Design of flow control devices in steam-assisted gravity drainage (SAGD) completion

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Abstract Commercialization of the steam-assisted gravity drainage (SAGD) process has made recovery of heavy oil/bitumen possible in a number of reservoirs hindered by hydrocarbon immobility. However, the economics of this process are highly sensitive to the efficiency of steam creation, delivery, and use, with a successful and unsuccessful SAGD well pair often separated by how effectively thermal inefficiencies can be mitigated in the flow profiles of steam injection and/or in emulsion recovery. To improve flow profiles, Albertan SAGD completions have experimented with the addition of flow control devices (FCDs). These completion tools have historically been used to regulate liquid inflow across long producing laterals, adding a variable pressure drop along the lateral to improve the conformance of hydrocarbon production and delay water breakthrough; within SAGD completions, FCDs find novel use to force a more even flow distribution of steam in the injector and a thermally dependent inflow profile in the producer to maximize recovery of heavy oil/bitumen. This paper provides a comprehensive overview of different FCD designs, discussing their respective methods of regulation, the fluid-adaptive behavior of “autonomous” FCDs, operational strengths and weaknesses of different commercial offerings, and suggestions on how to use existing pressure loss models for FCDs and apply them to the non-traditional application of regulating SAGD flow profiles, both for equipment sizing and estimation of pressure loss/flow rates across the device. From this

work, it is proposed that use of autonomous FCDs in the production lateral are of greater value than use of flow control in the injector; however maximum benefits are achieved by coupling simple orifice-style FCDs in the injector lateral with autonomous, large flow path (non-orifice) FCDs capable of controlling steam flash events in the production well.

Keywords Flow control devices · Steam-assisted gravity drainage · Autonomous hybrid design · Multiphase flow in injection and production pipes · Reynolds number

Abbreviations

cSOR	Cumulative steam to oil ratio
FCD	Flow control device
HO-B	Heavy oil/bitumen reserves
ICD	Inflow control devices
NPV	Net present value
RCP	Rate-controlled production
SAGD	Steam assisted gravity drainage
SSSV	Subsurface safety valve

Introduction

Starting in the 1980s, advances in drilling technology have made horizontal and multilateral wells a primary design type to economically develop reservoirs particularly with unconventional resources. Horizontal wells have been widely used to increase wellbore contact with the reservoir, increase flowing area, and thus, increase the well productivity by reducing coning tendencies, mitigating the risk of sand production, connecting disconnected drainage areas,

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and generally lowering drawdown-related production problems (Babu and Odeh 1989; Joshi 2003; Dikken 1990; Ihara et al. 2013; Novy 1995).

Due to higher drawdown at the heel of a horizontal well, the “heel-to-toe effect” occurs which leads to early breakthrough (Li et al. 2013; Li and Zhu 2010; Moen and Asheim 2008; Sagatun 2010). During “heel to toe effect,” as the in-situ oil vacates the region near the heel more rapidly than at the toe, any existing gas cap or aquifer is seen as advancing more quickly toward the wellbore in this regions than at points along the wellbore with lower flux (Atkinson et al. 2004; Tabatabaei and Ghalambor 2011).

Because flow in the wellbore is interdependent with flow in the reservoir, even when the wellbore pressure drop is insignificant relative to reservoir pressure drop, non-conformance of the injection/production fluid front may still be observed. In these cases, an uneven profile is generated by difference in horizontal and/or vertical permeability distribution (Al-Khelaiwi et al. 2010; Baker et al. 2008; Nasr et al. 2000; Yang and Butler 1992), variations in porosity (Llaguno et al. 2002), water saturation heterogeneity (Baker et al. 2008), variations in the distance between the wellbore(s) and fluid contacts (Al-Khelaiwi et al. 2010; Baker et al. 2008; Edmunds and Chhina 2001), variations in localized reservoir pressure (Al-Khelaiwi et al. 2010; Tabatabaei and Ghalambor 2011), changes in capillary pressure and relative permeability along the wellbore (Wang and Leung 2015), localized skin damage or fractures (Furui et al. 2005; Tam et al. 2013), changes in mineralogy or wettability (Ipek et al. 2008; Le Ravalec et al. 2009; Pooladi-Darvish and Mattar 2002), changes in thermal properties (Bois and Mainguy 2011; Irani and Cokar 2016), changes in fluid density, viscosity, or both (Gates et al. 2008; Larter et al. 2008), and the presence or absence of in-situ emulsifiers that blend reservoir and/or introduced fluids into (Ezeuko et al. 2013). With the exception of geospatial heterogeneity, like variations in the distance between wellbore(s) and fluid contacts, these root causes serve to change the local mobility ratio. When the local mobility ratio deviates strongly from the average mobility ratio along the wellbore, thief zone communication, sand production, and/or uneven production/injection profiles will occur (Green and Willhite 1998). This coning behavior undermines the economic value of a horizontal well as the most productive zones are now producing an unwanted fluid (water, gas) while oil reserves are ineffectively recovered from other points along the reservoir.

To control or regulate fluid velocity or fluid flow rate within a horizontal well, flow control devices (FCDs) are implemented (Foster et al. 1987). The larger family of devices accomplish this task in a multitude of roles, inclusive but not limited to subsurface safety valves (SSSVs), wellhead chokes, flow metering valves, valves

downstream of the well within the process chain (surface safety valves), and downhole throttles on reservoir flux (Denney 2015; Li et al. 2013). Used in this fashion, downhole FCDs are often referred to in industry as “inflow control devices” or “injection control devices” (ICDs), depending on the direction of reservoir flux (Banerjee and Hascakir 2015; Bybee 2008; Jain et al. 2013).

The first downhole field application of FCDs for the recovery of hydrocarbon is credited to Norsk Hydro and Baker Hughes in the early 1990s (Al-Khelaiwi and Davies 2007; Bybee 2008; Mikkelsen et al. 2005). In this first industrial trial, flow control devices were applied to horizontal wells in the Troll field, a subsea giant gas field found on the Norwegian shelf of the North Sea. The Troll field is characterized by a thin oil column (Halvorsen et al. 2012; Henriksen et al. 2006). The main reservoir drive mechanism of this field is gas expansion so horizontal wells were selected and placed ~ 0.5 meters above the oil–water contact to maximize oil recovery despite initial water cuts typically being higher than 50% (Mikkelsen et al. 2005). Because coning of the gas cap dominated the hydrocarbon production, FCDs were placed to regulate the production profile and longer horizontal laterals were drilled. This way water/gas breakthrough was delayed, longer well life was observed, higher cumulative oil production was obtained, and net present value (NPV) was increased (Henriksen et al. 2006).

Since that initial field trial, FCDs/ICDs have been extensively used across the globe to delay water/gas breakthrough in high production rate horizontal wells (Abdelfattah et al. 2012; Al-Khelaiwi and Davies 2007; Jain et al. 2013; Karim et al. 2010; Li et al. 2013). In late 2008, FCDs were proposed for the use in a steam-assisted gravity drainage (SAGD) well pair. A field trial on Surmont well pair 102-06 was started in late 2009 to assess the validity of these theories with promising results (Stalder 2013; Vachon et al. 2015). However, in this type of FCD design, unlike to other applications of FCD, both heat and mass transfer concepts must be considered together to define fluid flow. Hence, addition to the gas coning control problems encountered in light-oil applications, multiple conformance issues were identified in SAGD horizontal wells (Stalder 2013).

Before discussing these problems, it might be useful to define SAGD process first and then, the problems associated with steam injection and bitumen/water production will be discussed.

Overview of steam-assisted gravity drainage

The two horizontal well configuration used in the SAGD process have typical lateral length ranging from 500 to 1500 meters with laterals arranged parallel to each other in

a vertical plane a few meters from the bottom of the pay zone (Butler and Stephens 1981a; Wilson 2015). Interwell spacing vertically is typically 5 meters, though drilling tolerances may cause this distance to vary anywhere between 3 and 10 meters (Irani 2013). These horizontal wells are surrounded by heavy oil/bitumen reserves (HO–B), a low-value product that is economically unrecoverable at native viscosity and temperature (Edmunds and Gittins 1993). The steam chamber development unique to SAGD due to its well configuration makes the bitumen extract feasible.

To initiate a steam chamber, steam is circulated in both wellbores for a period of up to 3 months through tubing and out of the annulus (Chen et al. 2008; Gates and Chakrabarty 2006). Thermal energy moves via conduction between the two wellbores (Irani and Cokar 2016). Once thermal and hydraulic communication between the two wellbores is established, true SAGD begins. The upper well in the pair no longer circulates steam but injects it into the reservoir (Irani and Ghannadi 2013). The bitumen flows at the edge of the steam chamber to the production well (Butler et al. 1981; Butler and Stephens 1981a, b; Butler and Yee 2002; Chow and Butler 1996).

As mobilization of bitumen is dependent on delivering thermal energy via steam, it is unsurprising that the economics of SAGD are controlled by the costs of generating steam and waste water treatment/recycling of the produced condensate (Yang et al. 2009; Morrow et al. 2014;). Additionally, SAGD is often criticized for its environmental footprint; in spite of its viability as a bitumen extraction technique, SAGD generates considerable greenhouse gas (GHG) emissions in the process of generating the quantities of steam necessary for the process (Al-Murayri et al. 2011; Brandt 2012; Kovscek 2012; Welch 2011). Based on field data, between 2 and 5 tons of steam are injected into the reservoir to produce each ton of bitumen (Gates and Leskiw 2010). This illustrates how critical energy maintenance is to the SAGD process, with an optimal process delivering injected energy solely to producible bitumen.

Thus, effective utilization of steam through homogeneous distribution along the horizontal well is very important to minimize the environmental impact of SAGD and maximize the oil production from SAGD.

Steam bypassing from injection to production well is another factor impacts the thermal efficiency of steam injection. The producer is designed to remove condensed steam and movable bitumen through gravity drainage. If the condensation rate of fluids is in balance with the fluid movement created by gravity, then, the steam bypassing is prevented (Yuan and Nugent 2013). During bitumen production, a liquid pool is formed around the

production well. This liquid pool, being denser than steam, is not easily displaced by the steam phase and prevents live steam from flowing directly into the producer. This phenomenon is known as steam trap and the maintenance of this liquid pool is called steam trap control (Gates and Leskiw 2010).

In field practice, the liquid level cannot be directly measured from surface. Instead, temperature gauges are installed along the length of the producer well to measure the temperature difference between the fluid exiting the upper injector and entering the lower producer. This temperature difference is referred to as subcool and serves as a surrogate variable for liquid level height (Wilson 2015). The smaller the interwell subcool difference, the closer the produced liquids are to the steam temperature, and thus the smaller the height of the liquid pool (Gotawala and Gates 2012). However, subcool is not constant along the length of the production lateral; there is localized variability in subcool. Moreover, flow capacity of the wellbore is large compared to that of the reservoir in the same direction, making compensating steam movement in the reservoir difficult (Vander Valk and Yang 2007). Furthermore, local liquid levels cannot effectively drain parallel to the well due to the very low drainage angles (Edmunds 2013). Too low an average subcool and steam breakthrough will occur at points along the producing lateral, negatively impacting cumulative steam to oil ratio (cSOR), thermal efficiency, and the economics of the project. Too large an average subcool and liquid occupies a significant fraction of the steam chamber, preventing the free movement of steam to the chamber boundaries and potentially flooding the injector well itself (Banerjee et al. 2013b; Carpenter 2015; Gotawala and Gates 2012). Flow control devices (FCDs) are used to overcome the problems with uneven steam trap height, allowing for more aggressive production rates and less manipulation of subcool.

Types of flow control devices

Multiple differing FCD geometries have been commercialized to accomplish the goal of equalizing reservoir flux along the wellbore. All FCD geometries are similar in that they induce an additional pressure drop as fluid travels between the reservoir and the completion base pipe so that the total pressure drop for any fluid flow path is equivalent and thus fluid conformance is maximized (Atkinson et al. 2004). However, the mechanism by which this pressure drop is created can vary wildly between geometries, resulting in drastically different long-term injection/production behavior as reservoir and operational conditions change (Carpenter 2015; Denney 2015). Following sections will explain the existing FCD types.

Channel-style flow control devices

Channel-style flow control devices (FCDs) are one of the earliest geometries of FCDs used downhole in the oil and gas industry (Banerjee et al. 2013b; Li et al. 2013). It is the first type of FCD used to equalize production on a horizontal producer (Al-Khelaiwi and Davies 2007; Henriksen et al. 2006; Mikkelsen et al. 2005) as well as the first geometry used in a SAGD production well (Stalder 2013). Common geometries include helical channels wrapped around a base pipe and labyrinth pathways. Figure 1 is an illustration of a helical geometry on a joint of production pipe. Fluids move from the reservoir through a sand control screen to filter out solid materials. The remaining fluid phase moves in a micro-annulus between the screen and base pipe into the ICD subassembly where it must pass through one or more constant area channels set in parallel. Upon exiting the helical channels, the produced fluid passes through perforations into the production tubing (Qu-daihy et al. 2005).

Predicting multiphase flow performance through a channel has been well established in fluid flow mechanics. For fully developed flow in a horizontal pipe, the pressure drop may be expressed as (Lauritzen and Martiniussen 2011; Lee et al. 2013):

$$\Delta p_{\text{channel}} = f \left(\frac{L}{D} \right) \left(\frac{v^2}{g_c} \right) \quad (1)$$

In this equation, L [ft] is the length of the channel, D [ft] is the diameter of the channel, v is the fluid average velocity [ft/s], g_c [lbm–ft/lbf–s²] is the gravitational constant, and f is the dimensionless friction factor which is the function of Reynolds number (N_{Re});

$$f = a_2 N_{\text{Re}}^{b_2} + \frac{a_2 N_{\text{Re}}^{b_2} + a_1 N_{\text{Re}}^{b_1}}{\left(1 + \left(\frac{N_{\text{Re}}}{t} \right)^c \right)^d} \quad (2)$$

Fig. 1 Expanded view of flow in a channel-style FCD. Adapted from Bitto (2005)

$$N_{\text{Re}} = 1488 \frac{d_h \rho v}{\mu} \quad (3)$$

In where d_h [ft] is the hydraulic diameter, ρ [lb_m/ft³] is the density, v [ft/s] is the fluid velocity, μ [cP] is the viscosity, and a_1 , a_2 , b_1 , b_2 , c , d , and t are empirically determined dimensionless constants intended to force a fit of the model to experimental data (Lee et al. 2013).

Reynolds number is defined as the ratio of the inertial forces to viscous forces. Viscous forces consist largely of fluid drag along the channel walls while inertial forces refers to shear forces within the fluid that resist changes in direction or velocity (Bird et al. 1960; Lauritzen and Martiniussen 2011). The ratio of the inertial forces to viscous forces creates the pressure drop across pipe and the channel-style FCDs placed in the pipe induce pressure drop over a longer interval which creates an advantageous condition where erosion or plugging of the FCD can be avoided (Al-Khelaiwi and Davies 2007; Visosky et al. 2007). However, this device's dependence on friction to generate the majority of its pressure drop makes it highly sensitive to the viscosity of the flowing fluid.

Restriction-style flow control devices

For multiple industries, it is a common practice to flow liquid and gas mixtures through restriction-style chokes (Ajenka et al. 1994; Alimonti et al. 2010; Almeida 2013; Campos et al. 2014; Elgibaly and Nashawi 1998; Grose 1985; Kojasoy et al. 1997; Perkins 1993; Schüller et al. 2003; Zhang and Cai 1999). Specifically, within the oil and gas industry, restriction-style FCDs are heavily used as wellhead chokes to control production from wells, as a critical part of single or multiphase flow measurement valves, and within gas lift valves (Ajenka et al. 1994; Al-Attar 2013; Almeida 2013; Surbey et al. 2013). In SAGD operations, restriction-style FCDs have been used in injection wells as a “steam splitter,” a tool to both mechanically divert steam down the wellbore, add additional points of steam injection, and control the rate of injection into particular reservoir zones to equalize steam delivery along the lateral length (Ghesmat and Zhao 2015; Medina 2015).

Figure 2 portrays a restriction-style FCD arranged for production well (Oyeka et al. 2014). Here, an optional sand control screen is illustrated around a production base pipe. Fluid produced from the reservoir is filtered of solid material by the sand control media before being channeled into a micro-annulus between the screen and base pipe. This annular gap is adjusted by wire stand-offs which separate the annulus into several sections evenly distributed around the circumference of the base pipe, providing the dominant flow path (Atkinson et al. 2004).

Fig. 2 Expanded view of a restriction-style FCD in a production joint. Adapted from Oyeka et al. (2014)

When the fluid reaches the end of the pipe, it encounters the FCD subassembly where it encounters a sudden restriction in its flow path, oriented axially in this illustration. This constriction to flow creates a differential pressure drop across the restriction, in line with Bernoulli's principle for incompressible flow (Darby 2001; Van Ness and Abbott 2008). Fluid, once downstream of the FCD, encounter perforations to allow entrance into the production base pipe (Banerjee et al. 2013a). If the restriction-style FCD is oriented radially, the FCD also serves as the entrance into the production base pipe (Al-Khelaiwi and Davies 2007). The particular type of restriction may vary with common styles including thin and thick orifice chokes, nozzles, short tubes, and venturi restrictions (Abdelfattah et al. 2012; Atkinson et al. 2004; Banerjee et al. 2013a, b; Banerjee and Hascakir 2015; Bybee 2008).

Significant effort has gone into characterizing flow behavior across restriction-style chokes by numerous researchers. Published models fall into either empirical or theoretical models (Alsafran and Kelkar 2013; Elgibaly and Nashawi 1998). Empirical models largely follow the form of Gilbert (1954), and include proposed models by Ros (1960), Achong (1961), Ashford and Pierce (1975), and Osman and Dokla (1992). These models were developed on specific ranges of data and should not be used to extrapolate beyond those ranges (Alsafran and Kelkar 2013; Elgibaly and Nashawi 1998).

The second category, theoretical models, attempts to derive performance relationships from mass, momentum, and energy balances. Models within this group are more often used by industry due to their ability to model both critical and subcritical flow, adding to a perception of greater accuracy (Alsafran and Kelkar 2013). Note that the critical flow occurs

when fluid velocity across the restriction is equal to the speed of sound in that medium, conversely, subcritical flow is when fluid velocity is less than the speed of sound. If the flow is subcritical, the flow rate is related to the pressure drop across the restriction. However, if the flow is critical, the pressure drop is related only to upstream pressure as reduction in downstream pressure cannot be communicated upstream (Darby 2001; Janssen 1967; Ramamurthi and Nandakumar 1999; Roul and Dash 2012). To optimize a restriction-based FCD, understanding the critical/subcritical boundary and the fluid flow pattern across the restriction is of absolute importance. Prominent theory-based restriction models used by industry include those proposed by Sachdeva and Schmidt (1986), Perkins (1993), Fortunati (1972), and Alsafran and Kelkar (2013) as their models are able to simulate the physical phenomena in both subcritical and critical regimes.

In single-phase fluid flow, the theoretical analysis to evaluate pressure drop caused by abrupt contraction of the flow area is accomplished with one-dimensional analysis. We begin by considering the orifice restriction case: as a fluid stream passes through a sharp edge "thin" orifice restriction, the flow contracts to an area smaller than that of the orifice itself. This smaller area, A_c , is called the vena contracta (Van Ness and Abbott 2008). As fluid converges toward the opening of an orifice, it builds up considerable inward radial momentum that causes the flow stream to continue to flow "inwards" for a distance downstream of the restriction (Darby 2001; Sahin and Ceyhan 1996). As the flow stream continues downstream of the vena contracta the flow expands in an irreversible process to the pipe cross-sectional area, A . Correspondingly, the pressure of the flow stream decreases across the restriction and continues to decrease to the point of the vena contracta,

with some recovery of pressure occurring as the flow stream expands outward to the pipe cross-sectional area.

As establishing the pressure drop across a restriction-style FCD is not an analytical exercise, optimizing usage for the production lateral in a SAGD completion is difficult. Establishing single-phase flow behavior for emulsions of bitumen and condensate is a daunting enough task, given the variability with phase externality and temperature. To then run multiple laboratory trials with steam to obtain an empirical fit and appropriate two-phase multiplier correction factor borders on impossible when cost and effort are considered. Yet, restriction-style FCDs can be optimized and analytically modeled for the pseudo-multiphase fluid that passes through the injector in SAGD well pairs. High-quality steam is used for injection in SAGD projects, which means that the injected steam behaves as a multiphase mixture of liquid and vapor (Medina 2015). However, this two-phase flow behavior is not as complicated as others (Steven and Hall 2009). Thermal EOR operations use wet steam, a mixture of saturated liquid and saturated vapor, which maintains equilibrium conditions (Chien and Schrodtt 1995). The thermodynamic properties of steam are also well known and available in published steam tables (Griston and Cire 1989). The rate of steam injection and steam quality are all controllable factors. As a result, the general orifice flow equation may be adapted for wet steam as follows (Chien and Schrodtt 1995):

$$\Delta p_{\text{steam}} = \left(\frac{w\sqrt{1-\sigma^4}}{1888.56C_dF_aY_2d^2} \right)^2 v_{\text{exp}} \quad (4)$$

where w [lbm/hr] is the steam flow rate, σ [dimensionless] is the ratio of restriction diameter to pipe diameter, C_d [dimensionless] is the discharge coefficient, d is the restriction diameter [inches], F_a [dimensionless] is the thermal expansion coefficient, and Y_2 [dimensionless] is the vapor expansion coefficient. These last two coefficients are calculated according to Miller (1996). The last term, v_{exp} [ft³/lbm] is the two-phase specific volume of the steam as it flows through the restriction. James (1965) offers Eq. 31 as a means of calculation of v_{exp} :

$$v_{\text{exp}} = A(v_{\text{fg}}) \left(\frac{X}{100} \right)^B + v_f \quad (5)$$

Here, X [percent] is the steam quality, v_{fg} [ft³/lb_m] is the specific volume of vaporization, and v_f [ft³/lb_m] is the specific volume of the saturated liquid. A and B are dimensionless constants that are experimentally determined for a specific range of steam pressure and temperature. Using Eq. 5, inexpensive restriction-style FCDs can be optimized and easily modeled for SAGD injector wells where steam trap control/FCD autonomy is not a necessary feature for establishing fluid conformance.

Autonomous hybrid flow control devices

A fundamental problem that exists with most passive FCDs is how they respond to breakthrough for unwanted fluids. The restriction-style and frictional-style FCDs can improve conformance and delay breakthrough (as might occur due to a fracture, well trajectories that bring segments of the lateral close to gas cap/aquifer, etc.) of unwanted water/gas/steam depending on the goals of their installation. However, these FCD geometries exhibit lower pressure drop for the unwanted fluids than they do for the oleic hydrocarbons. As a result, that segment will see an increase in flow rate and in water/gas cut compared to other segments of the lateral, potentially creating a new non-conforming fluid profile later in well life. The class of FCDs known as “autonomous” FCDs reverses this behavioral trend. Instead of a reduced pressure drop for unwanted fluid, autonomous FCDs increase the pressure drop to unwanted fluid. Hence, if an unwanted breakthrough event happens, the segment in contact with the unwanted fluid exhibits a decrease in flow rate compared to other segments in the lateral, correcting the conformance profile along the lateral over time.

At this point, it is important to distinguish “autonomous” FCDs from “active” FCDs; autonomous FCDs exhibit the control over unwanted fluids passively and without operator intervention relying on properties intrinsic to the fluid or fluid regime to trigger changing behavior. By contrast, active FCDs (such as intelligent control valves and FCDs with sliding sleeves.), require oversight by operators and direct intervention in order for there to be a change in performance behavior. Three commercial FCD geometries exhibit autonomous behavior: fluidic diodes, rate-controlled production valves, and hybrid FCDs. However, the manner by which each provides autonomy varies wildly from manufacturer to manufacturer and introduce new operational advantages and risks depending on the mechanism of action.

The fluidic diode FCD alters how restrictive it is to fluid flow based on the spinning momentum of the fluid passing through (Least et al. 2014). Autonomous behavior is achieved by driving fluid flow through preferential channels based on the fluid’s inherent inertial and viscous forces with simplified internal FCD geometry described in Fig. 3. If viscous forces are dominant, fluid is fairly evenly divided between the straight and divergent pathways of Fig. 3, a typical response for most oils. However, fluids where inertial forces are significantly greater than viscous forces (e.g., gas and water) will favor the straight pathway and bypass the divergent pathway (Fripp et al. 2013). Viscous fluids moving through the divergent pathway are generally lower velocity, and as such require little change in angular momentum to exit the FCD and exhibit minimal rotation in

Fig. 3 Simplified Internal Schematic of a Fluidic Diode FCD. Adapted from Fripp et al. (2013)

the vortex chamber. If moving through the straight pathway, fluids enter the vortex chamber tangentially and with higher angular momentum. This momentum must be dissipated and fluid velocity reduced by frictional drag while spinning within the vortex chamber before the fluid flow path can be directed to the FCD exit.

Physically, the fluidic diode occupies a space similar in size to a credit card. Figure 4a is an external view of a fluidic diode device while Fig. 4b illustrates the housing into which the fluidic diode FCD is secured to a production joint. Due to its reduced size, the pathway cross-sectional area is quite small compared to its commercial peers,

Fig. 4 **a** Photograph of a fluidic diode unit with credit card for size reference and **b** the housing subassembly securing a fluidic diode unit to the production joint

leading to higher velocities for the same volumetric flow-rates and raising questions about potential operational risks with channel plugging or erosion. Similar to frictional-style FCDs, fluidic diodes performance is highly dependent on fluid viscosity. As such, it shares similar issues regarding changing performance as production fluid viscosity changes due to emulsification, temperature change, etc. Unlike frictional-style FCDs, the fluidic diode only provides a pressure drop in one direction, either injection or production, depending on installation. Thus, fluidic diodes will not equalize steam distribution during SAGD start-up and circulation, only production profiles during true SAGD.

Figure 5 provides an illustration of the flow path from the reservoir, through the fluidic diode FCD, and into the base pipe. An additional concern is that should a fluidic diode induce steam flashing, it is most likely to occur at the exit nozzle and thus jet uncontrolled steam into the production tubing.

A second autonomous FCD geometry is that of the Rate-Controlled Production (RCP) valve. This FCD geometry modifies a more traditional restriction-style FCD by introducing a moving disk into the flow path. The position of this disk is dependent on the fluid properties and flow conditions within the RCP. For highly viscous and heavy oils, the disk remains at the bottom of the FCD chamber and provides no obstruction to the restriction at the FCD exit. However for low viscous fluid (e.g., gas), the pressure on the flowing side of the disk is lower than the pressure on the back side of the disk due to the high velocity of the flowing fluid. In this case, the pressure imbalance pushes the disk upward toward the disk seat and reduces the flow area of the exit orifice (Halvorsen et al. 2012). Figure 6a, b illustrates the changing disk position for oil and gas flow while Fig. 6c shows how the RCP valve is inset into the production joint.

When reduction in flow area at the exit orifice occurs, there is a corresponding increases in pressure drop across the FCD. Though the RCP has the strongest autonomous response to unwanted gas flow of any commercial autonomous FCD, it brings with it a number of operational challenges that limit its suitability for field use. One

Fig. 5 Fluid flow path (from reservoir to base pipe) through a fluidic diode FCD installed for production equalization

Fig. 6 Expanded view of RCP insert in base pipe Movement of the RCP internal disk under oil and gas flow conditions (Halvorsen et al. 2016)

immediate concern is FCD orientation; should the RCP not be installed in the well with gravity initially pulling the internal disk downward, the FCD will not function as designed. Another major concern is in the operational reliability of the disk itself; dependent on a moving part, the FCD fails should the disk ever jam, deform, break, or have its range of motion compromised by foreign materials (Banerjee and Hascakir 2015). In contrast, no other FCD geometry introduces the additional risk of a moving part. Erosion and plugging continue to be an operational risk of the exit orifice, just as it is for the RCP's non-autonomous counterpart. Finally, the throughput of the RCP is exceptionally low. To quantify this, a flow rate of 2.5 gallon/min [16.37 m³/day] of water across the RCP would require a drawdown on the order of 450 psi [21.55 kPa], well beyond a desirably pressure drop for such a low production flowrate.

The final autonomous design available commercially is the hybrid FCD (Fig. 7), a design that uses multiple restrictions in series placed in a labyrinth pathway. This design hybridizes restriction-style FCDs (by using multiple restrictions within the flow path) and frictional-style FCDs (by creating pressure losses through wall drag and tortuosity) while providing autonomous choking to steam. By distributing the pressure drop over multiple subcomponents, no one individual point of pressure loss is critical to overall function. Cross-sectional flow area through this geometry is 4–10 × larger than other autonomous FCDs, significantly lowering internal velocities and thus, lowering the risk of both plugging and erosion (Banerjee et al. 2013b). The staggered restrictions within this geometry also serve to add a secondary control over steam flashing. Should steam flashing across the restriction of any given cell, the downstream cells serve to create a stronger choke to steam passage, controlling the rate at which it may enter the production tubing. Figure 7 provides a view of the interior of the hybrid FCD along with a close up view of one of the selectable flow paths; depending on which flow path is left unplugged, the pressure drop behavior across the hybrid FCD may be scaled up or down due to the number of cells in the flow path.

Unlike most other FCDs, multiphase testing has been done on the hybrid FCD by third-party laboratories. As a result, this geometry has one of the better characterized pressure drop response to a multiphase fluid. Lee et al. (2013) have suggested that multiphase performance may be accurately described by Eq. 6, where the pressure drop across a hybrid FCD is dependent on a unique friction factor term ($ff_{mixture}$) that is a function of the dimensionless Reynolds number. This friction factor term is defined in Eq. 7.

$$\Delta p_{FCD} = ff_{mixture} \frac{l_{channel}}{D_h} \rho_{mixture} \left(\frac{v_{mixture}^2}{288g_c} \right) \quad (6)$$

$$ff_{mixture} = a_2 N_{Re}^{b_2} + \frac{(a_2 N_{Re}^{b_2} + a_1 N_{Re}^{b_1})}{\left(1 + \left(\frac{N_{Re}}{t}\right)^c\right)^d} \quad (7)$$

Here $ff_{mixture}$ and N_{Re} are dimensionless numbers, $l_{channel}$ is the length of the FCD channel [ft], D_h is the hydraulic diameter [inches], $\rho_{mixture}$ is the mixture density [kg/ft³], $v_{mixture}$ is the mixture velocity [ft/s], g_c is the gravitational constant [lbm–ft/lbf–s²], and a_1 , a_2 , b_1 , b_2 , c , d , and t are dimensionless constants used to fit the empirical laboratory data for multiphase flow.

Like the fluidic diode, the hybrid FCD has no moving parts to introduce additional operational risk. It is less prone to plugging or erosion due to the larger flow areas within its geometry. The redundancy of restrictive cells placed in series provides a theorized benefit in terms of controlling a steam flash event within the FCD. This geometry, unlike the fluidic diode, has demonstrated viscosity insensitivity up to 300 cP. Finally, the hybrid FCD has the most extensive run history for both heavy oil and conventional FCD use.

Summary

There are multiple inflow/injection control device (FCD) geometries commercially available with varied focus on specific operational risks or methods of generating a pressure drop (Fripp and Dykstra 2013; Fripp et al. 2015;

Fig. 7 View of a Hybrid ICD assembly with transparent housing subassembly (Banerjee et al. 2013b) One of multiple pathways set in the circumference of a hybrid FCD subassembly (Banerjee and Hascakir 2015)

Table 1 Summary of commercially available FCD designs

Geometry	Mechanism of action	Strengths for SAGD applications	Weakness for SAGD applications
Channel-style FCD	Frictional drag	Low risk of plugging or erosion May control steam flashing No moving parts	Sensitive to flowing fluid viscosity
Restriction-style FCD	Bernoulli principle	Inexpensive No moving parts	Significant risk of plugging or erosion May cause steam flashing
Autonomous FCD	Varied	Additional steam trap control	Varied

Table 2 Comparison of commercially available autonomous FCDs

Autonomous FCD type	Mechanism(s) of action	Strengths for SAGD applications	Weakness for SAGD applications
Hybrid	Frictional drag, Bernoulli principle, momentum effects	Low risk of plugging or erosion May control steam flashing Insensitive to fluid viscosity Additional steam trap control No moving parts	Smallest autonomous response
Fluidic diode	Momentum effects	Additional steam trap control No moving parts	Risk of plugging or erosion May cause steam flashing
Rate-control valve	Variable-size restriction	Additional steam trap control Strongest autonomous response	Risk of plugging or erosion Moving parts Limited maximum throughput May cause steam flashing

Garcia et al. 2009; Loretz and Hosatte 2007; Russell et al. 2013a, b). Yet all FCDs may be sorted into three broad categories: channel-style FCDs, restriction-style FCDs, and autonomous FCDs (Al-Khelaiwi and Davies 2007; Banerjee et al. 2013a; Lauritzen et al. 2011).

While FCD performance has been reasonably well characterized for controlling water breakthrough, no public data exists for FCD performance for fluids at or near saturation temperature as would exist in a SAGD process (Riel et al. 2014; Vachon et al. 2015). Limited information exists for FCD performance with any sort of gas-phase fluid (Coronado et al. 2009; Lauritzen and Martiniussen 2011; Lauritzen et al. 2011; Least et al. 2014, 2013; Lee et al. 2013; Peterson et al. 2010). For a SAGD injector, steam splitters have a limited run history, but not in conjunction with any sort of production control and with little to no performance characterization (Kyanpour and Chen 2013; Medina 2015). Therefore, we summarized strength and weakness of the existing FCDs for SAGD use with two tables. Table 1 summarizes the operational strengths and weakness of all FCD geometry categories for the SAGD application. Table 2 expands upon autonomous FCD subtypes with details again provided in the relevant subsection.

As a result, hybrid autonomous FCD design seems to yield better response than the other FCD designs for SAGD. Detailed public evidence that FCDs provide a benefit to the SAGD process has long been limited to a single field trial, the Surmont 102-06 well pair. Though a number of operators have since experimented with FCDs based on the strength of the Conoco-Phillips Surmount case, as of January 2017 none has published a case history that replicates or refutes the Surmount results (Stalder 2013; Vachon et al. 2015).

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