PROJECT DESIGN HYDRATE MANAGEMENT BY APPLICATION OF MULTIPHASE FLOW SIMULATIONS TOOLS WITH HYDRATE FORMATION AND TRANSPORT

Jefferson Creek*, Douglas Estanga, Sivakumar Subramanian
Chevron Energy Technology Company
1400 Smith Street
Houston, TX 77002
USA

Kristian Krejbjerger
Calsep, Inc.
11490 Westheimer Rd, Suite 500
Houston, TX 77077
USA

ABSTRACT

Flow assurance combines phase behavior and multiphase flow. Presently it is industry practice for various operating scenarios to overlay hydrate pressure-temperature profiles on transient multiphase flow simulations. This can be misleading when trying to evaluate the risk of hydrate plugging. In several areas of Flow Assurance including hydrates work is underway to take advantage of coupled flow simulation with phase behavior and reaction kinetics.

The hydrate growth is limited by the transport of gas components from the hydrocarbon phases into the water phase where the hydrate formation takes place. The formation of hydrates is further known to be exothermic and the heat released when hydrates form will limit further hydrate growth. The heat release and (delayed) gas uptake during hydrate formation may potentially offer a path forward in field developments when conventional approaches would deny development due to the cost of hydrate prevention by more traditional methods.

This paper will describe a flow simulation tool, which is coupled with a hydrate kinetics algorithm accounting for the influence of multiphase flow effects on transport of hydrocarbon gas to the water phase as well as for the heat released when hydrates form. It will be shown how this tool can be used in project design to develop a risk management based hydrate mitigation strategy for a field. The paper will also be a guide to experimental research needed to validate the strategy.

*Corresponding author: Phone: +01-713-372-2670 Fax +01-713-3725991 E-mail: LCRE@chevron.com

Keywords: gas hydrates transport, design of capital projects, risk management
NOMENCLATURE
AQ Aqueous
A Contact area between HC and AQ subsystem
°API API Gravity = 141.5/S.G. - 131.5
BPD Barrels per day
BOPD Barrels of oil per day
BWPD Barrels of water per day
CAPEX capital expenditures
CSMHyK Colorado School of Mines Hydrate Kinetics Program
°C degrees Celcius
d diameter of pipeline
D diffusion coefficient
f fugacity
°F degrees Fahrenheit
gal gallon
gal/min gallon per minute
GOR gas to oil ratio
HC Hydrocarbon
k mass transfer number
MEG Monoethylene glycol
mg/L milligrams per liter
n number of moles
OLGA SPT transient multiphase flow simulator
OPEX operating expenses
Sh Sherwood number
S.G. specific gravity at 60°F
t time
THI Thermodynamic Hydrate Inhibitor
TDS Total Dissolved Solids
U heat transfer coefficient
Vol% volume percent
WAT Wax Appearance Temperature
...
INTRODUCTION,
Management of hydrates is typically the subject area that consumes the most resources and presents the highest risk to safe secure production of hydrocarbon assets in harsh environments like the deep water. From the time of Hammerschmidt[1] to the present time, the primary philosophy for dealing with potential hydrate problems was to eliminate hydrate formation all together. Although several new approaches have and are being developed, hydrate avoidance is still the guiding principle for hydrate management. Hydrate mitigation and management in a deepwater oil system typically ends up being comprised of a collection of strategies that involve thermal management (eg. insulation of subsea equipment and flowlines to retain heat and provide cooldown time), chemical injection (eg. pumping methanol and or low dosage hydrate inhibitor during shutdowns and restarts), pressure reduction (eg. blowdown), and fluid composition management (eg. dead oil displacement during extended shutdowns). Hydrate mitigation philosophy for a deepwater gas/gas condensate production system typically comprises of continuous thermodynamic inhibitor injection such as Methanol or MEG. For oil systems and gas/gas condensate systems with high water production, the volumes of thermodynamic inhibitors required to avoid hydrate formation for steady state operations can be substantial. This poses challenges such as large expensive facilities both topsides and subsea to support continuous injection. The impact on inhibitor supply logistics, weight and space on the facility for storage and associated pumping systems, and operational upkeep all add up to significant issues to contend with during the design and life of the facility. Disposing of the inhibitor rich water is problematic as well since toxicity becomes an issue at high enough concentrations. Further, refineries are penalizing operating companies with the associated costs of dealing with production contaminated with THIs.

Even with these barriers, the difficulties and inefficiencies, one of the major challenges is the expense associated with continuous inhibitor injection. The cost of inhibition for a typical deepwater production of 50,000 BPD with 40% water cut (20,000 BWPD) would be as much as $800,000 per day for methanol. In addition, an inhibitor dosage of this quantity require pump capable of delivering 300 gal/min to successfully dose the produced water with inhibitor prior to the fluids reaching hydrate forming conditions.

For a comparable case where typical anti-agglomerate chemicals are used at 2 vol% dosage based on the water production, assuming a $20/gal chemical cost, cost would be about $336,000 per day to inhibit for hydrates. These numbers illustrate why continuous inhibitor injection is not an economic alternative when water production increases. This leads to hydrate management by thermal management via passive insulation or active heating. However the thermal management strategies to stay out of the hydrate region come at a considerable CAPEX cost and are not always justifiable especially when the reserve base for the deepwater asset being developed is marginal-small. In addition, even with the best insulation materials, there is a limitation on the longest flowline offsets
one can successfully achieve to provide adequate heat retention over majority of field life.

Is there another solution for managing hydrates? Certainly in specific applications where dosage is low and the hydrate formation driving force (subcooling) is small (<10°C) kinetic inhibitors have been effectively deployed on a large scale [2]. However OPEX cost is still an issue and these applications are not suited to handle the large subcoolings possible in our current deepwater assets under development.

There have been suggestions since the mid 1990s that one could live with hydrate formation with “natural” inhibition in much the same way as anti-agglomerates reportedly disperse hydrates and limit growth. Operators in Brazil have reported producing oils with “no blockage” problems for a number of years. [3-5]. Testing in flow loops sponsored by Deepstar [6] have also indicated the possibility of flowing at relatively high water cuts without blockage formation. These test results were verified by field data. Also BP have noted that they have used a “self inhibited” approach for the production from their King West oil well in the Gulf of Mexico [7]. Chevron also has some operating experience for fields where the brine TDS was ~ 300,000 mg/L, essentially salt saturated, which naturally inhibited hydrate formation in spite of deepwater conditions.

Further modern simulation tools have become available for problem areas like wax deposition. These have allowed progress in understanding what effects are important as far as wax deposition is concerned. Since the heat and mass transfer effects are tightly coupled with multiphase flow, having a simulation tool that can incorporate the basic flow and phase behavior is vital. For hydrate formation correctly accounting for the dispersed phase volumes of gas bubbles and water droplets is important as is the heat of formation for hydrates.

Recent years has seen the development of two such tools specifically tailored for hydrate formation and the effects of transporting solids on the bulk liquid phase viscosity. Both use similar kinetic models for the rate of hydrate formation. The first such tool, CSMHyK, was developed through the Deepstar consortium. It incorporates a hydrate kinetics and slurry transport module in the SPT industry recognized transient multiphase flow simulation tool OLGA. This tool has been deployed for novel project work over and above the range of phenomena it was designed to handle because of the coupling of mass and heat transfer effects to steady state and transient multiphase flow. In addition the program incorporates the heat of formation of hydrates in its energy balance algorithm.

The second tool based on similar concepts for hydrate reaction kinetics is Flowasta™ from Calsep. This tool uses multiphase flow correlations to capture the steady state flow characteristics of hydrate slurries formed during flow. This tool dynamically calculates the changes in composition and the variation in the hydrate formation conditions. This allows detailed component tracking during the traverse of a control volume from the source to the end of the flow line under investigation.

The Flowasta simulations presented in this work show that for a simple tie back with insulated flow lines the growth of hydrates could be controlled. If appropriately planned, the hydrate fraction controlled formation might enable the hydrate transportability without additional chemicals for hydrate mitigation. Further, this works presents specific examples where Flowasta could be used to facilitate the design of a hydrate field strategy.

PROJECT DESIGN
Typically projects are completed in phases:
1. Frame the opportunity. Define fluid properties.
3. Front End Engineering and Design (FEED) on preferred alternative.
4. Detailed design and Project execution. Construct facilities, commission and start-up.
5. Operate development and perform look backs.

In the first phase of development, the fluid samples for gas, oil, and water are collected, analyzed and characterized. Fluid property challenges are identified; preliminary production profiles and early facilities costing is performed and potential operational problems are identified. For hydrates,
special attention would be paid to gas composition, GOR, and water salinity to define the pressures-temperatures for hydrate formation. The second phase would involve defining of the hydrate mitigation philosophy and its impact on a given development concept. The initial production profiles and field architectures for the promising development concepts along with the fluid properties in the design basis allow for determination of flowline sizes necessary and pressure drops that can be tolerated. Thermal management requirements for wax and hydrates typically drive determination of the preliminary insulation design. This information is used to develop “doable” alternatives for economic evaluation and support decision around a preferred alternative to take into the FEED stage of the project.

Typically hydrate “101” in Phase 2 of a project presently would involve determination of insulation to attempt to keep the fluid temperature above the WAT and the hydrate formation temperatures under flowing conditions. If the assets are incapable of staying above the hydrate formation temperature for most of field life in spite of insulation during steady state flow due to some combination of low flow rates, low flowing wellhead temperatures, and long offsets to the host, other options are considered. These include direct electrical heating (DEH) or remote subsea gas-liquid separation to separate the water from the hydrate formers or some continuous inhibition via chemicals or reduction in the tieback distance by addition of a local host facility such that passive insulation becomes a viable option. Further transient multiphase simulations are used to determine whether or not a given facility can be safely and economically shut down and restarted during the life of the field as well as examining the potential for slugging.

The application of an unconventional risk management approach for hydrates, instead of the conventional risk avoidance approach, depends on additional production chemistry measurements. These measurements will be required in phase 2 to assess the ability of the oil to naturally disperse and transport hydrates over a range of field operating conditions. Benchtop studies characterizing water in oil emulsion stability, rheological properties of the emulsion, transient rheological properties of the transition from emulsion to hydrate suspension, and the behavior of the hydrate suspension through changing water cuts, shutdowns and restarts, etc. will be required. In addition, if oil samples are available, pilot scale flow loop studies that allow scale up and confirmation of benchtop observations would be necessary.

A tool like Flowasta can be an invaluable steady state design tool during the conceptual engineering phase 2 of a deepwater oil tieback project considering a risk management approach that relies on the ability to naturally transport hydrates. Flowasta simulations can build upon benchtop and flow loop fluid property testing that may indicate viability of the concept. Flowasta can facilitate modeling of the impact of producing and transporting hydrates from a multiphase flow standpoint. The flow assurance engineer could use the tool to generate the operability envelope for such a hydrate strategy by –

- Determining where and how quickly in the production system hydrates may form as a function of fluid flow rates and other design parameters
- Assessing the impact of hydrate formation and increase in solid hydrate fractions on the viscosity of the suspension
- Predicting resulting pressure drop from suspension flow as a function of flowline sizes and offsets
- Providing guidance on insulation requirements and how they will impact the hydrate fractions in the system and hence, overall pressure drop
- Risk and magnitude of increased backpressure on the reservoir with a negative impact on production profiles, etc.
- Performing quick sensitivity studies to assess changes in production profiles, water cuts, etc.

A tool like Flowasta can be used for example to compare the overall U value for line insulation desired. Here with 2” of insulation the U value was about 2 BTU/hr/ft²/°F. Simulations will show that if the insulation is decreased then line blockage will likely occur indicated as a no flow result. Typically this could also be taken when the fraction of solids exceeds 20%. Flowasta results can then be supported and benchmarked with other studies to verify hydrate formation fractions and whether or not the solids can be effectively transported.

The hydrate kinetics terms appear adequate and the larger questions have to do multiphase flow effects
including mass and heat transfer. The formation of hydrates represent a significant heat source and can be used to flow fluid systems with hydrates forming.

**Flowasta - HYDRATE GROWTH MODEL**

The applied flow simulation tool simulates hydrate growth in steady state pipelines. The compositional growth model considers transport of components between a hydrocarbon sub-system and an aqueous sub-system. Within each sub-system equilibrium is assumed to exist, while the two sub-systems may not be at equilibrium. The transport of component \( i \) between the two sub-systems is expressed as [3]

\[
\frac{dn_{AQ}^i}{dt} = (k_{i,\text{Gas}} A_{\text{Gas}} + k_{i,\text{Oil}} A_{\text{Oil}})(f_{i}^{HC} - f_{i}^{AQ})
\]  

(1)

where \( n_{AQ}^i \) is the number of moles of component \( i \) in the \( AQ \) sub-system, \( t \) is time, \( A \) is the contact area between the hydrocarbon and the aqueous phases, \( k_i \) the mass transfer number for component \( i \), \( f_{i}^{HC} \) is the fugacity of component \( i \) in the hydrocarbon sub-system and \( f_{i}^{AQ} \) the fugacity of component \( i \) in the aqueous sub-system.

The simulation is steady state and therefore the temperature profile in the pipeline is calculated by solving equation 1 with a PH (pressure-enthalpy) specification. This means that the heat released by hydrate formation can prevent further hydrates from forming in a well insulated pipeline where the heat is not lost quickly to the surroundings. The simulator therefore considers both heat and mass transfer limitations to hydrate growth.

The mass transfer rate in Equation (1) depends on the contact area \( A \) between the two subsystems and the mass transfer number \( k_i \). \( A \) is calculated based on the flow regime in the pipeline and the \( k_i \) from the Sherwood number, which is given by

\[
S_{h_{i}} = \frac{k_{i}d}{D_{i,\text{water}}}
\]  

(2)

where \( d \) is the pipeline diameter and \( D_{i,\text{water}} \) is the diffusion coefficient for component \( i \) in the water phase. The Sherwood number is calculated from other dimensionless flow simulation numbers

\[
S_{h_{i}} = Re^{exp1} Sc_{i}^{exp2} We^{exp3}
\]  

(3)

where \( Re \) is the Reynolds number, \( Sc \) is the Schmidt number and \( We \) is the Weber number. The exponents \( exp1, exp2 \) and \( exp3 \) in Equation 3 are parameters that should be optimized to model experimental data.

**BENCHMARKING**

The model has been validated against flow loop data from the University of Tulsa, both in terms of the mass transfer calculations and in terms of assessment of transportability.

**Mass Transfer limited Hydrate Growth**

For hydrate kinetics simulations to be useful to pipeline operators it must be possible to configure the model to simulate a hydrate growth rate representing a worst case scenario. That means the simulated hydrate build-up must be at least as high as that seen experimentally. The model has been benchmarked against experimental data from a flow loop at University of Tulsa. Experiments were selected where the hydrate growth was mass transfer limited. The experiments were conducted at constant pressure meaning that additional gas was added during the experiment in order to keep the pressure constant in the flow loop as hydrates were forming.

Figure 1 shows the simulated and experimental gas added for 22 experiments. In order to obtain the conservative simulations in Figure 1 the parameters in Equation 1 and 3 were tuned. The tuned parameters for Equation 3 are listed in Table 1.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>exp1</td>
<td>0.5</td>
</tr>
<tr>
<td>exp2</td>
<td>0.5</td>
</tr>
<tr>
<td>exp3</td>
<td>0.0</td>
</tr>
</tbody>
</table>

Table 1. Tuned parameters for Equation 3

In addition to the parameters in Table 1, a multiplication factor of 4.0 was used on the interfacial area between the gas and the water system for the simulations in Figure 1.

**Transportability**

The applied flow simulation tool is able to conservatively simulate the amount of hydrate formed in a pipeline, but in order to assess plugging risk it is necessary to correlate the amount of hydrate in a pipeline with the possibility of forming a plug. Experiments addressing transportability were also conducted in the University of Tulsa flow loop as described by Hadsbjerg et al. [9]. These experiments were constant mass experiments where the amount of hydrates were controlled by decreasing the temperature in stages and the system pressure. For each temperature stage, hydrates will form until the pressure in the flow loop drops sufficiently to obtain equilibrium. Figure 2 shows the experimental and simulated pressures for one of the staged cooling experiments with gas, water and hydrates flowing in the flow loop. During the experiment the pressure drops from around 1500 psia to around 700 psia as hydrates are forming and the volume % hydrates in the liquid phase increases from 0% to around 20%.

As seen in Figure 2 the system with gas, water and hydrates maintained flow for more than 12 hours without plugging. It is also seen that the simulated pressure in the experiment decreases faster for each stage than is experimentally observed. This means hydrates form faster in the simulation than in the experiment which is expected with the model parameters used in Figure 5.

Figure 2 does not address how big an influence the formed hydrates have on the frictional pressure drop in the pipeline. Experimental evidence from Hadsbjerg et al. [9] suggests that up to 10 volume % hydrate can be transported in a gas, water, hydrate system without causing a significant increase in frictional pressure drop and therefore plugging risk, whereas flow disturbances and significant increases in frictional pressure drops are seen when the volume % of hydrates increases beyond 15% for gas, water and hydrate systems.

One of the lessons learn in the study of wax deposition was that one cannot visualize how all the coupled phenomena interact during a given production scenario. There are two tools now available which can be used to study hydrate management without or with limited chemical application. The present hydrate kinetics simulation is coupled with a steady state multiphase flow simulation tool and thermodynamic engine of PVTSim. Thus the tool described here gives full compositional simulation that allows transport of hydrates with mobile liquid phases and detailed compositional output as well as mass and heat transfer considerations required to account for much of the physical phenomena encountered during the flow of hydrate forming systems. A second tool utilizing a similar approach to hydrate kinetics with CSM HyK kinetics program and transport is coupled to a transient multiphase simulation tool OLGA and allows simulation of start up and shut down operations. This allows safe and secure design of production facilities that can correctly take advantage operating windows with specific systems where little if any of the typical inhibition schemarios are required.

Flowasta has characteristics that allow mimicking many scenarios quickly and efficiently. The tool is based on PVTSim and therefore allows dynamic calculation of the hydrate phase boundary with the current local concentration. The simulation tool does not allow salts but does allow methanol and MEG. The salinity can be mimicked using MEG as
an effectively nonvolatile solute. It also allows ready capture of GOR effects as well.

DEPLOYMENT OF HYDRATE SIMULATION TOOLS DURING CONCEPTUAL DESIGN

The following illustrates the use of Flowasta in project work. The example case is a 41 km tie back with a water depth of 1050 m. The line diameter is 12” with some nominal level of insulation, 1” polypropylene giving a nominal U value of about 4 BTU/hr/ft²/°F. The oil flowing from a subsea manifold to a host platform is 33.5 °API crude with a gas oil ratio of 1076 SCF/STB.

Figure 3, it can be seen that total liquid rates and water cuts change dramatically with time necessitating hydrate risk assessment and system design from a “life of the field” perspective.

Figures 5 and 6 can be compared to illustrate the effect of hydrate formation on the flow line fluid temperature. Figure 5 shows the Pressure and Temperature profile at 40% water cut with reduced flow as one would expect after a few years of field life based on the production profile. Forcing Flowasta to ignore hydrate formation, Figure 5 shows that the fluids cooldown continuously and reach about 42 °F at the flowline exit.

Figure 3 Production Forecast for Field X

Figures 3 and 4 show the production profile expected for Field X and the flowline geometry from the subsea manifold location to the host.

Figure 5 Flow with no hydrates formation

Figure 4 Flow Line layout for Field X
Figure 6 Hydrate formation enabled base case

Figure 6 shows the Pressure and Temperature profiles for the same case i.e. 40% water cut with reduced flow except that hydrates are allowed to form in the Flowasta simulation. A feature apparent from Figure 6 is that the hydrate reaction caused by the pressure and temperature is causing the fluid temperature to almost plateau out in the flowline and be relatively stable around 60°F starting at 15,000 m. The break shown in the temperature profile in Figure 6 at about 15,000 m corresponds to the onset of hydrate formation shown in Figure 7 below. The exothermic nature of hydrate formation is well known. The temperature profile’s gentle slope after hydrate formation is indicative of hydrate formers methane, ethane, and propane being consumed from the fluids as they move from source to sink in the simulation. The system temperature moves to the equilibrium temperature for hydrate formation at the local system pressure in the pipeline. Both Flowasta and CSMHyk give this result.

The fraction of hydrates formed in Figure 7 can lead to problems based on available test data. One could conceivably limit hydrate formation by using suitable insulation to maintain the heat released by hydrate formation to limit hydrate growth and avoid blockage formation. This would be used as a management method instead of dosing with chemicals for example in cases where sufficient heat would not be available.

Figure 7 Solids formation at 40% water cut for 25,000 BPD flow case.

Figure 8 3000 BPD Late Life

Figure 8 shows the PT profile in late field life where we know the production is mostly water from Figure 3. For the initial case studied here with
40% water cut one can produce pressure and temperature profiles like those shown in Figure 8.

Figure 9 Low Flow Hydrate formation, 3000 BPD

Figure 9 gives the results for hydrate formation in the late life case of 3000 BPD flow. From a design point of view we wish to limit hydrate formation to less than 20% solids to transport. In the case shown in Figure 9 the suspended hydrate volume percent is greater than 30% in places.

The high conversion of water to hydrates and the fraction of solids produced can be controlled in this case by changing the insulation material. For example, for illustration purposes only, changing from polypropylene (thermal conductivity ~400 mW/m°C) to polyurethane foam (~26 mW/m°C) which has much lower thermal conductivity and increasing the thickness from the initial estimated 1”, can make a difference. The initial U value was 3 BTU/hr/ft²/°F.

Figure 10 Hydrate Formation with U~0.22 BTU/hr/ft²/F and 3,000 BPD

In this illustration case, changing the insulation material to the far better Polyurethane foam at 1” thickness gave an overall U value of 0.22 BTU/hr/ft²/F. The design calculation of impact of insulation quality on possible hydrate transportability is readily performed with Flowasta. Figure 10 shows the hydrate fractions formed with this better insulation case and Figure 11 shows the pressure and temperature profile. Even at low flow and late life production, hydrate fractions can be maintained low thereby making it possible to naturally transport hydrates and do so without inhibition.

Even at 70% water cut (Figure 12) the system still flows at projected operating conditions. Without an additional source the formation of hydrates is limited to less than 10% conversion.
Figure 11 PT profile for $U \approx 0.22 \text{ BTU/hr/ft}^2/\text{F}$ and 3000 BPD

Figure 12 70% WC with 0.22 BTU/hr/ft$^2$/F insulation and 3000 BPD production

Other tools exist that can be used for project design in the way demonstrated here. The CSM-HyK module for the OLGA transient multiphase flow simulator has been compared on example cases. Where Flowasta would be used for steady state simulations to determine the operating envelop for the production processes and for screening alternatives, a transient multiphase tool is required for operability studies. We find the tools have complimentary functions in project work.

A simple case comparison of flow through an 8” flowline from 1500 m dept to a host some 48 km away. The fluids are the same as the earlier example in this paper.

The temperature profiles produced for the two tools on the same flowline with the same fluids is shown in Figure 13.

The system temperature here is dictated by the hydrate formation temperature at the local operating pressure in the flow line. The agreement is good considering the OLGA model does not take into account the changing composition of the fluids and hence the changing formation temperature as the fluids move down the flow line. The change in formation temperature is led by the preferential consumption of ethane and propane from the solution gas. Flowasta does show a higher pressure trend. Again it difficult to match the pressure profile exactly since the sink pressure is set with OGLA and the source pressure depends on pressure loss and mass flow rate. With Flowasta the source pressure is set and the sink pressure floats. Generally in a failed run on Flowasta, the fluid pressure drops to zero before the end of the line (sink) is reached by the flow. For OLGA the source pressure was 3810 instead of 4000 psia.
Table 2 Comparison of Key Pressure in Flowline

<table>
<thead>
<tr>
<th></th>
<th>OLGA</th>
<th>Flowasta</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source</td>
<td>4000</td>
<td>4000</td>
</tr>
<tr>
<td>Bottom of the Riser</td>
<td>2773</td>
<td>3055</td>
</tr>
<tr>
<td>Sink</td>
<td>1366</td>
<td>784</td>
</tr>
<tr>
<td>Flow line $\Delta P$</td>
<td>1037</td>
<td>945</td>
</tr>
<tr>
<td>Riser $\Delta P$</td>
<td>1407</td>
<td>2271</td>
</tr>
</tbody>
</table>

Because Flowasta has a lower viscosity in the flow line, the pressure drop is lower even though both have hydrate formation. Figure 14 shows the pressure profiles from the two simulators are also comparable.

The higher predicted flowline pressure with Flowasta offsets the higher line temperature in CSMHyK so the net formation of hydrates in the flow line is similar.

Figure 14 Pressure Profile Comparison

**DISCUSSION**

The application of simulation tools that account for hydrate formation in multiphase flow is described above. If early experimental work on a project suggests that natural hydrate transportability at low hydrate fractions may be a viable option to consider within the flow assurance philosophy, then having modeling tools that allow easy integration of this natural transportability into conceptual engineering and design calculations can be very useful. The tool applied here is fully compositional and relatively easy to apply to study sensitivities and
perform conceptual engineering design calculations leading up to selection of alternatives as part of a deepwater project development. We have used the tool also to verify the expected results regarding heat transfer limited reaction of hydrates in an insulated system. This is shown in the example project development scenario for Field X where the process was worked from an initial field low water cut scenario when the pressures and temperatures were high at about 25,000 to 40,000 BPD production finally declining to production near 3000 BOPD and finally examining a 70% water cut case.

The insulation used to facilitate transportation of oil and hydrates at low flow was more than adequate at high flow.

Typically 50 vol% WC is considered to be out the range of “natural” hydrate slurry transport. However, suppressed hydrate equilibrium region due to low GOR, high salinity brine, and emulsion stability can enable the transportation of hydrates dispersed in a mobile oil phase. [10].

Currently under investigation are the relationships regarding the transports of hydrates and water droplets dispersed in the oil phase. The correlations used in Flowasta were developed for wax. Wax particles are known to gel with fractions as low as 2 wt%. Better parameter assignment can be made once proper experimental data are available.

CONCLUSION
The application of a multiphase simulation tool with hydrate formation to project development was described. The effects of flow rate and water cut were examined. A process was also identified using these tools to transport dispersed hydrates by limiting formation through managing the heat released when hydrates formed. Comparison with other tools reveals a consistency between the hydrate kinetics modules and the heat and mass transfer simulations. Work is continuing to identify and implement correct parameterization for the transport of hydrates formed dispersed in the oil phase.

REFERENCES