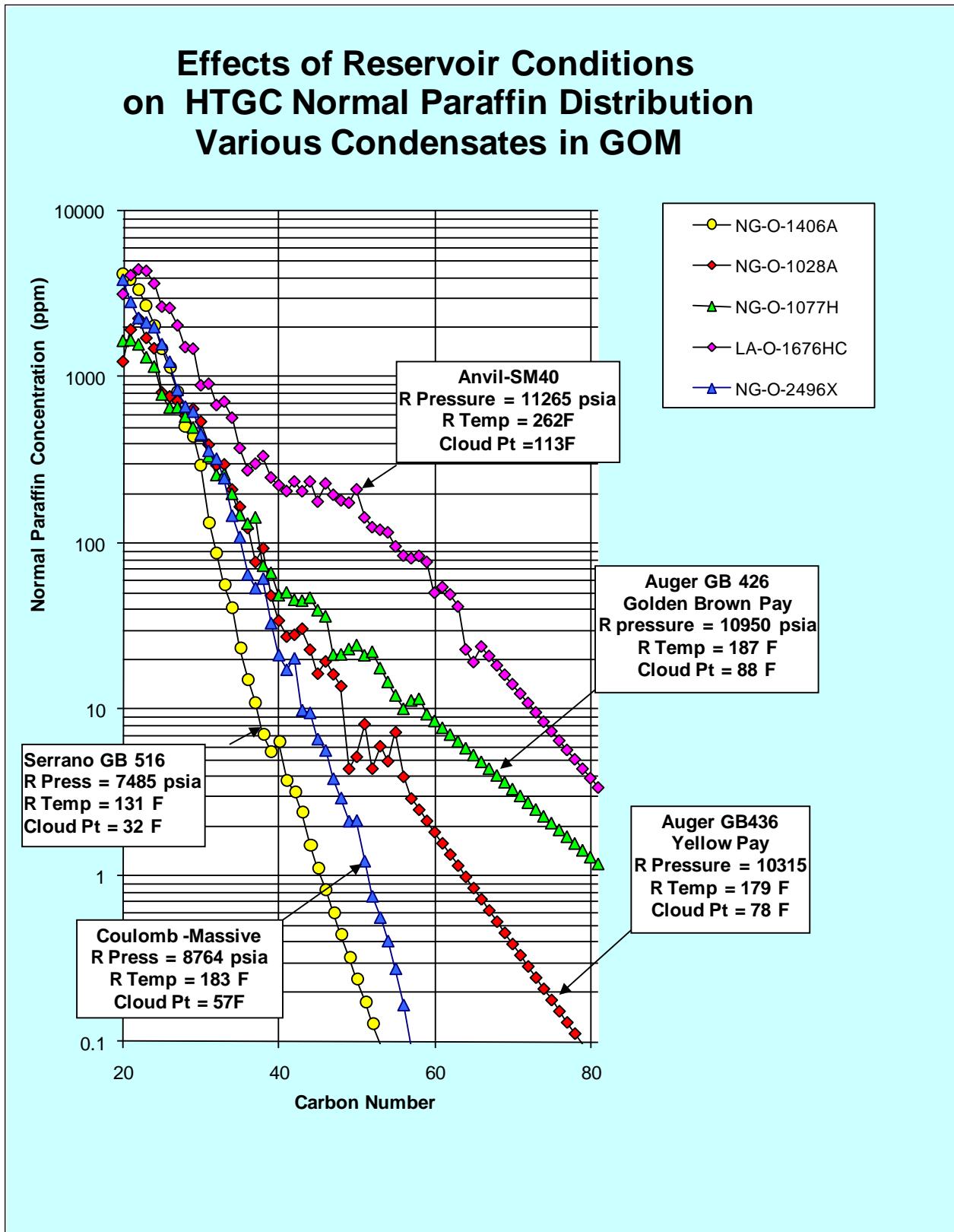


Figure 4.5: Effects of reservoir conditions on normal paraffin distributions.

## 4.2 Thermodynamic Modeling – Wax Precipitation

### 4.2.1 Inputs and QC

Wax precipitation modeling is an important component to assessing paraffin risks in production systems. The modeling process uses a number of experimental inputs and is then compared to data for quality control.

- Fluid properties - typically from a PVT report
  - C<sub>n+</sub> data (either for the reservoir fluid or the gas/liquid separated phases). C<sub>30+</sub> is preferred but usually not found in old PVT reports.
  - Constant composition expansion (CCE) experiments
  - Differential liberation (DL) - oils
  - Constant volume depletion (CVD) - gas condensates
  - Separator tests
  - Mud composition, properties and wt% if any
- Normal paraffin distributions (up to n-C99) from HTGC (§4.1.2.3)
- Cloud point (CP) measurements via CPM or coldfinger – used for model QC
- Wax cut HTGC data (§4.1.2.3) – used for model QC

The quality (QC – quality control) of the above data must be taken in consideration. First, the particulars of the sample need to be determined as discussed in §4.1.1. It is important to note items such as:

- Reservoir depth
- Reservoir temperature
- Reservoir pressure
- Region of world
- Field
- Sample ID numbers throughout process
- Point of sampling (bottom hole (BH) sample, drill stem tool (DST), well head (WH) sample, separator sample, etc.)
- Opening pressures (this important to compare with saturation pressures)
- Sample contamination levels (and whether there is compositional data for the contaminant or drilling fluid)
- Sample history (transportation, storage, sub-sampling, etc.)

The weight percent of each component is plotted in a bar graph. If contamination is present and not reported, unusual trends will be seen in the C<sub>15</sub>-C<sub>25</sub> range. When a number of samples from a region or field have been taken, it is good practice to assess the compositions of the different fluids against each other. A qualitative assessment can be made for the variability of the fluids in the region.

### 4.2.2 Wax Precipitation Predictions

The next step (after data quality control) is to input property data and HTGC data for the fluid to the in-house fluid modeling package, PVTTool (an Excel based package that runs off Shell developed macros). The user can implement an overall C<sub>n+</sub> reservoir fluid (rather than a separated gas and liquid phase) by entering the overall fluid for both the gas and liquid phases and setting the liquid mass fraction to 1.

PVTTool capabilities include:

- Tuning the SMIRK (Shell Modified Redlich-Kwong) equation of state (EOS) via specific gravity (SG), molecular weights (MW), and binary interaction parameters (BIP).
- Decontaminating sample with either a generic contaminant (e.g., a drilling mud) or a user defined contaminant
- Characterizing a fluid with its n-paraffin distribution
- Predicting CP and critical wax deposition temperatures (CWDT)
- Characterizing a fluid for the presence of asphaltenes (not needed for wax)
- Predicting saturation pressures, upper asphaltene onset line, and lower asphaltene onset line (not needed for wax)

**Table 4.2: Example of Tuning Parameters in PVTTool**

<b>I. Model parameters. To be specified and available for tuning.</b>				
Name of Parameter	Fitting indicator (y/n/s)	Value	Lower Bound	Upper Bound
$L / (L + V)$ mass ratio	s	0.9500	0.93	0.97
SG function: slope $SL$	s	0.0600	0.0001	0.2
SG function power, $m$	s	0.9500	0.0001	1.2
Cx+ atm. BP (K)	s	800.0000	700	850
Cx+ fraction $\alpha$	s	1.0000	0.9	2
Cx+ fraction $\beta$	s	2.0000	0	30
BIP function constant, a	s	9.00E-02	-0.3	0.3
BIP function $T_b$ (pseudo)-slope, b	s	0.00E+00	-0.0004	0.0005
BIP function T-slope, c	s	0.00E+00	-0.001	0.01
BIP function: $k(\text{methane, pseudo}) = a + b * T_b(\text{pseudo}) + c * T$				
SG function: $SG = SG(n\text{-hexane}) + SL * [(T_b(\text{pseudo}) - TBC6) / TBC6]^{**m}$				

The tuning process of the EOS is the key step to developing a reliable fluid model. The data for the CCE, CVD/DL and separator tests are entered into PVTTool. The SG, MW, and BIP are manipulated to find the “best fit” for the data. At this point of time, the Shell best fit is user defined (meaning the modeler is making the judgment on the fitted equation). Note that the EOS is easier to tune in temperature than pressure, and this is inherent to the EOS itself. This becomes an issue when it is important to extend the model over 20,000 psi (e.g., seen recently in the Gulf of Mexico Paleogene).

A number of additional options exist in PVTTool. The lumping of the heavy components can be controlled via an input. Further, the number of pseudocomponents can also be controlled, from 1 to 10.

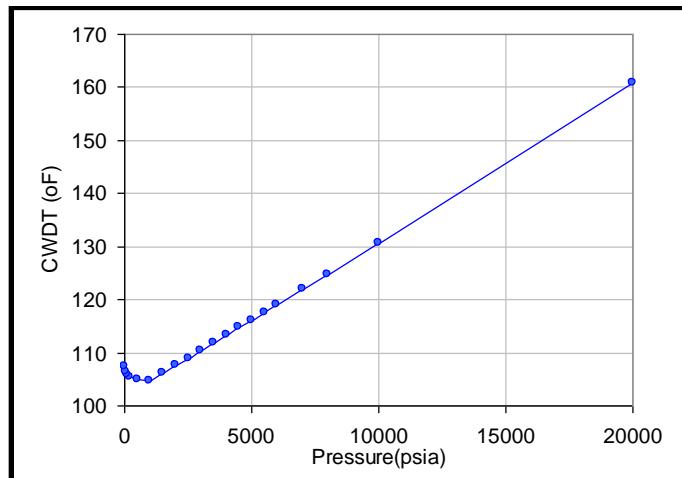
**Table 4.3: Example of Additional Options in PVTTool**

III. Options Grid Setup (advanced user options)		
Option Identifier	Description	Value
2	carbon #, lowest pseudo	6
3	carbon #, lowest in plus fraction	30
5	breakdown needed? (0=no, 1=yes)	1
6	type of break (1=fixed max MW, 2=adjusted)	2
7	max MW of Cx+	1500
8	# pseudos in Cx+ fractionation	10
9	# standard components & spacing	0
10	standard components source (0=dll, 1=user)	0
11	is gridding option included in fit (0=no, 1=yes)	0

After a satisfactory fluid model is created, and the HTGC data have been entered into PVTTool, the user characterizes the fluid for the presence of n-paraffin. The user is ready to perform CWDT and CP predictions.

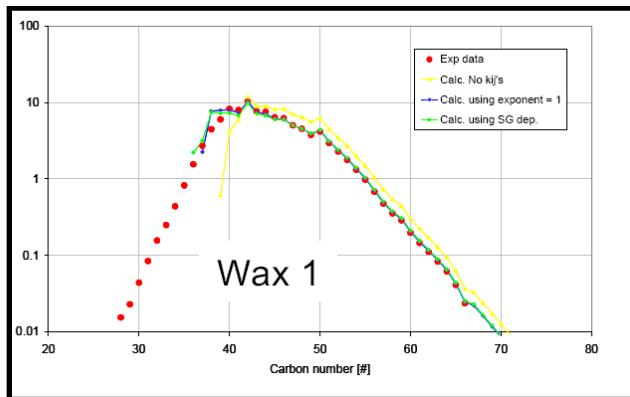
#### 4.2.3 Cloud Point/Critical Wax Deposition Temperature

The CP and CWDT are calculated via PVTTool. Wax precipitation model 41 is the recommended model for predicting CWDT and CP. Option 10, using the “wax-out-of-solution” basis, is also recommended. The model has been calibrated to lab and field data for the CP and CWDT. Other models, such as wax precipitation model 46, can be used but calibrations were not performed on this model. Later on, other wax precipitation model features will be described for the FATool. For the wax precipitation model 41, the CP and CWDT are defined as 0.04 and 0.2 wt% of wax precipitated, respectively.

**Figure 4.6: CWDT predicted results.**

#### 4.2.4 FATool (Flow Assurance Tool)

The FATool is a sister tool to the PVTTool. FATool uses the MW, SG, TB, and BIP parameters from PVTTool (PVTTool characterizes the fluid for wax, and FATool uses that characterization). FATool has many unique functions. The tool allows the user to perform flashes, assess compositional distributions of vapor, liquid, and solid wax phases (Option2 = 1) and make CWD calculations (Option2 = 10, Cond14 = wt% wax out of solutions). Routinely, the tool is used to “flash/blow down” a sample at a particular condition, and predict a composition that would be representative of a fluid at a particular point (T and P) in a process stream.



**Figure 4.7: Example of tuning wax precipitation model to experimental wax data.**

Another use is to assess the wax precipitated distribution from “dead oil” that has the gas flashed off. The incorporation of “wax cut” data into the fitting procedure may require the user to “tune” the BIP between the pseudo components and the n-paraffin characterized components. The tuning is only accomplished when the wax precipitation model is set to 40. The default BIP parameters between pseudo components and n-paraffin are overwritten by user-defined values.

$$\begin{aligned}
 k_{ij} &= 0 \\
 k_{ij} &= 1 - 2 \frac{(v_{c,i} v_{c,j})^{1/6}}{v_{c,i}^{2/6} + v_{c,j}^{2/6}} \\
 k_{ij} &= \Theta_0 + \Theta_1 T
 \end{aligned}$$

With

$$\begin{aligned}
 \Theta_0 &= -0.513820078 \ln(CN_j) + 0.792242415 + 1.010223 SG_j \\
 \Theta_1 &= -0.001622558 \ln(CN_j) - 0.002164931 - 0.003471048 SG_j
 \end{aligned}$$

**Figure 4.8: BIP for pseudo-wax.**

## 4.3 Wax Deposition Rate Measurements

### 4.3.1 Methods

There are several parameters that are recognized to control wax deposition: fluid composition, thermodynamics, heat transfer, mass transfer, shear and kinetics. The driving force for deposition is a liquid-phase concentration gradient (thermodynamics) set up by a temperature difference  $\Delta T$  between bulk fluid and the colder wall. That temperature difference is controlled by heat transfer, while the mass transfer and shear are generally controlled by the flow. The role of kinetics is not well understood but generally thought not to be rate limiting. (There are some fluids for which kinetics do play a role, as evidenced by suppressed cloud points and deposition rates.) Composition is matched by testing with the actual crude; thermodynamics are matched by using the same P/T conditions. The driving force can be matched by using an appropriate  $\Delta T$ . Therefore, the remaining controlling parameters are largely flow-related.

Table 4.4 compares the flow-related phenomena in pipelines, flow loops and some bench-scale devices. Flow loops have the best matching capabilities but require large fluid volumes (0.5 – 10 bbl) and more time and manpower to operate. Of the bench-scale devices, coldfingers do a modest job at best of mimicking the field flow. They have the advantages of low expense, small fluid volume (50 ml per test) and several tests can be run in parallel. With care, they can give reproducible and scalable results. Tube flow deposition (~500 ml) is usually laminar and it therefore used to measure the results of molecular diffusion only. All turbulent aspects of the prospect are modeled. The organic solids deposition cell (OSDC; 134 ml) provides a good compromise between fluid volume and turbulent pipe-flow conditions. Coldfingers, OSDC and flow loop tests are described in later sections.

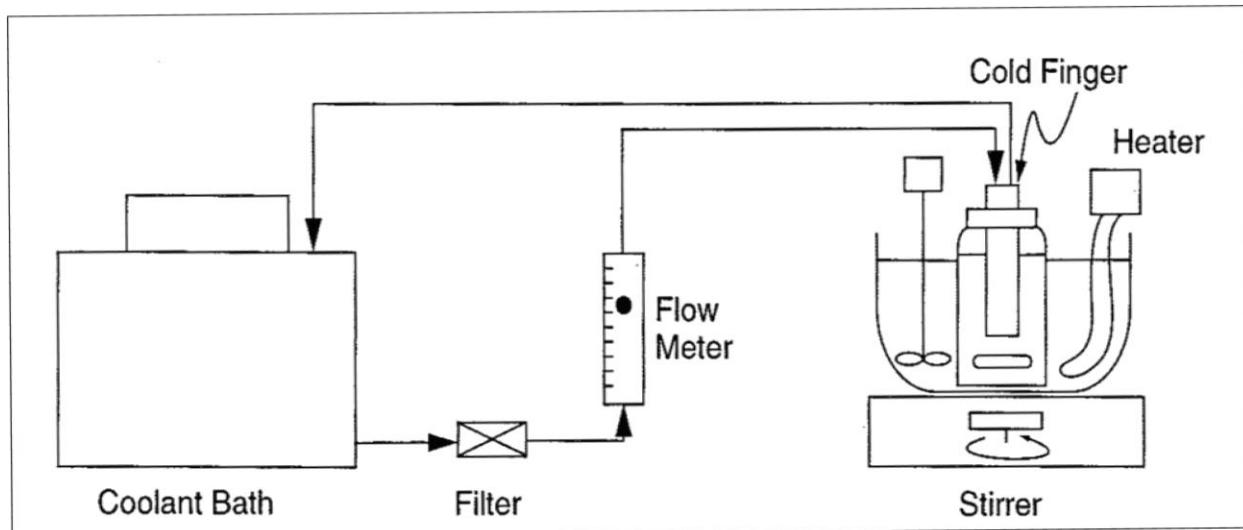
**Table 4.4: Comparison of Field Conditions to Capabilities of Deposition Devices**

Device	Parameter				
	Fluid Condition	Flow Regime	Flow State	Heat/Mass Transfer	Shear Stress
Pipeline	Live or STO	Single or multiphase	Turbulent	High	Moderate to high
Flow loop	Live or STO	Single or multiphase	Turbulent	High	Moderate to high
Coldfinger	STO	Single phase	Weakly turbulent	Low to moderate	Low
Tube Flow	STO	Single phase	Laminar	Diffusion limited	High
OSDC	Live or STO	Single phase	Turbulent	Moderate to high	Moderate to high

#### 4.3.2 Coldfinger

A coldfinger is a chilled metal cylinder which is submerged for a prescribed time in a stirred bottle of oil with controlled oil and surface temperatures. A coldfinger can be used to measure either the deposition onset temperature (called the "cloud point") or the deposition rate. This section is focused on deposition rate measurements only.

Figure 4.9 shows a schematic of a coldfinger test apparatus. The finger itself is a nominal 5/8" stainless steel tube with 0.611" OD and 0.510" ID, sealed at one end and extending approximately 3" through the bottle cap (approximately 2" below the oil free surface). An ethylene glycol solution is circulated through the coldfinger, being introduced through a 3/16" tube extended into the finger to a distance approximately 1/8" from the inside bottom surface and exiting from a similar tube 1/2" from the top. The glycol is kept at a constant temperature by circulator baths.

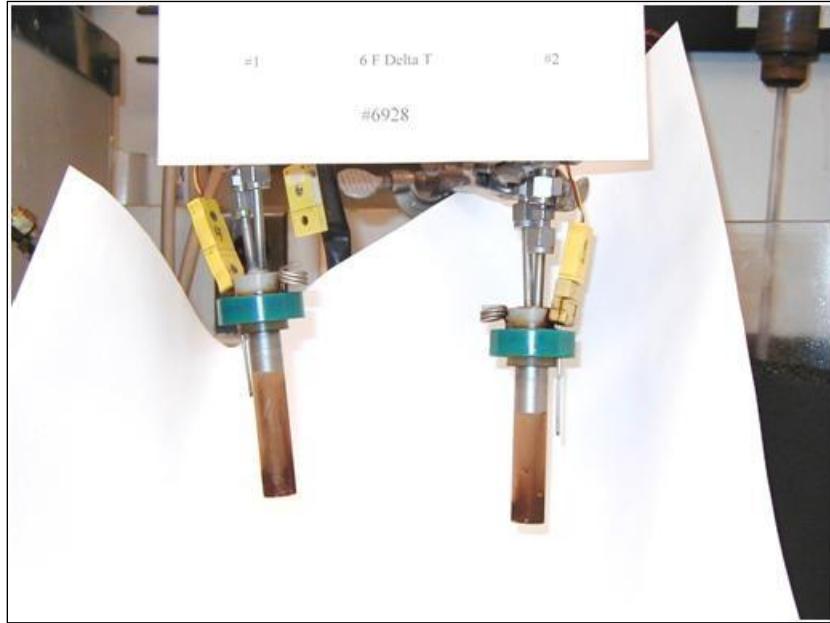


**Figure 4.9: Schematic of Coldfinger Test Apparatus.**

To conduct a test, 50 ml of sample fluid and a 7/8" or 1" stirrer bar are placed in a test flask, the coldfinger is inserted, and this assembly is placed in a water bath on a stirring plate set to a prescribed rate. The oil temperature is indirectly controlled by controlling the water bath temperature with an electric heater. Temperatures are measured using thermocouples inserted in the water bath, the sample fluid, and the coldfinger glycol inlet and outlet tubes. After the test runs for the prescribed time, the assembly is removed from the water bath and the test flask and fluid are removed to expose the coldfinger. Figure 4.10 is a photograph of duplicate coldfinger tests at  $\Delta T = 6^{\circ}\text{F}$ . The finger is then rinsed with cold methyl ethyl ketone (MEK) to remove any oil clinging to the deposit surface. The remaining deposit, containing wax and occluded oil, is then dissolved in hot toluene and analyzed. The analytical results are then interpreted as described in §4.3.3 to determine total mass and wax and oil fraction.

##### 4.3.2.1 Standard Test

The "standard" coldfinger deposition test is run with 50 ml of fluid in a small bottle (approximately 80 ml volume, 1.5" OD x 4" H). The oil is kept at the cloud-point temperature and the coldfinger surfaces are kept at 5, 10 and 15 °F below the cloud point. Duplicates are run, for a total of 6 simultaneous tests. Variations on the standard test include higher or lower oil temperatures, larger oil-surface  $\Delta T$ 's and larger (330 ml) sample bottles.



**Figure 4.10: Photograph of duplicate coldfinger deposits.**

#### 4.3.2.2 $\Delta T$ Model

These data are fit empirically to Shell's wax deposition model for use in flow simulations. Shell uses a deposition model based on  $\Delta T$ , i.e.

$$\gamma = A \Delta T^b ,$$

where  $\gamma$  is the deposition rate (mass/area/time) and  $A$  and  $b$  are constants determined from the experimental data. The exponent  $b$  indicates the relationship between  $\Delta T$  and the liquid-phase paraffin concentration difference (between the bulk and the wall), which drives deposition. The general range for the power-law exponent  $b$  has been empirically observed to be  $1 \leq b \leq 2$ ; this is in agreement with a physics-based theoretical model of deposition behavior based on mass transfer and kinetics. As described in §4.4, there are several models used in the industry based on a variety of physical phenomena. However, this  $\Delta T$  model is a simple, reliable way to check data quality and consistency.

#### 4.3.2.3 Previous Deposition Data

An examination of deposition results prior to mid-1996 showed large scatter in deposition rates [17]. Figure 4.11 shows data from a number of tests. The rates were "predicted" by computing a power-law least squares curve fit, then calculating the expected rate using the power law ( $A \Delta T^b$ ). In some cases, it was necessary to let the exponent take on values greater than 3 to achieve the best fit, a value which is well above that indicated from thermodynamic/mass transfer models (approximately  $1 < b < 2$ ). The average error of these data is 41%, far more than the expectations from the uncertainty analysis (10-11%). Two-thirds of the data are more than 20% from the prediction. The scatter was too large to validate any prospective models. Clearly, other factors are influencing the deposits which are not accounted for in the uncertainty analysis. As discussed above, these factors are expected to be the fluid mechanics inside and outside the

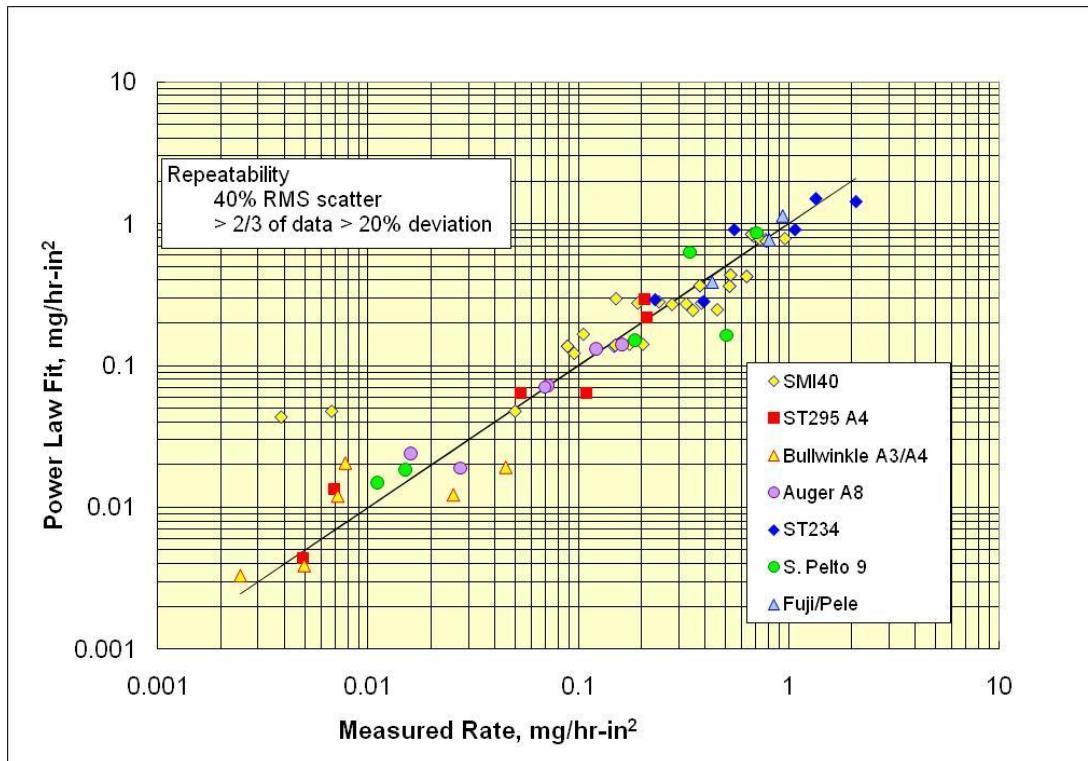
coldfinger, and its influence on heat and mass transfer. These factors were investigated, problem areas were identified and modifications were undertaken.

#### 4.3.2.4 Summary of Modifications

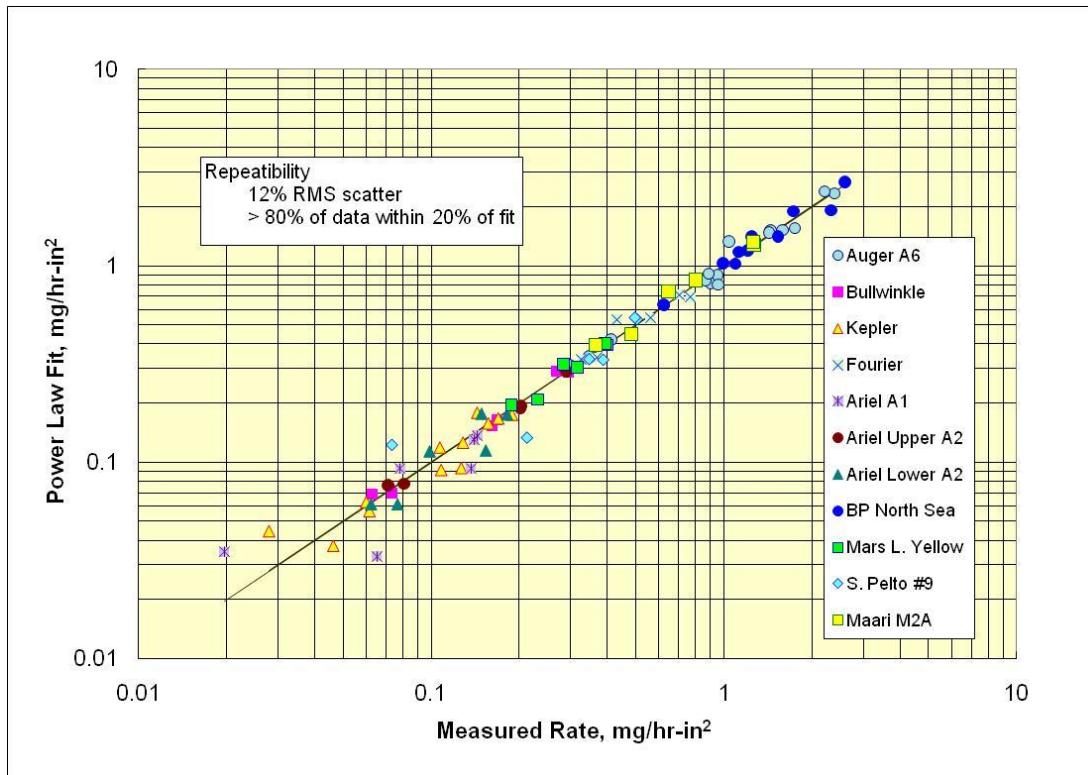
As a result of this investigation, a number changes were made [17]. First, the target coolant strength was set at 30% volume ethylene glycol in water, yielding viscosities in the 1-3 cS range for most test temperatures. A protocol was established to check the glycol strength (based on specific gravity) monthly to ensure continued uniformity of fluid properties. Further, coolant tubing and filters were increased in size to increase flow rates and  $h_i$ . This is important because it is desirable to minimize  $\Delta T_i$  and make  $\Delta T_o$  as close to  $T_{oil} - T_{cool}$  as possible. In addition, in-line flow meters were installed to enable quick flow rate checks and give accurate measurements for use in an  $h_i$  correlation. To improve temperature control on the water baths, PID controllers were installed which control both electrical heat and a cooling coil in each bath, allowing positive control in each direction. Probes were slightly roughened to improve deposit adhesion. Tachometers were installed in the stirrer tables to measure stirring rates directly. Centering rings were added to the water bath to hold the sample bottles and stabilizing rings were added to the stirrer bars, enabling higher stirring rates required to keep the oil turbulent.

#### 4.3.2.5 Deposition Results after Changes

After these modifications were made to the equipment and procedures, the subsequent test results were checked for scatter. Figure 4.12 shows the results. Unlike data in Figure 4.11, it was not necessary to let  $b$  take on values any greater than 1.7 to achieve the best fit, much more in line with expectations from thermodynamic/mass transfer models (approximately  $1 < b < 2$ ). The average scatter is 12%, close to the expected value from the uncertainty analysis (10-11%). 83% of the data are within 20% of the predicted value; the uncertainty analysis showed that 90% were expected within 18-20%. This indicates that most of the hidden sources of error have been eliminated.



**Figure 4.11: Deposition rate data before modifications.**



**Figure 4.12: Deposition rate data after modifications.**

### 4.3.3 Wax Deposit Interpretation

Each deposition test creates deposit samples, as described in §4.3.2 for coldfingers and in 4.3.4 and 4.3.5 for the OSDC and flow loops respectively. From coldfingers and OSDC, the deposit is dissolved in toluene; for flow loops, the deposit may also be a solid removed by pigging. These are analyzed and interpreted according to a standard Shell protocol to determine the oil and wax fraction in the deposits.

#### 4.3.3.1 Analytical

Topping: For the deposits in toluene solution, the first step is to evaporate the toluene (“top the sample”) and weigh the topped deposit. Topping is done under nitrogen flow at a temperature at or below 60 C until the weight changes by less than 1 mg in a topping interval (usually 2 hours). The topping process removes some light ends from the occluded oil, which will need to be accounted for in the interpretation.

High-Temperature Simulated Distillation: We use HTSD to obtain the mass fraction carbon number distributions of the basis oil and the topped deposit. Our preferred vendor in Houston is Triton Analytics.

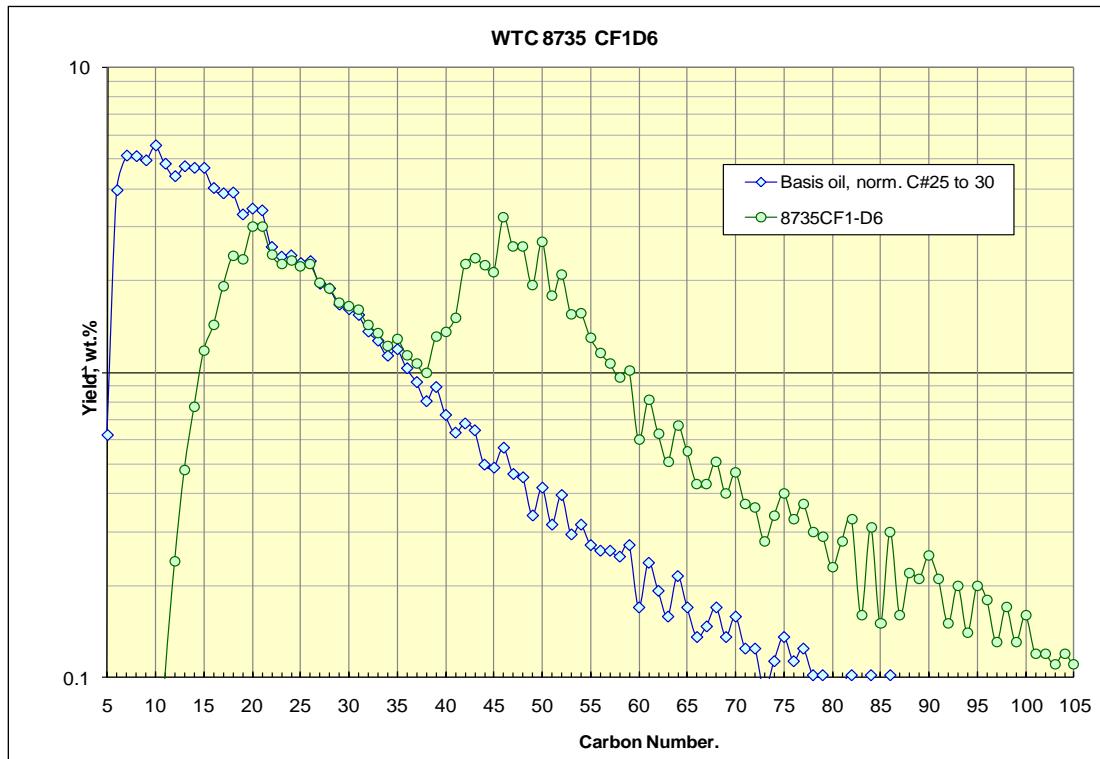
High-Temperature Gas Chromatography: Our usual practice is to have one of the six topped deposits analyzed for normal paraffin distribution so that we can do a mass balance and check for depletion.

#### 4.3.3.2 Deposit Interpretation

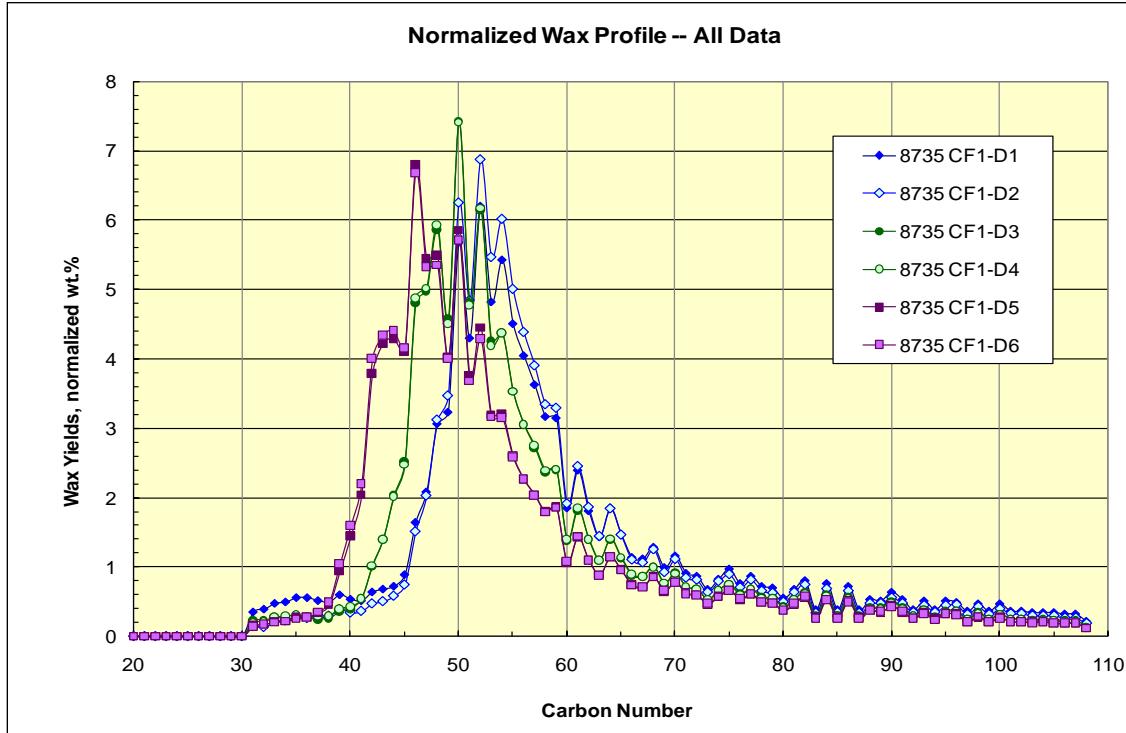
For each deposit the HTSD of the basis oil and deposit are compared. In principle, the oil occluded in the deposit should have the same distribution as the basis oil itself. Therefore, 3 steps are used to estimate oil content of the deposit.

- The oil HTSD is scaled to match the deposit HTSD in a user-selected CN range. The goal is to select a matching range that is above the topping range and below the deposit-containing range. The matching is usually chosen in the range of  $20 \leq \text{CN} \leq 30$ .
- The CN distribution of the deposit is “restored” in the low-CN range to replace the oil that was evaporated with the toluene.
- The scaled oil distribution is subtracted from the deposit distribution. The mass fractions of the oil and wax in the deposit are calculated, as are the masses.

Figure 4.13 shows an example matching of oil and deposit HTSD’s. The chosen matching CN range is 25 – 30. Figure 4.14 shows the CN distribution results of a set of 6 coldfinger tests. Repeatability in this case is excellent, with the duplicate tests (1 & 2, 3 & 4, 5 & 6) overlaying very well. Table 4.5 shows the numerical results. The wax-only masses repeat to within  $\pm 2.6$  mg; the whole deposit masses repeat to within  $\pm 4.3$  mg. The % wax results are not as repeatable for deposits 1 and 2, varying from 20 to 36 %, but agree well for the other pairs. This is typical when measuring deposition rates; the greatest variation is often seen in % wax in the deposit. In addition, low-shear deposits (e.g., coldfingers) usually have lower wax contents than pipe flow. Therefore, it is sometimes better to use wax-only results for determining rate coefficients and assume oil content for the deposits. This is especially useful if (a) the CF deposits are very oily and (b) there is any field data indicating higher wax contents.



**Figure 4.13: Example HTSD of oil and deposit.**



**Figure 4.14: Example Deposit HTSDs by Subtraction.**

**Table 4.5: Example Wax/Oil Results from HTSD Subtraction**

Test	SAMPLE	Volatile loss of topped deposit	Topped Deposit Mass		Wax, topped deposit basis	Wax, Whole deposit basis	Wax mass	Total Deposit mass, volatiles restored	HTSD Recovery
		% wt	g	mg	% wt	% wt	mg	mg	% wt
1	8735 CF1D1	54.7	0.0272	27.2	55.7	36.0	15.2	42.1	92.2
2	8735 CF1D2	69.1	0.0288	28.8	34.2	20.2	9.9	48.7	99.0
3	8735 CF1D3	58.1	0.0679	67.9	45.6	28.9	30.9	107.3	96.4
4	8735 CF1D4	64.2	0.0601	60.1	42.9	26.1	25.8	98.8	99.0
5	8735 CF1D5	57.1	0.1229	122.9	42.5	27.0	52.2	193.1	97.9
6	8735 CF1D6	53.8	0.1276	127.6	41.1	26.8	52.5	196.2	98.6

**Table 4.6: Example Wax Deposition Rates**

Coldfinger/HTSD Results						
Test	T <sub>cool</sub> (F)	T <sub>oil</sub> (F)	H (in)	Wax (g)	Tot Dep (g)	Oil (g)
1	97.7	104.3	1.623	0.0152	0.0421	0.0270
2	97.7	104.4	1.684	0.0099	0.0487	0.0389
3	92.0	104.1	1.872	0.0309	0.1073	0.0763
4	91.8	103.8	1.766	0.0258	0.0988	0.0730
5	85.6	104.9	1.808	0.0522	0.1931	0.1409
6	85.9	104.3	1.789	0.0525	0.1962	0.1437

Deposition Rates						Depletion Factor
Area	Est. T <sub>wall</sub>	ΔT	Wax Only	Wax + Oil		
Test	in <sup>2</sup>	F	F	mg/in <sup>2</sup> /hr	mg/in <sup>2</sup> /hr	
1	3.12	98.5	5.8	0.46	1.27	1.5
2	3.23	98.5	5.9	0.29	1.41	1.5
3	3.59	93.6	10.5	0.81	2.80	1.5
4	3.39	93.4	10.4	0.71	2.73	1.5
5	3.47	88.4	16.5	1.41	5.22	1.5
6	3.43	88.6	15.7	1.43	5.36	1.5

#### 4.3.3.3 Rate Plots

The next step is to use the deposit masses, calculate the mass fluxes and plot versus  $\Delta T$ . To obtain mass fluxes (mass/time/area), the masses are divided by coldfinger surface area and deposition test time. Examples are shown in Table 4.6. Note that the  $\Delta T$  used is not  $T_{oil} - T_{cool}$ , but is instead less by about 15%. This is to account for the fact that there is some thermal resistance inside the coldfinger, making the finger surface slightly warmer than the coolant itself. For simplicity, previous work has shown that we can use  $\Delta T = 5/6 (T_{oil} - T_{cool})$ . More precise estimates of the temperature distributions can be made using heat transfer correlations for the inside and outside fluids, where  $Nu$  is Nusselt number,  $Pr$  and Prandtl number and  $Re$  is Reynolds number [17].

$$Nu_{cool} = 2.89 (Re_{cool} Pr_{cool})^{1/3}$$

$$Nu_{oil} = 0.103 Re_{oil}^{0.61} Pr_{oil}^{1/3}$$

Using the calculated  $\Delta T$ s and mass fluxes, the rates can be plotted as shown in Figure 4.15.

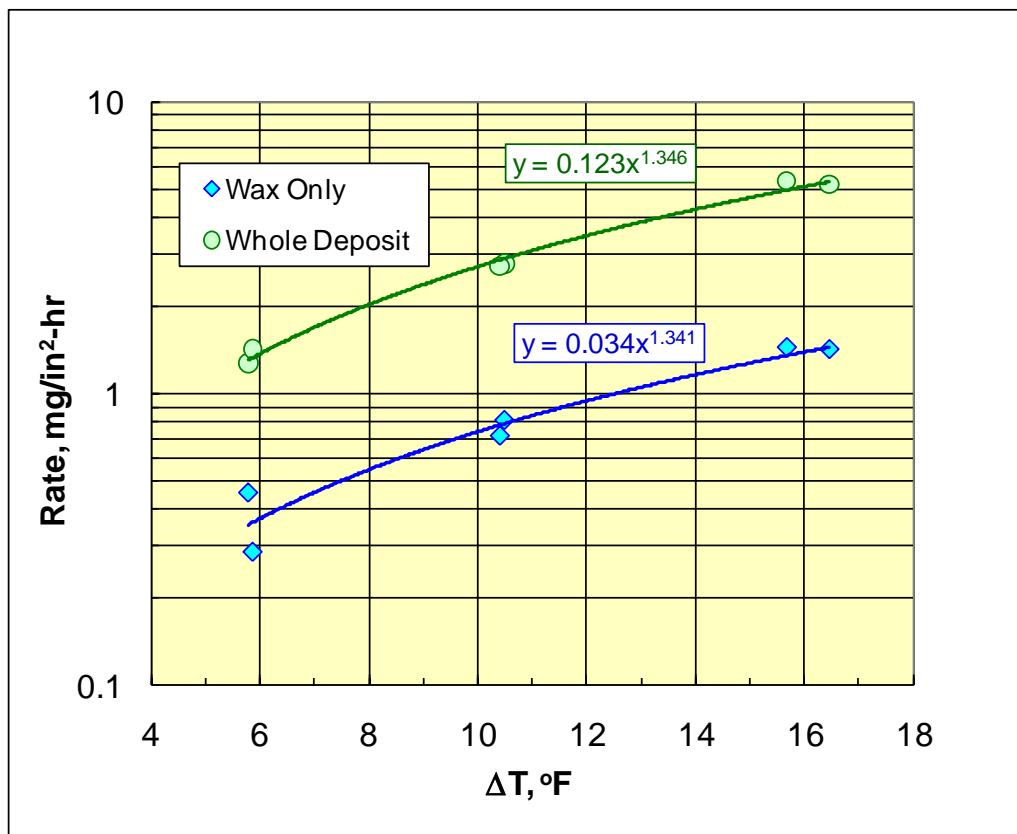


Figure 4.15: Example wax deposition rates.

#### 4.3.3.4 Coldfinger Depletion Correction

During the course of a test, the deposition rate changes due to changes in coldfinger surface temperature (insulation effects of the wax layer) and depletion (because the wax concentration in the bulk decreases as the deposit grows). Therefore, the *average* deposition rate can be lower than the *initial* deposition rate; however, we need the *initial* rate for input to the model. A simple model is proposed to correct the average deposition rate for depletion. (A separate correction is used to adjust the  $\Delta T$  for insulation effects; §4.3.3.3.) This is illustrated in Figure 4.15.

#### Definitions

- t length of test
- m mass of normal paraffins in the deposit at time t
- $m_{\max}$  mass of depositable normal paraffins
- r deposit fraction, i.e., the ratio of normal paraffin deposit mass at test time t to maximum mass;  $r = m/m_{\max}$ . This is also the depletion fraction.
- $\tau$  deposition time constant that arises in the model
- f depletion correction factor, = rate @  $t=0$  divided by the average rate.

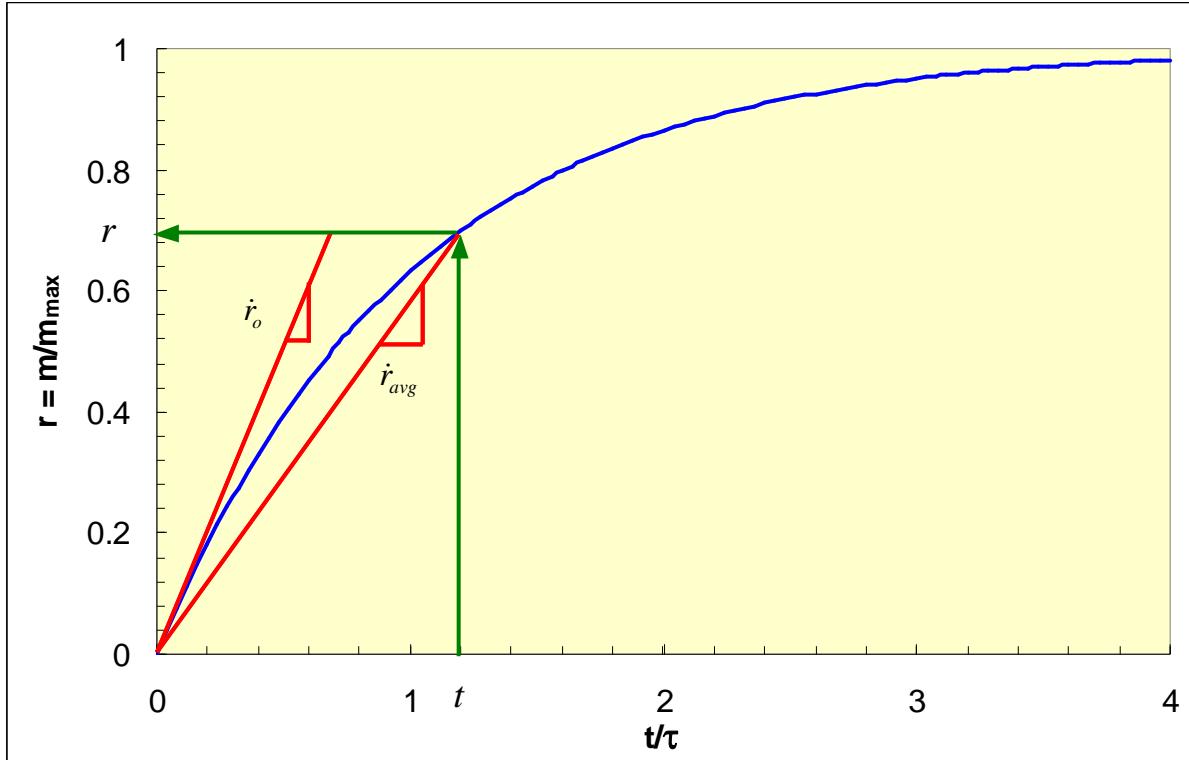


Figure 4.16: Solution of simplified rate equation.

#### Assumptions

Wax insulation is neglected; this effect is accounted for by correcting  $\Delta T$ .

Bulk crystallization/redissolution is neglected. If there is a large amount of wax precipitate in the bulk oil (*i.e.*, the oil is well below cloud point), then this precipitate could potentially redissolve when the wax solute was depleted. This would replenish the wax in solution and prevent depletion effects. In this event, a depletion correction factor would be conservative.

The deposition process is gradient driven, and this gradient is proportional to the *undeposited wax fraction*, i.e.,  $1-r$ .

### Rate Equation

On this basis, a simple equation can be derived and solved:

$$\dot{r} = k (1-r) \Rightarrow \ln (1-r) = -k t + C$$

Initial condition :  $r = 0$  when  $t = 0 \Rightarrow C = 0$

$$\text{Define } k = \frac{1}{\tau}$$

Then  $r = 1 - \exp(-t/\tau)$  and

$$t/\tau = -\ln(1-r)$$

### Depletion Correction Factor

To find the depletion correction factor  $f$ , we need to calculate the rate at time = 0 and the average rate.

Initial rate (set  $t = 0$ ):

$$\dot{r} = -\frac{1}{\tau} \exp(-t/\tau)$$

$$\dot{r}_o = -\frac{1}{\tau}$$

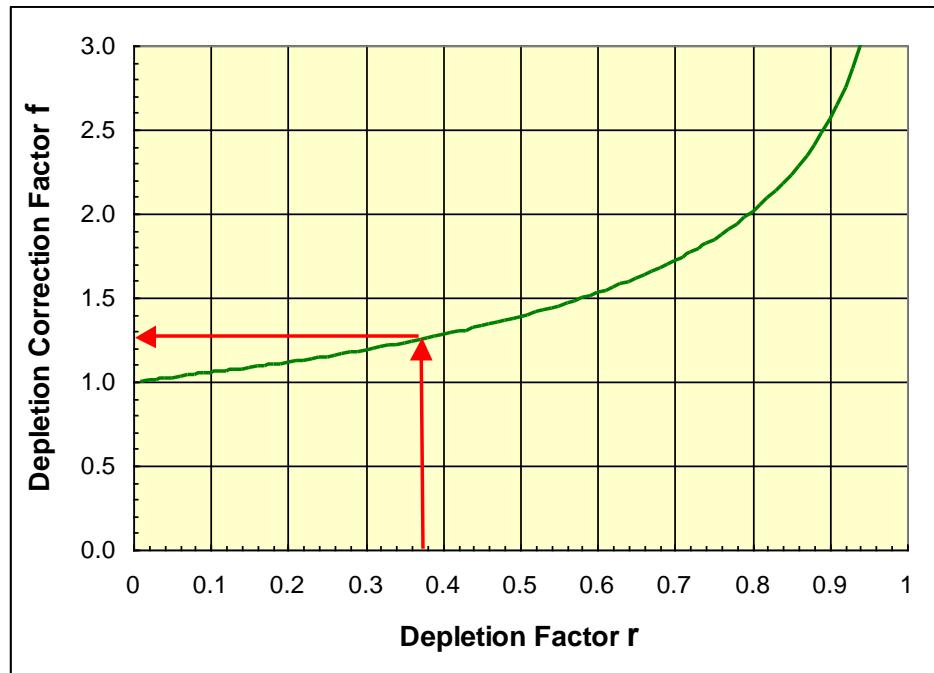
Average rate:

$$\bar{r} = \frac{r}{t}$$

$$\text{Then } f = \frac{\dot{r}_o}{\bar{r}} = \frac{t}{r \tau} = \frac{-\ln(1-r)}{r}$$

The asymptotic behavior is as expected: as  $r$  approaches zero,  $f$  approaches 1. Thus an undepleted system needs no depletion correction. (As  $r$  approaches unity,  $f$  approaches infinity. This indicates that tests that run too long produce highly uncertain results that cannot be corrected properly.)

The results are shown in Figure 4.16-17. Although the correction is very large for extremely depleted systems, note that  $f \leq 2$  for  $r \leq 0.8$ . In other words, even in a test where 80% of wax is deposited, the correction factor is only 2.



**Figure 4.17: Depletion correction factor.**

#### Estimation of Depletion Fraction

The depletion factor  $r$  can be difficult to measure or estimate. The ratio must be based on solids, not the whole deposit. HTSD is one choice to estimate  $r$ . However, many in-house examples show that HTSD reveals *almost no depletion*; this is because deposition preferentially concentrates normal paraffins over other components, but normals are only a small fraction of the whole. Therefore the normals are depleted while the other components are not. Comparing the deposit and oil HTSD chromatograms at high carbon numbers shows this. Further, it is generally accepted (yet to be proven) that normals drive the deposition process while other compounds are more passive. So it makes sense to focus on the normals.

In the past 2-3 years, we have usually analyzed one wax deposit by HTGC in order to do a mass balance on the normals. To analyze all 6 is cost-prohibitive, but we can use one as a general indicator. We recommend using this depletion mass balance to estimate  $r$  and therefore  $f$ .

#### Examples

Figure 4.18 shows the normal paraffin distribution for a highly depleted sample and its parent oil. Figure 4.19 shows the depletion by carbon number. Below  $nC_{42}$ , the depletion factor drops dramatically; very little of those components deposit because they remain in solution. Therefore, when averaging over a range of carbon numbers, we must be careful not to start too low. For this deposit, I chose  $nC_{42}$  and  $nC_{45}$  as the starting points. The results were  $r = 0.72$  and  $r = 0.84$  respectively. The corresponding depletion correction factors are 1.77 and 2.18. Obviously, this test is too depleted for accurate estimates.

Figure 4.20 shows the normal paraffin mass distribution for an Abalone sample and its parent oil. Figure 4.21 shows the depletion by carbon number. The deposit peaks at  $nC_{59}$  and is still on the plateau at  $nC_{57}$ . The respective depletion fractions are  $r = 0.37$  and  $0.33$ . The corresponding correction factors are  $f = 1.25$  and  $1.21$ .

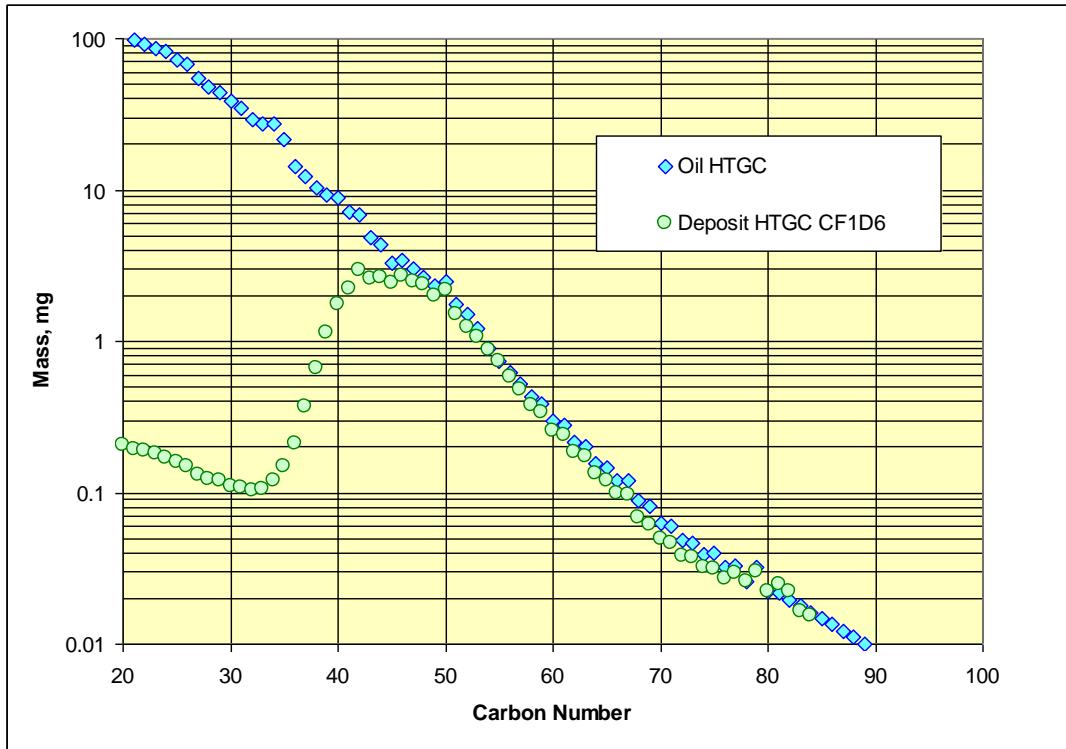


Figure 4.18: Example deposit mass balance.

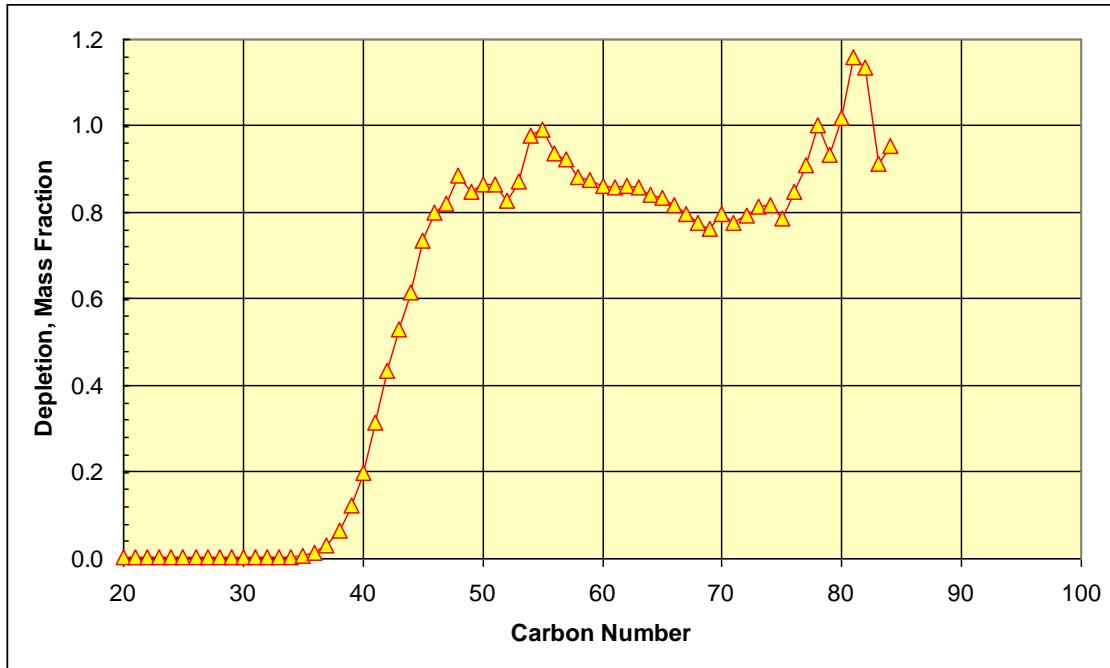
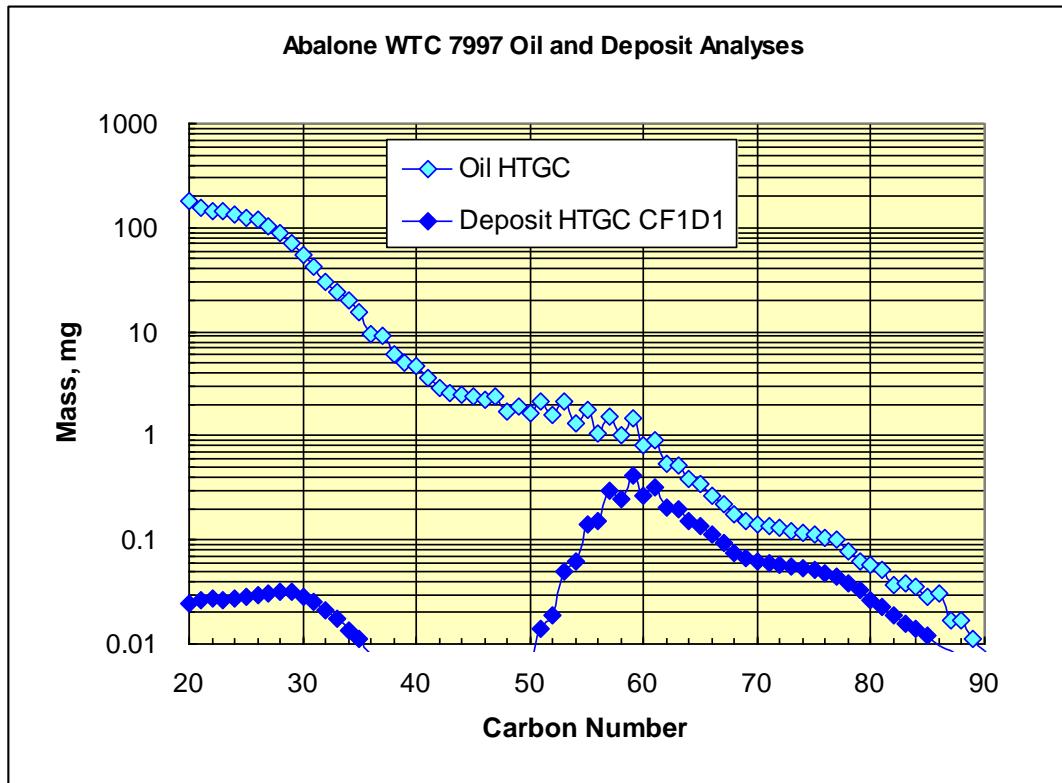
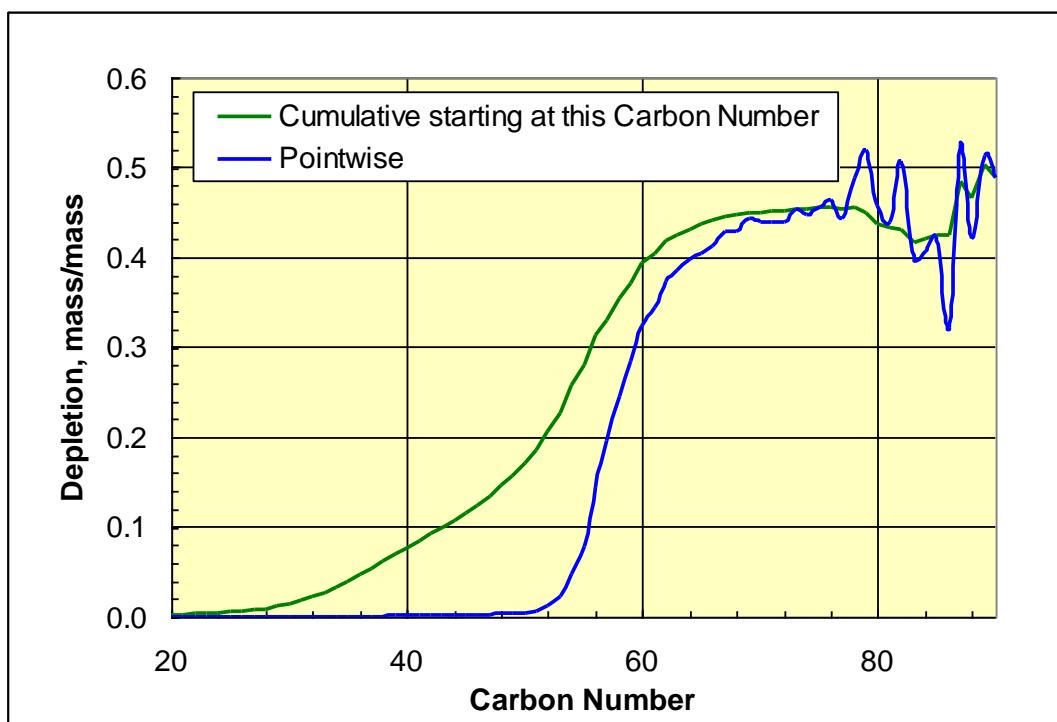


Figure 4.19: Example normals depletion by carbon number.



**Figure 4.20: Abalone deposit mass balance.**



**Figure 4.21: Abalone normals depletion by carbon number.**

#### 4.3.3.5 Scaling for Concentration Gradient and Viscosity

Deposition tests are usually run at a single oil temperature to determine the scaling with  $\Delta T$ . If more tests were run, the change of rate with  $T_{oil}$  could also be determined. In lieu of a very large test matrix, basic physical principles can be used to extrapolate to lower temperatures. As will be discussed in §4.4, the deposition mass flux is expected to scale as molecular diffusivity  $\mathcal{D}$  multiplied by the concentration gradient  $dC/dT$ . Diffusivity  $\mathcal{D}$  varies inversely with viscosity  $\mu$ , so a scaling factor can be constructed that is  $1/\mu dC/dT$ . Figure 4.22 shows an example scaling factor. Concentration gradient is calculated from the thermodynamic model; viscosity is measured or estimated from correlations. The factor has been normalized to equal 1 at the test temperature of 104 F.

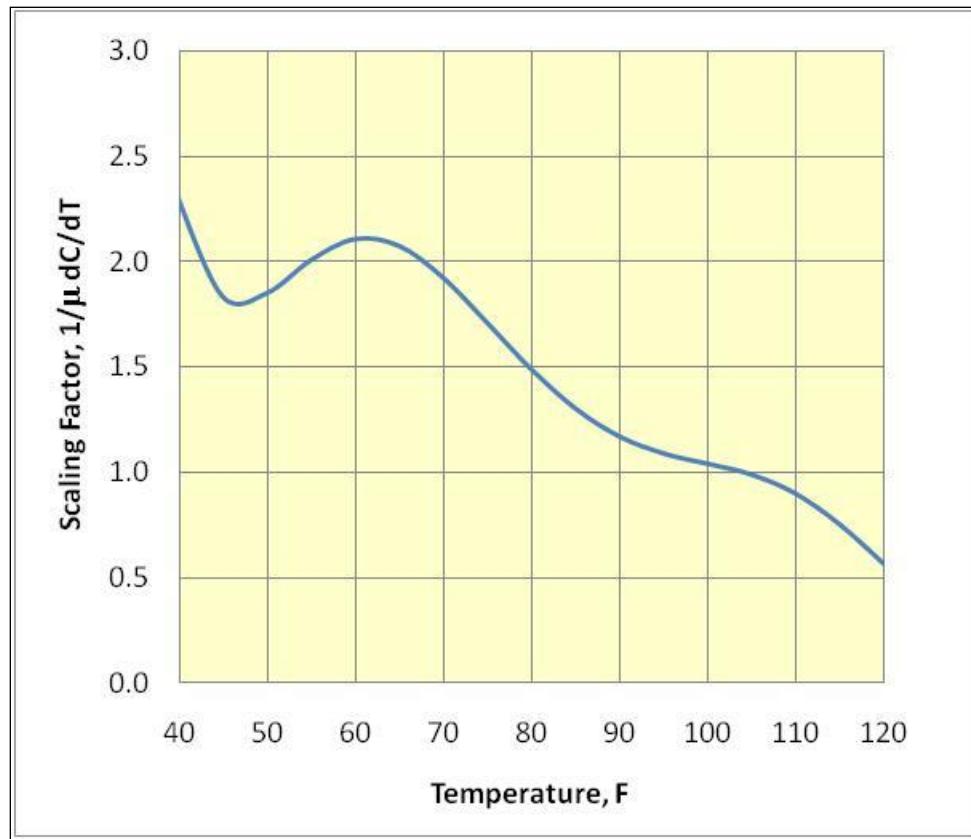


Figure 4.22: Example rate scaling factor.

#### 4.3.3.6 Scale-up and Comparison to Pipe Flow

In order to use these data in deposition simulations of production systems, scale-up needs to be done. Most wax deposition modeling approaches make use of small scale test devices, e.g. coldfinger, benchtop flow loops etc. In order to adequately apply results derived from these devices, a good understanding is required how these results compare to field conditions for which they are intended.

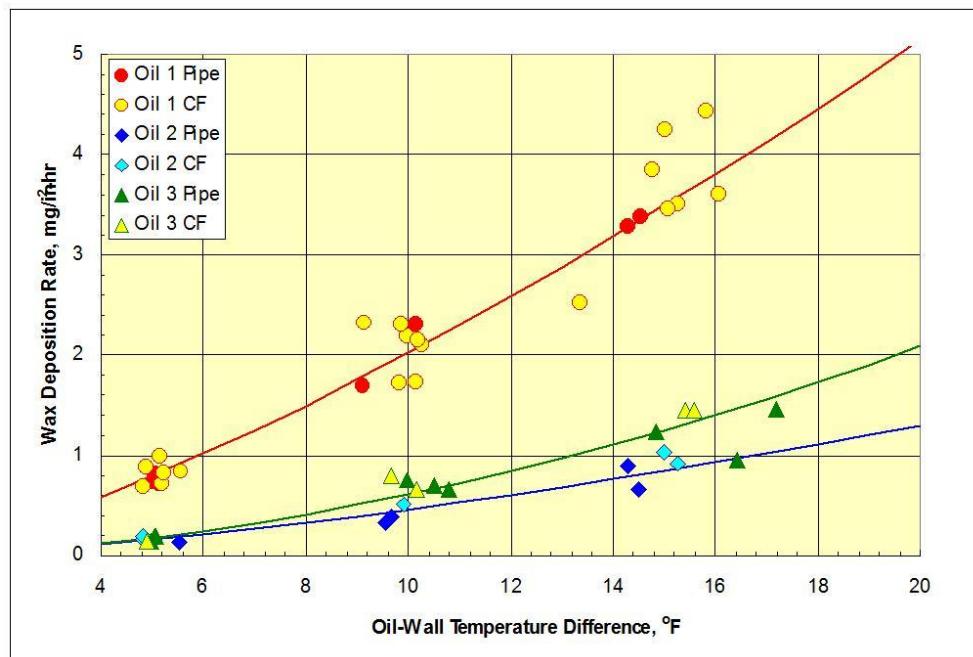
Shell uses coldfinger devices extensively to determine kinetic wax deposition rates given certain thermal conditions. In order to relate these deposition rates to flowline/pipeline conditions, a scaling process needs to be invoked [18].

This scaling compares the theoretical wax deposition rates in both coldfinger and flow loop geometries under equal deposition premises, i.e. assuming the same underlying deposition mechanism. Based on this analysis, a scaling factor has been derived involving information about the thermal behavior of the systems under consideration via the Nusselt number as well as geometric scaling parameters, expressed explicitly as

$$\frac{\dot{m}_{\text{Pipe}}}{\dot{m}_{\text{Coldfinger}}} = \frac{Nu_{\text{Pipe}}}{Nu_{\text{Coldfinger}}} \frac{D_{\text{Coldfinger}}}{D_{\text{Pipe}}}.$$
 Eq. 1

For coldfinger setups as used in-house and a 3/4 " ID flow loop, recent results [19] have shown this scaling factor (SF) to be in the range  $5 < SF < 10$ . This implies that wax deposition rates within this small flow loop are approximately one order of magnitude higher than coldfinger results obtained (with thermally similar setups). The same analysis applied to the comparison of a 12" single-phase operated flowline with coldfinger results yields a scaling factor of about 1.2. This indicates that field-applied wax deposition rates should be based on coldfinger wax deposition rates multiplied by 1.2 in this case.

Earlier results comparing coldfinger to 2" pipe loop deposition tests showed correction factors were required in the order of 1.5 – 2. Figure 4.23 shows reasonable agreement of the two methods for three different oils.



**Figure 4.23: Deposition rates from 2" pipe flow and scaled coldfinger data.**

#### 4.3.4 Organic Solids Deposition Cell

The organic solids deposition cell (OSDC) is a novel device to measure wax and asphaltene deposition at realistic operating conditions [20]. The device is rated to 10000 psi and 200 C working conditions, and can achieve turbulent flow while matching flowline shear stresses. A key feature of this device is the ability to conduct a deposition test using only 140 ml of fluid.

The OSDC was developed in a JIP with Schlumberger, who retain the commercial rights to use the device. However, Shell has the rights to use the OSDC for internal purposes, either research or technical services. In 2009, we obtained the prototype OSDC from Schlumberger and have commissioned it for wax deposition testing. Additional equipment has been budgeted for asphaltene testing capabilities, which is intended to become operational in 2010-11. The device and capabilities are shown in more detail in the figures following.

Figure 4.13 shows the cell geometry: a fixed outer cylinder with a rotating inner spindle. Studies show the flow to be fully turbulent at a Reynolds number of 13000. Light condensates may have Reynolds number of 40,000 to 130,000 at flowline conditions; very viscous fluids may have difficulty reaching turbulence without excessive wall shear stress.

Temperature is controlled by a cartridge heater inside the inner spindle and coolant flow through the outer jacket (Figure 4.14). Both fluid and wall temperature are tightly controlled. Multipoint thermocouples are inserted in the fluid and wall and several radial and axial positions for data acquisition and control. The schematic shows an established velocity profile across the cell and wax depositing on the outer wall.

Figure 4.26 shows a CAD drawing and photograph of the OSDC. The spindle is driven through a magnetic coupling attached to a speed-controlled motor than is raised from below the cell. Coolant flow is measured and controlled through three flow controllers to ensure uniform cooling along the entire wall. All operations and data acquisition are computer controlled.

Figure 4.27 compares calculated wall shear stresses for the OSDC and various pipe flows. The OSDC is able to cover the range of pipe flow stresses for ease of matching deposition parameters.

Photographs of wax deposits from live-oil and stock-tank deposition tests are shown for a Gulf of Mexico crude oil (Figure 4.28) and a Thai crude oil (Figure 4.29). The dark deposits still have oil clinging to the surface; the light deposits are after the oil is rinsed from the surface using MEK. The deposits are uniform and have a slightly grainy texture.

Figure 4.30 compares deposition rates from the OSDC to those measured in a 2" flow loop and in coldfinger experiments. Coldfinger experiments have to be scaled up to field conditions, while OSDC deposits agree well with pipe flow data without scale-up.

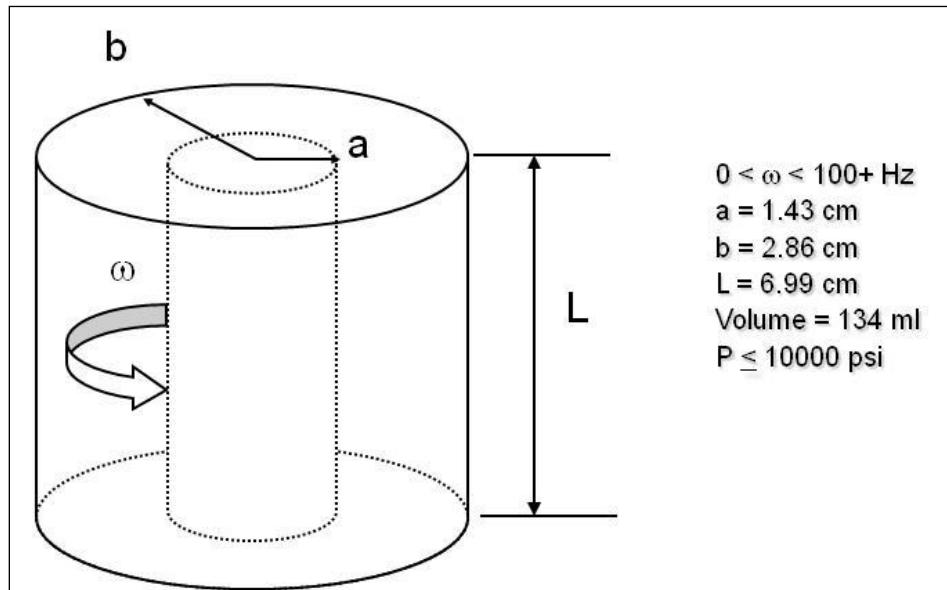


Figure 4.24: Basic OSDC geometry and dimensions.

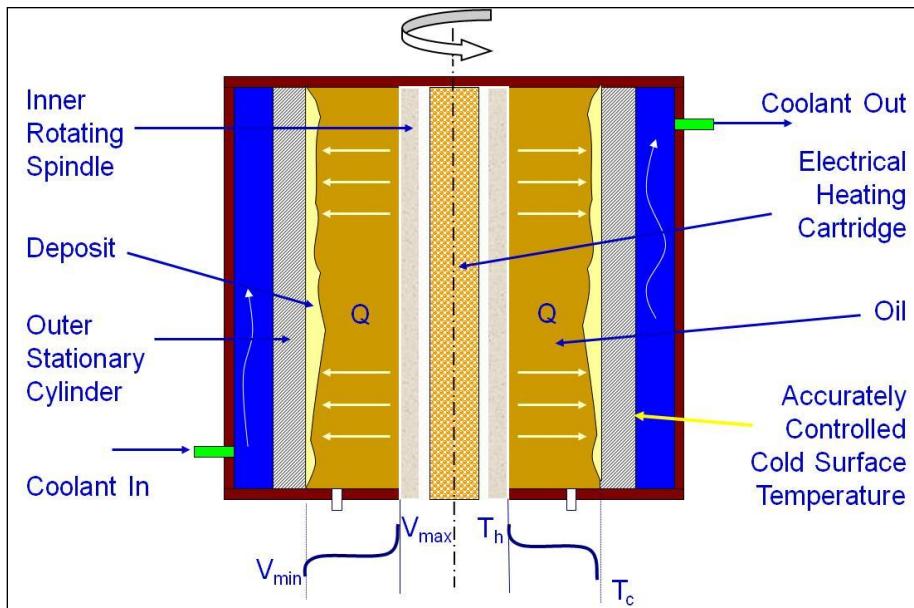


Figure 4.25: OSDC cross-section and operating principles.

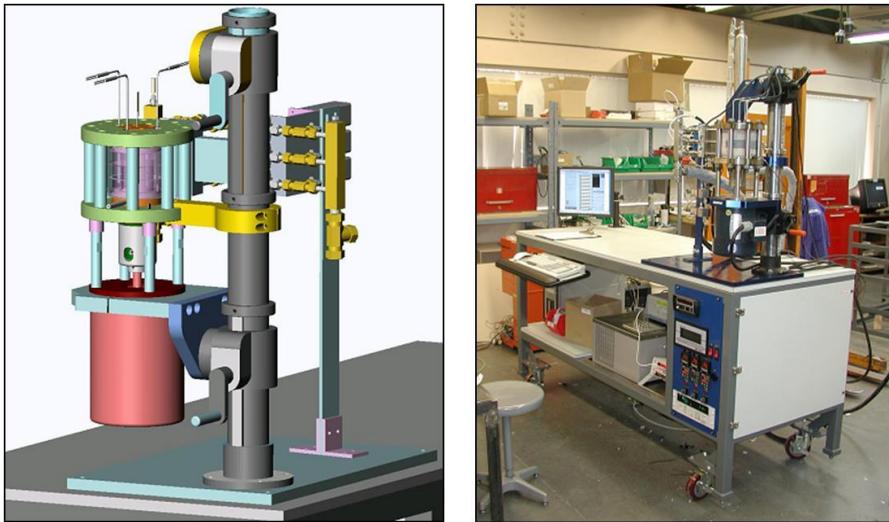


Figure 4.26: OSDC CAD drawing and photograph.

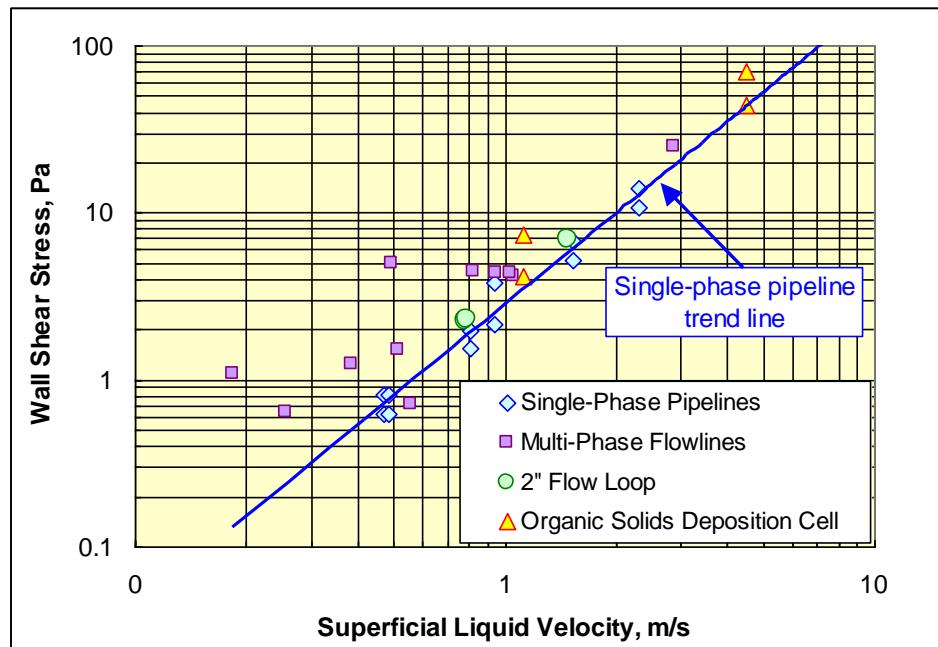


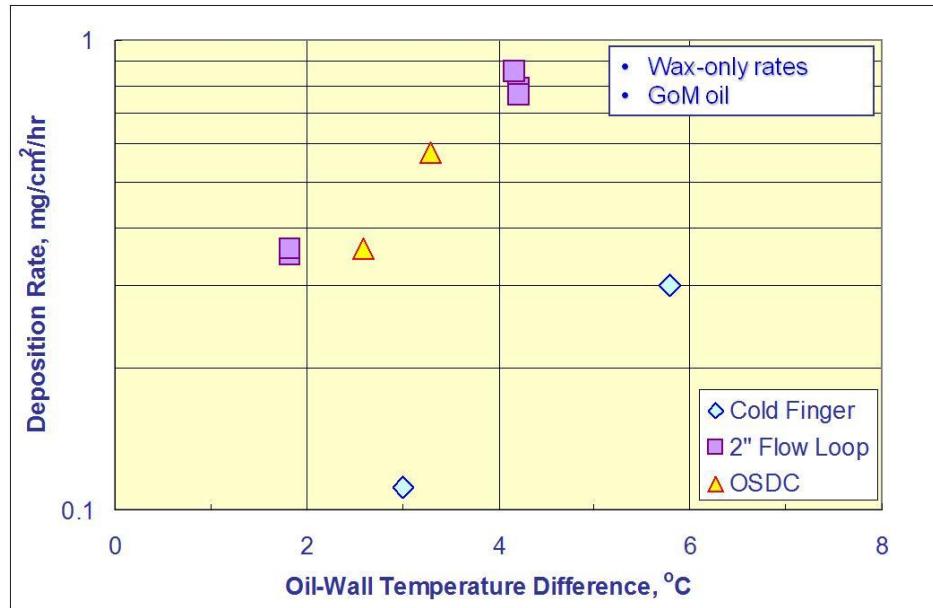
Figure 4.27: Comparison of wall shear stress for OSDC and pipe flows.



Figure 4.28: OSDC wax deposits for a GoM oil.



Figure 4.29: OSDC wax deposits for a Thai oil.



**Figure 4.30: Comparison of deposition rates for 3 devices.**

#### 4.3.5 Flow Loops

The Flow Assurance group at Westhollow Technology Center (to become Shell Technology Center Houston) has several flow loops for deposition rate measurement. A 2" south loop for single-phase testing and 2 each  $\frac{3}{4}$ " loops for multiphase testing; the east loop is standard tubing and the west loop is polished tubing. Numerous flow regimes, temperature profiles and flow lengths can be achieved in these systems. Wax deposition rates can be estimated using flow loops in a variety of ways depending on the level and accuracy of the instrumentation. We use 5 basic methods for deposit assessment. These methods must be checked for a given system to determine the expected changes in P and T compared to the uncertainty in the instruments.

Pressure drop analysis: As wax deposits, the pipe diameter will decrease and  $\Delta P$  will increase (for fixed flow rate). This method can be complicated by the fact that wall roughness also changes as the deposit grows. In turbulent flow,  $\Delta P$  depends on both diameter and roughness.

Thermal analysis: Deposits provide insulation on the pipe wall, which will change the amount of heat transferred in a test section (usually 20 to 50' long). Thus if the oil or coolant have fixed inlet temperatures, their outlet temperatures will slowly change with time. Because the changes are usually small, the thermocouples or RTDs may not be sensitive enough for accurate estimates.

Pigging: The test section can be opened and pigged. The deposit can be collected, weighed and analyzed. The only caution here is that the test section be well drained before pigging to reduce the amount of free oil collected with the deposit.

Removal with solvents: As with the coldfingers and OSDC, a test section can be rinsed with cold MEK and then soaked with hot toluene. The toluene sample is then subsampled, topped, weighed and analyzed like samples from the other devices.

**Borescope:** The test section is opened and visually inspected with a borescope camera. This gives a qualitative idea of the thickness and texture of the deposit.

#### 4.3.5.1 Single-Phase Flow Loop

WTC has a 2" flow loop for single-phase wax deposition testing. It has an upper loop and a lower loop with different capabilities. A schematic of the lower loop is shown in Figure 4.31 [21]. The loop is connected to a 5-barrel oil tank, and the fluid is pumped by a 53-gpm progressive cavity pump with a variable-speed DC drive. Two glycol loops and heat exchangers supply heat and cooling as needed. The lower loop has a jacketed 80' section (the "back jacket") used primarily for bulk heating or cooling. This is followed by 4 each 10'-long electrical contact heaters with individual PID controllers for precise temperature control. There is a 20' deposition test section which includes a removable 4' spool piece (Figure 4.32). Thus, deposits can be examined and removed for analysis in an analogous way to the coldfinger and OSDC. Instrumentation and controls for the lower loop are shown in Figure 4.33. In this short test section, changes in  $\Delta P$  and outlet T are not usually significant enough to estimate deposit thicknesses with high accuracy. However, it is ideal for measuring initial deposition rates which are not altered by wax insulation or depletion (Figure 4.34). Recently it has been used for testing deposit-resistant surfaces and coatings with excellent results.

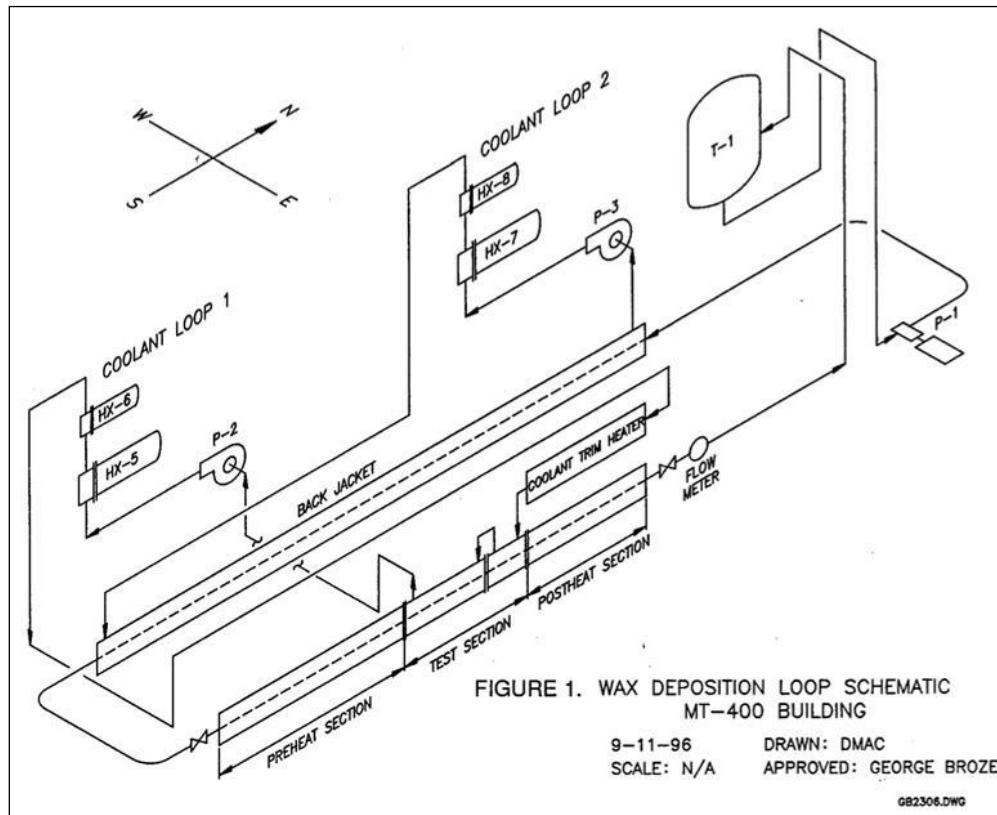


Figure 4.31: Schematic of lower 2" wax deposition loop.

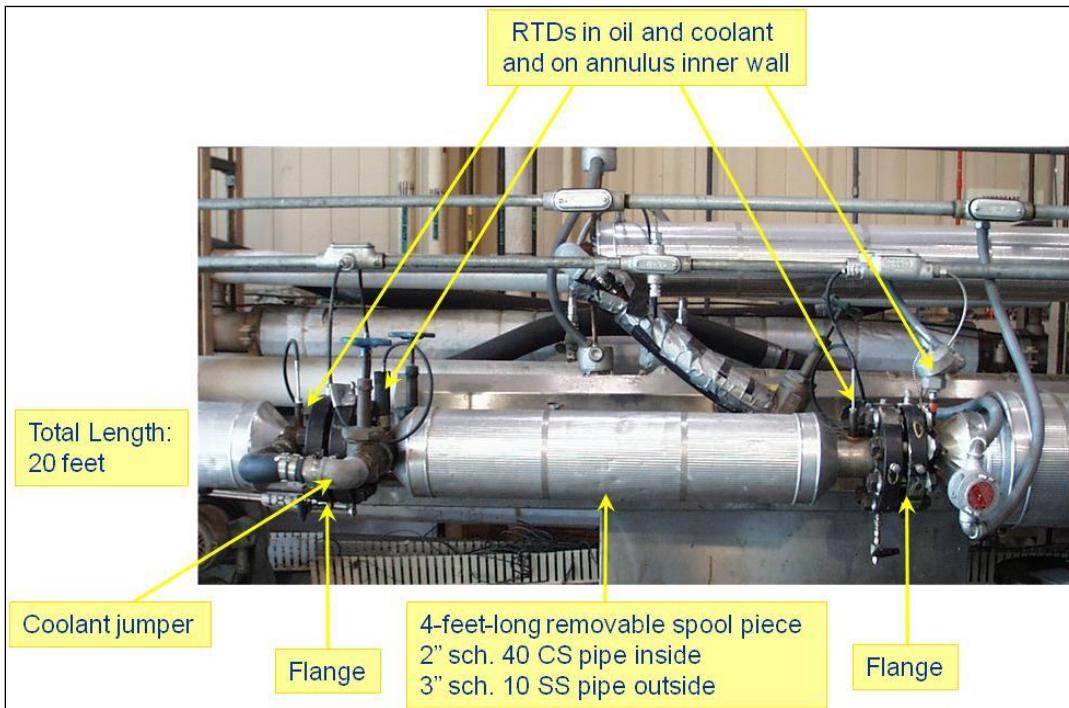


Figure 4.32: Photograph of test section spool piece.

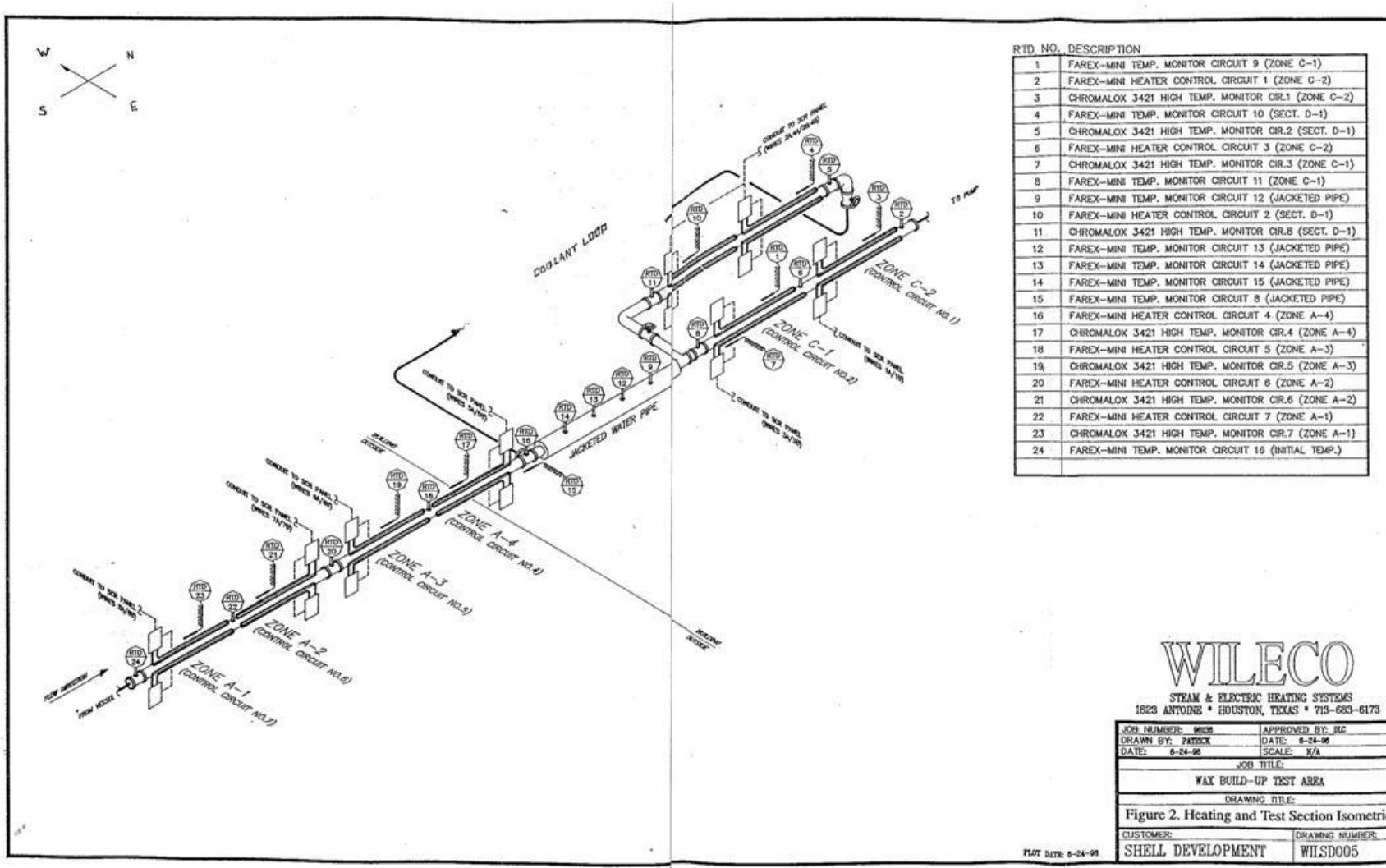
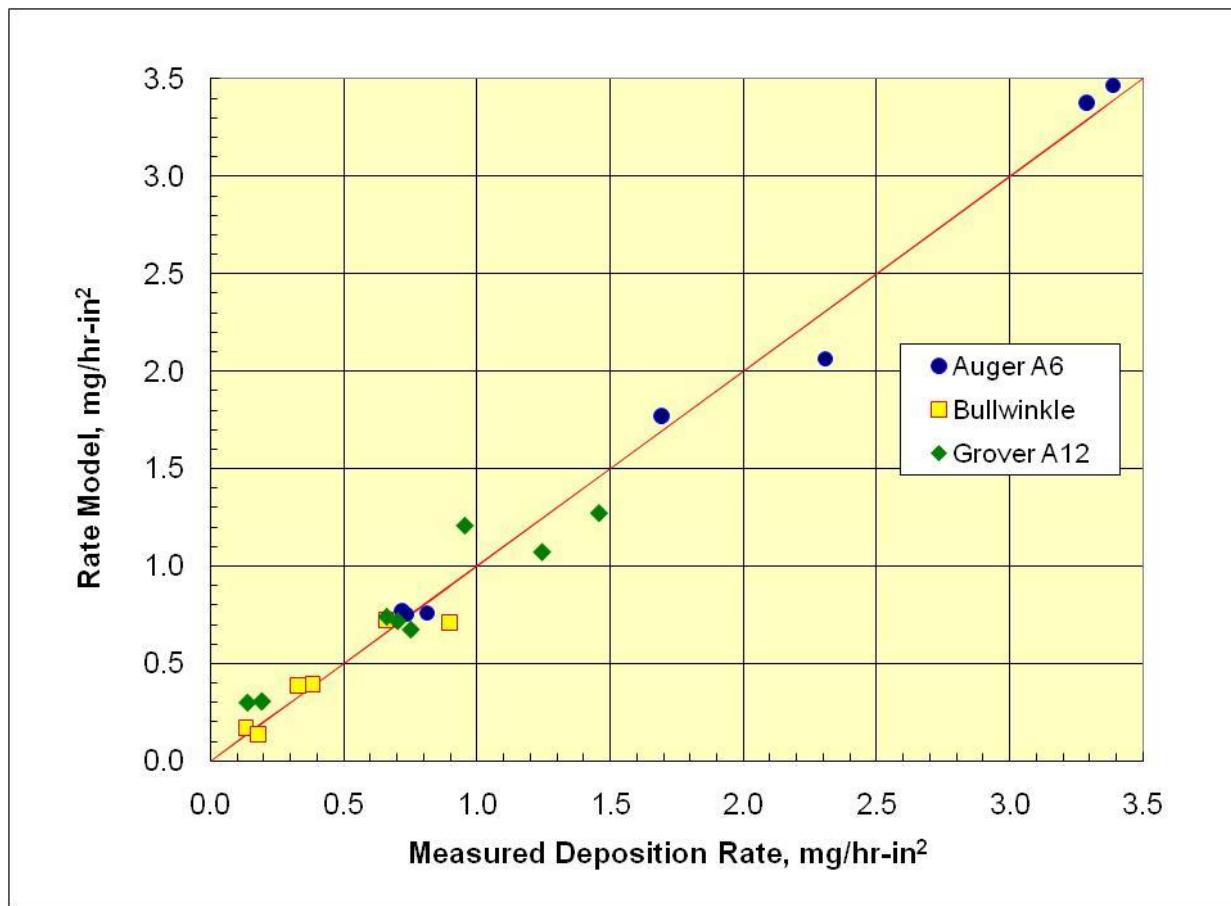


Figure 4.33: Instrumentation and controls for lower 2" flow loop.



**Figure 4.34: Scatter in 2" flow loop deposition rates.**

The upper loop [22] utilizes the same pump, tank, heaters and glycol loops as the lower loop. However, there are two much longer (80' each) deposition sections (Figure 4.35) – one is standard pipe and the other is polished pipe to test roughness effects on wax deposition. In addition, this loop is equipped with a pig launcher and receiver (Figure 4.36). Pigging returns from the standard section are shown in Figure 4.37. Not all returns are this solid, but returns from the standard section are always more consolidated than from the polished section (Figure 4.38), which is typically very slushy. This has demonstrated the value of polished surfaces in both reducing the deposit volume and in changing the structure of the pigged wax to a more transportable slurry.

Studies have also been conducted to study pigging efficiency. Figure 4.39 shows DP across the 80' standard pipe section during 5 successive pigging runs. The first run illustrates the increase in  $\Delta P$  as the pig moves down the pipe, consistent with a wax plug building up in front of the pig. The 2<sup>nd</sup> runs show that not all the wax was removed with the 1<sup>st</sup> run, as  $\Delta P$  is lower but still significant. After several runs, the  $\Delta P$  is essentially the same as a run with no wax on the wall.

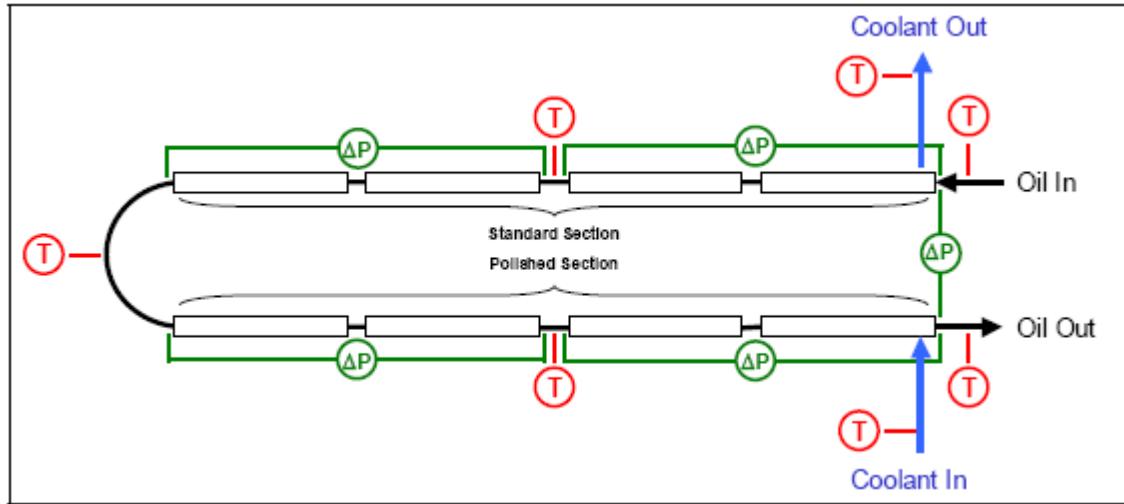


Figure 4.35: Schematic of upper 2" flow loop.

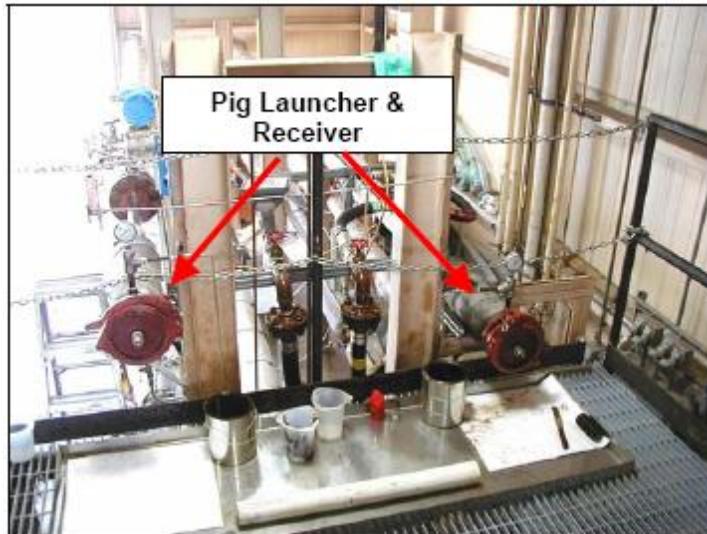


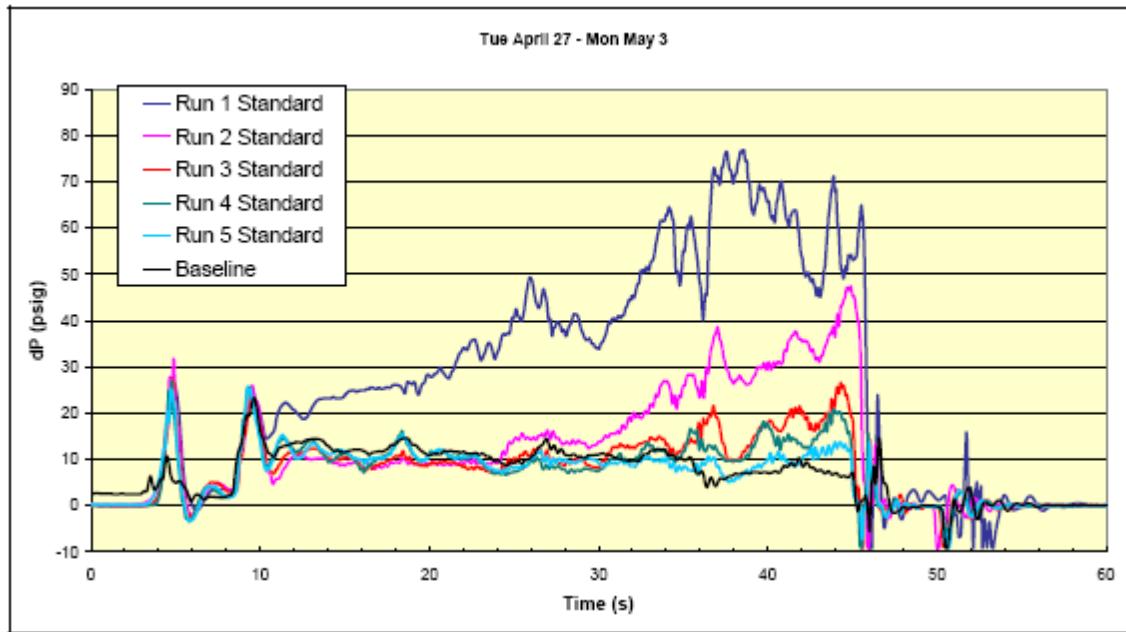
Figure 4.36: Pig launcher and receiver.



**Figure 4.37: Pig returns from the standard section.**



**Figure 4.38: Pig returns from the polished section.**



**Figure 4.39: Pressure drop during successive pigging runs in standard pipe.**

#### 4.3.5.2 Multiphase Loop Data

Flow loop testing within a  $\frac{3}{4}$ " ID 800 ft long counter-currently operated pipe-in-pipe deposition flow loop allow for two of the above wax deposition rate measurement techniques to be deployed. Figure 4.40 shows the flow loop as it stacks up in 8 individual loop sections each containing two 50ft straight pipes with 4ft radius bends.



**Figure 4.40: East Multiphase Flow Loop.**

Analysis can be conducted based on available pressure drop data within selected 50ft sections of this flow loop. The standard pipe-flow pressure drop equation below provides the basis for the data analysis.

$$\Delta p = f \frac{L}{D} \frac{\rho}{2} u^2$$

One limitation to this approach is that the deposit roughness is not known. Common assumptions are either (a) the same as the pipe or (b) smooth. These can have significantly different results.

However, by pigging various sections of the loop, the deposit can be recovered and measured. The findings can be used to assess the assumptions made about the surface roughness and provide some quantitative reassurance.

Alternately, steady-state thermal analysis cannot be deployed when there is a large change of temperature over time. This technique has been used elsewhere, though it requires accurate temperature measurements of the test fluid. In our current research, we are developing a customized tool to analyze transient flow loop temperatures and extract deposition rates as functions of time. This will be presented in future reports.

#### Countercurrent flow experiments

Figure 4.41 shows an example of consolidated wax deposition rate results derived from the pressure drop analysis as well as the direct pigging assessment. These results were derived from countercurrent (oil-coolant) flow deposition experiments. In such experiments, we often see the greatest deposition in the sections where we expect the smallest  $\Delta T$ s, which contradicts the  $\Delta T$  deposition model. These  $\Delta T$ s are difficult to measure because they are usually within the uncertainty of the thermocouples. Work is ongoing to understand whether this is an incorrect estimate of  $\Delta T$ s or whether there is an unaccounted-for phenomenon. More recent tests in concurrent oil-coolant flow do not follow this trend, which suggests that the concurrent flow should become our standard test configuration.

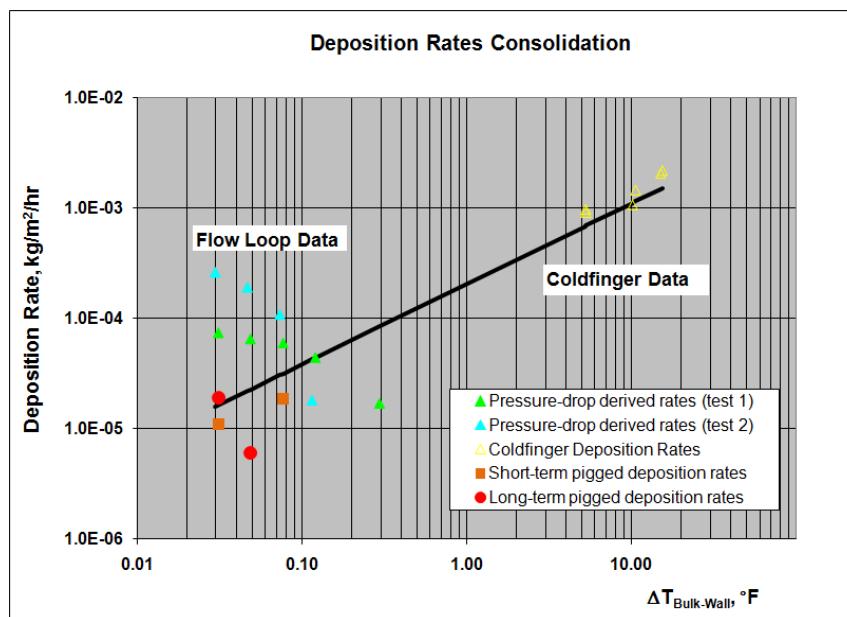


Figure 4.41: Wax deposition results comparison.

### Concurrent Flow Experiments

After the data in Figure 4.41 were obtained and analyzed in 2008-2009, a research program was initiated for Long-Offset Gas Condensate Production in 2010. Within that program, additional tests were conducted. The loop was modified to allow either countercurrent or concurrent hydrocarbon/coolant flow. In addition, a software tool was developed to analyze the huge volumes of flow, pressure and temperature data taken in flow tests and to put the side-by-side with the results of flow and deposition simulations. The tool incorporates Shell flow correlations and a number of deposition models, enabling us to test and validate proposed deposition mechanisms. These data and the tool will be reported in 2011.

We compared results of countercurrent and concurrent flows. The following figures are for tests using Onyx condensate in single-phase flow. The deposition model used is a concentration-gradient-driven mass transfer model with a single coefficient adjusted to match the  $\Delta P$  trend.

Figure 4.42 is countercurrent flow. In this configuration, hot loop hydrocarbon and cold jacket glycol enter at opposite ends of the loop. Therefore, there is always some temperature driving force, although it can be small at the cold end of the loop (estimated to be about  $0.5^{\circ}\text{F}$  in this test). The measured and model-predicted pressure drops agree very well for the first 550 feet of the loop; beyond that point, the measured  $\Delta P$ 's grow rapidly with time, but the model does not. This is similar to the data in Figure 4.41, where countercurrent deposits appear to grow in sections with very low  $\Delta T$ s. This behavior is still being studied but has yet to be explained. The deposit profiles in Figure 4.42 are calculated using the measured temperatures and a deposition rate coefficient tuned to match the bulk of the  $\Delta P$  data (but not the last sections). The calculations predict a steady growth but no huge deposits in the last sections.

In comparison, Figure 4.43 is concurrent flow. In this configuration, hot loop hydrocarbon and cold jacket glycol enter at the same end of the loop. The oil and glycol temperatures approach each other exponentially as they move down the loop. For this test, the final  $\Delta T$  is essentially zero. The pressure drop profiles for measurement and model agree very well. (There is some excess  $\Delta P$  predicted at 63 feet and a deficit predicted at 322 and 428 feet.) In the data, there is no rapid increase in  $\Delta P$  that was seen in the countercurrent experiments. The  $\Delta P$  and predicted deposit profiles reach a peak in the early-midsection of the loop, as expected. The deposit peaks at short distance early in the test; the peak diminishes as deposits insulate the pipe and shift downstream as the wax insulation improves heat retention and decreases  $\Delta T$ . The test results agree well with the expectations based on wax deposition theory.

Since concurrent flow tests give expected results but countercurrent tests give surprising, perhaps anomalous, results, this raises the question as to which mode of loop operation more closely mimics thermal conditions in production lines. In either case, the coolant flow in the annulus will create much higher external heat transfer coefficients and thus higher overall U factors than seen in subsea lines. In countercurrent mode, that can be mitigated somewhat by turning down the coolant flow. Concurrent mode does not allow as much flexibility, since the target outlet oil temperature may not be achieved if the coolant flow is low. Concurrent will always create very high  $\Delta T$ 's where the oil is hot, while this can be controlled better in concurrent mode. Countercurrent mode maintains some nonzero  $\Delta T$  over the entire loop (in the tests we have run), while concurrent mode does allow the  $\Delta T$  to go to zero as it will in the field. So there are some advantages and disadvantages to both. We would prefer to run and interpret tests in both modes if afforded the opportunity. However, until the low- $\Delta T$ , high- $\Delta P$  events of the countercurrent tests have been resolved. We will rely most heavily on concurrent tests.

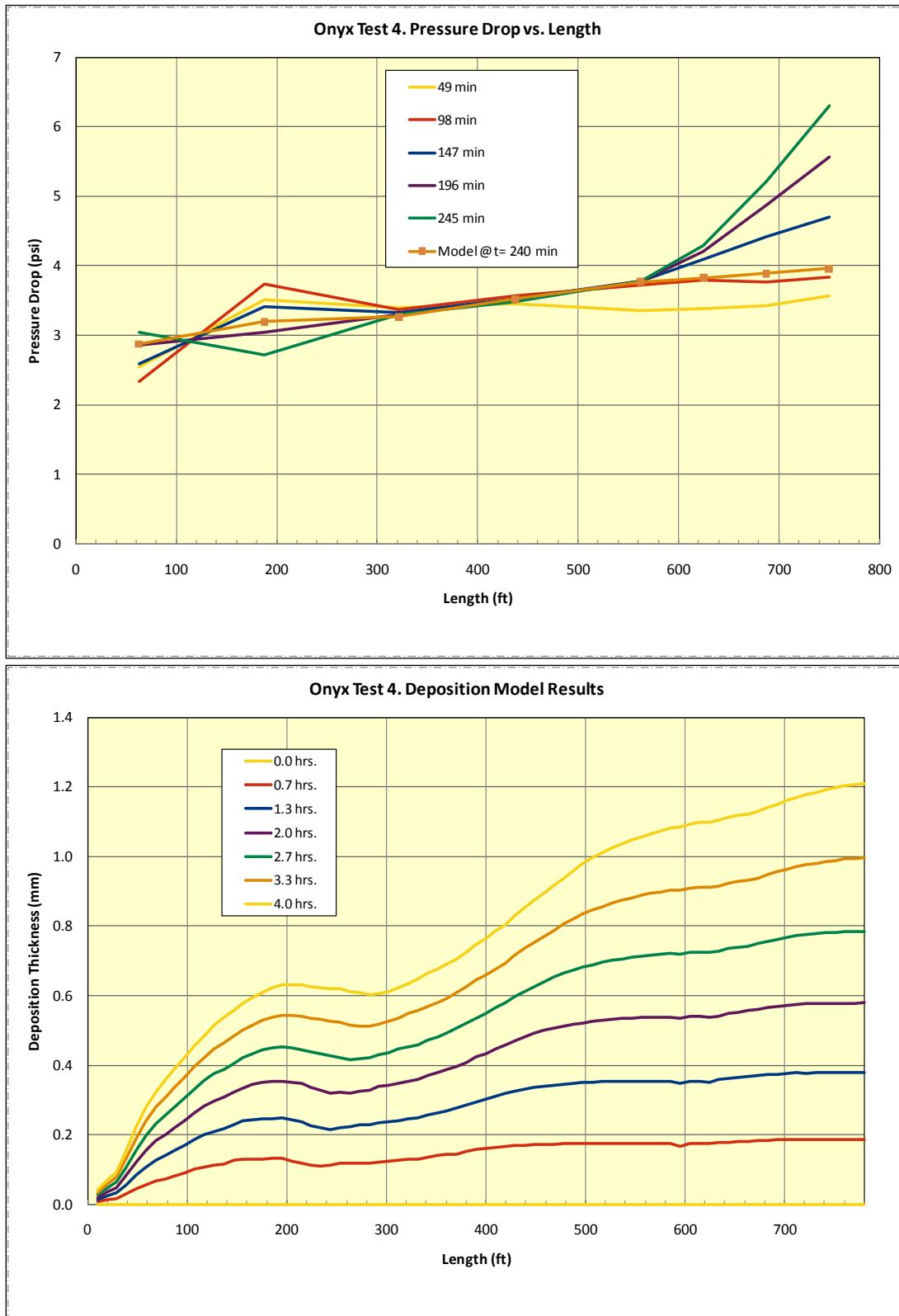


Figure 4.42:  $\Delta P$  and deposition model results for countercurrent flow.

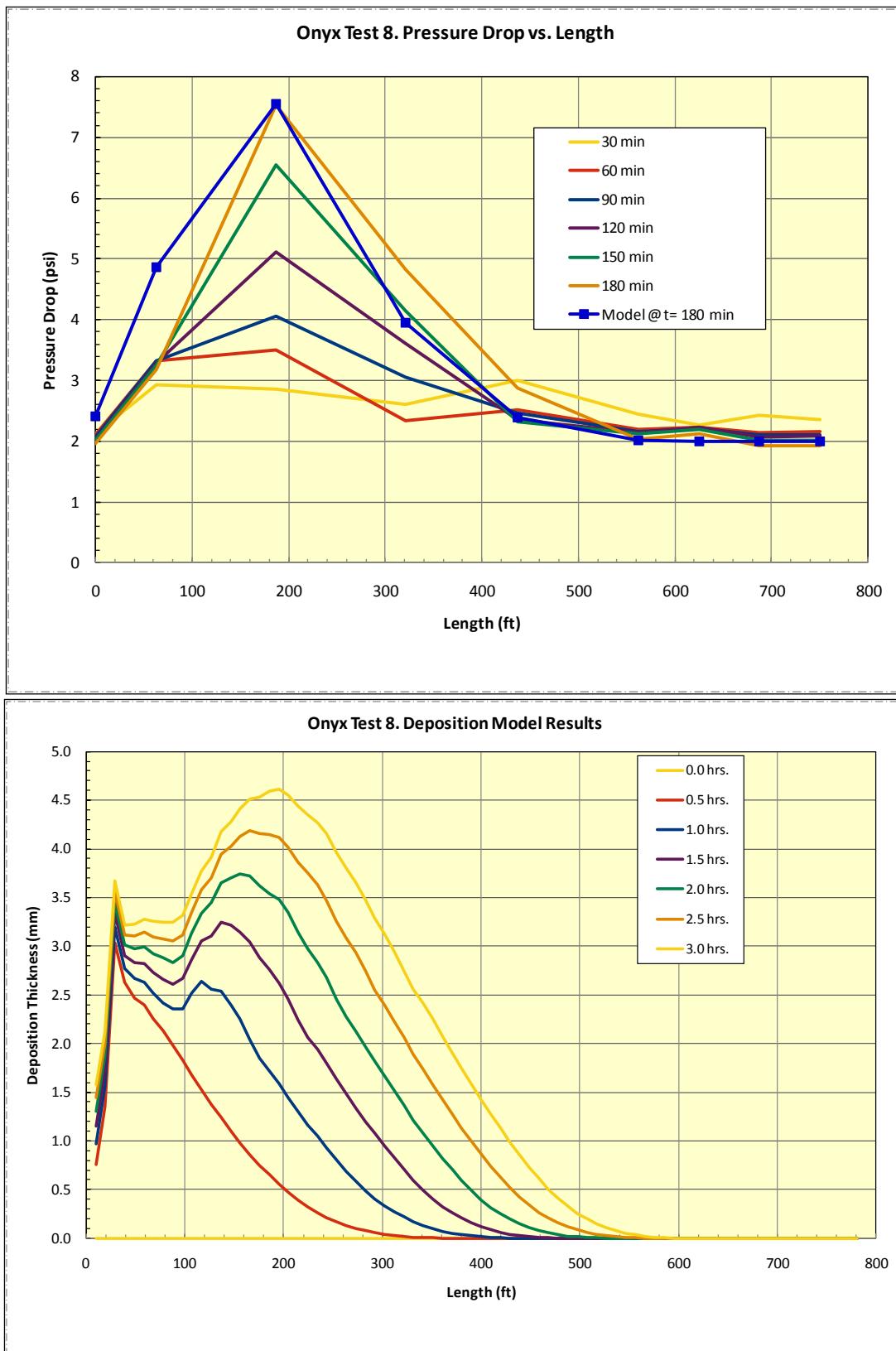


Figure 4.43:  $\Delta P$  and deposition model results for concurrent flow.

### 4.3.6 PI Performance

#### 4.3.6.1 Vendor Testing

Vendors for specialty oilfield chemicals use a variety of test methods in order to qualify their products. The most widespread test methodologies for paraffin-related testing are the cloud point determination, wax deposition testing, and pour point determination. Due to evolving technological advances, not all of the applicable techniques may be documented by the American Society for Standards and Materials (ASTM). Qualification protocols for deepwater deployment of chemicals, such as fluid-fluid compatibility, fluid-material compatibility, filtration specifications and/or viscosity specifications may not be available as ASTM documents. In typical project-related test and development work, mutual agreement on the test protocol by both customer and vendor are preferred.

##### Cloud Point Determination

Cross-Polarized Microscopy (CPM) is among the most typical deployed measurement techniques for establishing the cloud point of a given fluid. This test follows ASTM D5773 [23]. Should the paraffin content be small enough that kinetic effects prohibit an unambiguous cloud point determination via CPM, long-time (e.g. typically between 2 and 16 hrs) coldfinger testing is performed. The subsequent visual observations allow the cloud point to be reported with the accuracy of the coolant temperature spread used during the test. Subsequent tests (if requested) with smaller differences in coolant temperatures allow a more accurate cloud point determination.

##### Deposition Testing

Coldfinger testing to evaluate the performance and concentration requirements for paraffin inhibitors is commonly used among vendors due to the low fluid volume requirements and the small experimental footprint, which allows several of these units to be consolidated into a single apparatus.

The analysis of these tests is often limited to a visual assessment and a gravimetric determination of the total wax deposit. This limitation is due to the amount of tests typically run for a particular project. The gravimetric analysis is compared to blank deposition tests such that a % inhibition can be reported. HTGC analysis (vendor or external testing) is only performed if requested.

After establishing possible chemistries of paraffin inhibitors as well as reasonable concentration ranges, samples of these chemistries are often available for flow loop testing.

##### Pour Point Testing

Pour point testing follows the standard ASTM protocol D97 Standard Test Method for Pour Point of Petroleum Products [24]. Deviations from the execution of the above ASTM method are only permissible via customer agreement and have to be specifically documented. The use of automatic testers, smaller sample volumes or deviations from the experimental protocol may constitute such deviations.

#### 4.3.6.2 Shell Paraffin Inhibitor Tests

As part of a chemical tender or selection process, Shell labs may validate PI performance for selected chemicals and concentrations. It is typical to run coldfinger deposition tests for the treated and untreated oil samples for side-by-side comparison. On the standard coldfinger test,

best inhibition efficiency is usually seen at the smallest  $\Delta T$  ( $5^{\circ}\text{F}$ ), with less at the larger  $\Delta T$ s. Because vendors rarely go to the analytical expense to determine the solids content of the deposits, Shell's analysis can often distinguish between inhibitors that are actually reducing solids and those that are reducing only occluded oil.

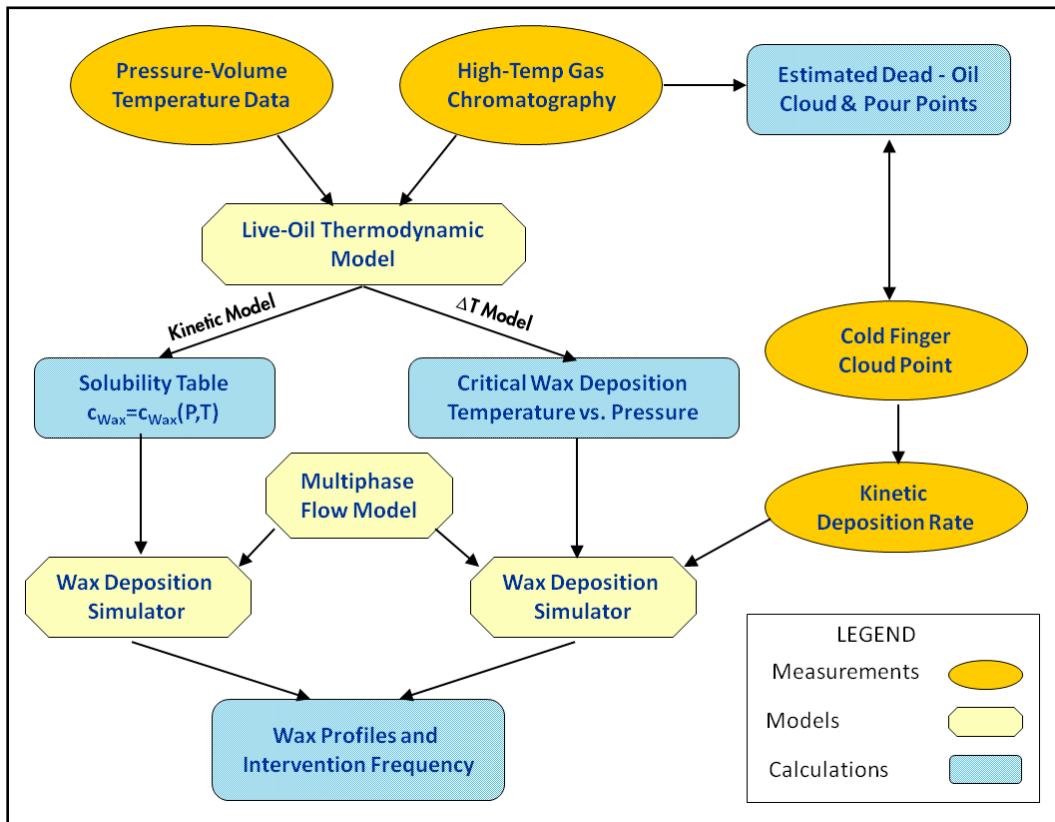
Since most lab deposition tests used by vendors and Shell are low-shear, the benchtop results are likely to show lower inhibitor efficiency than will be seen in the field. Vendors typically will say that "40-60% efficiency in the lab correlates to 80-90% efficiency in the field." Since field validation data is difficult to verify, this statement is hard to prove. Usually changes in pipeline  $\Delta P$  are too small to use as quantitative indicators of deposit thickness, and much of the pig return volumes are not captured in the pig trap. However, operations can use these to judge the risks and performance of inhibitors. Owing to the cost of chemicals, 80-90% efficiency is probably required to make inhibitor use economical in a piggable system.

#### **4.4 Deposition Modeling**

The wax deposition process – while intrinsically transient by nature – can be considered as a quasi-stationary process due to the fact that the deposition process typically takes place over longer periods of time, e.g. weeks, months, years. Therefore, first a steady-state thermal-hydraulic solution is determined. The transient character is introduced into the model by explicitly updating all relevant variables (change in pipe diameter and U factor due to deposits) after each deposition time step, then re-solving the steady-state problem. This iteration is continued until a stopping criterion (e.g., time limit, wax thickness, wax volume) is reached.

At the time of this writing, Shell's wax deposition modeling services are based on the  $\Delta T$  wax deposition model. A second generation wax deposition model is being deployed based on solving solute concentration profiles.

Figure 4.44 shows the general deposition modeling process for both deposition models.



**Figure 4.44: Wax deposition flow process.**

Mathematically, most (if not all) models describe the wax deposition process as being equivalent to a transport process, i.e. all of the material that crystallizes at the wall/surface can be accounted for by the material transport to the wall/surface. A convenient mathematical form to interpret this process is given by

$$\dot{m}_{Wax}'' = -D \frac{\partial c}{\partial r} \Big|_R = -D \frac{\partial c}{\partial T} \Big|_R \frac{\partial T}{\partial r} \Big|_R, \quad \text{Eq. 2}$$

where  $\dot{m}_{Wax}''$  is the wax mass flux, D is the diffusion coefficient,  $dc/dT$  the solute concentration gradient with respect to temperature, and  $dT/dr$  is the temperature gradient at the wall/surface. Both of the latter gradients are to be evaluated at the wall/surface.

Early attempts to evaluate Equation 2 make use of an equilibrium solubility curve, i.e.  $\partial c/\partial T$  is determined using thermodynamic equilibrium calculations. For a more accurate estimate of the concentration gradient incl. possible kinetic crystallization effects, the associated transport equation needs to be solved.

#### 4.4.1 $\Delta T$ Model

Shell's in-house first generation wax deposition model is based on the idea that the deposition process can be attributed to a great extent to the thermal driving force, i.e.  $\partial T/\partial r$  in Equation 2. Without solving the macroscopic energy balance to determine this gradient, it is related to the

applicable temperature difference via a Taylor series expansion, truncated and non-linearized to account for higher-order terms to

$$\dot{m}_{Wax}'' = a\Delta T^b \quad \text{Eq. 3}$$

in which the parameters 'a' and 'b' are determined from suitable coldfinger experiments. In comparison of Equations 2 and 3 it appears that the knowledge about the diffusion coefficient and the solute solubility gradient has been consolidated into the empirical parameter 'a', while the temperature gradient has been approximated by  $\Delta T^b$ .

The model as expressed by equation 4.4.2 has been incorporated for use in Honeywell's UniSim process simulator. Figure 4.45 shows the primary input tab. Besides the earlier mentioned deposition rate parameters 'a' and 'b', the Critical Wax Deposition Temperature (CWDT) needs to be inserted. This pressure-dependent temperature is estimated using Shell's in-house thermodynamic simulator (see Section 4.2.3).

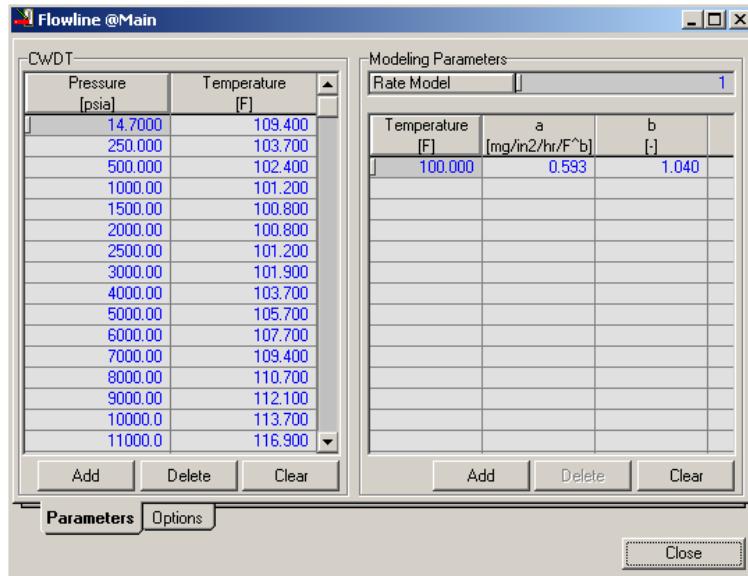


Figure 4.45: Model parameter input tab.

Various simulation control parameters are user-adjustable via the 'Options' tab. Details of their description and use may be found elsewhere [25].

#### 4.4.2 Mass Transfer/Kinetic Model

The wax deposition model described herein has been developed by Shell Global Solutions. It is largely based on the solution of the associated transport equations. Facilitating steps have implemented for the momentum and energy transport equation. Details as to their implementation are described elsewhere [26-28]. The rate of wax deposition at the internal pipe wall is based on the mean solute concentration gradient at this surface, i.e.

$$\dot{m}_{Wax} = -DA \frac{\partial c}{\partial r} \Big|_R \quad \text{Eq. 4}$$

The mean solute concentration profile is obtained from the solution of the transport equation for the dissolved wax. It is given by

$$\frac{\partial v c}{\partial z} = \frac{1}{r} \frac{\partial}{\partial r} D r \frac{\partial c}{\partial r} - k_{bulk}(c - c^*) \quad \text{Eq. 5}$$

subject to suitable boundary conditions. The diffusion coefficient in Equation 4 is based on the well-known Wilke-Chang correlation augmented with a multiplicative tuning factor  $c_{Diff}$ , i.e.

$$D = C_{Diff} \cdot D_{Wilke-Chang} \quad \text{Eq. 6}$$

An additional empirical term responsible for reducing wax deposits due to shear stresses is added after the solution of Equation 5 is available. The mathematical form of this additional term is given to

$$\dot{\delta}_S = C_{Shear} \tau_W \quad \text{Eq. 7}$$

It states that the rate of wax deposit thickness reduction is directly proportional to the applied wall shear stress. The constant C is a model parameter calibrated against flow loop data sets. This form of the model has been implemented in Honeywell's UniSim process simulator.

Kinetic effects are incorporated into this model via the last term on the right-hand side (RHS) of Equation 5. The solute concentration at the pipe wall/wax surface is assumed to be at equilibrium.

Figure 4.46 shows the main input tab within UniSim for the kinetic wax deposition model. The thermodynamic description with respect to wax solubility is contained in a lookup table. This table needs to be created for each oil and/or blends of oils.

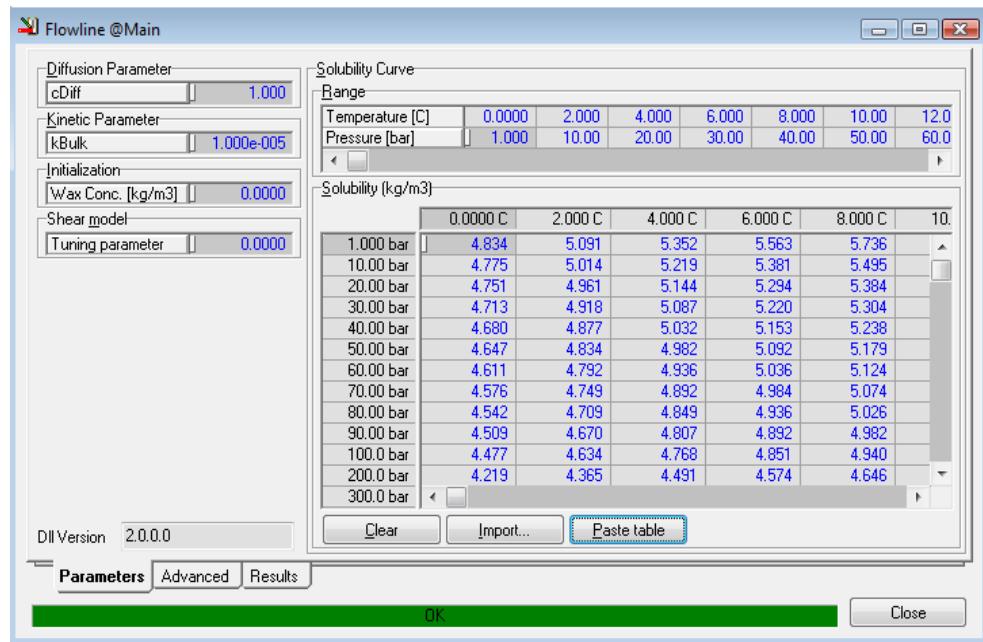


Figure 4.46: Main input tab.

#### 4.4.3 Model Validation

In order to deploy wax deposition models, they have to be validated against actual deposits. Most deposition models contain one or more parameters which may not be determined a priori via independent experimentation. All model parameters that cannot be or have not been determined independently, are subject to determination via an optimization process based on available wax deposition data.

The model validation within these guidelines is limited to the kinetic wax deposition model. Tulsa flow loop data have been used primarily to estimate the parameters used with the kinetic wax deposition model. It should be noted that a total of 3 parameters were determined, the diffusion coefficient multiplier  $C_{Diff}$ , the kinetic bulk crystallization  $k_{Bulk}$  and the shear stripping parameter  $C_{Shear}$ .

Weatherford Pipeline and Specialty Services group conducted 2 SAAM (Smart Acquisition and Analysis Module) pig runs in the Ram Powell 12", 26.57 mile-long export oil pipeline. The data were analyzed by Weatherford [29] with respect to longitudinal vibration, pressure differentials across the pig, acceleration of the pig as well as bulk temperature. Qualitative assessments as to the location of wax including its characterization (soft, hard, forming) have been provided, but actual wax thickness profiles were unavailable.

Equations 5 and 7 portray these parameters as they occur within the set of base equations. While Equation 5 shows the embedded use of the diffusion coefficient within the solute transport equation, it is the direct proportionality of the diffusion coefficient to the deposition rate (Equation 4) which is of greatest influence.

#### 4.4.4 Parameter Description and Selection

Three new parameters are introduced with the kinetic wax deposition model;  $C_{Diff}$ ,  $K_{Bulk}$  and  $C_{Shear}$ . Each of these parameters controls certain aspects of the mathematical description of the deposition process which are believed to be dominant in the deposition process.

- $C_{Diff}$  The diffusion coefficient multiplier directly controls the wax deposition rate and is typically cited within the range  $1.0 < C_{Diff} < 3.0$ . It should be noted, though, that often the underlying mathematical description of the various deposition models differs – a fact which may render numerical values for this parameter difficult to compare. Provided that the kinetic parameter introduced with this model provides an additional basis to describe deposit growth, it is suggested to leave the diffusion multiplier set to unity (1.0). This, in fact, transfers the actual determination of the diffusion coefficient to the implemented Wilke-Chang correlation. It is evident from this correlation that not only fluid properties determine the diffusion coefficient but also process conditions.
- $k_{Bulk}$  Control of the crystallization kinetics is introduced via this parameter. Its explicit appearance in the transport equation can be used in combination with other parameters to describe the solute transport behavior in the crude oil matrix. Large values of  $k_{Bulk}$  effectively incorporate a thermodynamic equilibrium into the transport equation while small values provide the potential to produce supersaturated solute concentrations. This parameter therefore not only provides a means of controlling the saturation state within the bulk of the flow domain but can also have large impacts in the near wall region. If, for example, local solute concentrations in the near wall region increase significantly due to crystallization kinetics, large solute transport gradients may occur which, in turn, may increase the mass deposition rate significantly. Para-

meter sensitivity studies indicate a transition region between 10-3 and 10-4 for the distinction of large and small values for  $k_{\text{Bulk}}$ . It is beneficial if this crystallization parameter can be determined *a priori* via independent experimentation for the fluid under investigation.

- $c_{\text{Shear}}$  This parameter is introduced on an empirical basis in order to accommodate mechanical forces which may act on the deposits. It is not unambiguous whether the underlying fundamental relationship between the material removal rate and the acting shear stress ought to be linear – as expressed in Equation 7. Model refinements may reveal that nonlinear relationships provide a better approximation. In combination with the crystallization kinetics introduced here, it is contemplated that all major physical phenomena have been addressed. It remains open to investigate whether the shear stress parameter can be determined *a priori* based on the adhesive/cohesive state of the deposit itself. If not, the hope for an *a priori* determination of the crystallization kinetics (in conjunction with the above diffusion coefficient correlation) may render well-defined shear stress experiments sufficient to cast a comprehensive correlation for the shear stress parameter.

#### 4.4.5 Commercial Wax Deposition Simulators

##### 4.4.5.1 Application of Simulation Tools

It is well known that commercial wax deposition simulators provide large discrepancies in prediction. The origins of the discrepancies are multifaceted and inherent to the simulation package. For example, Pipesim, UniSim, and Olga are the prevailing simulation tools in the oil industry. Each package has different methods of treating fluid properties, wax precipitation, and thermal-hydraulics. As a result, many of the predictions of the controlling parameter for wax deposition will vary from package to package for a specific system design. When making design decisions based on a flow simulated prediction, one must be confident that the simulation package is giving representative predictions of the fluid-solid thermophysical properties.

##### 4.4.5.2 Available Commercial Wax Deposition Tools

Olga (Scandpower) and Pipesim (Schlumberger) are two major simulation tools that offer wax deposition modules. Other smaller simulation companies that offer wax deposition tools are Schlumberger-DBR, Infochem, Calsep, and Multiphase Solutions Inc. The methodologies vary and only a select few have been touted as being applicable to two-phase flow cases.

##### 4.4.5.3 Academic Wax Deposition Models

Two universities have specialized in developing wax deposition models. The University of Michigan under the leadership of Scott Fogler has produced a wax deposition tool. The University of Tulsa also has a simulation tool which was extended to Olga as a module. Both universities developed the tools with joint industry funding. Shell was involved in the programs and has access to some of the tools.

##### 4.4.5.4 Application of Wax Deposition Modeling

Wax deposition methodology focuses on transport of precipitated wax from solution to the wall, not the precipitation itself. The majority of simulators calculate wax precipitation *a priori* to a

simulation via other thermodynamic packages. This ensures the speed of the pipeline simulation.

The transport of precipitated wax to the wall has one main driving force,  $dC/dr$ , which is the rate of change in wax concentration from the bulk fluid to the wall. A number of ways have been proposed to arrive at this quantity. One route is find  $dC/dr$  via the chain rule, *i.e.*,

$$\frac{dC}{dr} = \left( \frac{dC}{dT} \right) \left( \frac{dT}{dr} \right)$$

$dT/dr$  is found from a Nusselt number (heat transfer) correlation and  $dC/dT$  is found from a thermodynamic model.

Another route is to calculate the wall temperature from a prescribed fluid temperature. With the wall temperature, a concentration of wax at the wall and in the bulk is calculated. The Sherwood number ( $Sh$ , dimensionless mass transfer coefficient) is then employed, and the resulting driving force goes as  $dC/dr = Sh(\Delta C/D)$ .

The last method of calculating  $dC/dr$  is by estimating the boundary layer thickness. By knowing the wall temperature and the boundary layer thickness, the temperature gradient can be approximated as  $\Delta T/\delta$ . This gradient, along with the thermodynamic driving force, acts to transport wax to the wall.

The last important quantity that governs wax transport is the diffusion coefficient. Two correlations are commonly used for calculating the diffusion coefficient. The Hayduk-Minhas and Wilke-Chang correlations are sufficient to represent the diffusion coefficients.

#### 4.5 Gel Strength Measurement

A gel is defined as a physical form between liquid and solid, having a heterogeneous structure with the elastic properties of a solid and viscous properties of a liquid.

When the temperature of a waxy crude oil or condensate drops below a certain temperature, paraffin molecules will precipitate out of the solution as wax crystals. In many cases, the precipitated wax crystals form inter-connected networks. The wax crystals are typically needle or platelet shaped such that a relatively small volume of wax will suffice to build such a network. This network, essentially a porous structure of wax, filled with oil, may attain some mechanical strength at sufficient subcooling. If this happens in a flowline (or in a transport carrier!) one may have a problem. To initiate restart, a certain wall shear stress is required. If the strength of this gel is very high, such a flowline can no longer be forced to flow (restart), simply because the required pressure would be larger than the mechanical specifications of the flowline. Figure 4.47 illustrates the location of the cloud point and pour point with respect to formation of a gel.

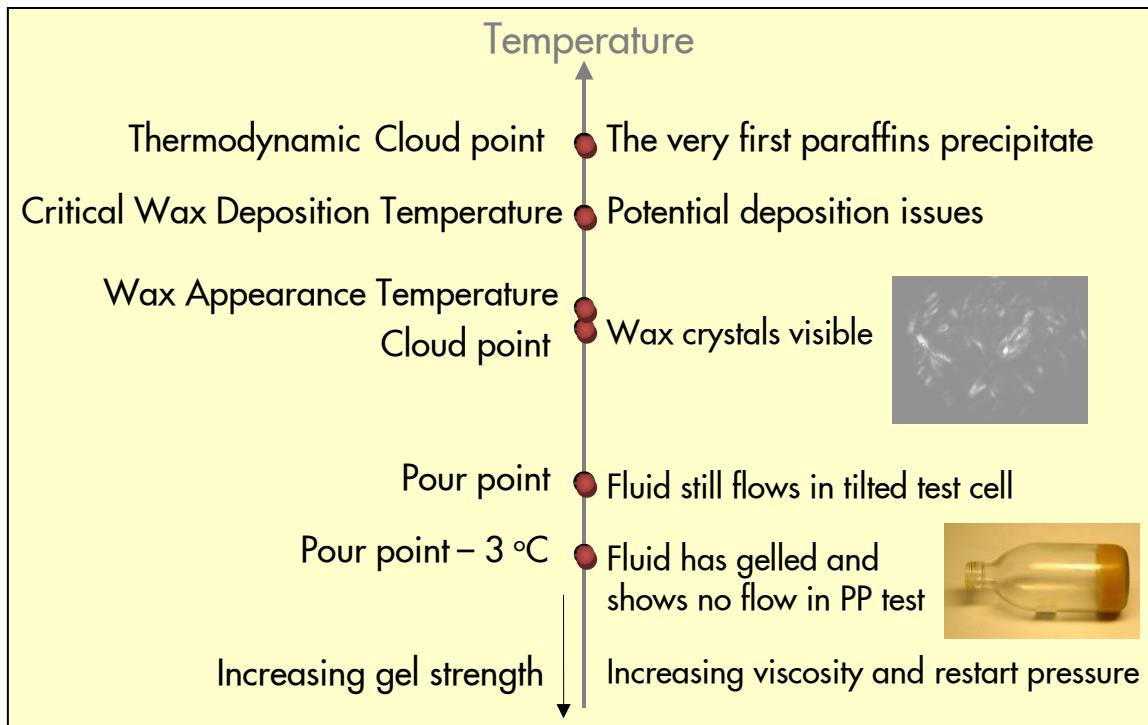
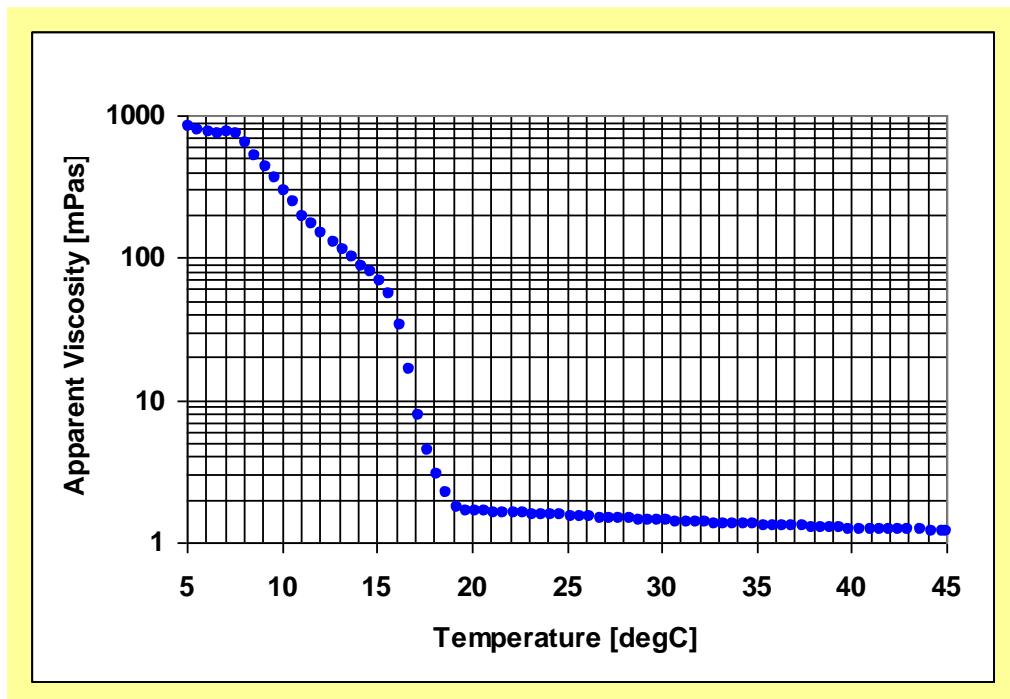


Figure 4.47: Illustration of increasing gel strength in oil with respect to temperature.

Traditionally, a key number to describe gelling in oil is the pour point. In the ASTM pour point test, the fluid undergoes a precisely defined cooling trajectory in a precisely defined cup. At the pour point temperature the fluid is still liquid (pourable). At a lower temperature the fluid gels and does not flow. This means that a finite stress is required to make the fluid flow at all. This stress, the so-called **yield stress**, increases with decreasing temperature, due to increasing amounts of wax crystals contributing to the network.

An everyday example of a fluid with a yield stress is mayonnaise. The fact that a blob of mayonnaise is stable and does not flow, despite the forces of gravity acting on it, indicates that it possesses a yield stress. There is one important difference between mayonnaise (an emulsion) and gelled waxy oil: mayonnaise retains its properties after having been deformed: the oil drops in the emulsions have been deformed and rearranged during the deformation but it is still a tight emulsion. In contrast, if one deforms gelled waxy oil, the wax network that builds it is (partly) destroyed and the gel may become fluid again or at least a gel with a significantly reduced yield stress. In addition the wax network structure and hence the strength, also depends on the cooling history (e.g., fast cooling vs. slow cooling).

Figure 4.48 shows the results of a measurement of the apparent viscosity of a waxy condensate fluid as a function of temperature. The viscosity was measured at a shear rate of 10/s and a cooling rate of 1 °C/min. The viscosity follows the “normal” increase of viscosity with decreasing temperature down to about 19°C (cloud point of fluid). At 19°C, the temperature profile shows a sharp bend upwards. Now the precipitating wax crystals start to have a dominating influence on the fluids rheological properties. At 5°C, a typical seabed temperature the apparent viscosity of the condensate is almost three orders of magnitude larger than at 20°C.



**Figure 4.48: Temperature viscosity profile of a waxy condensate.**

The viscosity curve will differ for different shear rates. At higher shear rates the bend will be less pronounced, because the network is more efficiently broken down, and at lower shear rates, the bend will be steeper.]

Clearly, for a good understanding of the challenges of producing waxy oil under sub-pour point conditions, one needs to properly understand both the gel rheological properties as well as the thermal and mechanical history of the oil in the production system.

#### 4.5.1 Pour Point as an Indicator of Pumpability?

The pour point of a crude oil can be defined, following the ASTM D-5853 protocol, as “the lowest temperature at which movement of the test specimen is observed under the conditions of the test”.

In order to decide if a crude oil is likely to form a gel in the pipeline, it is necessary to measure its pour point after a pretreatment, which simulates the normal production procedure. It may also be useful to measure a worst case scenario, *i.e.* the highest gelling temperature. Therefore a maximum and minimum pour point is distinguished, and the methods to determine them differ in the prescribed treatment. For the maximum (upper) pour point, the treatment enhances gelation of wax crystals and solidification of the test specimen; for the minimum (lower) pour point, the treatment delays these processes. Differences between minimum and maximum pour points for North Sea crudes are reported to be as much as 50°C [30]. As indicated in ASTM D-5853 [31], pour point is affected by many factors such as thermal treatments of the fluid.

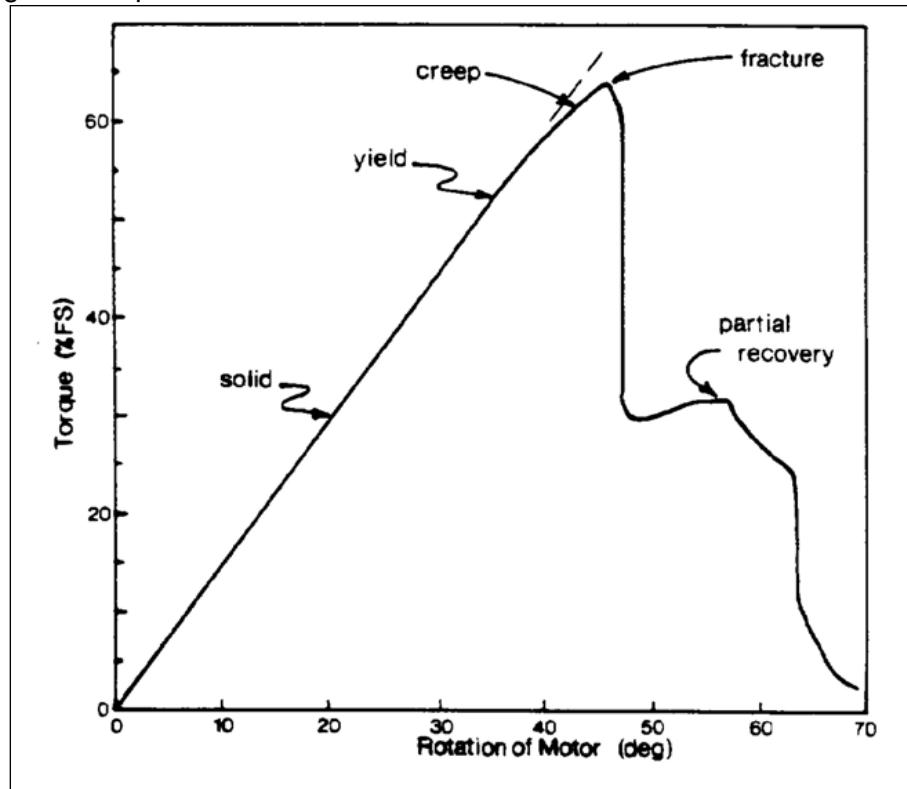
Even though pour point is a very important factor in facility design, it has long been recognized as “*Not a satisfactory index of pumpability*” partially because it does not measure the gel strength [32].

#### 4.5.2 Yielding Process

Various models have been proposed to explain the rather complicated process of yielding. Wardhaugh and Boger (1991), [33], proposed a model with 3 phases in the yielding process (Figure 4.49): (i) elastic behavior; (ii) creep; and (iii) fracture. Note that in the figure the solid behavior is equivalent to the elastic behavior mentioned.

While providing experimental data demonstrating wave-like pressure propagation in a model pipeline, Borghi *et al.* (2003), [34], proposed a “fracture model” that considers the following effects:

- The fracture takes place at the wave front
- The viscosity dissipation takes place behind the wave front
- The gel is compressible.

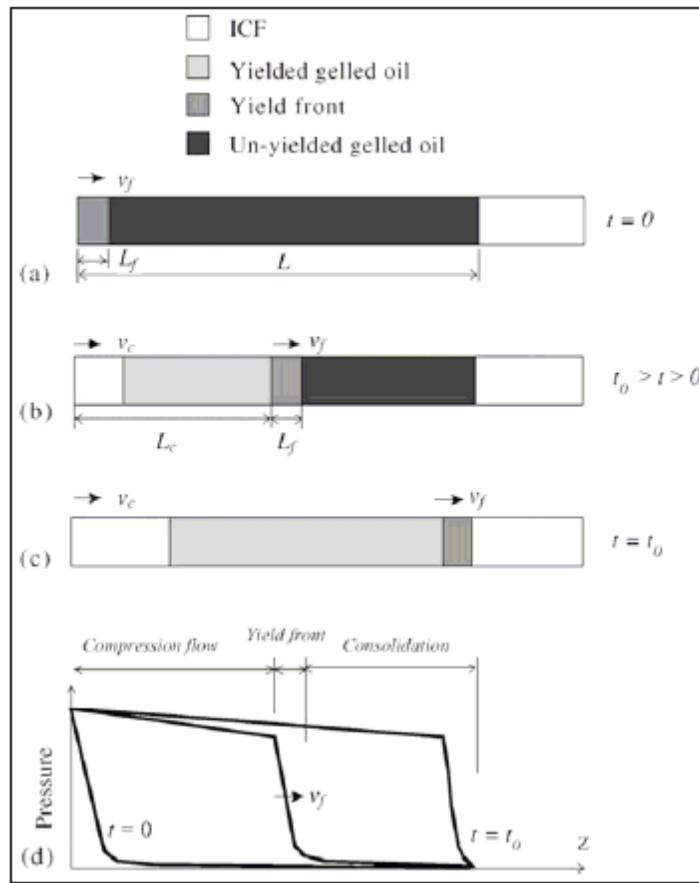


**Figure 4.49: Typical response of the measurement of the yield point using the vane technique. (Wardhaugh and Boger, Figure 3, [37]).**

In Borghi’s work, the authors believe that “the total pressure drop along the pipeline is not a meaningful quantity” because the distribution of pressure in the pipeline is not homogeneous. They believe that the slow pressure propagation is due to the slow movement of the gel front, and only when the gel front reaches the end of the pipe the whole gel starts to move (restart).

Davidson *et al.* (2004), [35], discussed a newer version of the TNO model where yield front and compression flow is combined. As shown in Figure 4.50, upon application of pressure at the inlet of the pipe at  $t = 0$ , the gel within a narrow region (length  $L_1$ ) deforms under the stress (Figure 4.50a). If the wall shear stress exceeds the static yield stress of the gel, the gel breaks down in this region, which then moves along the pipe as a yield front (Figure 4.50b). The high

inlet pressure compresses the yielded part of the gelled oil, which allows the incoming fluid (ICF), which is also compressed, to enter the pipe. When the yield front reaches the end of the gelled oil plug (at  $t=t_0$ , say), the entire plug and ICF move together with the same mass flow rate (Figure 4.50c). Figure 4.50d illustrates the sudden pressure drop across the yield front, and the more gradual pressure variation expected through the compression flow behind it. Ahead of the front, the oil velocity is zero and the pressure is constant and equal to the exit pressure, assumed to be atmospheric.



**Figure 4.50: Schematic of compression flow and yield front, (Davidson, et al, 2004, [38]).**

#### 4.5.3 Yield (Gel) Strength Measurement

The yielding process of gelled oil may be very complicated, and different models are available to explain observations (partially). Nguyen *et al.* (1998) [36] defined static, dynamic and elastic yield stresses. The most important measure of interest to pipeline operators was the fracture stress or point of maximum stress of the gelled crude oil. Numerous authors [34-36; 40] have pointed out that yield stress is a time-dependent property of a material. Rønningsen (1992) [37] states that it would be more appropriate to use an apparent yield stress rather than a true yield stress.

Nevertheless, the determination of the yield stress, and especially, the yielding behavior, is still very useful for engineering applications as long as experimental conditions reflect those at real restarts, because it gives an approximate measure of the force (or pressure) required to achieve flow and the time required to fully clear the line of the gelled oil.

#### 4.5.3.1 Factors affecting Gel Strength

Similar to the pour point, gel strength is also affected by many factors such as:

**Stress loading rate (SLR):** rate-of-change of the applied shear stress

**Shear history:** shear conditions during the cooldown of fluid

**Cooling rate:** indicator of the type of insulation in place in the field

**Aging:** time for which a fluid is shut-in at the lowest temperature

**Other:** Removal of light components would significantly increase gel strength (with other factors fixed).

Intrinsic properties such as thermal expansivity, compressibility, etc., are also determining factors in gel strength measurements.

#### 4.5.3.2 Methods of Measurement

Several types of apparatus and different direct and indirect techniques have been used to determine the yield stress, and results and conclusions regarding the validity and usefulness differ widely. Setups used are:

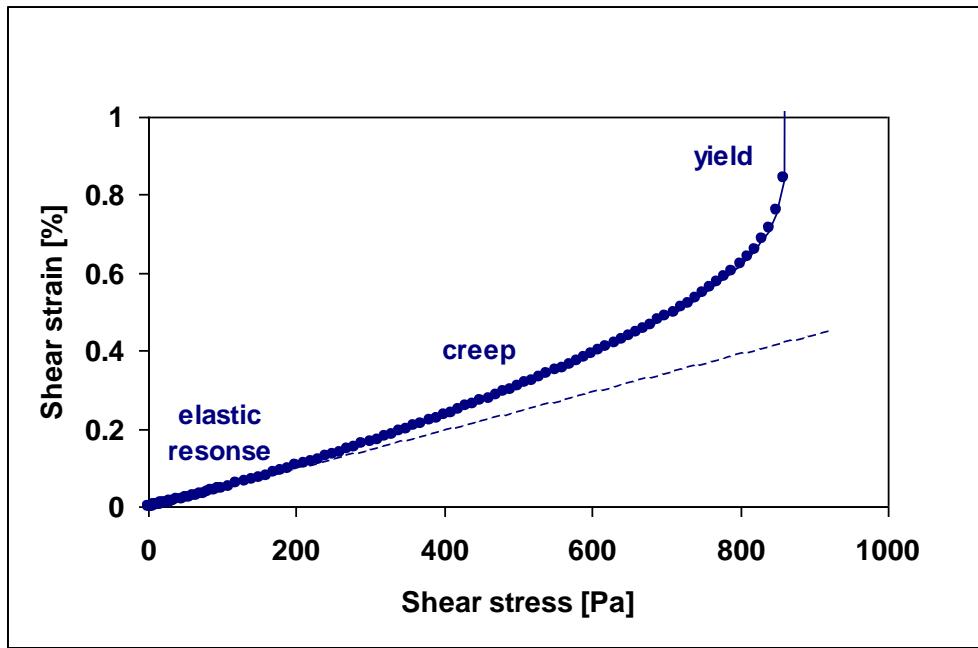
- U-tubes
- Large pilot pipeline facilities
- Lab-scale model pipelines
- Sections of real pipelines with pressure-driven flow, and
- Controlled-stress or -shear rotational rheometry experiments (CSR).

In each of these measurement methods, there are common factors that affect the end results. In most measurements, many factors that directly affect gel strength as indicated in the previous section are recognized and controlled. Shell Flow Assurance has used rheometer and flow loop measurements of yield stress in restart calculations and these methods are described here.

#### 4.5.3.3 Rheometer Measurements

A rheometer allows measurement of rheological properties with great accuracy and under well defined conditions (shear stress, shear rate, temperature and thermal/mechanical history). For gel strength (yield stress) measurements the thermal/mechanical history needs to be well defined as the gel properties will be strongly dependent on it. In Shell Flow Assurance's standard yield stress test, the fluid is cooled from a sufficiently high temperature to the required test temperature  $T_x$  at a rate of 1 °C/min. Then the fluid is allowed to age at  $T_x$  for one hour. Both cooling and aging are done under quiescent conditions (no shear). The shear stress is then increased at a rate of 10 Pa/min in steps of 1 Pa, while the strain is being measured. A typical result in the form of a strain versus stress curve is shown in Figure 4.5.1.

One typically observes three regions: (i) an elastic region at low stress, (ii) a "creep" region where the fluid flows irreversibly with an effectively very high viscosity, followed by (iii) a region of accelerated creep and ultimate yield. Only after yield does the fluid flow at any significant shear rate. The stress level where this occurs is noted as yield stress (~ 860 Pa in Figure 4.47). Note that this does not imply that the fluid will never yield if one applies a constant stress of 700 Pa. Many fluids appear to pose a critical strain level. If that strain level is reached, the fluid will yield. In the above example this would be around 0.9%. At 700 Pa the fluid will also creep to this level, taking longer time and then yield.



**Figure 4.51:** Rheometer data showing different responses to increase in shear.

Yield stress measurements for an Asia-Pacific fluid at various temperatures of cool down are shown in Figure 4.52 and Figure 4.53. In this case, the yield stress increases with higher sub-cooling, and the measurements are fairly repeatable.

The rheometer yield stress can be used to calculate the restart pressure of a gelled fluid in a flowline/pipeline. The restart pressure calculated using the rheometer is a conservative estimate as several other conditions like, gas addition, compressibility, gel-auto destruction, temperature variation in the fluid while gelling, would act to decrease the restart pressure. However, the advantages are that it is a relatively simple experiment to conduct and requires very low fluid volumes for testing.

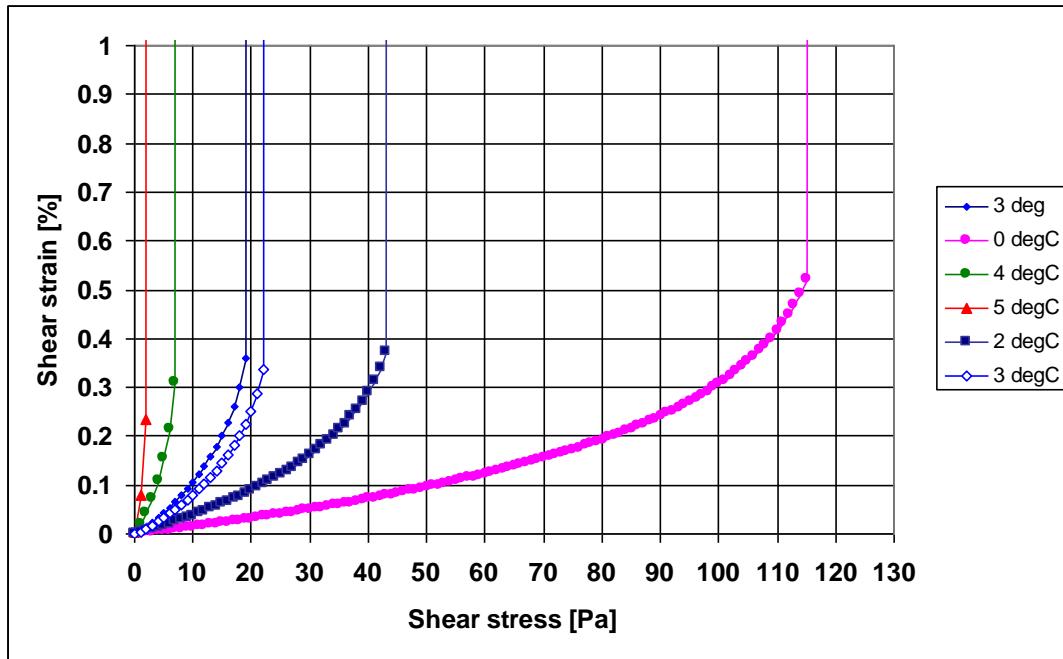


Figure 4.52: Yield stress determination for Asia-Pacific fluid from rheometer measurements at various temperatures.

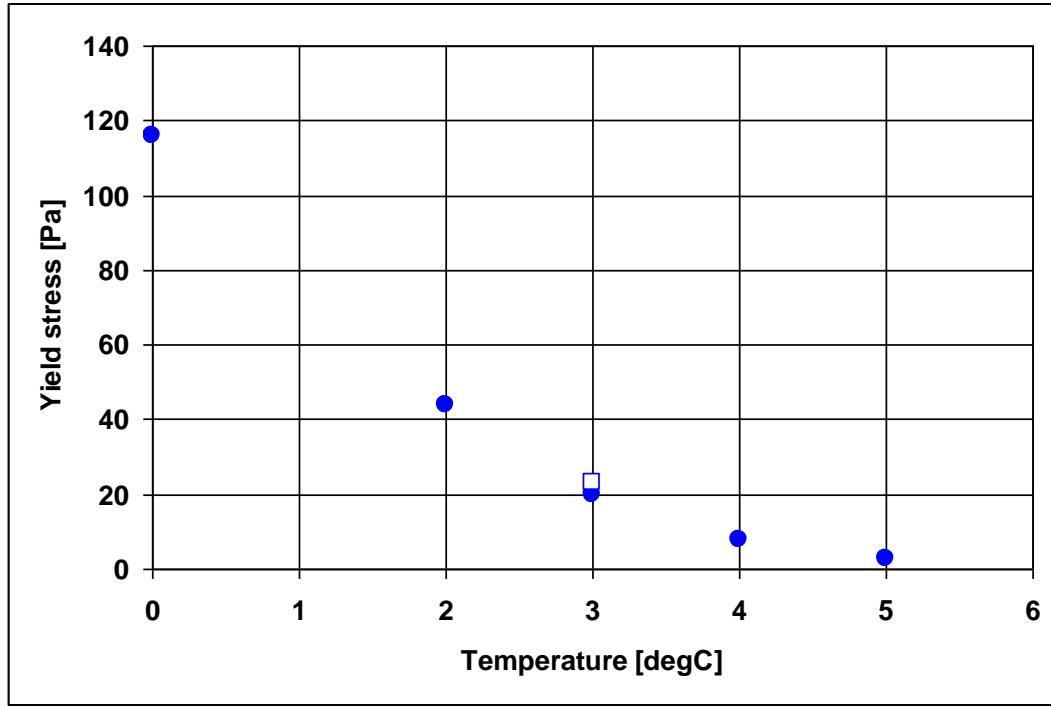


Figure 4.53: Example of yield stress variation with temperature for an Asia-Pacific fluid.

#### 4.5.3.4 Flow Loop Measurements

Flow loop tests can be used to obtain yield stress information when higher fluid volumes are available. The flow loop is used to determine the differential pressure at which gelled oil in the pipe loop begins to flow while monitoring pressure distribution along the loop. This is determined by cooling the oil in the flow loop under prescribed conditions ("cooldown"), holding the oil at set conditions for a prescribed period of time ("shut-in"), and then gradually increasing the upstream pressure until the gel moves ("restart"). The pressure at which the gel moves is termed as "restart pressure" and is used to determine an equivalent wall shear stress that can be scaled to field conditions. These tests are carried out in the flow loop located at WTC, Houston.

Cooldown profiles used in the loop tests to control fluid temperature are calculated based on possible profiles that may be experienced in offshore fields. The cooldown profiles used reflect the various insulation options available for the flowline/pipeline. An example of cooldown profiles used in the flow loop tests for a fluid from the Asia-Pacific region is provided in Figure 4.54. The three cooling profiles spanning 2, 8 and 60 hours to reach a target temperature of 30F were calculated for insulations with U values of 300, 25 and 3 W/m<sup>2</sup>K, respectively.

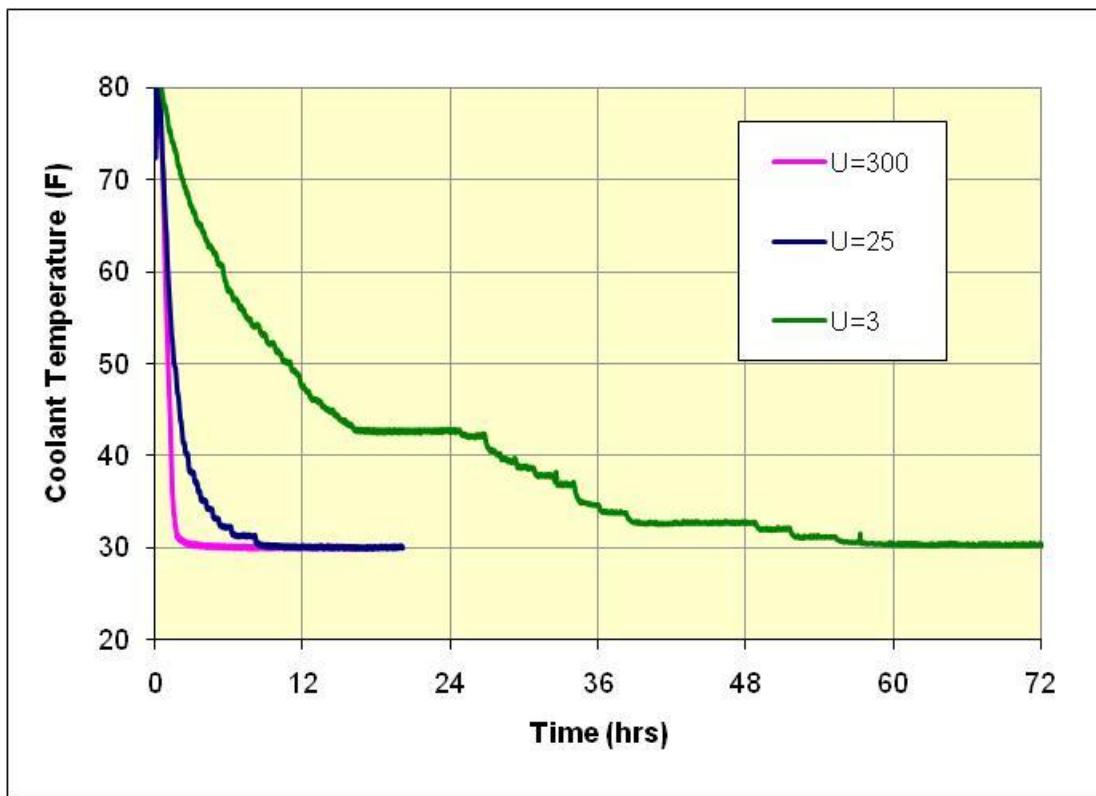
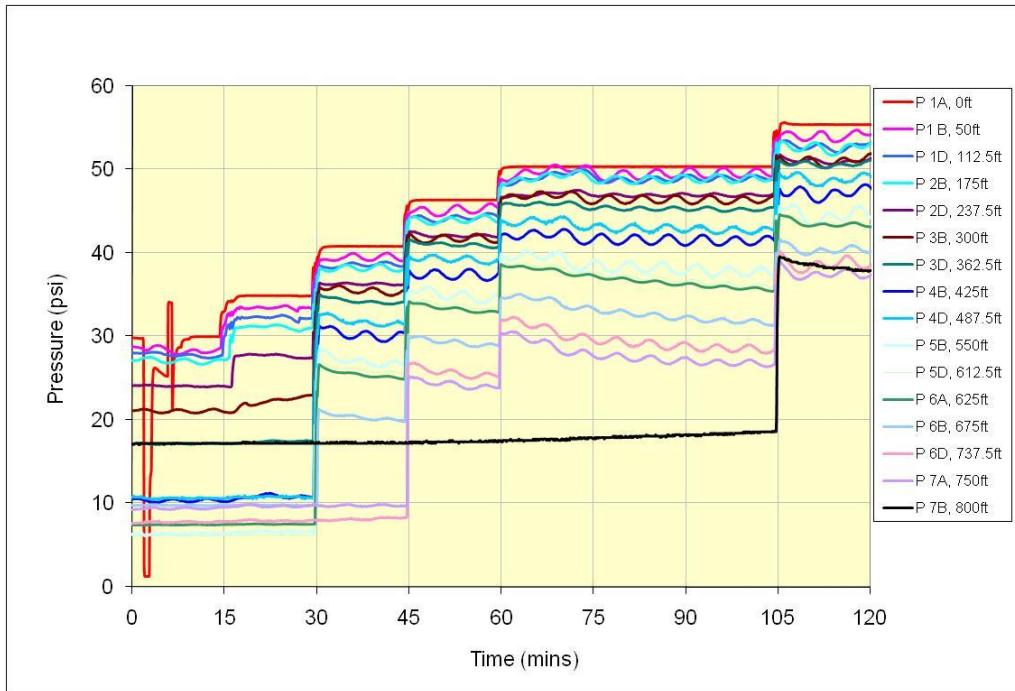


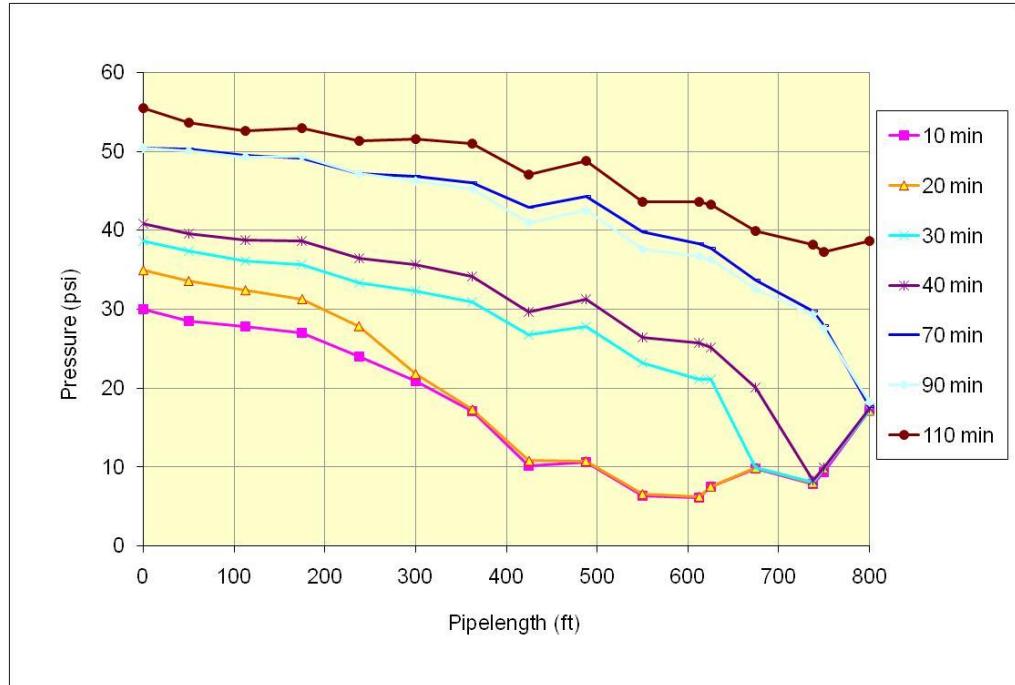
Figure 4.54: Example of test fluid cooldown profiles used in a flow loop test.

The test fluid may be flowing, static or a combination of both during the cooldown phase. The fluid is maintained at the test temperature for a pre-determined time period (aging). In the restart phase, the gel in the loop is pushed with nitrogen gas at the upstream entrance of the loop. The pressure is increased in steps with time and the pressure changes throughout the loop are recorded. An example of the pressure profile across the loop at various times in a test is provided in Figure 4.55. Yield is defined as a definite pressure increase at the last point in the loop and is seconded by a visual observation from a sight glass connected to the end of the loop. For

example in Figure 4.55, yield is seen at 105 minutes at flow loop location 7B (downstream end of flow loop). The sudden jump in 7B pressure shows that yielding has occurred everywhere in the loop. The pressure propagation through the loop is provided in Figure 4.56, which illustrates that the gel in this example breaks in sections and does not move as one whole plug.



**Figure 4.55: Pressure at various points in the flow loop during restart.**



**Figure 4.56: Pressure propagation through the flow loop during restart.**

Two different yield stress values were calculated from the restart data of the flow loop test. An average yield stress value is calculated based on overall pressure drop at the time of yield. The average yield stress underestimates the gel strength (when scaled up) by applying the pressure to extended length where gel may have already yielded.

The second yield stress value termed, maximum yield stress, is calculated based on the assumption that the gel formed may yield as a whole plug and may thus give the highest possible yield value. Even though this value may reflect the “true” gel strength of one particular unyielded section, when this value is extrapolated to pipes with large L/D, it would over estimate the restart pressure by assuming that large L/D pipes will also yield as a whole plug.

The gel strength ( $\tau$ ) is calculated as:

$$\tau = \frac{\Delta P}{4L/D}$$

where  $\Delta P$  is the differential pressure across the model pipeline, and L/D is the length to diameter ratio of the flow loop.

The gel strength obtained in the flow loop and rheometer are scaled up and used to calculate restart pressures that be seen in the field flowline/pipeline. The average and maximum yield stresses can be used to bracket the restart pressures. The various methods of calculating the restart pressure is described in §4.6 – Restart Modeling. These models are not fully robust, and more research is need to improve them in cases where restart pressure is a deciding factor in system selection or operating strategy.

#### 4.5.3.5 Lab Data versus Field Data

Some researchers noticed that rheometer measurements are more conservative than model pipeline measurements [34; 42]. While in some cases field data agree well with model pipeline measurements [43-44], most researchers have found that lab-scale measurements are more conservative than field data [32, 45-46]. Various hypotheses have been proposed to explain the discrepancy. In a series of U-tube tests, Russell and Gill (1954) [32], found that there is a minimum L/D, above which the yield value is dependent on the L/D. They observed slow pressure propagation (pressure wave effect) and believed that pressure distribution in the pipeline is not linear as a result of gel compressibility. Concluding that lab measurements are overly conservative, Gill and Russell (1954) [32] believed that the effective gel strength tends to be reduced in the field by slow cooling, gelled line pressure distribution effects due to compressibility, and gel autodestruction due to contraction. Verschuur *et al* (1971a) [45] modeled autodestruction and compressibility effects. For compressibility effects, they derived a differential equation whose solution is as follows:

$$\frac{L_{yc}}{D} = \frac{1}{2} \sqrt{\frac{\varepsilon_y}{c \tau_y}} \ln \left[ \frac{\tau_y + \sqrt{\tau_y^2 - \tau_o^2 + \frac{c \tau_y}{\varepsilon_y} \left( \frac{p_o}{2} \right)^2}}{\frac{p_o}{2} \sqrt{\frac{c \tau_y}{\varepsilon_y} + \tau_o}} \right]$$

where:

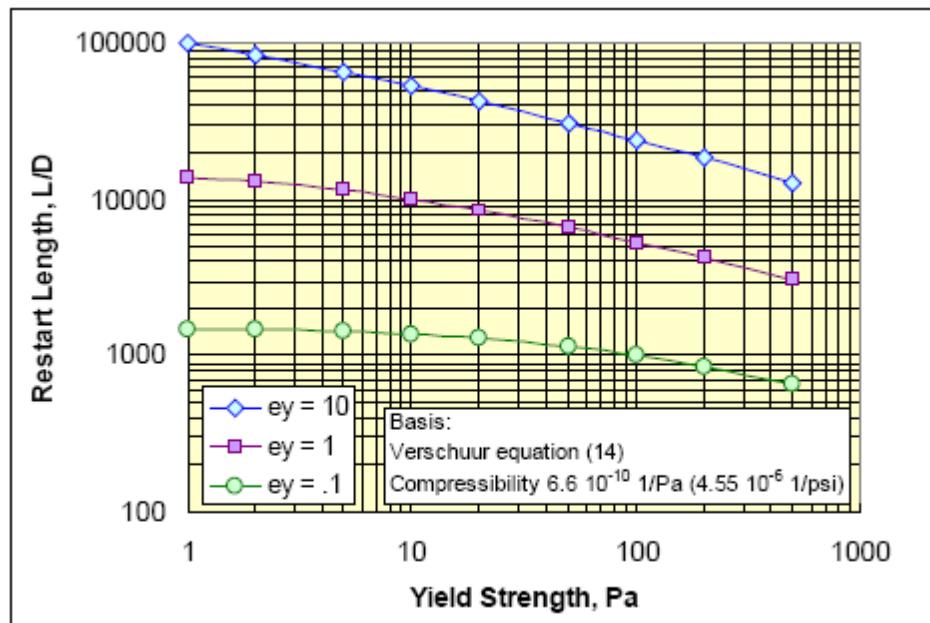
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$L_{yc}$	unyielded length from compressibility effects
D	pipe diameter
$\varepsilon_y$	displacement relative to diameter at yielding
c	compressibility ( $1/V \frac{dV}{dP}$ , $\text{Pa}^{-1}$ )
$\tau_y$	yield stress (Pa)
$p_o$	pressure at exit (Pa)
$\tau_o$	shear stress at exit (Pa)

By this concept, yield strength value from a small L/D model pipeline cannot be extrapolated to large L/D pipeline because the unyielded gel length may be much shorter than the pipe length under gelling conditions. In turn, the pressure required to restart a gelled pipeline is much lower because only a section of the pipeline is subject to yielding. Figure 4.57 shows the range of values that can be obtained for  $L_{yc}/D$  using the yield displacement  $\varepsilon_y$  as a parameter.  $L_{yc}/D$  is quite sensitive to  $\varepsilon_y$ , but  $\varepsilon_y$  is difficult to measure or estimate accurately.

In a later paper by Verschuur *et al.* (1971b) [46], a non-uniform shear stress distribution was observed, which supported Gill and Russell's hypothesis. They also observed much weaker gel when the effective compressibility is large (*i.e.* system is cooled but without thermal shrinkage compensation).

While Verschuur's (1971b) [46], maximum unyielded length theory explains why lab measurements can be overly conservative. The theory requires many parameters as inputs and those parameters are sometimes difficult to obtain.



**Figure 4.57: Range of unyielded restart lengths calculated from equation for compressibility effects.**

#### 4.5.3.6 Summary

- Various lab scale measurements are available to estimate crude oil gel strength.
- It is observed that rheometer based data are more conservative than model pipelines, and model pipelines are sometimes conservative compared to field data.
- The difference between model pipeline and field results is likely caused by factors such as autodestruction and compressibility that affect large pipes but have little or no impact on small-scale lab equipments.
- Many factors such as cooling rate, shear loading rate, aging time, and shear history have significant impacts on gel strength.
- While shear loading rate and shear history effects appear to be similar for all oils in all systems, cooling rate and aging time seem to act differently on different oils and different systems.
- Different models are available to describe complicated yielding process and explain observations. Each model may have been based on specific observations and thus may have limited applicability.

#### 4.5.4 CFD Modeling of Restart

Rigorous modeling of a restart is possible using Computational Fluid Dynamics (CFD), where the governing equations of fluid flow, using an adequate constitutive model for the waxy oil, are solved numerically in 2D or 3D and account for transients.

The waxy oil is modeled as a weakly compressible Bingham fluid, and the governing (weakly compressible) Navier-Stokes equations are written in terms of velocity, pressure, and stresses. Once the governing equations are formulated, numerical methods are used to discretize and solve the mathematical model. This task is non-trivial, as the mathematical setting for the model involves a non-smooth constitutive law (in the Bingham model), strong nonlinearities, weak compressibility, unsteady terms, and a “tough” variational saddle-point problem involving the pressure and stresses. We use an in-house state-of-the-art (least-squares) finite element formulation to efficiently tackle these numerical difficulties.

Simulation examples of successful restarts and restart failures in rigid pipelines, and simulation of cool restarts using peristaltic motions with small traveling wave amplitudes can be found in [47].

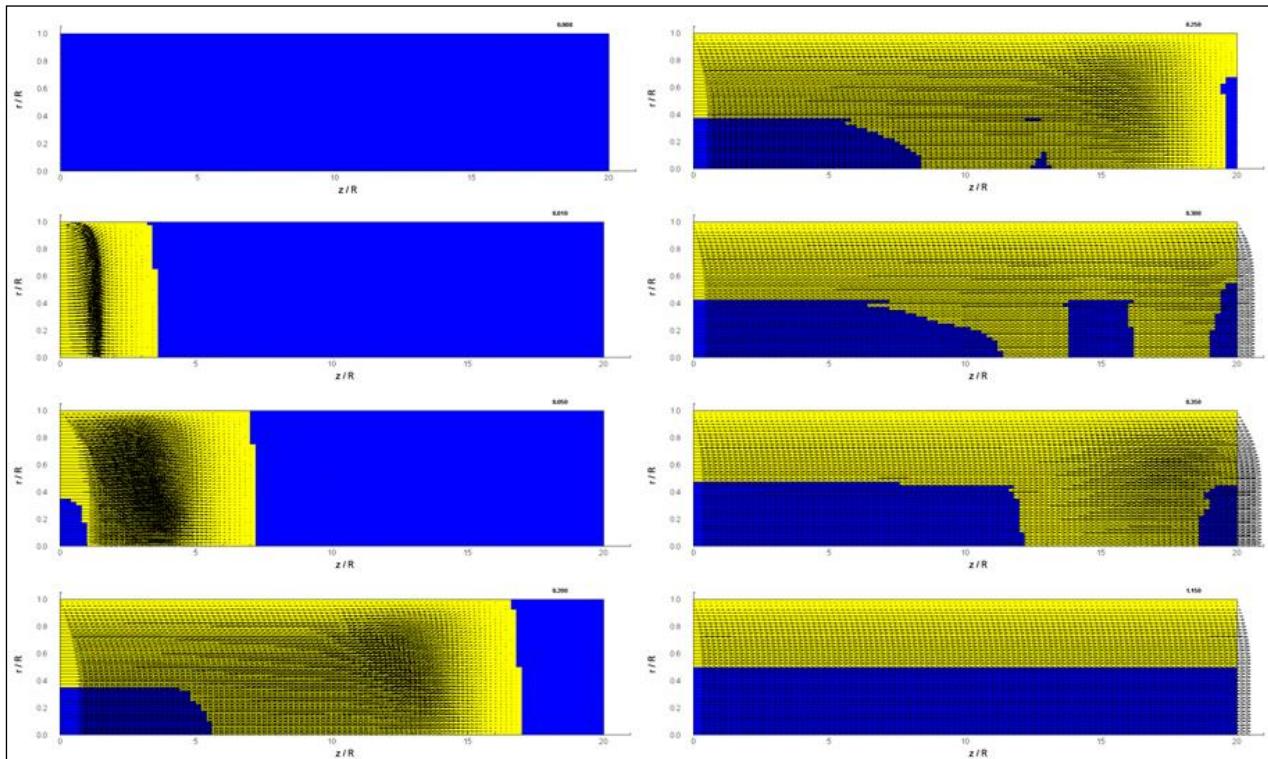
Figure 4.58 shows a simulation example of a successful restart. The simulation is performed in a time-accurate manner and is initialized with a completely gelled pipeline. At  $t=0$  a pressure difference is applied across the pipeline. The flow is assumed to be axisymmetric, implying that there is no angular dependence of the flow variables. This simplifies the analysis greatly, as only a two-dimensional slice of the pipe at a constant angle needs to be considered, albeit in a cylindrical coordinate system.

In this example the Reynolds number is set to be 1.0 and the Bingham number to be 4.0, and we choose  $\Delta P$  (the applied pressure difference) such that  $L_{\text{critical}} / R \sim 40$ , so that the compression front is strong enough to establish a flow field. Figure 4.58 shows instantaneous snapshots of the flow field at different times. The length of the pipe has been scaled by a factor of 5 for ease of presentation.

Figure 4.58 shows the un-yielded / yielded (blue / yellow) regions and velocity vectors of the flow field in time. We can clearly see the location of the compression front as all the fluid in its im-

mediate vicinity is yielded. At  $t \sim 0.27$  the compression front reaches the pipe outlet and the pipeline has been restarted. Here  $t$ , is a non-dimensional time measure.

In the steady state ( $t > 1.10$ ) there is plug flow in the middle of the pipeline, at exactly half the radius,  $r / R = 0.50$ . This is in accordance with the analytic solution for fully developed Bingham flow in a pipe, for a Bingham number of 4.0. In reality, the steady state plug flow region may never form due to thixotropic effects, which are not modeled here. Viscosity temperature dependencies and thixotropic effects could be easily accounted for in the constitutive equations if needed.



**Figure 4.58: A successful restart of a pipeline with rigid walls.**

Instantaneous snapshots of un-yielded (blue) / yielded (yellow) regions in the flow and velocity vectors. Note how the compression front yields the gel to initiate the flow field.

## 4.6 Restart Modeling

In case of an extended production shut-in, the fluid in the flowline will lose heat and cool to ambient temperature and will form a gel. Flow can be restarted by applying pressure on one end of the flowline to break the gel. Simple models are used calculate the pressure that should be applied to break the gel from the laboratory measured yield stress for the fluid. The models use the yield stress data from the rheometer/flow loop experiments. The restart calculation answers whether the total effective yield stress is low enough to allow restart of the flowline inventory by the maximum available pressure drop over the flowline (from well or pump pressure).

### 4.6.1 Models for Restart Pressure Calculation

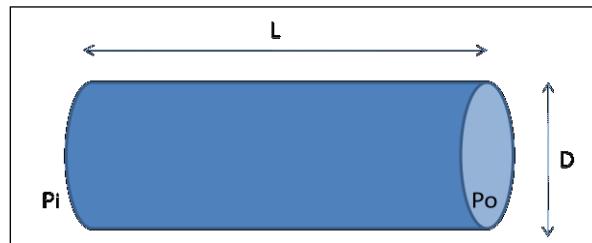
Various methods of determining the yield stress have been described in earlier sections. The restart pressure for a flowline can be calculated using the measured yield stress and variations in the yielding behavior:

1. Plug yielding – This model assumes that the entire fluid yields at once with a single yield stress. This is a conservative method and unrealistic in the case of long flowlines.
2. Sectional yielding – In this model, the fluid yields in sections owing to stress concentrations from fluid compressibility. This method gives lower restart pressures than the plug-yielding concept. The yield length and the maximum sectional yield stress data are needed for calculating the restart pressure.
3. Yielding that accounts for shear/thermal history – Different sections will yield at different stresses depending on their shear history and temperature at shut-in. This method gives lower restart pressures than method 1. It may also be lower than pressures from method 2, depending on the length of sections at different shut-in temperatures.
4. A combination of 2 and 3.

#### 4.6.1.1 Plug Yielding

The plug yielding model is the basic starting point for restart pressure calculation. This model assumes that the entire fluid in the line yields at once with a single yield stress. This is a conservative method but leads to unreasonably high restart pressures in the case of long flowlines. This model does not take into account other factors such as compressibility or auto-destruction that lead to reduced yield stresses and in turn lower restart pressures.

This calculation for this model is straightforward; L is gel length, D is pipe diameter,  $\tau_y$  is yield stress,  $p_i$  is inlet pressure,  $p_o$  is outlet pressure, and  $\Delta P$  is the pressure difference.



The force balance indicates that the axial force from pressure equals shear force on wall  
Solving for yield pressure:

$$\pi \frac{D^2}{4} \Delta P_y = \pi D L \tau_y$$

$$\Delta P_y = 4 \frac{L \tau_y}{D}$$

#### 4.6.1.2 Sectional Yielding

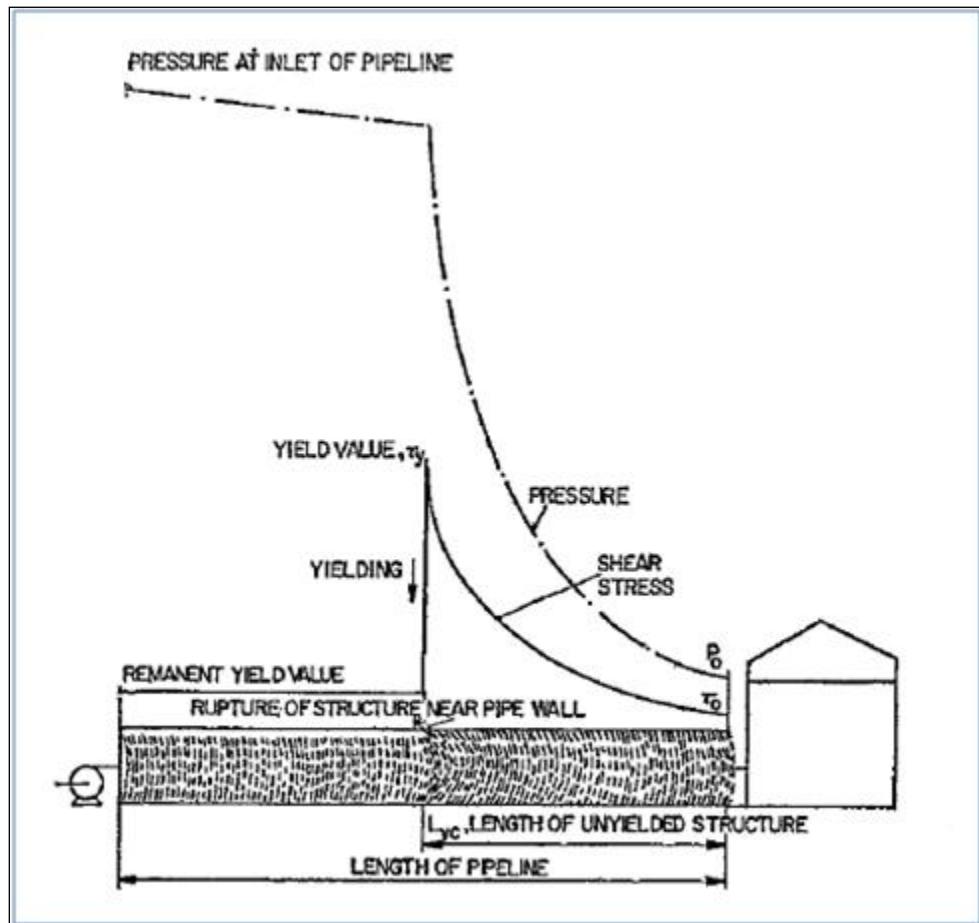
The gelled fluid yields in sections (local gel-breaking) owing to stress concentrations from fluid compressibility. The stress concentrations then propagate to further locations downstream in the line. After the gel is broken, there is a residual yield stress (like a Bingham fluid) that is the remnant yield value. In this case, the restart pressure is represented as a two-stress model by a combination of a high yield stress in a short section and a smaller yield stress in other sections. This behavior was explained by Verschuur [45] (Figure 4.59). Based on this theory, the restart pressure is divided into two parts:

$$\Delta P = \tau_{avg} 4(L_{total}/D) = \tau_{yield} 4(L_{yc}/D) + \tau_{residual} A(L_{total} - L_{residual})/D$$

The yield length and the maximum sectional yield stress data are needed for calculating the restart pressure. This method gives lower restart pressures than the plug-yielding concept. The residual yield stress is calculated as:

$$\Delta P = \tau_{avg} 4(L_{total}/D) = \tau_{yield} 4(L_{yc}/D) + \tau_{residual} A(L_{total} - L_{residual})/D$$

The variation in restart pressures obtained by the ‘plug yielding’ and the ‘sectional yielding’ is demonstrated by the example in Table 4.7 calculated for an Asia-Pacific fluid [49].



**Figure 4.59: Pressure and shear stress distribution in a partially yielded gel (Verschuur et al 1971) [45].**

**Table 4.1: Example of Estimated 18" Pipeline Restart Pressures for the 'Average' (Plug Yielding) and the 'Combined' (Sectional Yielding) Methods**

Approach	Deepwater Length	Total L/D	$L_{yc}/D$	$L_{res}/D$	$\tau_y$	$\tau_{res}$	Safety Factor	$\Delta P$
	km				Pa	Pa		psi
Average	22	52493	52493	0	20	0	2	1218
	22	52493	52493	0	15	0	2	914
	35	83511	83511	0	20	0	2	1938
	35	83511	83511	0	15	0	2	1453
Combined	22	52493	1000	51493	220	16	2	1211
	22	52493	1000	51493	140	16	2	1118
	22	52493	1000	51493	95	16	2	1066
	22	52493	1000	51493	220	11	2	912
	22	52493	1000	51493	140	11	2	820
	22	52493	1000	51493	95	11	2	767
	35	83511	1000	82511	220	16	2	1787
	35	83511	1000	82511	140	16	2	1694
	35	83511	1000	82511	95	16	2	1642
	35	83511	1000	82511	220	11	2	1308
	35	83511	1000	82511	140	11	2	1216
	35	83511	1000	82511	95	11	2	1163

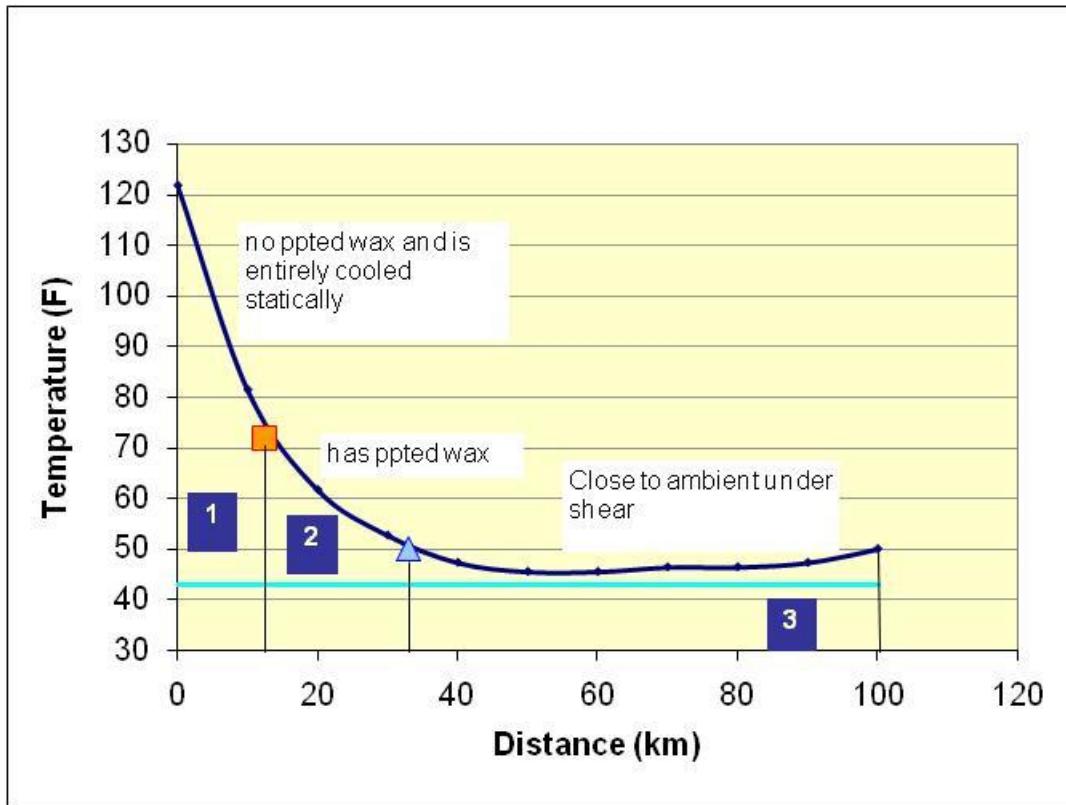
#### 4.6.1.3 Shear-Thermal History Dependent Yielding

This model takes into account the variation in temperature and shear in the flow line when flow is shut-in. In a flowline/pipeline with temperature variations, sections cool-down very differently to form a gel. This would apply to the fluid flowing from a well head to the host or from a host to an export terminal. The fluid may be at a higher temperature than the cloud point to start with and can go below the pour point in some sections. Based on this, the pipeline/flowline can be broadly split in three different sections:

- Section 1 – Fluid is above the cloud point at shut-in and cools down under static flow conditions to ambient T (“static cooldown”).
- Section 2 – Fluid is below cloud point at shut-in. Some wax precipitate was sheared before shut-in (“mixed cooling”), weakening the gel formed upon cooldown.
- Section 3 – Fluid is close to ambient T at shut-in. All precipitate has been sheared before shut-in (“dynamic cooling”).

An example of described sections is provided in Figure 4.60 where they are overlaid on the steady state temperature profile of a fluid in a 100km long flowline from a host to the export terminal. The subsea temperature (42F) is indicated in light blue color. Section 1 is where the fluid is above the cloud point (72F). Section 2 has the fluid above the pour point (50F) and Section 3 has the fluid flowing below the pour point under normal operation conditions.

The restart pressure for this flowline can be calculated by applying different yield stress values to the three sections based on shear (thermal) history after shut-in. For example, the rheometer yield stress (static cooling) and rheometer yield stress (dynamic cooling) both measured at field ambient temperature can be applied to Sections 1 and 3 with the yield stress for the middle section determined by interpolation. The result of this calculation is provided in Figure 4.60 [50]. Based on these calculations, the restart pressure for 100 km flowline is estimated to be ~260 psi. This would still be a conservative estimate as the rheometer measured yield stresses are higher than those in the field as discussed in the 'Gel Strength Measurement' section.



**Figure 4.60:** Example of a steady state temperature profile in a 100km flowline during fluid flow with a fluid cloud point of 72F and pour point of 50F.

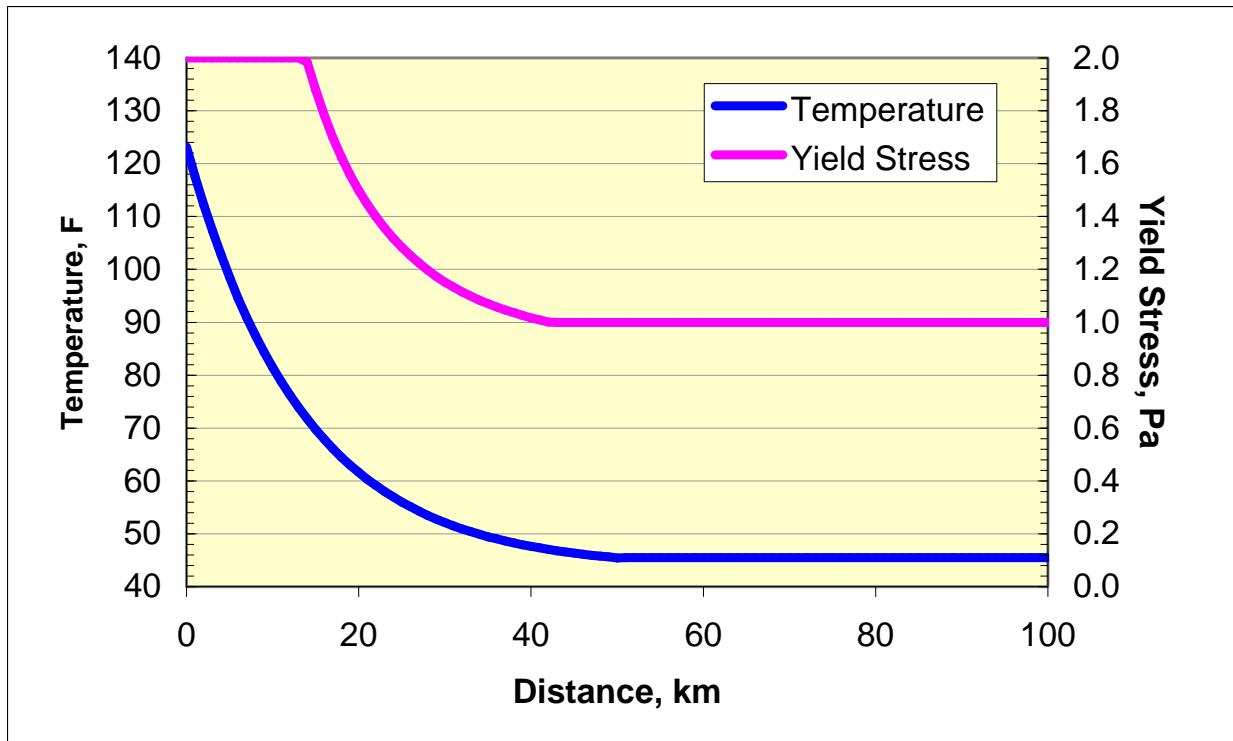
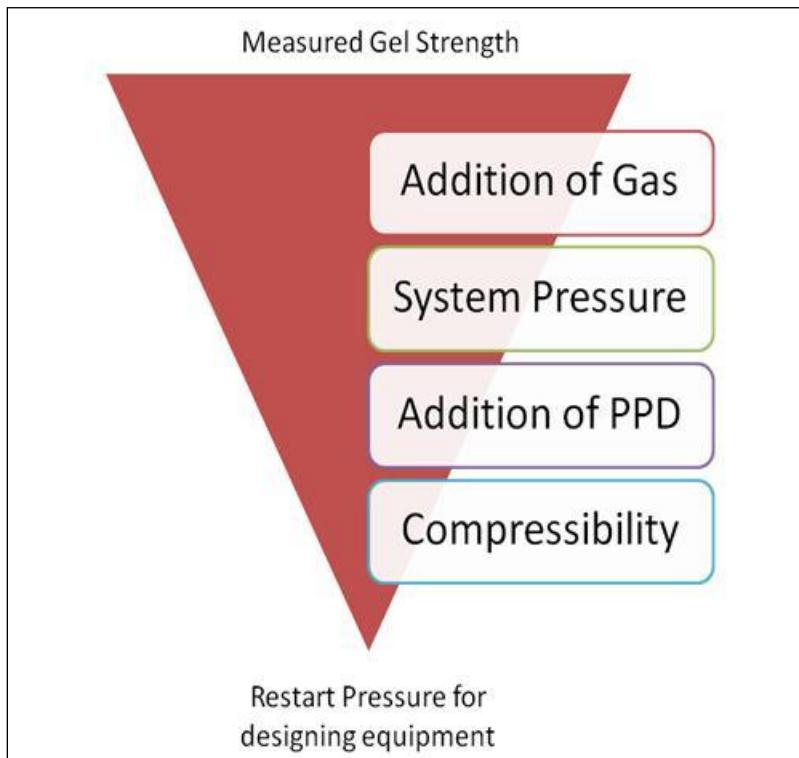


Figure 4.61: Calculated yield stress values at various lengths for a 100km flowline.

#### 4.6.2 Other Factors

Currently, the restart model does not take into account other factors that would further reduce the calculated restart pressure. These factors include the effect of gas in the system, system pressure effects, efficiency of a pour point depressant. A field that will have increasing gas production will have progressively decreasing restart pressures. This can be used to design PPD injection rates. If efficiently managed, the need for bigger pumping capacity in the event of a gel is eliminated. Recent work suggests that the pressure effects are not negligible and should be considered in restart models. At elevated system pressures, the gelation temperature was found to increase while it formed a weaker gel. A power-law relationship was found to exist between system pressure and yield pressure when the pipe system was bled prior to restart, while the time required to break the gel decreased as a logarithmic function of yield pressure. A restart model that takes these factors into account will have to be developed to tighten predictive capability.



**Figure 4.62: Other factors that reduce the restart pressure calculated from rheometer/flow loop measurements.**

## 5. Wax Management Options

### 5.1 Introduction

A full strategy is composed of strategy components and management options. Figure 2.3 shows an analogy of the wax management strategy to the HEMP process. From this, the strategy can be thought of as having 3 components: prevention, maintenance and remediation. (Maintenance is part of the prevention category but is listed separately to distinguish it from complete risk avoidance.) In developing a strategy such as that shown in Figure 2.3, the full range of options must be known. Options for managing deposition fall into 3 main groups: thermal, chemical and mechanical.

Table 5.1 shows a notional matrix for developing a strategy. It is necessary for a strategy to have at least one prevention/maintenance option and one remediation option. (Although, in the extreme case, the prevention option could be “do nothing” and the remediation option could be “abandon the line.”) The number and type of options in each category are determined by the PDT based on their risk tolerance and the reliability of the management methods used. Take as an example an insulated dual flowline system. In Table 5.1, the prevention option is heat retention. In late life, assume that flow rates and arrival temperatures drop and prevention is no longer possible. Therefore, the maintenance options are periodic pigging and hot oiling to remove wax. Should this fail, the remediation options are progressive pigging and riser-end coiled tubing to remove heavy deposits.

**Table 5.1: Strategy Matrix Example**

	Insulation	Pigging	Hot-Oiling	Progressive Pigging	In-situ Heat	Coiled Tubing
Prevention						
Maintenance						
Remediation						

The cost of adding options may be high or low, depending on system configuration. In a dual flowline system, the cost of adding a topsides pig launcher is minor. The CAPEX of hot-oiling may be negligible if the system is already in place for start-up heating to prevent hydrates. Similarly, CAPEX for paraffin inhibitor would be small if there is spare umbilical capacity. On the other hand, coiled tubing can be very expensive if topside piping is not configured for CT access. And, of course, the assumed system is expensive; CAPEX for dual flowlines is large compared to a single line.

In the sections below, we describe some of the management options and their advantages and disadvantages.

## 5.2 Deposit Management Options

### 5.2.1 Prevention

#### 5.2.1.1 Insulation

Wax deposits can be prevented by maintaining the pipe wall above the CWDT at all locations and times. The steady-state temperature profile of a line can be given approximately by

$$T(x) = T_{amb} + (T_{inlet} - T_{amb}) \exp(-K x)$$

$$K = \frac{4U}{\rho C_p D V}$$

Where x is distance, D is diameter,  $\rho$  and  $C_p$  are fluid properties, V is speed and U is overall heat transfer coefficient. The fluid temperature approaches ambient exponentially fast with distance. To keep temperatures high, U values should be low, velocities high, or lines short.

There are a range of commonly selected insulation options. Costs increase significantly as U value decreases.

- Bare (U ≈ 60 BTU/ft<sup>2</sup>-hr-F; 340 W/m<sup>2</sup>-K)
- Wet insulation (U ≈ 0.8 BTU/ft<sup>2</sup>-hr-F; 4.5 W/m<sup>2</sup>-K)
- Buried (U ≈ 0.6 BTU/ft<sup>2</sup>-hr-F; 3.4 W/m<sup>2</sup>-K)
- Pipe-in-pipe (U ≈ 0.2 BTU/ft<sup>2</sup>-hr-F; 1.1 W/m<sup>2</sup>-K)

It may not be practical or even possible to stay above CWDT for all stages of the project life. In late life, reduced production rates may cause temperatures to fall, and wax will deposit. However, the  $\Delta P$  caused by the thicker deposit may be offset by the lower flow rate, and no prevention may be required. In addition to economics, there may be other FA requirements (e.g., cooldown times may be sufficient with buried lines; reducing platform processing temperatures at high production rates) that argue in favor of higher U values.

#### 5.2.1.2 Chemical Inhibition

Paraffin inhibitor (PI) can reduce but not eliminate wax deposition. The inhibitor efficiency is often claimed to be in the 60 to 90+% range. Therefore, PI can increase the time between maintenance cleanings or remediation procedures. Field performance of PI is difficult to verify. If pigging is also used, then pig  $\Delta P$  or wax returns can be used to get an idea of effectiveness. PI is a continuous OPEX that must be evaluated.

#### 5.2.1.3 Coatings

In the past few years, Shell has been testing coatings for their resistance to deposit adhesion. Both commercially available and proprietary coatings have been tested. We have observed correlations between surface roughness and the minimum wall shear stress required to prevent deposits. Results are very promising, with some coatings expected to reduce the threshold shear stress by an order of magnitude compared to polished steel pipe. This might eliminate wax deposits at even moderate flow rates (say, less than 2 m/s). This is a technology that Shell expects to deploy within 2-5 years.

#### 5.2.1.4 Electrically Heated Flowlines

Shell to date has only used pipe-in-pipe electrical heating (*i.e.*, Serrano field in GoM); the PIP adds significant CAPEX. It was designed for managing hydrates under shut-in conditions, by heating the stagnant fluid. The only heat loss was convection to the environment. To use EH to prevent wax deposition, the system would have to heat the fluid under flowing conditions as well, resulting in a much higher heat duty. To use EH for wax removal, the system could be shut in but would require much higher temperatures than for hydrate removal. Either application (wax prevention or removal) would require significantly more capacity in the power generation and distribution system. The feasibility and economics of this have yet to be fully evaluated.

More recently, SINTEF [92] has developed direct electrical heating for insulated lines by strapping the power cable (“forward conductor”) to the pipe and using the pipe as the reverse conductor. It promises to be less expensive but does not solve the power requirements for wax management.

Serrano experience: Serrano’s EH was designed to be turned on when the field was shut-in. The EH was included for hydrate concerns. Operations speculated that the effect on paraffins may have been more negative than positive – possibly hardening the wax deposits and making them less adhesive to the wall. When the line was blown down, a line blockage was formed. One hypothesis is that the wax sloughed off during blowdown and accumulated in the riser base.

Flowloop riser tests using a waxy condensate (Coulomb C2/C3 blend) were conducted at WTC in 2009 to attempt to verify this blowdown hypothesis, but results were inconclusive. Wax was collected at the riser base, but the amount was rather small. Depressurization rate was not well controlled, so the effect of depressurization rate on wax adhesion could not be verified.

#### 5.2.1.5 Cold Flow

Cold Flow is a new technology in the pilot stage, which is a subsea heat exchanger that rapidly cools the crude, forms wax precipitates and deposits and is cleaned by a recycle pig. The slurry formed is then transported at ambient temperature with low risk of deposition. The primary advantage of Cold Flow is that it would enable long, bare single-flowline tiebacks with greatly reduced costs and risk of plugging. Plans have been developed for a field pilot at the Rocky Mountain Oil Test Center in Wyoming; the project is currently seeking an external partner to share costs.

### 5.2.2 Maintenance

Maintenance cleaning of wax deposits is usually achieved by scraper pigs. Most Shell-operated pipelines are cleaned with slightly oversized disk pigs, launched and retrieved manually from topsides facilities. Hot-oiling is also shown to be a viable method for insulated systems.

Export lines are frequently pigged, because there is easy access at both ends and no production interruption from pigging. However, subsea systems may not be pigged for the following reasons:

- In early life, flow rates are high and there is no wax deposition.
- An OM will often not agree to the deferment every pigging event will take.

- Even if a pigging frequency is agreed to from the start, the uncertainty in deposition rate estimates lead to concerns that the deposits are thicker than predicted and thus there is a risk of sticking a pig.
- In late life, the perceived risk of sticking a pig is considered greater than the benefit of cleaning the line. Since lower rates mean less pressure drop, the decrease in line diameter from deposits may not result in noticeable deferred production.

There is clearly an opportunity for greater feedback between operations and design and a need to reduce uncertainty in deposition estimates and pigging risks.

#### 5.2.2.1 Types and Selection of Pigs

There is a wide variety of maintenance cleaning pigs available in the industry.

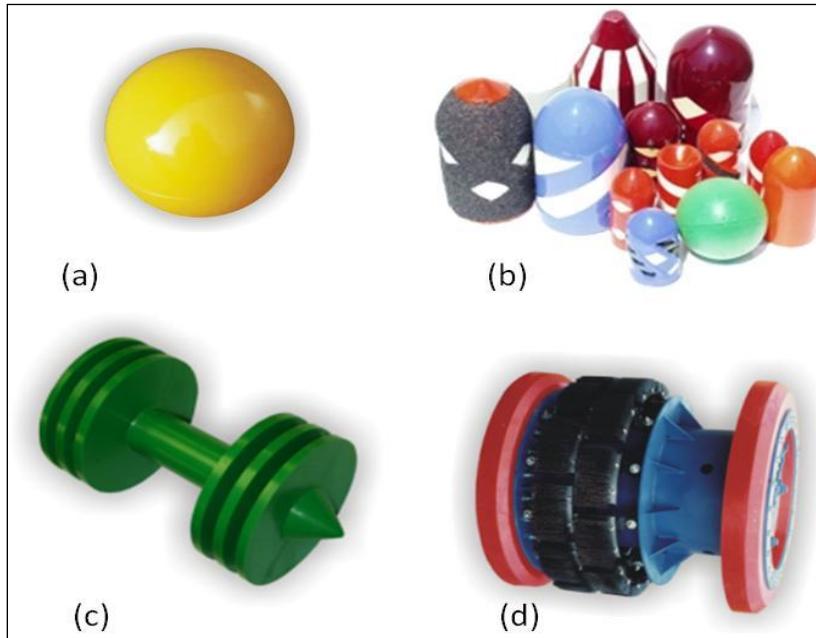
**Spheres:** These are used largely for sweeping liquids from a line. Anecdotally, there is speculation that they could actually squeeze liquid out of a wax deposit without removing the solids, which might make the deposit harder. They also may get trapped in wide spots (tees, wyes, expanded sections) where liquid is able to go around them.

**Foam pigs:** These are typically molded from polyurethane foam and can have other strips or abrasives bonded to them for rigidity or scraping. They are soft and very deformable, making them safe for lines where the minimum restriction is not known. Conversely, they do not do a thorough job of cleaning.

**Solid cast pigs:** These are usually made of polyurethane and molded as a single piece. The pig can have disks or cups, and each disk can have a specified diameter, thickness and hardness.

**Mandrel pigs:** These have a central tube (usually metal) onto which various tools (disks, cups, brushes, metal studs, and abrasives) can be attached to perform specific tasks. These are more aggressive and are regarded by some as having higher risk of becoming stuck.

**Gel pigs:** These are highly viscous gelled liquid systems. There are numerous applications for gel pigs, including removing debris, sweeping liquids and distributing chemical. As a liquid, although highly viscous, the gel can be pumped through any line which will accept liquids. A major advantage is that the risk of sticking a gel pig is almost eliminated.



**Figure 5.1: Types of Pigs: (a) Sphere, (b) Foam, (c) Cast and (d) Mandrel.**

#### 5.2.2.2 Pigging Guidelines Workshop

A US wax management guidelines workshop (SIEP-EPT-PDS, SEPCo, Shell Pipeline Company and SGS (US) Inc.) was held in August 2002. SGS Flow Assurance was asked for recommendations/assessments in 3 areas: wax deposition model accuracy, plugging risks while pigging, and plugging risks if wax is left in place without pigging. These guidelines were based on only limited field data. There is a serious need for surveillance and validation data to improve them.

At the time of the workshop, the model uncertainties were qualitatively assessed:

- $P_{50}$ : Standard model output for deposit thicknesses and volumes
- $P_{10}$ : Twice model output; *i.e.*, there is a 10% chance that the deposit is twice as thick
- $P_{90}$ : Half the model output; *i.e.*, there is a 90% chance that there is at least half the wax.

#### Risks during Proactive (Maintenance) Pigging

Proactive pigging is defined as pigging often enough that (i) deposits are kept small enough to avoid reduced production and (ii) wax is removed in a single pig run. In most cases, these deposits are too small to detect by ordinary surveillance means.

It was agreed that the basis for proactive pigging with disk pigs is the pressure drop ( $\Delta P_{\text{plug}}$ ) required to push the wax plug formed by the pig. Probabilities of sticking the pig were estimated to be

- $P_1: \Delta P_{\text{plug}} = 50 \text{ psi}$
- $P_{90}: \Delta P_{\text{plug}} = 500 \text{ psi}$ .
- No  $P_{10}$  or  $P_{50}$  limits were proposed or recommended.

### Risks during Progressive Pigging

Progressive pigging is defined as the removal of wax by pigging in stages. Progressive pigging is one alternative to use when too much wax is predicted to be removable in a single pig run. A sequence of pigs are run, progressing from smaller, softer pigs to larger, harder pigs until the line is cleaned. Levels of risk were proposed in the workshop:

$P_{50}$ : deposit volume equivalent to  $\Delta P_{\text{plug}} = 500 \text{ psi}$

$P_{90}$ : deposit volume equivalent to  $\Delta P_{\text{plug}} = 1000 \text{ psi}$ .

Unfortunately, there is no available data to validate these numbers even approximately. To predict  $\Delta P_{\text{plug}}$  requires an estimate of deposit volume and hardness, but we know of no cases where such predictions were made prior to or validate during a progressive pigging operation.

### Risks of Self-Plugging Lines (Wax Left in Place)

It was agreed that the risk of leaving wax in place would be based on maximum predicted deposit thickness  $\delta$  relative to the line inner diameter  $D$ . A  $P_{10}$  level of  $\delta/D = 2.5\%$  was proposed in the workshop. After subsequent discussion, Shell Global Solutions recommends the following:

$P_{10}$ :	$\delta/D = 2.5\%$ ,	90% open cross-section
$P_{50}$ :	$\delta/D = 5\%$ ,	81% open cross-section
$P_{90}$ :	$\delta/D = 25\%$ ,	25% open cross-section

Again, these are estimates because little or no validation data are available. Anecdotally, few if any cases have been reported of lines plugging off with wax *except when pigging*.

#### 5.2.2.3 Standard Pigs

For (nominally) zero-bypass disk pigs, the usual criterion for pigging interval is based on the pressure drop across a plug if all the deposit was scraped into a single plug. Because  $V_{\text{plug}}$  is usually below detectable limits (using current techniques of flowing pressure drop or tracer tests as indicators), it must be estimated from deposition models.

The Shell recommended pigging interval is  $\Delta P_{\text{plug}} = 50 \text{ psi}$ . This limit is often increased to 100 or 150 psi depending on the confidence of the operator. The pigging interval is the time it takes to deposit  $V_{\text{plug}}$  on the pipe wall.  $\Delta P_{\text{plug}}$  is converted to deposit volume using the following force balance:

$$L_{\text{plug}} = \frac{D}{4} \frac{\Delta P_{\text{plug}}}{\tau_w}$$

$$V_{\text{plug}} = \frac{\pi D^2}{4} L_{\text{plug}} = \frac{\pi D^3}{16} \frac{\Delta P_{\text{plug}}}{\tau_w}$$

To calculate  $V_{\text{plug}}$ , the wax-plug wall shear stress  $\tau_w$  is also required. Laboratory and field measurements indicate the range of  $\tau_w$  is between 0.1 and 1.0 psi or even somewhat higher [53]; it is a strong function of oil content in the deposit. Shell Global Solutions uses a value of  $\tau_w = 0.3 \text{ psi}$ , corresponding to deposit oil contents of approximately 50% wt.

#### 5.2.2.4 Bypass Pigs

Bypass pigs are similar to standard pigs except that some flow is allowed to pass around or through the pig. The purpose is to allow removed wax to be swept away by the bypass flow and prevent the buildup of a solid plug that could cause high  $\Delta P$ . Bypass pigs require some care to determine the operating envelope: too little bypass and the solids are not swept away; too much bypass and the pig does not move. A study was done for the Malikai development [51; 54], and a methodology for determining the operating envelope was presented.

Bypass can be achieved by cutting a channel through the pig body, ports through the disks or by sizing the disks to be smaller than the pipe ID. For example, Shell Pipeline Company uses bypass in a progressive pigging sequence. The bypass pigs are undersized disk pigs, typically 99% ID (2% bypass area). Alternatively, they use 4 to 6  $\frac{3}{4}$ " holes in the pig disks for bypass.

The criterion for selecting bypass pigging frequency is usually either maximum deposit thickness or total volume. The volume criterion is usually much greater than that for the standard disk pig – say, 50 barrels. This criterion does not appear to have a firm physical basis. The thickness criterion can be directly connected to the operating envelope [51] and is the preferred method. The Malikai study was done using 2 mm maximum thickness; information shared by Conoco-Phillips on their Kerisi field (Indonesia) suggests that they may have used bypass pigs on deposits of 6 mm or more. Kerisi oil has a high pour point and likely produces deposits with high oil content (low yield stress), so lower thicknesses would be recommended for bypass-pigging most oils.

#### 5.2.2.5 Gel Pigs

Gel pigs can actually flow in a recirculating fashion, especially if the gel has a shear-thinning rheology. High shear along the pipe wall drags the outer layer backward while the core of the gel flows more like a solid plug. This can be used to pick up debris and entrain it into the gel itself.

Gel pigs are sometimes used to move a stuck mechanical pig. If the pig has lost its seal and is unable to establish enough pressure drop to move, the gel can create the seal and allow the pig to restart. This is also sometimes done with low-density foam pigs.

#### 5.2.2.6 Hot Oiling

In well-insulated systems, hot-oiling can be used to remove deposits. Many deepwater subsea systems are designed with round-trip hot-oiling capabilities in order to do warm start-up to avoid hydrates. In such cases, wax management by hot-oiling would be an easy solution. Since wax solubility increases exponentially with temperature, hot-oiling is most efficient if the oil contacting the deposits is in the 50-70 °C range.

In deepwater subsea Gulf of Mexico operations, a number of assets were evaluated for possible hot-oiling remediation. Shell Global Solutions developed models that combined thermal/ hydraulics, thermodynamics and mass transfer to estimate the time and temperature required for effective wax removal [55]. One such case was the Llano – Habañero system [56]. These recommendations were carried out in the field operations. From SEPCo IMSA surveillance records:

"Since the new sidetrack of Habañero #1 has come online in Oct 07, it has been arriving to Auger below its CWDT. In January, we flowed the wells 1 and 2 together to remediate

the paraffin deposition. The remediation appeared successful based on acoustic responses topsides. The acoustic responses were assumed to be sand that was trapped in the deposited paraffin in the flowline. As the paraffin was removed so was the sand. After acoustic activity died down it was assumed that the paraffin had stopped being removed. Also significant quantities of paraffin were caught in the Norman filters during the initial remediation.

In March of 08 an agreement was made within Shell and with partners that paraffin would be dealt with by hot oiling at a 6 month frequency. We hot oiled at the six month frequency, but in addition we performed a tracer test to quantify the amount of paraffin in the line. The results of the tracer test indicated that the amount of paraffin build-up reduced significantly after 10 hours of hot oiling."

### 5.2.3 Remediation

When deposit volume and/or thickness are large, there is a risk that conventional pigging can plug the system. In this case, alternative methods must be used to remove the deposits.

#### 5.2.3.1 Progressive Pigging

In progressive pigging, a sequence of pigs is used, going from smaller, softer pigs to larger, harder pigs. Here is an example from Shell Pipeline Company (Owen Borne).

The sequence often starts with light foam pigs (2-lb and 5-lb density) and continues with disk pigs (usually polyurethane) of increasing diameter. Next, undersized polyurethane disk pigs may be run. These are typically 99% of ID; alternatively, 4 to 6  $\frac{3}{4}$ " holes are drilled in the pig disks for bypass. Finally, oversized pigs are used with disks that are 1% and 3% greater than line ID.

Progressive pigging requires a great deal of judgment. If operations become too aggressive too quickly, then a large, hard pig may remove too much wax and plug the line. It is hard to get good quantitative data on pig performance from one run before selecting the pig for the next run. The amount of wax removed is hard to measure since it may flow through the pig trap. Instead, qualitative observations about pig wear may be used to infer the nature of the remaining deposit.

#### 5.2.3.2 Chemical Solvents

Chemicals can be injected into the line and either flowed or soaked to dissolve and remove deposits. This was successful at Gannet D (§6.3), where a round-trip flowline was filled with chemical, which was then circulated to remove the wax. This approach was partially successful at Mensa (§6.4), where a well tieback to a subsea manifold was filled and soaked. This system was unable to be circulated, which is one of the reasons it was not as successful as Gannet D.

#### 5.2.3.3 Hot Oiling

This is exactly the same as the hot-oiling method in §5.2.2.5. However, thicker deposits require longer hot-oiling. If deposit volumes are sufficiently large, there is some concern about the carrying capacity of the hot oil if it is recirculated for a long time through the flowline. This can be addressed by modeling.

#### 5.2.3.4 In-situ Heating

Exothermic heating can be used to remediate wax deposits in lines. The method injects sodium and ammonium solutions (e.g.,  $\text{NaNO}_2$  and  $\text{NH}_4\text{Cl}$ ) into the flowline, which react to release large amounts of heat and nitrogen. Shell has never used this method, but it has been used extensively by Petrobras (more than 200 applications), who report that they have melted flexible flowlines more than once. Baker Petrolite has developed a field service to apply this method. Usually, operators are discouraged by the perceived risk to the flowline, possible HSE concerns and the complexity of the field operation.

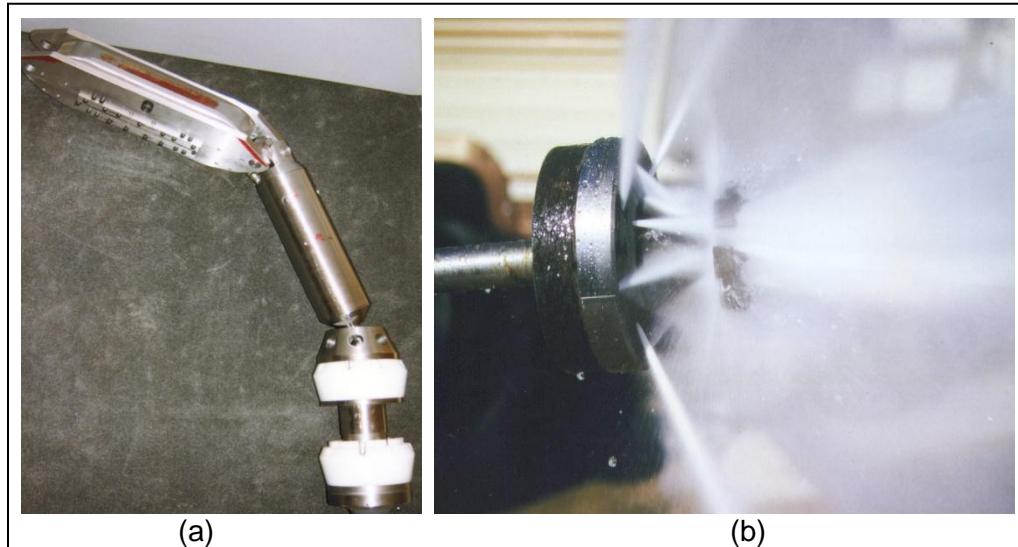
#### 5.2.3.5 Line Burial

As noted in §5.2.1, the difference in  $U$  factors for bare and buried pipe can be 1-2 orders of magnitude. Therefore, burial can be used for heat retention either at the design stage or as remediation. §6.4 shows the Coulomb example, where the fluid from one well was much waxier than expected. Burial was estimated to increase Coulomb riser base temperature by 30-40 °F.

#### 5.2.3.6 Hydraulically Activated Power Pig (HAPP)

HAPP (the “jet pig”) is a bypass pig with an internal braking system. Figure 5.2 shows a picture of the pig assembly, including its hydraulic pump/brake module, a reservoir for hydraulic fluid, the seal module and a jet head. A high  $\Delta P$  is developed across the pig and converted into a high velocity fluid stream to jet deposits from the wall and break them into small pieces. Because the fluid moves much faster than the tool (~50 times faster), the particles are swept away with no chance of creating a plug. Therefore, much thicker deposits can be remediated than with ordinary bypass pigs. It has a long travel time (speed is ~0.1 – 0.2 m/s); it is suited to export lines but would cause significant production deferment in a subsea flowline.

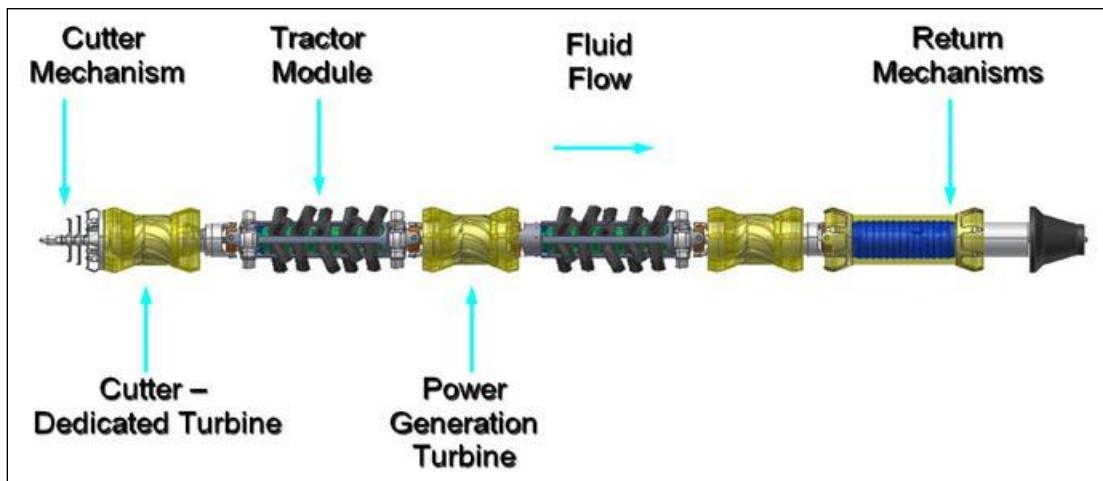
HAPP was developed by Transglobal, Ltd and Shell E&P Technology Company in the 1990s and underwent a successful field trial in 2001 [57]. Although some further development was required, the tool was nearly market ready at that time. It has remained a tool in search of a customer.



**Figure 5.2: Photos of (a) pig assembly (brake, fluid reservoir and seals) and (b) jet head.**

### 5.2.3.7 Autonomous Tractor (“Crawler Pig”)

In the course of evaluating options to remediate wax in Gannet D (§6.4), Shell Expro initiated the development of the crawler with Astec Developments [58]. The crawler is a novel tetherless counterflow device (Figure 5.3); that is, it crawls upstream against the flow. Turbines in the tractor generate power to activate tractor feet on the tractor module and to turn a cutting mechanism. The operating envelope of the tractor has limits; fluid velocity has to be high enough to generate sufficient power but not so high that it overcomes the friction between the tractor feet and the pipe wall. The major problem was that the cutter did not pass performance tests for cutting wax. The clearance between cutting blades and the wall has to be quite small; even 1-2 mm residual deposit might impede the turbine seals. These problems might not be insurmountable, but the project was not funded for further development. Astec was acquired by Weatherford in 2003, but further developments are not known.



**Figure 5.3: Drawing of the autonomous tractor.**

### 5.2.3.8 Coiled Tubing

In coiled tubing intervention, tubing with a jet head is inserted into a well or flowline to blast away deposits. Flow goes down the tubing and returns in the annular space between the tubing and the pipe wall. This is a well established, robust technique that has been shown to remove all kinds of deposit materials and can even remediate total blockages (since it does not require through flow to work). It has several limitations. First, the weight and space requirements are large, often exceeding available space on offshore platforms; therefore, vessel operations might be required. Second, it cannot go through tight bends; therefore, piping on topsides must be designed to accommodate it. Third, there are limits to the distance that the tubing can be pushed. This has been enhanced by some vendors who have added “skates” to reduce friction with the pipe wall or pulling devices such as “umbrellas” (pop-up disks between the tubing and the pipe that can be used to push the jet head) or fluid powered tractor devices to pull the tubing. Coiled tubing was used in the Serrano remediation job discussed in §6.4.1.

## 5.2.4 Wax in Place

This approach is to let wax deposit, hoping that its growth is limited by self-insulation or increased shear caused by decreased diameter. As noted in §5.2.1.1, it may be practical to leave

wax in place in late life of an asset, and then allow it to deposit wax when few recoverable are at risk. Alternatively, late-life burial might provide an extended wax-free period. As noted in §5.2.2.2, we do not have validated guidelines for the self-plugging risk associated with wax-in-place.

In Table 5.2, we show these options along with some advantages and disadvantages.

**Table 5.2: Wax Deposition Management Options in Subsea Systems**

<b>Strategy</b>	<b>Method</b>	<b>Single Flowline</b>	<b>Dual Flowline</b>	<b>Advantages</b>	<b>Disadvantages</b>
<b>Prevention</b>	<b>Heat retention</b>	+	+	Effective for moderate-length subsea offsets	High CAPEX
	<b>Inhibitors</b>	+	+	Claimed to reduce deposition by 80+%	High OPEX
	<b>Coatings</b>	+	+	Could prevent deposits at low-to-medium wall shear stress	In testing; not yet selectable
	<b>EH Flowlines</b>	+	+	CAPEX may decrease with SINTEF system	High CAPEX; high power to keep wall above CWDT (or reach melting T)
	<b>Cold Flow</b>	+	<b>NA</b>	Would prevent deposits in long tieback without CAPEX of dual PIP lines	Awaiting field trial
<b>Maintenance</b>	<b>Standard pigging</b>	-	+	Proven approach if frequent enough	Deferred production in subsea
	<b>Hot oiling</b>	-	+	Effective for insulated systems	Ineffective in uninsulated systems
<b>Remediation</b>	<b>Progressive pigging</b>	-	+	Slow process best for export lines	In subsea flowlines, high production deferment
	<b>Chemical Cleaning</b>		+	Circulation can be effective (Gannet D; Stuart McGregor)	"Inject & flowback" not as effective (Mensa; Cor Kuijvenhoven)
	<b>Hot oiling</b>	-	+	Effective for insulated systems	Ineffective in uninsulated systems
	<b>Burial</b>	+	+	Can significantly increase heat retention in late life	One-time OPEX
	<b>Exothermic heating</b>	+	+	Commercially available	Chemical handling, reaction control
	<b>Jet pig</b>	-	+	Tested but never deployed offshore	Requires two-ended access
	<b>Crawler pig</b>	+	+	If successful, would remediate single flowline systems without deferment	Failed wax cutter tests; development shelved
	<b>Coiled tubing</b>	+	+	Proven	Weight/footprint, costs, reach distance
<b>Leave in Place</b>		+	+	Low CAPEX/OPEX option where feasible.	Risk is not well determined and assumed to be high. Needs validation.

### 5.3 Options – Gel Management

A fluid will continue to flow below its gel point if enough shear is exerted; it is easier to keep a fluid moving below the gel point than it is to *start* it moving. The challenge with gelling is during shut-in conditions when the hot, still fluid cools below its gel point. The gel has a yield stress that increases with decreasing temperature.

#### 5.3.1 Prevention

Heat retention: Gel problems can be prevented by ensuring that the fluid is always above the pour point temperature. Sufficient insulation can achieve this for some time, but eventually a shut-in line will cool to ambient temperature. Similar to the cooldown time for hydrate management, insulation provides a no-touch time for gels.

Active heating: Electrical or fluid heating could be used for gel management. This is obviously an expensive option that would require strong justification.

Sheared cooling: Conversely, gels are weaker when the oil is sheared below the gel point. So if the fluid cools rapidly under steady-state flow, the fluid that is already cooled at shut-in (downstream) will form the weakest gel. The fluid that was hot at shut-in (upstream) will have the strongest gel. Unfortunately, rapid cooling causes more wax *deposition*, so this management option will cause more need for deposit mitigation.

Chemical injection: Continuous injection of pour point depressant chemical can ensure that the fluid will never gel. Again, this option can have high OPEX.

Displacement: When unplanned shut-ins occur, the oil can be displaced before it has time to gel. The displacement fluid could be treated oil or even seawater. This option requires that power be available to pump the displacement fluid, which may not always be the case during an unplanned shut-in.

#### 5.3.2 Remediation - Restart

As discussed in §4.6, there are many factors which go into the gel strength and restart pressure of a line. The primary remediation method is pressure, up to the limit of the piping, pump or well pressure. If this limit is reached without the gel breaking immediately, it may be possible to achieve creep failure by simply holding the pressure on the line for a long period of time. If that fails, a line intervention can be attempted, where the line is cut into at a midpoint and fluid pumped in. By bisecting the gel, the required restart pressure may be reduced by half.

Depending on line length, a coiled tubing intervention could be attempted. Unlike a deposit plug, the gel may fill the entire length of pipe. Therefore, the CTI needs to remediate a significant fraction of the gel in order to reduce the restart pressure substantially.

## 6. Surveillance and Operations Support

This section refers to the Operations and Surveillance functions of Figure 2.1. §6.1 describes a work process; §6.2-6.5 give examples of dealing with wax problems in different operating environments (onshore, shallow water, deepwater) in several regions (Gabon, UK North Sea, Gulf of Mexico and the Netherlands). This is not the whole of our experience but illustrates a number of problems and wax management approaches.

### 6.1 Example Work Flow: Subsea Surveillance in Upstream Americas

UA operates a large number of subsea assets and has a detailed work flow for dealing with subsea flow assurance problems. This section gives details of that process.

#### 6.1.1 Operations Support

Operations support for the Gulf of Mexico and Brazil is provided by the SEPCO Subsea Surveillance Team (SST), where on average two Flow Assurance engineers are responsible to keep the flow path open for the Gulf of Mexico and Brazil assets.

Given the importance of subsea operations in the Americas, the SST and thus the FA engineers are not only involved in applying Shell FA know-how, but also typically involved in subsea flow assurance technology development, e.g., funding research and software tool development by the former SGS organization, or supporting EPP-driven projects by peer reviews.

The support that the FA engineers provide to the GoM and Brazil fields for wax / paraffin – related issues are among others (but not limited to)

- Providing day to day support to the assets for any flow assurance related issue
- Organizing annual reviews on integrity and optimization for each individual subsea asset. During the FA section of such reviews the paraffin related risks are assessed
- Supporting wax remediation efforts for partially or fully restricted systems (chemical selection, remediation procedure, ...)
- Supporting research to better understand deposition and plugging mechanisms and facilitating sampling efforts to provide fluids
- Providing sampling guidance during steady state conditions and transient conditions for either retrospective studies to understand pressure-drop behavior of a system, or preventive studies to determine fluid cloud points / CWDT to understand risks of wax deposition over the life of the system

#### 6.1.2 Remediation Planning and Execution

Systems are checked on a regular basis whether pressure drops in the field match expected pressure drops when simulating the system with multiphase flow simulation software. In SEPCO OLGA is typically used for transient and steady state multiphase simulations.

When a system is suspected to be partially or fully blocked as a result of paraffin deposition, remediation is considered in a multi-disciplinary group, including (but not limited to) SGS experts, Subsea Surveillance FA and Subsea engineers, intervention specialists and operating representatives.

### 6.1.3 Model Benchmarking and ISOs

Wax deposition generally results in a slow build-up of additional pressure drop over a flowline, which may not necessarily be noticed if the pressure drop is being monitored on a daily basis. Upstream Americas has adopted a process to monitor subsea flowline performance by benchmarking and trending pressure drop prediction using appropriate multiphase flow simulation tools (SEPCO preferred: OLGA) versus field data).

Two processes are in place to monitor deposition effects over two different time scales:

- 1) Weeks to months: Exception-based surveillance by The Bridge ® (being implemented 2010)
- 2) Annual: Subsea Surveillance integrated Integrity and Optimization reviews (ISOs)

These processes will be discussed in more details below.

#### **The Bridge**

The Bridge ® is an exception based surveillance methodology. It has an automated service that tracks a system pressure drop corrected for flow over time. The background is that a single-phase fluid system will have a simple correlation between pressure drop and flow rate, that should remain fairly constant assuming all other parameters such as pipe diameter remain the same. If the flow-corrected pressure drop moves outside a pre-set bandwidth compared to a previous value (based on rolling averages) consistently for a pre-set period of time, an alarm will go off. However, this is a crude approximation for multiphase flow, since a change in flow-corrected  $\Delta P$  can have many causes other than deposition, e.g., change in GOR, watercut, change in boarding pressure, flow regime, etc.

Therefore alarm will first send notification to Bridge Analysts, who confirm that it is a legitimate alarm not caused by operational events such as shut-ins etc. If acknowledged, an automated email is generated and sent to the flow assurance engineers who will investigate the cause for the change in flow-corrected pressure drop with more appropriate tools for multiphase flow.

#### **ISOs (Integrated Subsea Optimization Reviews)**

- The Subsea Surveillance Team carries out regular reviews on the subsea assets, called Integrated Subsea Integrity and Optimization Reviews, also known as ISOs. The intention is to do these reviews for every asset on a yearly basis, though the integrity standard is only required once every three years. These reviews cover all aspects of subsea operation and integrity, including flow assurance, chemical surveillance, aftermarket and a flowline risk-based assessment for corrosion management.

An important part of the flow assurance section is to demonstrate that the multiphase models still produce valid pressure drops and thermal results compared to field data. The analysis focuses on

- The absolute difference between model results and current field data to understand what the application limitations of the model are for predicting cooldown, hydrate management, slugging, etc.
- Any trend in how the model deviates from the observed field data over time. Together with all other available data (CWDT, PVT, observed wax on coupons, etc) the likelihood of paraffin deposition in the flowline as a possible cause for the deviation is assessed. With this methodology the Serrano flowline blockage in 2006 was predicted to be paraffin-related before the remediation proved it.

The SEPCO preferred tool to simulate multiphase systems (transients, but also steady state to limit the number of models that need to be maintained) is OLGA. The OLGA models for all GoM and Brazil assets are benchmarked with some frequency (at least once per year as part of the ISO) and used for day-to-day flow assurance support.

#### 6.1.4 Deposit and Blockage Hypothesis Testing

The steps for determining the nature of an apparent restriction are:

- Confirm that there is no other explanation for a deviation that increases over time between the pressure drop as observed in the field and the pressure drop as predicted by multiphase modeling (e.g. modeling error, wrong allocation inputs, inappropriate PI tags for field data comparison, etc.)
- Consider the possible causes of increase in pressure drop.
  - i. Hydrates (timescale: hours. Was the system flowing inside the hydrate envelope? Were any inhibitors being pumped?)
  - ii. Sand (timescale: days-weeks, other indications available such as wellbore pressure characteristics, ASD alarms etc.)
  - iii. Asphaltene (timescale: weeks to a year, were any of the wells consider high risk for asphaltenes? In case of condensate: has the color of the condensate changed over time? Did the system fluid properties change significantly in the mean time, e.g. lower API gravity?)
  - iv. Paraffin (timescale: weeks to a year. Is the system flowing below CWDT / cloud point? Do we believe the CWDT / cloud point on file or did the system fluid properties change significantly in the mean time, e.g. lower API gravity?)
  - v. Other, e.g. viscosity increase due to emulsions, higher water content than reported per allocations, heavier crude than expected (e.g. Princess P7), ...
- If a restriction due to deposition is suspected in a system, there are a few methods to establish the order of magnitude of the deposited volume.
  - i. The preferred way to confirm deposited volume for a dual flowline system is a single-phase tracer test. This consists of dry-oiling the system with dead oil, and putting a tracer in the dry oil. Assuming that the volumetric pump rate is known with reasonable accuracy the timing of tracer returns indicates the actual volume of the flowline, and by subtraction of the original as-built volume the deposited volume can be determined. The accuracy for this method is relatively high ( $\pm 10\text{-}20$  bbls)
  - ii. In a single flowline system (or dual flowline system that cannot carry out a tracer test for whatever reason) the pressure drop can be matched by changing the ID of the flowline in the models. This is however a very crude method. The main challenge is that it is not always known if the deposition occurs at the inlet of the line (typical for asphaltenes), the riser (typical for paraffins) or spread out over the whole length of the flowline. And even if the location is somewhat certain, still there will be endless combinations of length vs. thickness of the deposit that can satisfy the boundary conditions of observed pressure drop. This method will at best determine the order of magnitude, but no accuracy within a few hundred barrels should be expected. If this test can be carried out with a single-phase fluid this is preferred over multiphase fluid, given that the uncertainty bands for multiphase flow pressure drops in general are larger than for single-phase flow.

### 6.1.5 Design for and Support of Remediation Operations

Once it is established that the system is restricted with paraffin deposition, the nature and location of the restriction determine the remediation strategy.

Possible remediation for 4 cases:

1. Riser (-base), restriction
  - Online chemical treatment with some reasonable concentration of a wax solvent
  - Full solvent wash, where the line is displaced with 100% solvent. This is generally only feasible for limited system sizes. Depending on the layout of the system the solvent can be pumped from the host through the riser, through the umbilical (note: lower rates) or from a vessel through the wellhead or manifold.
  - If serious enough a coiled tubing job can be considered from the host
2. Riser (-base), blockage
  - Coiled tubing job from the host
3. Flowline, partial restriction
  - Online chemical treatment with some reasonable concentration of a wax solvent
  - Full solvent wash, where the line is displaced with 100% solvent. This is generally only feasible for limited system sizes. Depending on the layout of the system the solvent can be pumped from the host through the riser, through the umbilical (note: lower rates) or from a vessel through the wellhead or manifold.
4. Flowline, blockage
 

This should be considered worst-case scenario

  - Extended coiled-tubing from either riser or wellhead (will involve lifting the sled for access) can be used to mill out the plug, using DB50 vessel or alike
  - If out of reach of even extended CT, more extreme measures may be necessary, such as (a) cutting out and replacing the affected section, (b) transporting the flowline to shore for cleaning or (c) abandonment. However, it should not be expected that Shell will be allowed to abandon in place.

The Subsea Minimum Functional Requirements (for subsea designs) now require that systems consider including a Y-piece in the riser top or any other means of giving easy direct access to the riser for e.g. coiled tubing jobs. This was a learning from the Serrano wax-plug remediation – the easy access to the riser made the intervention significantly easier than if the Y-piece would not have been in place, and no direct access would have been available.

## 6.2 Shell Gabon Field Experience (Michel Ondo Ella)

Crude produced from Shell concessions in Gabon is characterized by high wax contents and pour points. Deposition and gelling require continuous attention, and management strategies are frequently reviewed for improvement.

**Table 6.1: Gabon Crude Characteristics**

	Gamba	Rabi	Toucan	Awoun
<b>Max Pour Point, °C</b>	30	33	36	39
<b>Pour Point Min., °C</b>	12	18	30	30
<b>Wax %wt</b>	13	12	21	24

Wax appearance temperatures in these crudes are between 38 and 43 deg C. This means that wax deposition starts inside the production tubing of many wells.

The different activities related to wax are described hereafter, and refer to the current situation. Little has changed since the early production years. Mechanical scraping and pigging remain the main wax combatment method. The wax deposition problems tend to be of a temporary nature, as increased water cut apparently tends to water-wet metal surfaces, thereby reducing the magnitude of the problems with increasing water cut.

## 6.2.1 Wells

### 6.2.1.1 Scraping

To maintain optimum production and retain wireline access, the tubings need to be scraped using wireline. Frequency per well is determined by the time it requires to scrape the tubing. Frequencies range from daily to once per 25 days. At the time of dry production there is a clear correlation between wax deposition and production rate: lower producing wells had a lower well head temperature and therefore relatively more wax. In late life of a producing well, factors such as watercut, flowrate, lift gas etc. make it difficult to establish a correlation.

### 6.2.1.2 Hot Oil

In those instances where scraping fails due to unexpected wax build up in the tubing, a hot oil soak is conducted. Hot oil (temp 90 °C) is displaced in the well using a pumping unit. Normally a total of 40 bbls is used, after which scraping is re-attempted. In general 1 to 2 treatments are sufficient before scraping is successful.

### 6.2.1.3 Steam Heating

The flowline part between wellhead and pig launching valve cannot be cleaned mechanically. The same applies for the station production manifolds. These areas are regularly heated up with the use of mobile steam generator.

### 6.2.1.4 Alternatives to Well Scraping

At the peak of production in both the Gamba Ivinga fields (1976) and the Rabi field (1997), several alternatives to the well scraping were considered. These included the use of pour point depressants, tubing insulation, electrical heating of tubing and (for Rabi only) the use of automatic scrapers. The use of Shellswim 9 and Shellswim5 was trialled in Gamba Ivinga in 1976. Technically these trials were successful. Scraping times were reduced, and scraping intervals could be increased. However, the lack of modeling capacity and the inaccuracy of well production tests meant that no accurate production deferment due to wax deposition could be obtained. This made it impossible to justify the relatively high costs for chemical injection. The relative low costs of scraping operations were another limiting factor to finding alternatives. A squeeze trial (1976) was carried out in one of the Ivinga wells where Shell swim was displaced into the reservoir, anticipating a slow flowback and a prolonged wax free production tubing. The trial did not yield the expected results.

### 6.2.2 Flowlines

Flowlines of producing wells are being pigged. Pigs are launched at the wellhead by inserting them in a special Itag valve. They are displaced by the produced fluids. The pigs are retrieved at the production manifold, where the removed wax is displaced into the production system.

Pigging operations can cause serious surges in the production system, resulting sometimes in high-level separator trips. In the cooler season, daily pigging of some flowlines is required to prevent plugging.

### 6.2.3 Process

The crude in the reservoir has never been below the cloud point temperature and therefore does not contain any wax nuclei. Hence the reservoir crude is assumed to be in minimum pour point condition. During production, the crude cools down inside the tubing and the wax appearance temperature (38 – 43 °C) is reached somewhere in the well. From this point onwards wax is crystallizing in a dynamic way, which implies a gradual increase in pour point.

Typical producing wellhead temperatures are approximately 35 – 40 °C.

Heating capacity has been installed to keep the production system free from wax and ensure restartability of the export lines. Care should be taken that this heating is done to above the inversion temperatures. A lower heating temperature leads to crude reversing to maximum pour point condition.

Technical considerations for using wax inhibitor chemicals are continuously being reviewed. The challenges have led to the decision to stop the daily injection of chemicals in Shell Gabon Rabi Gamba 127 km Main oil line. 1) The main oil line pressure without wax inhibitor remains far below alarm and tripping set points under normal operation. 2) The main oil line restartability after accidental shut down can be achieved via appropriate pigging procedure and contingency plan.

Wax inhibitor is considered for time being in Toucan and Awoun fields. Both fields are with much higher wax content and pour points. The injection of wax inhibitor is also maintained in the loading line due to the shut down time (about 10 days) in between consecutive tanker loadings.

### 6.2.4 The Rabi – Gamba Flowline and Export of Rabi Crude

The crude produced in Rabi was split in equity between the two partners in the field; Elf Gabon (Now Total) and Shell Gabon. The Shell share of approximately 50% was transported to the Gamba terminal and export facilities through a 128 km pipeline.

At the onset of Rabi production and as recommended in the phase I field development plan, the evacuated oil was doped with an excess of 500 ppm Shellswim to prevent the line from gelling during planned or unplanned shutdowns. The dosage was rapidly reduced as operating confidence increased. Temperature profile of Rabi Gamba line using WAXLINE and COOLPROF associated with a series of model pipeline tests were carried out at KSLA to simulate the ease of restartability at various points along the line. It was concluded that treatment with 50 ppm was sufficient to guarantee the restart of the 127km Rabi - Gamba line. For a number of years a model pipeline was in use in the Gamba Production Chemistry laboratory to enable the produc-

tion chemists to give an accurate prediction of pipeline conditions in case of an unexpected shutdown. Detailed plans were in place to displace the pipeline with water in case of a possible gelling.

With the Shellswim injected at Rabi and the crude re-heated to above inversion temperature in the Gamba terminal, the exported Shell Rabi Export Blend was in a much more favorable pour point condition than the competitive Rabi Export Light as marketed by Elf/Total. An incident in 1996 when a Rabi Export Light parcel waxed up in a refinery pipeline in Texas confirmed this technical advantage. Stasco, who were marketing Rabi Export Blend on behalf of Shell Gabon claimed that the extended area over which the crude could be marketed and the more favorable condition yielded a gain of some 5-10 dollar cents per barrel on the price that was made for Rabi Export Blend. This was quite favorable compared to the 0.6 dollar cents/barrel costs for Shellswim. Over 1998 and 1999, however, Stasco could no longer justify the increased price and the economics for Shellswim injection gradually disappeared. This ultimately led to the injection being stopped.

## 6.2.5 Past Studies

### 6.2.5.1 Well Impairment

An infill drilling campaign resulted in a number of wells with a disappointing performance. One possible explanation for this was the cooling of the formation during drilling/completion operations with wax deposition as a result. It was decided to test this theory by pumping a mixture of Sodium Nitrate and Ammonium Chloride into the wellbore. A temperature increase of about 100 °C was realized. Although any wax should have been dissolved, a productivity increase was not observed.

### 6.2.5.2 Field Tests

A large number of field tests have been conducted with paraffin inhibitors, wax dispersants and pour point depressants. In most cases injection was via lift gas. In not one field test could the deposition of wax in tubing and flow line be completely eliminated although scraping and pigging could be reduced. (This is consistent with the generally understood PI behavior of reducing but not eliminating deposition.) It was also difficult to determine small changes in production rate due to the apparent inherent variations in well test data.

### 6.2.5.3 Wax Inhibitor Requirements

Rabi Gamba main oil line receives production oil from fields operated by other oil companies such as Perenco, Total and Addax. Usually we will receive less than 50 kg of wax at Gamba Terminal. In the following pictures unexpected massive wax was recovered from Rabi incoming line in Gamba terminal. This illustrates the difficulty of managing systems with multiple unknown inputs, such as changes in crude composition or inhibitor concentrations.



**Figure 6.1a**

**Unloading the pig and wax at the Gamba Terminal**



**Figure 6.1b**



**Figure 6.1c**

### **6.3 Case History: Wax Removal from Gannet 'D' – Shell Expro (Stuart McGregor)**

#### **6.3.1 Introduction**

The Gannet 'D' field is located in the Central North Sea, 16 kilometers northeast of the Gannet Alpha platform in a water depth of 90 meters. Production is currently from five wells, with the produced fluids flowing to the Gannet Alpha process facilities via two looped 6" subsea flow lines referred to as Riser 31 and Riser 32. These crudes typically have an API of 41, a wax content of approximately 7% and a wax appearance temperature in the region of 35.5°C.

Wax deposition in the flow lines was first identified in 1999 during the Gannet 'G' tie operation as a spool piece removed from the base of Riser 32 was found to contain significant quantities of wax. As a result, Shell Global Solutions was commissioned to carry out a study to estimate the likely extent of the deposition within the Gannet 'D' system and their findings proposed that a volume of up to 21 m<sup>3</sup> of wax could be present in the loop, with deposition being seen as much as 8 kilometers from the platform.

Since 1999, a number of remedial treatment proposals have been tabled, but as the perceived risks were felt to be significantly higher than the potential rewards, none of the proposals were considered viable. By 2005, however, it became obvious that substantial production was being lost, and a remediation plan was developed. [59]

### 6.3.2 Remedial Treatment Strategy

A large number of remedial treatment options were available on the market with the majority of these being based around conventional pigging or chemical cleaning technologies. However, a number of novel methods were also reviewed to ensure all possibilities were considered e.g. autonomous tractor cutting pigs, coiled tubing and in-situ heat generation were all considered. After careful evaluation of the twelve options presented, it was felt that the treatment offering the greatest chance of success with the lowest risk to personnel, equipment or the environment was solvent soaking aided by circulation.

The base case treatment strategy was to fill the flow line loop, some 600m<sup>3</sup> in volume, with neat wax dissolver and circulate this with diesel driven pumps until such time that the dissolver became saturated and no further wax could be removed.

### 6.3.3 Chemical Selection

With any chemical treatment, the selection of the chemical is critical if the desired outcome is to be achieved. In this case, a number of products covering a range of generic chemistries were tested for suitability. The primary function of any wax remediation chemical is to dissolve or break up as much wax as possible, but as this operation was to be carried out offshore in a large subsea system, there were a number of other factors that had to be considered before any final choice was made. Risk to personnel, material compatibility, environmental profile, availability, cost and impact on the platform and downstream processes were all taken into account to ensure that the eventual selection was as thorough and robust as possible.

A series of extensive soak tests were carried out by the Shell Production Chemistry Department in Aberdeen to screen the candidate dissolvers and examine their ability to break up or dissolve the wax under static and agitated conditions. Many of the chemicals tested were proprietary solvent blends based around aromatic solvents such as xylene or heavy aromatic naphtha, and although these products did perform reasonably well, two terpene-based products were found to offer the best balance between performance and the other specified selection criteria. It should be noted however, that xylene consistently outperformed the terpene products tested but was not selected for HSE reasons.

One unexpected outcome of the testing program was that heating the solvent on site was not required. In all tests, regardless of whether they were carried out in-house or by the chemical supplier, the candidate chemicals were generally more effective at the lower temperature. Being able to remove the heating requirement reduced the operational risks significantly.

### 6.3.4 Chemical Deployment, Circulation and Displacement

From the outset it was clear that successful execution of an operation of this size would require rigorous management of the various interfaces, and therefore, a major offshore service provider was commissioned to assist in the coordination process.

The chemical was supplied from the manufacturer in 22 x 20m<sup>3</sup> ISO tanks and sea fastened to the deck of a supply boat. Once on station, the vessel pumped the dissolver onto the Gannet platform using a 4" flexible hose. The hose was connected to the pig launcher assembly at the R31 end of the loop via two 20m<sup>3</sup> break tanks. The fluid was pumped around the flowline loop with the returns being taken back via the two 20m<sup>3</sup> break tanks. The tanks were used to collect wax and sand returned during the treatment and minimize the risk of blockages in the pipe work

or pumping equipment. Samples of fluid were routinely taken by an onsite chemist during the circulation process to assess the quantity of wax dissolved or suspended in the fluid. Using these samples an estimate of the level of saturation was made.

On completion of the circulation phase, a gel pig was then inserted into the line to remove any loose wax or sand not removed during the circulation process with the returns again being taken back via the two break tanks. Using inhibited seawater, the spent fluid was displaced in a controlled manner back through the production process and exported via the export oil pipeline.

### 6.3.5 Time-of-Flight Flow Measurements

Being able to accurately measure the impact of the dissolver treatment was a key requirement of the project. The ultimate measure of success was to establish if the production rate from the field increased post treatment, however, 'time of flight' measurements using a radioactive tracer were also carried out to try and establish how much of the wax had actually been removed.

The pre treatment measurement estimated that up to 81 m<sup>3</sup> of wax was now present in the flow line loop, but due to a number of delays, the post treatment assessment did not take place. However, fluid samples taken during and after the treatment allowed for a rough estimate.

### 6.3.6 Treatment Performance

The treatment was considered a success, based on the fact that an additional 480m<sup>3</sup> per day of oil was recovered from the field and an estimated 59m<sup>3</sup> of wax was removed from the system. In addition, observations of reduced pipeline differential pressure and increased fluid arrival temperature also indicated that the restriction in the lines had been significantly reduced.

### 6.3.7 Conclusions

- Wax deposition in large subsea production flow lines can be successfully removed.
- Good project management and integration of all disciplines is key to the success of an operation of this nature.
- Terpene based wax dissolvers can offer a viable alternative to more conventional dissolver chemicals even at ambient temperatures.
- Solvent circulation is a viable method of remediation.

## 6.4 Gulf of Mexico Case Histories (Kees Lagers)

### 6.4.1 Serrano SE3

When well SE3 came online in 2005, the fluids were assumed to have similar fluid properties as the previously flowed SE1 and SE2; this included a benign CWDT.

For operational reasons the field blew the flowline down in Nov 2006. When the flowline was re-pressurized (against Chilly Choke), pressure communication was lost between topsides and the subsea system.

First remediation efforts (heating with the Electrical Heating installation in the system) were all aimed at resolving a hydrate blockage and were unsuccessful. Field tests suggested that the blockage was close to the riser-base. After further analysis however the models indicated that

the pressure drop in the flowline had been increasingly higher than should be expected based on multi-phase models, which is typical for a hydrocarbon deposition (wax, asphaltene).

When the blockage was jetted out with coiled-tubing as the final remediation effort some 35 barrels of wax were removed from the riser base.

The current hypothesis is that due to the rapid depressurization of the flowline (blow down) whatever gas was captured in wax deposits in the riser expanded rapidly/explosively, causing tears in the deposited wax structure and causing the wax to “slough off” and accumulate in the riser base. At re-pressurization (to manage chilly choke risks) the wax got compacted and sealed off the flowline. Tests are currently being carried out to prove this concept and learn how this mechanism can be avoided in future cases where wax or asphaltene deposits are suspected in a flowline or riser.

#### 6.4.2 Mensa – General Behavior

A phenomenon has been observed in Mensa where an in-field flowline would have a higher-than-expected pressure drop, which disappeared after shut-ins. The explanation given at the time (still considered valid) was that the MEG would form a viscous emulsion with the condensate, the waxy components in the condensate and perhaps some water. During normal operation this viscous sludge would stick to the walls and effectively restrict the inner diameter of the line, causing higher pressure drops. During shut-ins, in the absence of shear stress, this viscous emulsion was thought to drop the bottom of the line and segregate. At start-up the sludge was dislodged and produced to the topsides, where indeed after each start-up “green snot” was observed in the separation vessels. The in-field systems would have “normal” pressure drops after such start-ups, which would over time build up again to higher levels until the next shut-in.

It may be noted that in the very early days of Mensa the system was not operated with MEG but with TEG; the experience was quite disastrous in terms of salt management but also in terms of the sludging behavior described above, which was much more prevalent and more solid than with MEG.

Laboratory experiments with MEG and condensate were able to form emulsions, especially when extra wax was added into the mixture. This was only true when the MEG fraction was quite high, *i.e.* closer to 50% than 5-10%. In the Mensa field, the MEG fraction is approximately 50%; the CGR is approximately 1.75 BBL/MMSCF, and the MEG injection rate is 1.5-2 BBL/MMSCF. Therefore, the emulsion build-up is plausible explanation for the observed  $\Delta P$ 's.

#### 6.4.3 Mensa A5 in-Field Line

Mensa has a history of non-Newtonian flow characteristics: pressure drop (corrected for flow) would build up over time but restore itself after a shut-in (as described in the previous section). This has been investigated [60] and was hypothesized to be a result of an emulsified mix of condensate, waxy components in it, MEG and water, that built up in the flowline under shear from the flowing gas, but relaxed back to separated fluids and got “coughed up” after a shut-in and subsequent start-up.

Mensa A5 however – flowing in the old Mensa A3 in-field line – started showing pressure drop increase without however the relaxation of  $\Delta P$  after shut-in / start-up events [61].

During an opportunity where A5 could be flowed back solo, samples were captured that showed a higher wax content than assumed for any previous Mensa well. Consequently the system was assumed to be restricted by more paraffinic deposits than the previously experienced sludge emulsion.

As the restriction became serious enough to significantly reduce production (~25 MMscfd reduction compared to what the well can do) a remediation was agreed on. After testing, toluene turned out to be the chemical of choice (next best solvent for this case after EC6009 – which was not allowed on the intervention boat).

Two batches of 800 bbls of toluene were injected through the wellhead into the in-field line from the BASS system (operated from the OI4). After each soak (first shorter than the second) the system was brought online slowly to allow additional agitation of the toluene without sweeping it out of the flowline too fast.

The job yielded mixed results: though some production gain was achieved (~7 MMscfd) the aspired production increase (order 20-30 MMscfd) was not reached. The in-field line still shows very high pressure drops. It is hypothesized that the low temperature at which the soak took place limited the dissolving effect more than we expected. For details, see [59].

#### 6.4.4 Crosby Pastel Pink Flooded Flowline Jacket

Crosby Pastel Pink (CPP) has a 3-mile 4" infield single PIP flowline tied back to the Crosby sub-sea production manifold. In the process of answering a FA-related question, it was noted that the CPP temperatures at the subsea manifold were lower than expected. This triggered a more extensive look into the thermal and hydraulic behavior of the infield line.

By comparing the pressure and temperature drops in the field versus those expected for that flowline a deviating trend was observed: the  $\Delta P$  in the field increased over time, and – interestingly – the deviation between expected temperature and observed temperature decreased. Sensitivity runs in OLGA were carried out to model what the pressure and temperature drop would be if a flooded PIP section were assumed, and a certain rate of deposition of wax (with associated insulation properties) were applied to that section. The results were closer to the observed values than any other quantified explanation.

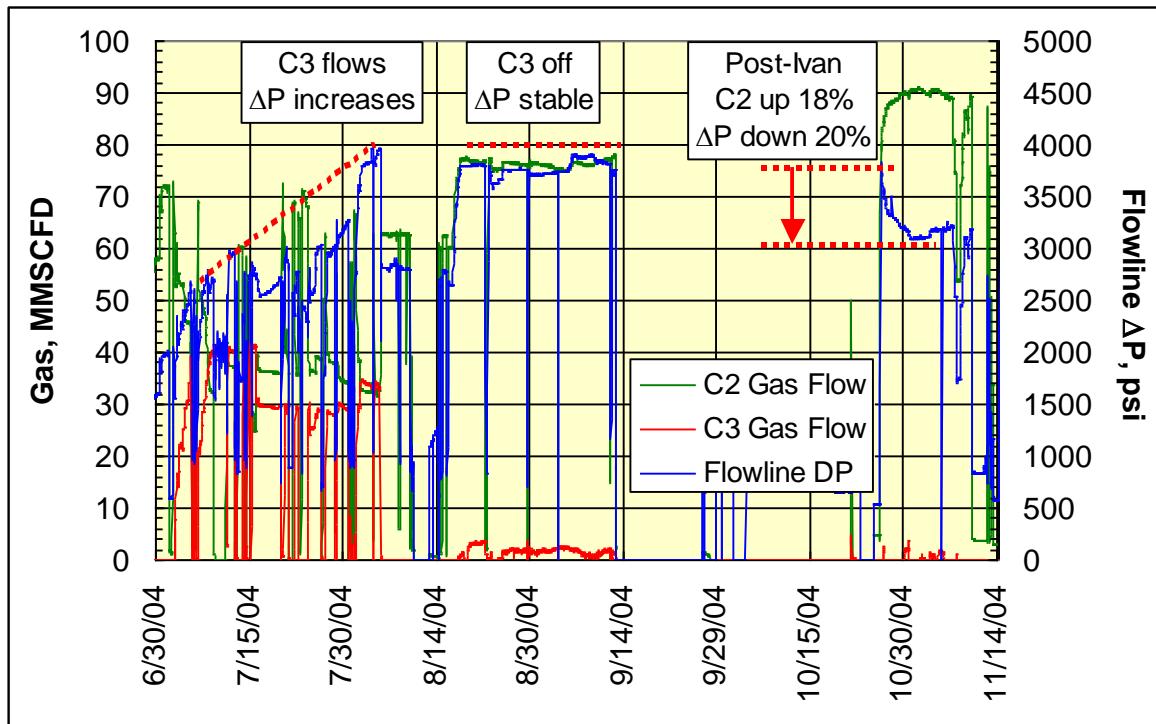
The wax is most likely the result of rapid cooling due to the flooding of a section of PIP jacket. EPP and several experts eventually agreed that this was the most likely explanation, and looking at the timing of events it is most likely that the flooding occurred during installation. There are currently no corrosion-related integrity concerns.

Given the limited field-life for CPP and lack of further development plans, it was decided to leave the wax in place. Further work needs to be done to assess how  $\Delta P$  changed after April 2008 and whether Wax-In-Place is a viable strategy for selection at the design phase of a project.

#### 6.4.5 Coulomb C3

Coulomb is a two-well gas/condensate system tied back through a 25-mile, single bare flowline. C2 (CGR = 55 BBL/MMSCF, CP = 63 F) was the first well started and behaved as expected. C3 is a well with much higher CGR (230 BBL/MMSCF) and much higher cloud point (91-97 F). After C3 start-up, the system showed a steady increase in pressure drop. Figure 6.2 shows (i) a

rapid  $\Delta P$  buildup when C3 came on stream, (ii) a high but stable  $\Delta P$  when C3 was shut off, and (iii) a partial recovery of  $\Delta P$  after a Hurricane Ivan shut-in, suggesting a partial self clean-up. Based on significant analysis work of SEPCO and SGS the hypothesis was formed that a wax/glycol/condensate emulsion or a wax slurry/deposit was being formed in the flowline and was stable at ambient seafloor temperature.



**Figure 6.2: Coulomb Early-Life Production History.**

Given the high liquid rates from C3, the solution was to bury the flowline, retaining heat retention and decreasing the build-up of emulsion or deposit [62]. The flowline was buried while still operating, and even before the full line was buried the topsides indeed received a few thousand barrels of viscous fluids. The liquids had significant amounts of wax but very little glycol, thus supporting the slurry/deposit hypothesis. System performance (Figure 6.3) improved immediately and dramatically; flow rate improved by 50% (70 to 105 MMSCFD) while  $\Delta P$  decreased by 33% (4000 to 2650 psi). The burial cost was recovered in weeks. Figure 6.4 shows the cumulative increase in production over 14-15 months compared with a baseline rate from early June 2006.

The Coulomb case is considered a showcase of how proactive surveillance, in-depth multiphase analysis and multi-disciplinary cooperation can result in a clear and correct problem assessment and focused and successful remediation.

Since then a slower pressure drop increase has been observed, which could be related to paraffin build-up in the riser, where the fluid cools down to as low as 30F. This pressure drop increase flattened when C3 was being cut back because of asphaltene problems.

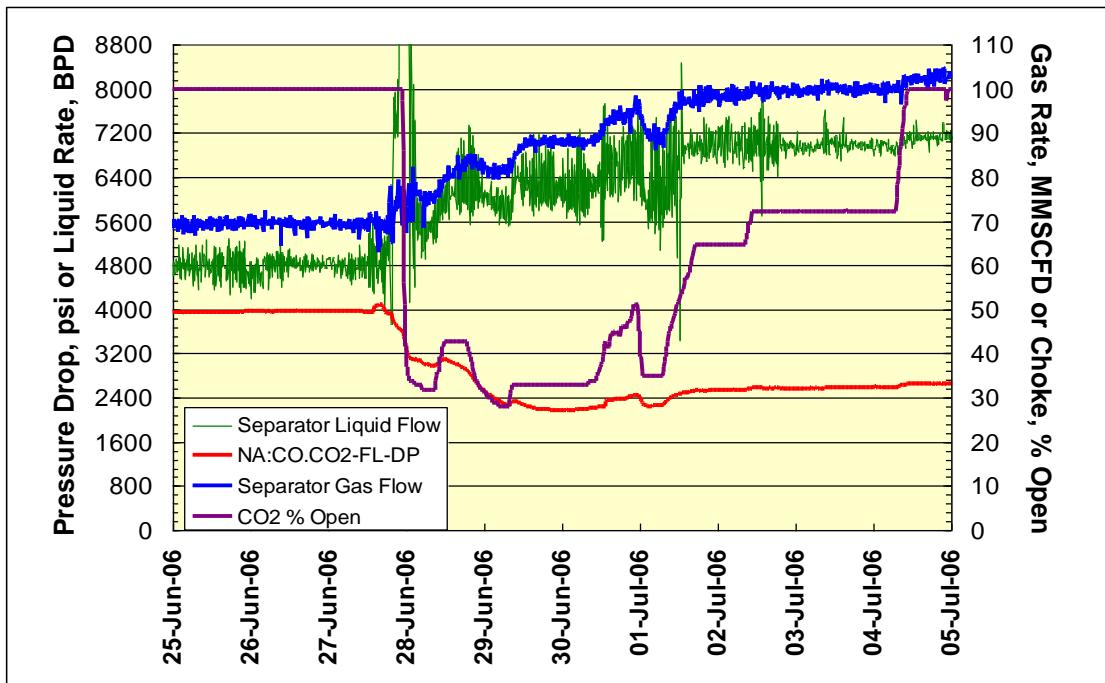


Figure 6.3: Coulomb performance after burial.

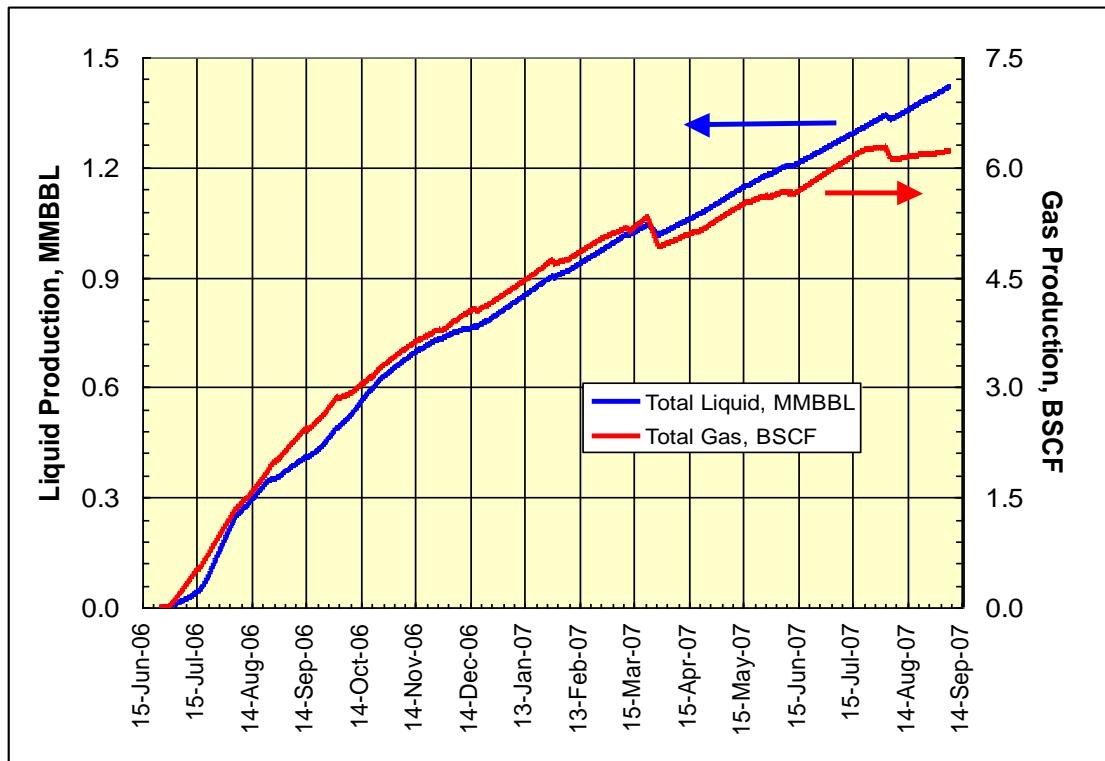


Figure 6.4: Cumulative increased production after burial.

## 6.5 Krabburen 1 Paraffin/Asphaltene Removal Treatment - NAM (Stuart McGregor)

### 6.5.1 Introduction

The KBB-1 well is located in the north of the Netherlands and is the only well producing from the Saaksum-West block [63]. The Saaksum-West field was discovered in 1998 and the first gas was produced in 1999 at an initial rate of 900,000 Nm<sup>3</sup>/day. However, production rapidly declined and since that time a number of well intervention programs have been carried out to maximize production and ultimate recovery from the block.

As early as October 2000, formation water influx was observed, and in May 2001 a downhole camera survey showed deposits in the liner around the perforations and also a clear water entry point. The perforations appeared to be plugged off by scale and the liquid-level in the well bore was found a few meters under the water entry point. Samples of the deposit were analyzed and found to be a mixture of radioactive lead and sulfate-based scales.

Water shut off was considered at the time but the risk of shutting off large amounts of gas was considered to be too high and therefore it was decided to re-perforate to try and increase the flow of gas and lift the water being produced.

The re-perforations were carried out in December 2001 and although the gains were significant, the well continued its rapid decline until such time that in 2003 the well started liquid loading and was often shut-in to build-up pressure. It eventually died in April 2004.

In August 2004, a higher-pressure lower layer was perforated to try and stimulate production and although successful (an increase of 30bar was seen in the Closed In Tubing Head Pressure), the well started to produce a very black oily condensate. This was first observed at the Delfzijl tank treatment park and then traced back via the Grijpskerk gas treatment facility to KBB-1. It should be noted that gas condensate from wells in the area generally produce a fluid that ranges from pale yellow to colorless so to produce a dark oil was extremely unusual. Although it was now clear that fluids from a different zone were being produced, production from the well was maintained and this new fluid did not appear to adversely affect production from the well, other than the change in liquid color.

Further perforations and water shut offs were carried out in 2005 and in 2006 the well was shut-in to allow the drilling of the neighboring well KBB-2. Prior to shut in, KBB-1 was producing on average 375,000 Nm<sup>3</sup>/d with 23m<sup>3</sup>/day of water and 5m<sup>3</sup>/day of hydrocarbon condensate. KBB-1 was initially shut in for a period of sixty days to allow the new well to be drilled but when it was reopened no flow was recorded. Over the next three months a number of interventions were carried out in an attempt bring the well back to life, but none of these were successful. Samples were collected at surface that again showed the presence of a black oily condensate. It was also reported that sticky waxy deposits had been observed on some of the well intervention equipment; however no samples were taken at the time.

A full review of the possible impairment mechanisms was carried out in 2007 and four possible causes were identified:

- High water inflow (observed in various production logs / gradients in period 2000-2005).
- Lead and/or sulfate scale build-up (observed in 2001 camera-run).
- Heavy paraffin or asphaltene skin (oily condensate /waxy deposits seen 2004 - 2006).
- Combination of above.

Based on the four most likely causes, a detailed step-by-step well intervention program was prepared [63]. It should be noted that although the feeling within the team was that the impairment was most likely associated with the presence of the oily condensate /waxy deposits, there was some uncertainty in this assumption and a full program was still required. This included Coiled Tubing Clean Out (CTCO), solvent treatment, data gathering (Production Logging Tool, Pulsed Neutron Log), water shut off and possible re-perforation if all else fails. It should also be noted that a scale dissolver treatment was considered but this was discounted at the time due to the chance of success being low, additional cost and the increase in time required on site.

The remainder of this article focuses mainly on Step 2 of the program, the selection and application of the paraffin / asphaltene dissolver.

### 6.5.2 Chemical Selection

With any chemical treatment the selection of the chemical is critical. Ideally in a case like this a series of dissolution test would be performed on deposit samples taken from the well to ensure the most effective chemical is chosen, but as only oily condensate samples were available this could not be done. Although waxy deposits had been reported during earlier intervention programs no samples were taken. The oily condensate samples were analyzed and the fluid was categorized not as a condensate but as a crude oil because of the relatively low API of 36.5, the n-alkane distribution up to n-C<sub>40+</sub> and the dark color of the fluid. The crude was also found to contain approximately 8%wt paraffin (wax) and 0.2 %wt asphaltene.

This information along with the well history was passed to the two incumbent chemical suppliers (Baker Petrolite and NALCO) and they were requested to recommend a suitable chemical treatment package. As described above there were no samples to allow lab testing to be undertaken so the recommendations had to be based on case history data in similar systems. Both companies submitted information regarding potential chemical solutions but only one of the suppliers (NALCO) was able to provide relevant case history data and this was the main reason their chemical package was selected.

The chemical package chosen (90% EC6004A / 10% EC9610A) was a proprietary blend of mutual solvents and heavy aromatic naphtha based solvents. The mutual solvent was included to minimize the risk of emulsions forming and act as a wetting agent when the oil soluble solvent is injected into a potentially water wet system. The solvent package was selected due to its reported ability to dissolve both paraffin and asphaltene. As the exact composition of the hydrocarbon deposition was unknown it was important to select a solvent that was suitable for a wide range of possible hydrocarbon types.

### 6.5.3 Chemical Deployment

Based on the assumption that the most likely position of the deposition was around the perforations, the base case treatment strategy was to spot the solvent package across the perforations using coiled tubing and then allow the solvent to soak for a minimum of 12 hours. This would allow the solvent to interact with the deposits and either dissolve or soften them such that they could be removed from the well. The well was then to be back produced to surface via a well test package taking samples during the flow back. Prior to the application of the solvent package a CTCO was performed to remove any sand or other solid debris that has accumulated to ensure the solvent had the best chance of contacting the target area.

Based on the length of perforated interval and size of the tubing, 25m<sup>3</sup> of solvent mixture were required to cover the complete perforated interval some 179m in length. The solvents were blended offsite and transferred to the location by road tanker.

The treatment was pumped without any problems and KBB-1 was shut in to soak.

#### 6.5.4 Well Flowback and Treatment Performance

On completion of the soak period the well was opened up to the well test equipment but initially no natural flow was observed. Nitrogen was used to lift the well until a flow was established at which point the well began to flow on its own to the well test package.

After a period of unstable production, the well eventually stabilized at a rate of approximately 200,000 Nm<sup>3</sup>/day with a liquid rate of 150m<sup>3</sup>/day, 90% of which was water. During the flow back, a series of liquid samples were taken from the test separator and these were sent to the laboratory for analysis. The samples were a mixture of solvent, water, oily/condensate and thick waxy deposits. The information obtained from these samples will be used to better understand what is happening in the well and optimize any future chemical selection programs.

As described above the well was now flowing naturally, however an unsustainable amount of water was being produced and therefore a mechanical water shut off was carried out. A plug was set at 4624m AHORT to shut off both the water and oil producing zones. This proved successful and the total liquid rate reduced to around 10m<sup>3</sup> /day.

After the water shut off was completed, KBB-1 was brought back into full production via the process train and the well test equipment removed from site.

As of early 2009, KBB-1 is still producing at a stable rate of 240,000 Nm<sup>3</sup>/day with a liquid rate of 10m<sup>3</sup>/day. It should be noted however, that evidence of black oily condensate has once again been seen at the Delfzijl tank treatment park and this is currently being monitored to establish if this is just an artifact of cross flow during the original long shut-in or if the well is still producing oil from an open zone.

#### 6.5.5 Conclusions

- Based on the performance of the solvent treatment, drop out of paraffin / asphaltene from the oily condensate seems to be the most likely cause of the production impairment. At this time it is still not clear if this was a temperature-driven effect or if it was due to cross flow and mixing of incompatible fluids during shut-in.
- Even with limited sample data, the chemical package selected proved to be effective. The impairment was removed and production was reinstated at a stable rate of 240,000m<sup>3</sup>/day.
- The mechanical water shut off was successful and the total liquid production rate was reduced from 150 to a manageable 10 m<sup>3</sup>/day.
- Accurate placement of the solvent package using coiled tubing was a key enabler in ensuring a successful outcome.

Detailed upfront planning and integration of the various teams lead to the operation being carried out without incident. Good project management and integration of all disciplines is key to the success of an operation of this nature.

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This report has been classified as Restricted and is subject to US Export Control regulations and has been classified as ECCN EAR 99.

Report Number	:	GS.10.51559	
Title	:	Guidelines for Managing Wax Deposition and Gelling in Production Systems	
Author(s)	:	G. Broze	SIEP-PTI/WD
Verified by	:	G. Broze	SIEP-PTI/WD
Approved by	:	G. van Spronsen	GSNL-PTE-EPFA
Content Owner	:	G. Broze	SIEP-PTI/WD
Issue Date	:	January 2011	
Activity Code	:	ZZPT/930701/010304	
Sponsor	:	A. Sluijterman (GSNL-PTU/EFES)	
Keywords	:	Wax, gel, cloud point, pour point, pigging, yield stress, restart, wax deposition, wax remediation, flow assurance	
Electronic file	:	GS.10.51559.pdf	
Issuing Company	:	Shell Global Solutions (US) Inc. Westhollow Technology Center, P.O. Box 4327, Houston, TX 77210, USA. Tel. +1 281 544 8844	

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