Drilling-with-Casing (DwC™)
Overcoming Wellbore Stability Issues

Steve Rosenberg — U.S. Region Product Line Manager

Tuesday April 21st, 2009
Presentation Outline

- Definition and Benefits of DwC
- Drilling Hazard Mitigation Value
- DwC Hydraulics.
- DwC Systems
- Drillable DrillShoes
- Casing Drive Systems
- Liner Drilling
- Applications Engineering
- Case Histories
- Future DwC Technology
What is DwC™ Technology?

Drilling-with-Casing/Liner technology uses the casing string as the ‘drill string’ instead of drill pipe.

*DwC* reduces well construction costs and improves drilling efficiency.
Key Value Drivers for DwC™

- Safety
- Cost/Time Reduction
- Problem Resolution
DwC™ / DwL™ Benefits

- Increased safety. Reduced trips and less handling of heavy BHA’s
- Improve efficiency by eliminating flat spots in the drilling curve = Reduced Well Construction Costs
- Improved wellbore quality (less wellbore tortuosity)
- Improved hole cleaning
- Risk reduction and problem mitigation (lost circulation, unstable formations, depleted reservoir sections)
- Trip margin requirement eliminated
- Getting casing to bottom
Drilling Hazard Mitigation
Problem Incidents – GOM Shelf Gas Wells

Wellbores Drilled 1993 – 2002; Water Depth = <600 feet

- Rig Failure: 21%
- Casing or Wellhead Failure: 5%
- Chem. Prob.: 3%
- Directional Completion: 5%
- Wait Weather: 13%
- Twist Off: 3%
- Stuck Pipe: 11%
- Kick: 9%
- Gas Flow: 0%
- Shallow Water Flow: 3%
- Lost Circulation: 13%
- Cement squeeze: 9%
- Wellbore Instability: 1%
- Sloughing Shale: 3%
- Other: 1%

Impact of Trouble Time

- 24% of 25,321 total drill days from spud date to date TD was reached

Trouble Time Cost Impact – GoM Shelf Gas Wellbores

- Deep wells average dry-hole cost per foot = $444. Average impact = $98
- Shallow well average dry-hole cost per foot = $291. Average impact = $71

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Client Value

Drilling Hazard Mitigation

The Issue

• Drilling hazards add 12% to drilling time
• 50% of hazards relate to pressures and wellbore instability (pie chart to right shows a breakdown of these drilling hazards)
• As fields mature, depletion issues increase
• Conventional methods are time consuming, costly and largely ineffective

The Answer

• Apply proper technology to address issue
• Drilling with casing, expandable tubulars and managed pressure drilling
• Combine complementing technologies to deliver integrated engineered systems and techniques
Drilling Hazard Mitigation

Drilling with Casing DwC™
A suite of technologies that individually, or in combination, radically reduce non-productive time due to drilling hazards.

Controlled Pressure Drilling®
A better way to drill

Solid Expandable Systems

THE SOLID CHOICE™
Hidden NPT - Time reduction

Drilling curve typically reported

\[ \Delta T_1 = \text{Time Fighting Loss Circulation Zone} \]

\[ \Delta T_2 = \text{Time Curing Loss Circulation Zone} \]

\[ \Delta T_1 = 4 \text{ days} \]
\[ \Delta T_2 = 3 \text{ days} \]

Total “Flat” Time = 7 days

Time

Depth

Reduced ROP

Event 2a

\[ \Delta T_1 \quad \Delta T_2 \]
Non-Productive Time (NPT)

Lost Circulation: Time spent curing losses

Drilling curve typically reported

\[ \Delta T_1 = \text{Time Curing Lost Circulation Zone} \]

\[ \Delta T_1 = 3 \text{ days} \]

Total “Flat” Time = 3 days???
Non-Productive Time (NPT)

Lost Circulation: Time spent fighting and curing losses

\[ \Delta T_2 = \text{Time Fighting Lost Circulation Zone} \]

\[ \Delta T_1 = \text{Time Curing Lost Circulation Zone} \]

\[ \Delta T_2 = 4 \text{ days} \]

\[ \Delta T_1 = 3 \text{ days} \]

Total "Flat" Time = 7 days
What is the “Smear” or “Plaster” Effect?

Industry belief the ‘Smear’ effect cures or reduces lost circulation

- **Conventional**
  - 7.25” TJ OD
  - 5.5” FH DP
  - 21.9ppf

- **DwC**
  - 13.375” casing
  - 14.38” casing coupling OD
Smear effect

- Finer ground cuttings
- 10% to 20% less cuttings circulated to the surface
DwC Hydraulics
DwC™ vs Conventional Annular Flow

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>OD DP</th>
<th>OD Csg</th>
<th>Flow Rate, gpm</th>
<th>Annulus Area, in^2 Conv DwC Vann, ft/min</th>
<th>Vann, ft/min</th>
<th>DwC V_ann vs Conv</th>
</tr>
</thead>
<tbody>
<tr>
<td>8 1/2</td>
<td>5 1/2</td>
<td>7</td>
<td>500</td>
<td>33 18</td>
<td>292 527</td>
<td>1.8 X</td>
</tr>
<tr>
<td>12 1/4</td>
<td>5 1/2</td>
<td>9 5/8</td>
<td>800</td>
<td>94 45</td>
<td>164 341</td>
<td>2.1 X</td>
</tr>
<tr>
<td>17 1/2</td>
<td>5 1/2</td>
<td>13 3/8</td>
<td>1000</td>
<td>217 100</td>
<td>89 192</td>
<td>2.2 X</td>
</tr>
<tr>
<td>26</td>
<td>5 1/2</td>
<td>20</td>
<td>1100</td>
<td>507 217</td>
<td>42 98</td>
<td>2.3 X</td>
</tr>
</tbody>
</table>
DwC™ ECD with 13-3/8” Casing

13-3/8” DwC ECD Comparison
1500ft, 900gpm, 8.6ppg SW

Drillpipe/Casing vs Hole Size

ECD, ppg

Annular Pressure Drop, psi

Conventional drilling

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DwC™ ECD with 9-5/8” Casing

9-5/8” DwC ECD Comparison
1500ft, 600gpm, 9.6ppg 13.0YP mud

Drillpipe/Casing vs Hole Size

ECD, ppg
Ann. dP, psi

Conventiona l drilling
Today’s DwC™ Technology

BHA latched into The Lower Casing Joint
Retrievable Bits & BHA’s

Cement-in-Place Non-Retrievable DwC System
Drillable Drill Shoes

4-1/2”, 5”, 7” x 8-1/2”, 7-5/8” x 8-1/2”, 9-5/8” x 12”, 9-5/8” x 10 5/8”, 11-3/4 x 12-1/4, 11-7/8” x 12-1/4”, 13-3/8” x 14-3/4”, 13-3/8” x 17”, 18-5/8” x 24”, 20” x 24”, 24” x 27”
DrillShoe™ and Latch Systems Compared

**Drillable DrillShoe System**

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Cost</td>
<td>Limited directional control</td>
</tr>
<tr>
<td>Simple to operate</td>
<td>Cased hole logs only</td>
</tr>
<tr>
<td>No rig modifications required</td>
<td>Limited DrillShoe selection</td>
</tr>
<tr>
<td>Zero risk of irretrievable tools in the hole</td>
<td></td>
</tr>
<tr>
<td>Cementing can commence immediately TD is reached</td>
<td></td>
</tr>
</tbody>
</table>

**Latch System**

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ability to steer</td>
<td>High Cost</td>
</tr>
<tr>
<td>MwD/LwD capability</td>
<td>More complicated to set up and operate</td>
</tr>
<tr>
<td>Wide range of bit selections to suit formation and distance</td>
<td>Rig modification required</td>
</tr>
<tr>
<td></td>
<td>Risk of irretrievable tools in the hole</td>
</tr>
<tr>
<td></td>
<td>Unable to cement immediately upon reaching TD</td>
</tr>
</tbody>
</table>
DrillShoe™ 2

The DrillShoe™ is made in 2 parts:

1. The “body” is machined from a piece of 4145 ASI Steel bar.

2. The “nose” is machined from Aircraft Grade Aluminium. 6mm round pieces of TSP (Thermally Stable Polycrystalline Diamond) are then pressed into pre-drilled holes on the front of the blades. The blades are then hardfaced with HVOF Tungsten Carbide.

3. Available in 3, 4 and 5 blade designs

7,000 psi CCS Formations

Excellent Reaming Tool
DwC DrillShoe™ 2 Construction

- Tungsten Carbide Hardfacing on Aluminum surface
- 6mm round TSP pressed into the Aluminum
- Premium PDC Cutters
- Copper or Ceramic Nozzles - PDC Drillable
- Aircraft grade Aluminum nose (fully PDC drillable)
- Threaded connection between the Aluminum Nose and Steel body/shoulder
- 4145ASI Steel Body
EZCase Bit

- Steel alloy PDC design for robust reaming / drilling
- **PDC drillable only with Genesis PDC bits**
- **EZ Case nozzles not field interchangeable**
- Secondary flow path for cement reliability

PDC cutting structure

Engineered internal profile for efficient drill-out

Nozzle placement optimized using Computational Fluid Dynamics (CFD)

Secondary bypass port

Casing bit crown welded to custom pups
DrillShoe™ 3

- 5 or 6 Bladed PDC Bit
- 13 to 19 mm PDC Cutters
- Up to 20,000 psi CCS
- Converts to drillable cement shoe
- Simple pressure cycle
- Drillout with tri-cone or PDC Bit
DrillShoe™ 3

- Drills like a PDC bit
- After simple pressure cycle, DrillShoe 3 becomes drillable
- Cement as normal
- Drill-thru with a normal PDC bit
- 15,000 to 20,000 psi CCS
Contributions to NPT
Running Casing and Liner

- Tight hole, stuck pipe: 49.9%
- Pressure test failed: 9.4%
- Set hanger: 4.8%
- Threads: 4.0%
- Mud loss: 3.5%
- Tong: 3.3%
- Seal Assembly: 3.2%
- Waiting time: 2.6%
- Fishing operation: 1.7%
- Others: 17.6%

Casing Running NPT Analysis by North Sea Operator

Non productive days due to tight hole/stuck pipe: 57 days over 27 months.

Excluding cost impact of setting casing high.
## Reaming Shoes

<table>
<thead>
<tr>
<th>Weatherford DrillShoe 2</th>
<th>Weatherford CleanReam</th>
<th>Tesco Warthog</th>
<th>Baker EZReam</th>
<th>Davis Lynch Penetrator</th>
</tr>
</thead>
</table>

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Centralizers for DwC Applications

Non-Rotating Rubber Lined

In-Line

HydroForm

Spray Metal Process
Surface Drive Systems

Internal Casing Drive Tool (ICDT)

Casing Drive System (CDS)

OverDrive™
OverDrive™ Casing Running and Drilling System

• Applications (rigs with top drives)
  - Casing Running
  - Drilling & Reaming w/ Casing
  - Extended Reach and Deviated Wells
  - Troublesome Well Bores
  - Safety Driven Operations
OverDrive System Features

- Removes personnel and equipment from derrick and rig floor
- Eliminates need for conventional tongs, elevators, and related personnel.
- Fill-up tool design allows switching between fill-up and circulation modes without repositioning tool.
- Multiple safety interlocks enhance efficiency and safety by preventing unplanned events such as dropped objects.
- Used for pushing down, reciprocating, circulating, and rotating casing if required.
- Torque sub measures the true torque applied to the connection without erroneous torque readings from mechanical losses and friction in the top drive and hydraulic swivel.
Liner Drilling Applications

- Depleted Formations
- Loss Zones
- Pressure Transition Zones
- Managed Pressure Drilling
- Unstable Formations
- Reaming liner through problem zones
- Just getting the Liner to bottom
Nodeco Liner Drilling/Reaming Systems

- Drillable casing bit or conventional bit
- Float Collar (auto-fill or conventional)
- Centralizers (in-line or solid slip-on)
- Hydraulic rotating or rotatable hanger
- Liner Top Packer (integral or second trip)
- Retrievable seal mandrel
- High torque running tool
- Effective junk screening
- Diverter tool (optional)
- Drill Pipe to surface
Mechanically Expanded Ball Seat

- Ball released with mechanical expansion
- No pressure surge to formation
- Can not prematurely shear out before hanger set and running tool released
- Enables higher shear pin setting pressures for hanger and running tool
BLTT Liner Drilling System

- Drillable Casing DrillShoe™ (or conventional bit)
- 5”, 5-1/2”, 7”, 7-5/8”, 13-5/8” Liner Sizes
- 2\textsuperscript{nd} Trip Packer Capability
- No Liner Hanger – Set Liner on Bottom
- Transmit torque to liner outer sleeve through spline.
  \(\text{\textit{\(\Delta\)P}}\) will not release running tool - A drop ball pumped down to setting sleeve with hydraulic pressure is required to release running tool.
- Drill Pipe to surface

\(\text{\textbf{\textit{\(\Delta\)P}}\text{ will not release running tool}}\)

\(\text{Transmit torque to liner outer sleeve through spline.}\)

\(5" \text{ Tool Torque} = 35K \text{ ft-lbs.}\)

\(7-5/8" \text{ Tool Torque} = 53,000 \text{ ft-lbs.}\)

\(13-5/8" \text{ Tool Torque} = 80,000 \text{ ft-lbs.}\)
Benefits of Reaming with Liners

- Maximum Insurance to get the Liner to bottom
- Minimum impact to normal running operations
- No need for extra wiper trips
  - Eliminate Trip Margin Required.
- Minimize mud losses
- Minimum open hole time / formation damage
- Reduces equipment handling (better HSE)
Gulf of Mexico Shelf DwC Opportunities
GoM Shelf

Projected Savings
Using DwC Given Daily Rig Spread Rates
Eliminate 16" Conductor / Drill in 9-5/8" Surface Casing
Projected Savings
Using DwC Given Daily Rig Spread Rates
Drill in 9-5/8" Surface Casing

GoM Shelf
• Economic savings can be achieved using DwC techniques

• Average around 26% drilling cost savings based upon flat time reduction

• Savings as much as $350K without additional individual savings if 16” and 10-3/4” casing are replaced with 9-5/8” DwC

• Savings still realized if only 10-3/4” section utilizes DwC technology
Financial Analysis Study – Drill in 20-in Conductor Casing with HP Housing

- Spread Rate $550k
  - Projected Time Savings = 24.5% or 24 hours
  - Projected Financial Savings = $380k
Applications Engineering

PLANNING IS KEY TO SUCCESSFUL DwC OPERATIONS!!
DwC Planning Tools

- Analyze electric logs to determine compressive strength
- D-Exponent
- Mud Logs
- Drill Bit Records
- Connection Design
- Torque Drag Model
- Stress Cycles Model
DwC Connection Design

Proven Connections

• Standard Buttress
• Modified Buttress - GB CDE, DWC/C
• Hydril Wedge Threads – 513, 521, 523, 563
• Vam SLIJ II, Vam Top
• Hunting SLSF

Design Factors

• MU Torque
• DLS – critical when rotating off whipstocks
• Fatigue (Stress-Cycles Plot)
• Torque Drag Modeling
Estimation of load and Number of cycle to failure for
7" 26# VM80 13Cr VAM TOP for 4.86°/100ft bending

Stress range (MPa)

Cycle number N

46,000
**Surface Torque Plot**

<table>
<thead>
<tr>
<th>Case:</th>
<th>Rotating On Bottom at 10 kips, 1000 ft-lbf Torque at Bit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Friction Factor:</td>
<td>CHFF 0.20 - 0.30 / OHFF 0.35 – 0.55</td>
</tr>
<tr>
<td>Remarks:</td>
<td>-</td>
</tr>
</tbody>
</table>

**Figure 13:** Surface Torque at CHFF 0.20 / OHFF 0.35 – 0.55

Calculations show that Rotating on Bottom does not exceed torque limit of DP and Casing for CHFF 0.20 / OHFF 0.35 – 0.55.
### Weight on Bit Plot

<table>
<thead>
<tr>
<th>Case:</th>
<th>Rotating On Bottom at 10 kips, 1000 ft-lbf Torque at Bit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Friction Factor:</td>
<td>CHFF 0.20 - 0.30 / OHFF 0.35 – 0.55</td>
</tr>
<tr>
<td>Remarks:</td>
<td>-</td>
</tr>
</tbody>
</table>

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**Figure 16: WOB Plot for Drilling at 10 kips**

- **Legend**
  - Red: WOB to Sinusoidal Buckle (Rotating)
  - Blue: WOB to Helical Buckle (Rotating)

- Lowest calculated WOB to sinusoidal buckling is approximately 44 kips
Case Histories
## Client Value

<table>
<thead>
<tr>
<th>Client</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mariner Energy</td>
<td>Enabled Operator to strategically set 7-5/8” liner in competent interval to &lt; MW and drill depleted production zone with no reported OBM fluid losses.</td>
</tr>
<tr>
<td>MC 674 – Gulf of Mexico</td>
<td></td>
</tr>
<tr>
<td>Results</td>
<td>7-5/8” DwL through thief zone @ 20,400’ where 2 wellbores were lost due to severe losses</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>El Paso (OTC 17687)</td>
<td>Saved <strong>96 hours</strong> of rig time and approximately <strong>US$ 750K</strong></td>
</tr>
<tr>
<td>EI 364 – Gulf of Mexico</td>
<td></td>
</tr>
<tr>
<td>Results</td>
<td>DwL 269 ft, with 9-5/8” liner through catastrophic thief zone without losses. Previous wellbore lost over 3,000 bbls.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Client</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pemex (SPE/IADC 105403)</td>
<td>Saved <strong>39.5 days</strong>, representing a cost reduction of <strong>US$ 4.5 million</strong></td>
</tr>
<tr>
<td>Veracruz, Mexico – Gulf of Mexico</td>
<td></td>
</tr>
<tr>
<td>Results</td>
<td>Drilled with liner in high angle hole to reach fractured formation susceptible to extreme losses</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>
## Client Value

<table>
<thead>
<tr>
<th>Client</th>
<th>Spinnaker Exploration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Location</td>
<td>High Island – Gulf of Mexico</td>
</tr>
<tr>
<td>Results</td>
<td>DwL system reams and drills through unstable shale and 2 ppge depleted sand in 38º hole without fluid losses. Reamed and drilled 5-1/2” liner with DrillShoe 2 from 13,685-ft to 13798 -ft MD to reach planned liner TD obtaining 18.3 ppge FIT</td>
</tr>
<tr>
<td>Value</td>
<td>Successfully installed liner by reaming and drilling through drilling hazards enabling client to subsequently drill required 4-1/2” hole for completion</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Client</th>
<th>CNOOC (SPE/IADC 118806)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Location</td>
<td>Banuwati Field, Offshore Indonesia</td>
</tr>
<tr>
<td>Results</td>
<td>DwL system drills through wellbore instability and severe loss interval to reach liner objective. Drilled 7” liner with DrillShoe 3 from 9,968-ft to 10,317-ft MD in 68º hole successfully isolating drilling hazards</td>
</tr>
<tr>
<td>Value</td>
<td>DwL technology was successful getting liner to planned TD, where conventional methods were unsuccessful. Estimated $1MM USD savings realized</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Client</th>
<th>Anadarko (OTC 18245)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Location</td>
<td>Salt Creek CO2 Injection Field, Wyoming</td>
</tr>
<tr>
<td>Results</td>
<td>5” casing was drilled to 2,300-ft using DwC and UB technology due to high shallow overpressures (est @ 18 ppge).</td>
</tr>
<tr>
<td>Value</td>
<td>ROP was doubled and cementing was completed within 3 hrs. of reaching TD. The well did not have to be killed to run casing</td>
</tr>
</tbody>
</table>
Deepwater DwC….. The Future
Based on the above cost/ft, this relates to $128/ft for Wellbore Instability.

Based on a hypothetical 20,000' MD well: $2,500,000/Well
Based on the above cost/ft, this relates to $380/ft for Wellbore Instability. Based on a hypothetical 20,000’ MD well: $7,600,000/Well
Why Deepwater DwC??

• Deepwater operations are notoriously expensive

• Daily rig spread rates frequently exceeding $750,000/day

• Ability to apply innovative technology to reduce time/cost spent in challenging sub-sea environments is a hurdle many operators face.

• The development of a system based on proven DwC technology that enhances drilling efficiency and mitigates many drilling hazards, can be applied in a Sub-Sea Environment.

• Conservative time savings estimates show Deepwater DwC to be 25% more efficient
DwC Applications – 6 Continents
Weatherford DwC Market

- Focus on cement in place system
  - Time saving
  - Problem resolution
- Drilled > 800 wells to date
- > 750,000 feet drilled
- Manufactured and shipped 1,000 DwC systems to date
- Over 60 Clients
Drilling-with-Casing (DwC™)
Overcoming Wellbore Stability Issues

Steve Rosenberg — U.S. Region Product Line Manager

Tuesday April 21st, 2009