Long a staple of conventional extraction methods, flow control devices (FCDs) are currently being tested, deployed and adapted for Canadian heavy oil projects. While challenges remain for commercializing this technology, the potential economic benefits are driving development in the laboratory and in the field. This article describes the technical basics of FCDs and discusses why this technology may one day be a standard completion within SAGD wells.

AN EMERGING TECHNOLOGY
Flow control is at the forefront of SAGD technical discussions, and for good reason: the first field trial of FCDs at ConocoPhillips’ Surmont well 102-06 produced 33 per cent more bitumen and reduced the steam to oil ratio (SOR) by 20 per cent as of 2012 when compared to wells of similar geology. Numerical simulations corroborated these two economic indicators, finding improvements of up to 38 per cent of net present value and 12 per cent in reduction of SOR when SAGD completions included FCDs.

Flow control for SAGD was a focal point of the 2014 Society of Petroleum Engineers (SPE) Heavy Oil Technical Conference, the 2014 Inflow Control Technology Forum and numerous CHOA technical knowledge-sharing sessions. The most recent overview of FCD use in Canadian formations was conducted by PTTEP in March 2015. A quick search within the SPE database yields a plethora of technical articles that includes but is not limited to FCD field trials, numerical simulation of completions, FCD placement and completion optimization, design of devices, flow testing, computational fluid dynamic (CFD) analysis and the quantification of the commercial impact of FCDs.

Not for the faint of heart, these are deep yet well charted technical waters. This article only scratches the surface of flow control devices. Readers are encouraged to take the technical plunge.
THE PROBLEM
Uneven flow is a reality that comes with producing fluid along a lengthy horizontal pipe. Whether that fluid is steam, heavy oil, water, or a combination thereof, as is often the case in SAGD wells, frictional losses create uneven pressure profiles across the wellbore. These pressure profiles, coupled with reservoir heterogeneities and directional drilling variations along 800–1,000-metre horizontal completions, can lead to uneconomic or catastrophic flow conditions. Some of the language used to describe these circumstances includes: “poor steam chamber development,” “uneven conformance,” “preferential flow,” “steam breakthrough,” or “liner failure.” These terms all refer to inefficient or failed SAGD well pairs.

One of the most widely used measurements for preventing these issues is subcool, which refers to the level of liquid emulsion relative to the producer well pair. Subcool measurement is an operator’s first line of defence against steam breakthrough. The subcool level is monitored with numerous temperature and pressure measurement devices within the reservoir, including thermocouples (single node and multi-node), distributed temperature sensing (DTS) fibre optics cables, bubble tubes, and piezometers. Trials are ongoing to determine the most cost-effective and robust measurement solution. While fibre optics measurement has suffered failures, this method provides operators with the best temperature resolution along the wellbore (one metre). Other technologies require interpolation between measurement points, increasing overall risk of measurement errors.

Technically, subcool is defined as the temperature difference between a reference fluid and the saturation temperature of that fluid at a given pressure. Practically, the subcool level is used to prevent or mitigate vapour production. A large subcool value means that more mobilized liquid remains above the production liner and that steam is less likely to be produced.

Figure 1 is an example of a subcool measurement. If the reservoir pressure is 3,000 kPa, the corresponding saturation temperature is 238 degrees Celsius, and if the temperature at the liner is 200 degrees Celsius, the theoretical reservoir subcool would be 38 degrees Celsius. In this example, the operator would have a 38-degree-Celsius safety level before steam is produced at the liner. In practice, subcool targets are typically eight degrees Celsius to 20 degrees Celsius. As an analogy, it might be helpful to think in Mac-and-Cheese terms. If noodles are cooking at 90 degrees Celsius and the saturation point of water at atmospheric pressure is 100 degrees Celsius, it would be operating at a 10-degree subcool. The only difference is that in SAGD this subcool temperature corresponds roughly to a liquid level above the producer well. Industry often refers to a 10-degrees-Celsius-per-metre rule of thumb.

Figure 2 illustrates basic subcool irregularities due to steam chamber conformance issues. Two common examples are when steam breakthrough inhibits overall production and high subcool levels that result in inefficient, conductive heating of the fluid. It is possible for these conditions to exist at any location along the wellbore.

Operators have a few options to control the subcool level. One straightforward method is to limit production rates, and the level of mobilized fluid will increase across the liner. Unfortunately, this methodology is also inefficient. Limiting overall production to manage one problematic zone is akin to shutting down all four lanes of a major highway because one person was caught speeding. An improved solution is to deploy FCDs at specific locations along the wellbore to regulate flow. When installed correctly, these devices have the potential to prevent preferential flow and improve production in low-yield zones without limiting overall production rates.

FLOW CONTROL AS A SOLUTION
INJECTION FCD
While generally referred to as FCDs or inflow control devices (ICDs), there are many different subcategories of this technology. The first category is steam injection devices, which encompasses any device that controls steam outflow into the reservoir. Rates are controlled by either frictional or restrictive (orifice) mechanisms that regulate flow based on the pressure differential across the FCD. Larger pressure drops cause increased flow, resulting in the need for placement of more restrictive devices near the heel of a well. The density of devices is also a factor; more devices may be placed in regions that require larger flow rates. Depending on the operator, injector FCD completions contain anywhere from one to 80 devices, deploying passive or shiftable designs. Assuming an equal number of devices are installed in both systems, passive designs can be cost effective, whereas shiftable products provide operators with the flexibility to redirect flow into the reservoir as cold or hot spots develop. Rather than limiting overall injection, hydraulically actuated tubing can be used to open or close steam distribution devices without sacrificing optimal rates.

PRODUCTION FCD (ICD)
Production inflow control devices, on the other hand, must control the inflow of viscous emulsion and limit steam production in the event of zero degrees subcool. It is very difficult to design a singular device that accomplishes both of these objectives. Generally, geometries with large open areas that promote viscous laminar flow are not effective at preventing steam production, and those that choke steam are too restrictive for bitumen production and more susceptible to erosion or plugging. The pros and cons of restrictive and fractional pressure drop mechanisms are well documented. Balancing these inflow objectives has resulted in more complex geometries for production FCDs than are necessary for injection FCDs. Various products have been developed including active (surface controlled) inflow control valves (ICVs), passive ICVs, Bernoulli-based circular flow orifices, and hybrid passive ICVs (PICDs). All devices have compelling reasons for deployment; however, the PICDs—with no moving parts—have been deployed in larger numbers than any other type of ICD. While all devices have a compelling story, it is laboratory testing and field trials that will determine how well each device performs within the dynamic SAGD operating environment.
FIGURE 2. BASIC SUBCOOL IRREGULARITIES DUE TO STEAM CHAMBER CONFORMANCE ISSUES.
LINER-VS. TUBING-DEPLOYED SYSTEMS

An important technical and economic design consideration is whether to deploy FCDs on the tubing or liner strings. Technically, liner-deployed systems have a hydraulic advantage. The larger pipes (seven-inch versus 4.5-inch tubing, for example) result in reduced pressure differentials across the liner, which is one of the primary causes of preferential flow. Economically, liner-deployed systems also have the potential to be more cost effective. Integrating FCDs into the liner eliminates tubing costs and enables sand control systems to be coupled with the FCD. Additionally, thermal packers are not required to isolate production zones for liner-deployed systems.

Pressure differentials that exist between the heel and toe of a well are exaggerated with reduced pipe sizes. This is problematic because, even with homogenous formations, these differentials result in preferential flow. This is one reason why steam breakthrough is often observed at the heel of a well: steam preferentially flows out of the injector, while fluid is also preferentially produced in the production string.

On the other hand, tubing systems reduce completion risk and provide added flexibility to operators. Devices can be installed, removed, recompleted and shifted to adjust flow. These benefits are why tubing-deployed FCDs have been deployed in larger numbers to date, especially in infill applications. It is reasonable to speculate that as liner FCD technology is de-risked, it will become the principal FCD completion.

FCD INSTALLATIONS

Some of the most valuable lessons have been learned from operational pilot projects. In addition to Surmont 102-06, a project referenced by nearly every subsequent technical paper on FCDs, there have been other publicly disclosed trials by major producers, including Devon and Statoil. Devon installed two SAGD wells with ICDs at Jackfish 2 with promising initial results. An additional 10 of 24 wells at Jackfish 3 are scheduled for tubing-deployed steam FCD installations. Statoil completed seven well pairs in 2013 with a combination of completions, including steam FCDs only, ICDs only and a combination of injection and production FCDs. The most comprehensive additional deployment of FCDs occurred at Surmont 2 with an additional 29 well pairs completed with FCDs. Southern Pacific might be the most public example of FCD use, citing FCDs in press releases throughout 2014.

FUTURE CHALLENGES

Though existing projects have instilled more confidence in FCDs, there are still obstacles to overcome as this technology matures. Evaluating the technology is made difficult by the harsh operating conditions of SAGD and long lifespans of wells. In an attempt to reproduce these conditions, industry primarily uses computational fluid dynamic (CFD) analysis and flow loop testing. CFD is a more cost-effective solution; however, flow loop testing is a necessity to verify model results. Both methods lead to difficult technical questions, including: is the fluid produced a water-in-oil or an oil-in-water emulsion? What size droplets should be used in CFD analysis? What is the emulsion viscosity-temperature profile? How do we reproduce a stable emulsion in the lab? Do we need to reproduce a stable emulsion in the lab? Recent progress has been made to verify pressure profiles across FCDs, to model steam flashing with CFD, and to analyze erosion risks.

Optimization of FCD completions is also the subject of research and capital-intensive field trials. How many devices should be installed on the injector? How many on the producer? How much more beneficial is it to install FCDs on both strings as opposed to one or the other? Could proportional-integral-derivate (PID) steam injection control be an effective solution? Integrated wellbore-reservoir models are providing industry with some insight into these questions. The results of comparative field trials will deliver findings and confidence in wellbore-reservoir models.
The commercial prospects of FCDs are compelling, but also imprecise. Unfortunately, the only known number is cost; commercial return is much more difficult to estimate. We understand how SOR impacts overall economics, for example, net present value (NPV), but we can’t yet definitively say how an FCD completion will affect NPV. There just isn’t enough data yet. Industry justifies installations of FCDs with a belief in the technology and the underlying value it creates, but improvements in quantifying and communicating this value are needed. SPE 170112, referenced in this article, is a step in the right direction to substantiate initial FCD completion costs against long-term return on investment.

Time and patience will provide us with some answers. This author is optimistic that technical knowledge will ultimately be translated into tangible commercial value, and that the terms FCD and SAGD will be linked for a long time to come.

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