DP Conference MTS Symposium

Flow Assurance

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Session Outline

• **Flow Assurance Overview**
  • Key Flow Assurance Issues
    • Wax
    • Hydrates
    • Slugging
  • Deepwater Impacts on Flow Assurance
  • Emerging Technologies

• **Design Considerations**
  • Black Oil Systems
  • Gas Condensate Systems
Flow Assurance Overview
What is Flow Assurance?

• Analysis of the entire production system to ensure that the produced fluids continue to flow throughout the life of the field.

• Optimization of the design and operating procedures to cost effectively prevent or mitigate slugging, surge volumes, wax deposition, gelling, hydrates, asphaltenes, etc.
Key Flow Assurance Issues

• Wax (Paraffin) – What is it?
  • A solid hydrocarbon which precipitates from a produced fluid
  • Forms when the fluid temperature drops below the Wax Appearance Temperature (WAT)
  • Melts at elevated temperatures (20°F+ above the WAT)
  • Rate of deposition can be predicted for pigging frequency
Key Flow Assurance Issues

• Wax
  • Since 1996, there have been 51 major occurrences that the MMS had to be involved in
    • All were paraffin-related
  • Means of remediation
    • Pigging
    • Continuous inhibition (150-250 ppm for Gulf of Mexico)
      ▪ Reduced wax deposition rate by 60-90%
  • Industry Technology
    • Modeling is overly-conservative (6X pigging frequency)
Key Flow Assurance Issues

Example WAT Measurement

Above WAT

Wax Crystals (WAT)

Seabed Temp. (40°F)
Key Flow Assurance Issues

• Factors effecting wax deposition rate
  • Wax Appearance Temperature, WAT
  • Production Fluid Temperature
  • Flowline U-value
  • Fluid Properties
    ▪ Viscosity
    ▪ N-Paraffin Content
Key Flow Assurance Issues

• Wax Deposition – Insulation Impact
Key Flow Assurance Issues

**Hydrate – What is it?**
- An Ice-like solid that forms when:
  - Sufficient water is present
  - Hydrate former (i.e., methane) is present
  - Right combination of Pressure and Temperature (High Pressure / Low Temperature)

*Molecular Structure of Hydrate Crystal*
Key Flow Assurance Issues

• Hydrates
  • Primary cause for insulated flowlines
  • Deepwater operations
    • Increased operating pressure
    • Cold ambient temperatures
• Means of remediation
  • Crude oil displacement (looped flowlines)
  • Depressurization
  • Coiled tubing
  • Continuous Inhibition (Prevention Only)
    ▪ Methanol/MEG
    ▪ LDHI
Key Flow Assurance Issues

- Hydrates – Base Information
Key Flow Assurance Issues

- Hydrates – Base Information
Key Flow Assurance Issues

• Slugging – What is it?
  • Periods of Low Flow Followed by Periods of High Flow
  • Occurs in Multiphase Flowlines at Low Gas Velocities
Key Flow Assurance Issues

- Slugging
  - Causes
    - Low fluid velocity
      - Bigger ≠ Better
    - Seabed bathymetry (downsloping)
    - Riser type
      - “Lazy-S” is a slug generator
  - Means of prevention
    - Increase flowrate
    - Separator pressure
    - Gas lift

<table>
<thead>
<tr>
<th>Gas Lift Overview</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Proven Technology</td>
<td>Erosion Concerns</td>
</tr>
<tr>
<td></td>
<td>Relative Inexpensive</td>
<td>Lower Temperatures</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Difficult with Catenary Risers</td>
</tr>
</tbody>
</table>
Key Flow Assurance Issues

• Slugging – Gas Lift Impacts
Key Flow Assurance Issues

Other Issues
- Asphaltenes
- Scale
- C-Factors
- Surge Volume
- Erosion
- Depressurization
- Pigging
- Chemical Inventory
- Pour Point
- Corrosion
- Emulsions
- Cooldown Times
- Sand
- Liquids Management
- Flare Capacity
Deepwater Impacts on Flow Assurance

- **Hydrate Formation/Wax Deposition**
  - Leads to:
    - Insulation / dual flowlines
    - Dry oil flushing
    - Active heating
    - Chemicals
    - Revamped operating strategies

- **Lack of pressure / need for boosting**
  - Deepwater + high water cut + long tiebacks
    - Riser base gas lift
    - Multiphase pumping
    - Subsea separation
Deepwater: Temperature Losses

- Potential Energy Losses
  - Gas does “work” in moving fluids
  - Function of water depth
- Expansion Cooling (Joule-Thomson Effect)
  - Exacerbated at large pressure differentials
- RISER DOMINATES DEEPWATER SYSTEMS
  - Insulation may not be the answer!
Deepwater: Temperature Losses

- **Joule-Thomson Cooling**: 46%
- **Surroundings (U-Value)**: 6%
- **Potential Energy (Work)**: 48%

**Temperature (°F)**
- **FLOWLINE**
- **WELLHEAD**
- **RISER**
- **TOPSIDES**
- **RISER BASE**
## Deepwater: Temperature Losses

<table>
<thead>
<tr>
<th>Flowline Length (miles)</th>
<th>Temperature Drop (°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Flowline</td>
</tr>
<tr>
<td>3</td>
<td>1.2</td>
</tr>
<tr>
<td>6</td>
<td>2.9</td>
</tr>
<tr>
<td>15</td>
<td>9.2</td>
</tr>
</tbody>
</table>
Deepwater: Temperature Losses

- Heat transfer coefficient (U-value) dictates steady state temperatures
  - $Q$ (heat loss) = $U \cdot A \cdot \Delta T$
  - U-Value ↓, $Q$ ↓ … $T$ ↑

- Thermal mass ($\rho$, $C_p$) impacts transient performance
  - Measure of heat storage
  - Prolongs cooldown times
  - Prolongs warm-up times
Transient Temperature Loss

- **HIGH (Gelled Fluid #2 – Water Base)**
- **MEDIUM (Gelled Fluid #1 – Oil Base)**
- **LOW (Nitrogen)**
Deepwater: Pressure Losses

- WELLHEAD
- FLOWLINE
- RISER
- RISER BASE
- TOPSIDES
### Deepwater: Pressure Losses

<table>
<thead>
<tr>
<th>Flowline Length (miles)</th>
<th>Pressure Drop (psia)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Flowline</td>
</tr>
<tr>
<td>3</td>
<td>143</td>
</tr>
<tr>
<td>6</td>
<td>238</td>
</tr>
<tr>
<td>15</td>
<td>405</td>
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</tbody>
</table>
Deepwater: Dry Trees vs. Subsea Tieback

- Dry trees preferred for accessibility
- Dry trees more difficult for flow assurance
  - Typically cannot depressurize
  - Short cooldown times (2-8 hours)
  - Fewer insulation/heating options than subsea
  - Limited chemical (MeOH/MEG) deliverability
  - Wax deposition more difficult to remediate
Dry Tree Analysis: Cooldown Comparison

Production Fluid Temperature

- Solid - Conduction
- Liquid - Conduction + Convection
- Gas - Conduction + Convection + Radiation

Dry Tree: Conduction / Convection / Radiation

HYDRATE FORMATION TEMPERATURE
Dry Tree: Concentric vs. Non-Concentric

• Accommodate Auxiliary Lines?

• Heat Transfer: \[ Q = k \cdot A \cdot \Delta T / L \] (Conduction Only)
Dry Tree: Concentric vs. Non-Concentric

Concentric (0.1 BTU/hr-ft -°F)

Non-Concentric (1.0° Offset)
Dry Tree: Gas Properties

Temperature (°F) vs. Time (Hours)

- 15 psia N2
- 30 psia N2
- 59 psia N2
- 102 psia N2

Dry Tree:

Gas Properties
Design for Expansion

- Transient issues drive deepwater design
  - Cooldown / restart - **Hydrates**
- Typical deepwater practice
  - Dual flowlines / crude oil displacement
  - Typically cannot depressurize (oil systems)
- **Consider potential for future expansion**
  - Insulation
  - Topsides facilities
Design for Expansion

Total Time to Displace Existing System = 22 Hours (Sequential)
Total Time to Displace Integrated System = 45 Hours (Sequential)

High Level Insulation, or Additional Topsides Facilities Required!
Emerging Technologies

- Artificial Lift
  - Subsea Separation (-)
  - Multiphase Pumping (+)
  - Gas Lift (+ / -)
- Passive Insulation Solutions
  - Microporous Insulation
  - Phase Change Materials
Emerging Technologies

• Active Heating
  • Hot Water Circulation
  • Electrically Heated
  • “Electrically-heated ready”

• Chemicals
  • Low Dosage Hydrate Inhibitors
  • “Cold Flow”
Design Considerations: Black Oil and Gas Condensate Systems
Black Oil System: Steady State Design Checklist

- **Hydraulics**
  - Line sizing
    - Dry tree vs. subsea tieback
    - Single vs. dual flowlines
    - **Dual flowlines becoming “standard” for deepwater**
  - Pressure drop
  - Velocity / erosion (minimum / maximum)
  - Slugging

- **Thermal**
  - Insulation requirements
    - Hydrate formation
    - Wax deposition
    - Gel formation
Black Oil System: Transient Design Checklist

- Shutdown
  - Planned
  - Unplanned
- Depressurization
- Restart
  - Warm
  - Cold
- Fluid displacement / pigging
- Flowline preheating
Black Oil Systems:
Steady State Design Considerations
Black Oil System: Steady State Hydraulics

- Pressure drop effects
  - Physical
    - Line size
    - Tieback distance
    - Water depth
      - Multiphase flow:
        - Head losses <> head gains
    - Pipe roughness (typical values)
      - Steel: 0.0018”
      - Tubing: 0.0006”
      - Flexible pipe: ID/250

- Fluid properties
  - Gas/oil ratio (GOR)
  - Density
  - Viscosity
    - May require insulation to limit viscosity
Black Oil System: Slugging

- Hydrodynamic
  - High frequency
  - Minimal facilities impact

- Terrain
  - High liquid / gas flowrates
  - Topsides concern
  - Riser fatigue concern
  - Utilize gas lift
Black Oil System: Slugging

- Slugging issues
  - Sensitivity to Fluid GOR / water cut

<table>
<thead>
<tr>
<th>Water Cut (%)</th>
<th>Terrain Slugging Regime (BPD) / Surge Volume (BBL)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>760 GOR</td>
</tr>
<tr>
<td>0</td>
<td>15000 / 150</td>
</tr>
<tr>
<td>20</td>
<td>20000 / 160</td>
</tr>
<tr>
<td>40</td>
<td>24000 / 175</td>
</tr>
<tr>
<td>60</td>
<td>26000 / 325</td>
</tr>
<tr>
<td>80</td>
<td>DNF</td>
</tr>
</tbody>
</table>
Black Oil System: Slugging

- Slugging issues
  - Sensitivity to Trajectory: up vs. downslope

![Graph showing slugging issues](image-url)
Black Oil System: Steady State Thermal Design

- Hydrates
  - Maintain steady state temperature above hydrate formation region, down to “reasonable” flowrate
    - Looped flowline ~ 25% of field production (50% per flowline)
  - For low water-cut systems, continuous hydrate inhibition is possible
  - Future: continuous LDHI inhibition
Black Oil System: Steady State Thermal Design

- Wax
  - Maintain temperature above WAT (stock tank), down to “reasonable” flowrate
    - Looped flowline ~ 25% of field production (50% per flowline)
  - Maintain viscosity at acceptable levels to reduce pressure drop
  - Insulate to minimize pigging frequency
    - Pigging frequency > residence time
  - Continuous paraffin inhibition (if necessary)
Black Oil System:
Steady State Thermal Design

<table>
<thead>
<tr>
<th>Insulation Option</th>
<th>Achievable U-value (BTU/hr-ft²-°F)</th>
<th>Issue / Concern</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flexible</td>
<td>0.75 – 1.50</td>
<td>• Limited insulating capacity</td>
</tr>
<tr>
<td>Wet (Syntactic)</td>
<td>0.50 – 0.75</td>
<td>• Buoyancy issues</td>
</tr>
<tr>
<td>Burial</td>
<td>0.50 – 1.00</td>
<td>• Dependant on soil properties</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Combined with insulation</td>
</tr>
<tr>
<td>Pipe-in-pipe</td>
<td>0.20 – 0.25</td>
<td>• Riser installation difficulties</td>
</tr>
<tr>
<td>Micro-porous</td>
<td>0.08 – 0.10</td>
<td>• Industry acceptance</td>
</tr>
</tbody>
</table>
Black Oil System: Steady State Thermal Design

Arrival Temperature
Water Cut = 0%

Liquid Flowrate (blpd)

Arrival temperature (°C)

- Adiabatic (0 BTU/ft² hr °F)
- 0.09 BTU/ft² hr °F
- 0.20 BTU/ft² hr
- 0.30 BTU/ft² hr °F
- 0.50 BTU/ft² hr °F
Black Oil Systems: Cooldown Design Considerations
Black Oil System: Cooldown

• Shutdown statistics
  • Typical shutdown durations
    • 89% shutdowns < 10 hours
    • 94% shutdowns < 12 hours
    • 99.9% shutdowns < 24 hours

• Typical shutdown causes

![Pie chart showing typical shutdown causes]
Black Oil System: Cooldown

- Planned shutdown Procedure
  - Inject hydrate inhibitor for one residence time (minimum)
    - At high water cuts, may need to reduce flowrate to effectively treat system
  - Inject hydrate inhibitor into subsea equipment
    - Particular attention to horizontal components
    - Self-draining manifold / jumpers
    - Treat upper portion of wellbore
      - SCSSV vs. top ~50 ft
  - Shut-in system
Black Oil System: Cooldown

- Unplanned shutdown Procedure
  - Determine minimum cooldown times
    - “No-Touch Time”
      - ~2-4 hours / no action taken subsea
    - “Light Touch Time”
      - ~2-4 hours / treat critical components
        - Time is a function of chemical injection philosophy / number of wells
    - “Preservation Time”
      - Time required to depressurize or displace flowlines with non-hydrate forming fluid

Time=0  Time=4  Time=8
“No-Touch”  “Light Touch”  “Preservation”
Black Oil System: Cooldown

- Insulation selection
  - Cooldown time determined by:
    - U-Value
    - Thermal mass ($\rho$, $C_p$)
      - Measure of heat storage
      - Line size impacts
        - Bigger = More Thermal Mass
  - Gas / liquid interface typically controlling point
    - Gas = low thermal mass
    - Highest pressure
    - Coldest temperature
Black Oil System: Cooldown

- RESERVOIR
- WELLHEAD
- FLOWLINE
- RISER

Graph shows pressure (psia) versus distance (miles) with two lines:

- Blue line: 0 hours (Steady State)
- Red line: 24 hours
Black Oil System: Cooldown

The graph represents the liquid holdup over distance for different time periods. The blue line represents the steady state condition at 0 hours, while the red line shows the condition after 24 hours. The graph is divided into sections labeled RESERVOIR, WELLHEAD, FLOWLINE, and RISER. The vertical axis represents the liquid holdup (-), and the horizontal axis shows the distance in miles.
Black Oil System: Cooldown

Hydrate Propensity, T-Thyd (°F)

Distance (miles)

RESERVOIR
WELLHEAD
FLOWLINE
RISER
Black Oil System: Cooldown Checklist

- Is there adequate chemical injection to treat subsea components within cooldown time?
  - Wellbore
  - Trees
  - Jumpers
  - Manifolds

- What is the subsea valve closure philosophy?
  - Packed: More liquid / higher pressures
  - Un-packed: Less liquid / lower pressures

- Does insulation provide sufficient cooldown time?
  - No-touch
  - Light-touch
  - Preservation

- Is gel formation a possibility?
  - **If yes, system design philosophy changes**

- Is SCSSV set deep enough to avoid hydrates?
Black Oil Systems: Depressurization Design Considerations
Black Oil System: Depressurization

- Hydrate remediation strategy
  - Reduce pressure below hydrate formation pressure at seabed
- Effectiveness based on:
  - Fluid properties
    - GOR
    - Water cut
  - Seabed bathymetry
    - Upslope
    - Downslope
- Deepwater issues
  - Reduce pressure to ~200 psia at seabed
  - Maintain pressure below hydrate conditions during restart

```
Time=0  Time=4  Time=8
```

```
“No-Touch”  “Light Touch”  “Preservation”:
Depressurization
```
Depressurization: Subsea Tieback

- **Pressure (psia)**
- **Distance (miles)**

- **BOTTOM HOLE**
- **FLOWLINE**
- **MUDLINE**
- **RISER BASE**

Graph showing the pressure drop over distance for different time intervals (0.0 hours, 0.5 hours, 1.0 hours).
Depressurization – Dry Tree

Distance (feet)

Pressure (psia)

BOTTOM HOLE

SCSSV

GAS/LIQUID INTERFACE

MUDLINE

0.0 hours
0.5 hours
1.0 hours
Black Oil System: Depressionization Checklist

- Can you depressurize below hydrate formation conditions?
  - If **YES**, can you depressurize in late-life at high water cuts?
  - If **YES**, can you maintain pressure below hydrate formation conditions during restart?
    - Difficult for deepwater
  - If **YES**, is there a pour point concern?
    - Depressurization increases restart pressure requirements
  - If **NO**, consider the following for hydrate prevention:
    - Displacement (dual flowlines)
    - Active heating
    - Continuous chemical inhibition
Black Oil Systems: Displacement Design Considerations
Black Oil System: Displacement Hydrate Prevention - Shutdown

- During “Prevention” time, displace produced fluids from flowline
  - Unable to get hydrate inhibitor to in-situ fluids during shutdown
  - Dual flowlines required
  - Sufficient insulation / cooldown time
  - Function of flowline length

Time=0  Time=4  Time=8

“No-Touch”  “Light Touch”  “Preservation”: Displacement
Black Oil System: Displacement
Discharge Pressure Required

HOLD BACKPRESSURE AT OUTLET
Black Oil System: Displacement
Hydrate Prevention - Shutdown

Dead Oil Flushing - Year 5
FPSO Pump Discharge Pressure
FPSO Arrival Pressure Controlled at 1500 psia

- Pig reaches base of first riser
- Produced fluids move up second riser
- Gas breaks through second riser
- Pig moves up second riser
Black Oil System: Displacement Hydrate Prevention - Shutdown

• During “Prevention” time, displace produced fluids from flowline
  • Topsides design considerations
    • Available backpressure
    • Circulation rate
      ▪ Limited by pig integrity
      ▪ Typically 3-5 ft/sec
      ▪ May be faster for “straight-pipe”
  • Storage volume
  • Circulation passes
    ▪ With pig: 1 residence time
    ▪ Without pig: 2-3 residence times for efficient water removal
Black Oil System: Displacement Hydrate Prevention – Dry Tree

• During shutdown, how quickly will fluids fall below SCSSV?
  • Very little work done with L/D ratios >100 (deepwater riser ~10000)
  • Field data shows oil/water separation ~ 70-80 ft/hr
• Bullhead / displace with non-hydrate forming chemical to SCSSV
  • Methanol/MEG (volume concerns)
  • Heavy diesel (high density, by-pass produced fluids)
  • Dead oil
    • Ability to bullhead a function of displacement rate
Black Oil System: Displacement Checklist

- Is there sufficient time to accomplish displacement operation?
  - Sufficient insulation / Cooldown time
- Is the topsides facility designed to accomplish displacement operation?
  - Pump capacity
  - Storage capacity
- Can system be restarted into crude-oil filled flowline?
  - Displace with gas?
  - High pour point fluids – what is the restart pressure required?
- For dry trees, is a proper fluid available for displacement?
Black Oil Systems: Restart Design Considerations
Black Oil System: Cold Restart

- System pressure < hydrate formation conditions throughout restart?
  - For deepwater, hydrostatic pressure in riser too high
  - Separator pressure: may need alternate start-up vessel

- Hydrate inhibition required until arrival temperature reaches “Safe Operating Temperature” (SOT)
  - Maintain hydrate inhibitor rate: Fluid completely inhibited
  - Reduce hydrate inhibitor rate: Fluid not completely inhibited to shut-in conditions

- SOT is minimum topsides temperature that provides sufficient cooldown time, in the event of an interrupted restart
Black Oil System: Cold Restart

![Graph showing the relationship between Shut-in Pressure (psia) and Methanol Dosage (BBL MeOH/BBL H2O) for different types of water: Pure Water, Sea Water, and Produced Water.]
Black Oil System: Cold Restart

Flowrate, BPD

Methanol, gpm

5% WATER

25% WATER

50% WATER

75% WATER
Black Oil System: Cold Restart

- Achievable restart rates determined by:
  - Shut-in conditions
  - Fluid GOR
  - Water cut
  - Hydrate inhibitor

- **“Rule of Thumb”:** Greater inhibitor injection rates result in lower overall inhibitor volumes used during restart
  - Small tiebacks: 5-10 gpm / well
  - Large deepwater: 25+ gpm / well

- Warm-up trends:
  - Wellbore: Very quick (<30 minutes)
  - Flowline: Function of flowrate / water cut / length / insulation
Black Oil System: Cold Restart
Black Oil System: Cold Restart

![Graph showing hydrate propensity at different time intervals. The x-axis represents time in hours, ranging from 0 to 35. The y-axis represents hydrate propensity in °C, ranging from -20 to 50. The graph includes data points at 0 hours, 1 hour, 2 hours, 3 hours, 4 hours, 8 hours, 9 hours, 10 hours, 11 hours, and 12 hours. Each interval is represented by a different line color or marker style.](image-url)
## Cold Restart: Case Study
### 3 Mile Tieback – Warm-up Time

<table>
<thead>
<tr>
<th>Insulation Type</th>
<th>5000 STBPD</th>
<th>10000 STBPD</th>
<th>Max Flowrate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Micro-porous</td>
<td>5.8</td>
<td>2.9</td>
<td>1.1</td>
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<tr>
<td>Pipe-in-pipe</td>
<td>6.1</td>
<td>3.0</td>
<td>1.1</td>
</tr>
<tr>
<td>Conventional</td>
<td>9.2</td>
<td>3.5</td>
<td>1.2</td>
</tr>
<tr>
<td>Flexible</td>
<td>10.6</td>
<td>3.2</td>
<td>1.1</td>
</tr>
<tr>
<td>Buried</td>
<td>&gt; 24</td>
<td>8.4</td>
<td>1.5</td>
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## Cold Restart: Case Study
### 15 Mile Tieback – Warm-up Time

<table>
<thead>
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<th>Insulation Type</th>
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<th>10000 STBPD</th>
<th>Max Flowrate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Micro-porous</td>
<td>&gt; 24</td>
<td>13.0</td>
<td>7.0</td>
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<tr>
<td>Pipe-in-pipe</td>
<td>&gt; 24</td>
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<td>Conventional</td>
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<td>&gt; 24</td>
<td>10.9</td>
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<td>Flexible</td>
<td>&gt; 24</td>
<td>&gt; 24</td>
<td>12.3</td>
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<td>Buried</td>
<td>&gt; 24</td>
<td>&gt; 24</td>
<td>&gt; 24</td>
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### Cold Restart: Case Study

15 Mile Tieback – MeOH Volume

<table>
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<th>10000 STBPD</th>
<th>Max Flowrate</th>
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</thead>
<tbody>
<tr>
<td>Micro-porous</td>
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<td>798</td>
<td>772</td>
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<tr>
<td>Pipe-in-pipe</td>
<td>&gt; 850</td>
<td>814</td>
<td>781</td>
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<td>Conventional</td>
<td>&gt; 850</td>
<td>&gt; 1700</td>
<td>1074</td>
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<tr>
<td>Flexible</td>
<td>&gt; 850</td>
<td>&gt; 1700</td>
<td>1053</td>
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<tr>
<td>Buried</td>
<td>&gt; 850</td>
<td>&gt; 1700</td>
<td>&gt; 2300</td>
</tr>
</tbody>
</table>
Black Oil System: Restart Checklist

- Is there sufficient hydrate inhibitor available?
  - Delivery rates
  - Storage volumes

- How will multiple wells be restarted?
  - Single well at max. rate
  - Multiple wells at reduced rate
  - Single flowline vs. dual flowline

- What is the minimum temperature required to achieve safe conditions?
  - Safe Operating Temperature (SOT)
Black Oil System: Summary of Design Considerations

- Hydraulics
  - Ensure Production Delivery Throughout Field Life
  - Minimize Slugging

- Wax Deposition
  - Minimize Wax Deposition (Insulation/Pigging/Chemicals)

- Hydrate Formation
  - Avoid Steady State Hydrate Formation
  - Optimize Cooldown Times (Insulation)
  - Prevent Transient Hydrate Formation (Depressurization/Displacement/Chemicals)
  - Minimize Inhibitor Consumption