



# Orchestrating A SYMPHONY

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**Paul Henderson and Matthew Crump, Rubicon Oilfield International, USA,** consider the steps that need to be taken to achieve proper cementation of the wellbore.

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As the industry reaches further and faster for producing zones, challenging wellbores become ever more frequent. A symphony of downhole components to ensure proper construction and well integrity is therefore required. One of the biggest challenges is achieving a good primary cement application.

The foundation of wellbore integrity is primary cement, the annular sheath of cement outside of the casing string which acts as a permanent barrier to ensure that well fluids move only along the engineered flow paths inside the casing. Primary cement also has secondary functions that are equally critical, such as resisting mechanical forces by supporting the casing and protecting it from corrosive formation fluids.

How and where primary cement is placed will ultimately affect all future operations of the well lifecycle. The quality of a cement job will determine if remedial secondary cementing is required to maintain integrity during production cycles, or if it will last until a cut

and cap. More importantly, good cement jobs will prevent negative environmental impacts such as casing vent flow and gas migration. Successfully creating this cement sheath during the first attempt introduces unique challenges, whether cementing takes place in the vertical or horizontal sections of the well. Fortunately, there are a suite of tools, technology, and solution providers available to make well construction decisions easier. The ultimate aim of a successful primary cement job is fully centralised casing with clean, capable cement placed along its length.

## **Vertical section applications**

From an environmental, well integrity, and long-term performance standpoint, the cementation of the vertical section of the well is most critical. The challenge with the vertical section is the different layers of formation the wellbore passes through, especially when compared to the more homogeneous formation encountered in the horizontal section of the well. Each of these different layers of rock

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the ECP and stage tool. Once opened the second stage cement can be pumped through the stage collar. The cement will be followed by a wiper plug that separates the cement from the displacement fluid and ensures all the cement is pumped through the collar. When the plug lands in the collar, additional pressure can be applied to close the collar. Finally, the operator will drill out the plugs and dart, if necessary, to free the wellbore for the completion operation.

While the operator's main concern with this process is going to be the reliability and performance of the system, there are a few items to consider when selecting a provider. First, the ease of the drill out operation after the cement job is important for the future of the completion operation. There are several different designs for the seats on the tool, with either aluminium or composite designs. The composite seats provide faster and more efficient milling operations that help to speed the start of the completion operation. For a hydraulically actuated stage collar it is important for the stage tool and ECP to be set up together to ensure they operate in concert. Choosing a vendor that can provide both will lead to more reliable operation.

### Horizontal section considerations

In the vertical section of the well the operator must be concerned with the different rock properties and how that affects their tool selection; in the horizontal section they must focus on the deployment of the casing and how that affects their tool selection.

A proper cement job is not necessarily the first thing on the operator's mind when it comes to casing in the horizontal section of the well. Their first concern may be getting the casing to bottom so that they can complete the well as designed. Casing deployment efficiency and cementation success starts with the drilling operation.

The traditional directional drilling operation can create ledges and inconsistencies in the wellbore that could cause the casing to get hung up during deployment. Running a reamer in the drilling bottomhole assembly (BHA) will provide a more uniform wellbore to ensure casing

deployment success. The gun drill reamer (GDR) provided by Rubicon has a simple blade design that uses tungsten carbide inserts (TCI) to provide more reaming or stabilisation, according to the drilling and formation conditions, and maintains the gauge for extended durations. TCI distribution is optimised to provide continuous reaming in longitudinal and radial directions. The PDC distribution works with an in-house cutter matrix design, resulting in balanced drilling and reduced vibrations. The PDC gauge is passive, allowing it to interact with the formation only when under gauge occurs.

After drilling, the second consideration for casing deployment is centralisation selection. The primary goal of centralisation is to move the casing into the centre of the wellbore to ensure a uniform cement sheath. However, the selection of the centraliser also has a big impact on the deployment of the casing. Typically the selection of centralisation means a trade-off between the amount and quality of the centralisation and the amount of friction caused by the centraliser during deployment.

From a deployment standpoint, the decision an operator usually makes in the horizontal is between steel and composite, or fibre reinforced polymer (FRP) centralisers. While the steel is going to be more robust the FRP provides a much better friction factor between the centraliser and the well. The company performed a study with an operator in the Eagle Ford, Texas, US, comparing the casing deployment time for wells with steel versus FRP. Analysis showed that the friction factor for a steel centraliser was 0.20 – 0.26 depending on the well conditions, while the steel centralisers were 0.27 – 0.30 (Table 1). Switching from steel to FRP saved the operator an average of 10 hours during the casing deployment phase of the well construction.

With respect to the cement job quality, one of the most determinant factors is based on the quantity of centralisers chosen. The more centralisers in a string of casing, the less the casing is allowed to sag between the centralisers. The company recently modelled a horizontal well for a customer drilling in the Eagle Ford. The study was designed to compare the amount of standoff achieved midway between two centralisers when running one centraliser per every two joints or one per joint of casing.

It can be seen that running one centraliser per every two joints of casing in this mode results in zero standoff at the midspan between the centralisers. This will result in no cement between the casing and the wellbore wall. This could affect proper zonal isolation during their completion operation. By running one centraliser in each joint, the cement sheath is able to completely surround the entire length of the casing.

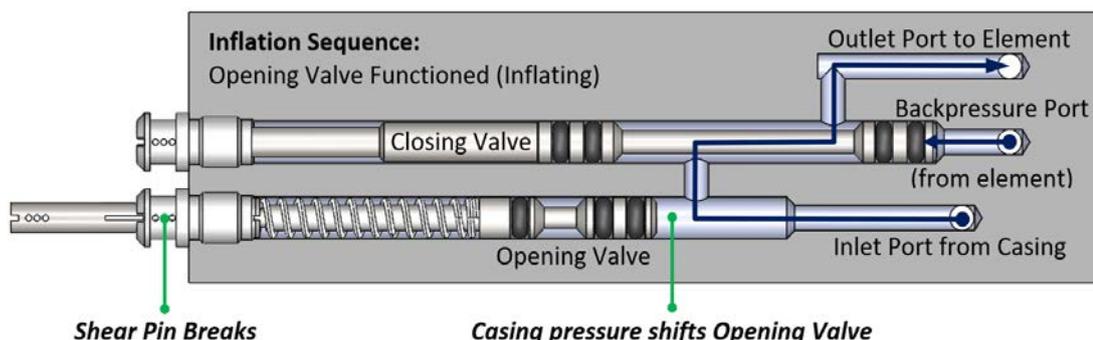
### Conclusion

In every step of the well construction process there are several different issues, tools and operations to consider when building a proper wellbore. Selecting a partner, such as Rubicon Oilfield International, that can provide all these products as

well as the analytics and support required for success, will provide the operator with a better understanding of the wellbore environment, establish the best approach to mitigate challenges along the well lifecycle and offer the solutions to achieve success. ■

**Table 1. Casing deployment time comparison – steel versus FRP**

Well	Centralisers	Casing running hours	Average friction factor	Rotation required?
Well 3	FRP	14.8	0.24	No
Well 2	FRP	15.6	0.2	No
Well 7	Steel	19.4	0.3	Yes
Well 4	Steel	20.3	0.29	No
Well 1	FRP	20.7	0.25	No
Well 8	FRP	21.4	0.26	Yes
Well 5	Steel	22.8	0.27	Yes
Well 6	Steel	52.3	0.3	Yes



**Figure 3. ECP inflation configuration valve.**