Enhancing SAGD

Techniques and technologies for improving a first-choice thermal recovery mechanism

By Trevor Phenix

STANDARD SAGD DESIGN AND BASIC operational principles in the highest-quality heavy oil assets in Alberta and Saskatchewan have driven rapid production growth and increased awareness of this technology. The overall success of SAGD has typically been driven by large projects with access to these extremely desirable resources, but this is changing.

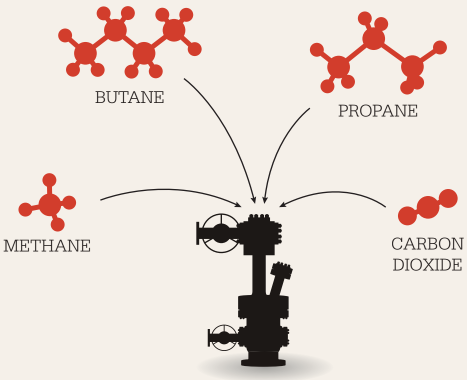
SAGD growth is increasingly supported by new projects developing lower-quality resources, as well as existing projects being forced to place sustaining wellpads away from their initial top-tier target areas.

Operators are looking for ways of increasing value from future phases, as well as actively deploying new technologies as a way of increasing recovery from mature fields. Just as SAGD is now a well-understood operational process,

140

SAGD wellpairs in Alberta have used some type of gas for co-injection

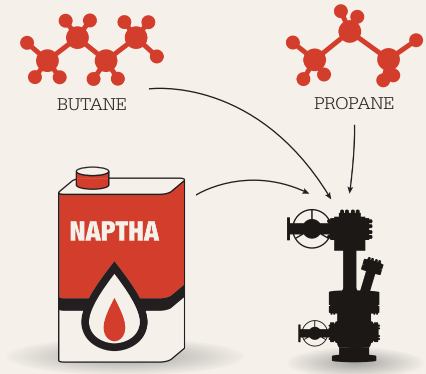
Most commonly, natural gas



60

SAGD wellpairs in Alberta have used some type of solvent

The majority for solvent soak prior to start-up



170

SAGD wellpairs have been drilled in Saskatchewan

150

have been operational as of May 2015

SAGD is now a well-understood operational process. Operators are looking for ways to increase the value of future phases and are implementing new technologies to further increase recovery from mature fields.

many of these tools are becoming second nature for the majority of thermal operators.

START-UP STRATEGIES

The start-up or circulation period is one of the most influential aspects on the ultimate performance of any wellpair. As such, many strategies have been trialled as a means to reduce the time to complete this period or to increase its overall effectiveness. The most commonly utilized start-up enhancements are solvent soaks, dilation or a combination of both.

A solvent soak is the most popular start-up enhancement as it is relatively low risk and typically requires little equipment to complete. A typical solvent soak consists of landing a batch of condensate or diluent in the producer, injector or both wellbores with the hope that it will propagate into the formation and diffuse into the heavy oil. The solvent is typically landed at least six months before the well is started up by way of the circulation or bull-heading strategy. The goal is ultimately to enhance inter-well connectivity without heat, which ultimately reduces the volume of steam and time required to initiate movement of the oil in the reservoir.

The dilation process attempts to increase the near wellbore permeability by realigning sand grains and increasing porous space between the injector and producer wells through a short-term pressurization and flow cycle lasting only a few days. The pressure and rate utilized are managed to mitigate the potential of any impact outside of the inter-well space. In this case, the hope is to reduce the time required for communication to occur between the injector and producer, ultimately reducing circulation time.

FLOW CONTROL DEVICES

In an attempt to enable longer SAGD wellpairs, more uniform steam chamber development and optimized artificial lift performance, the majority of operators are now utilizing a variety of different flow control devices for both steam injection and fluid production.

Two different device configurations exist: liner-deployed systems, which are permanently installed during the drilling process, and the more prevalent tubing-deployed systems, which are generally easier to modify or remove.

These flow control devices are designed to promote a more uniform distribution of steam along the injection well and fluid draw-down to the production well. They are also often utilized as a way of ensuring pump longevity by reducing the likelihood of steam interaction with artificial lift. In the past few years, it has become more common to include technology that hydraulically isolates various regions of the wellbore to ensure a more even distribution of injected steam or produced fluid.

INFILL WELLS

Infill wells are the most common method for increasing overall project resource recovery as a complement to SAGD wellpairs. An infill well is a single well drilled between two adjacent SAGD wellpairs, and is typically utilized as a way of accelerating pad production and producing some of the oil that may be left behind with SAGD wellpairs alone. The infill well's success is largely dependent on the adjacent SAGD wellpair's steam chamber development, and as such they tend to be most successful after two adjacent steam chambers have coalesced.

Although most SAGD projects did not include infill wells in the original project applications or scope of design, most are using or planning on using infill wells as a way of increasing and/or accelerating recovery from a SAGD drainage pattern and maintaining a lower steam to oil ratio. This strategy has allowed many projects to surpass performance expectations and has significantly increased the ultimate recovery of mature assets.

Standard SAGD operating procedure

The fundamentals of SAGD are fairly well understood, and although some variations exist from reservoir to reservoir, the general well design and operating philosophies are similar across Alberta and Saskatchewan.

A typical SAGD wellpair consists of two horizontal wells, an injector and producer that are drilled at the base of the exploitable reservoir. The injector is orientated directly above the producer with a vertical separation of approximately five metres for a horizontal length of approximately 700–800 metres, although shorter and longer wells are common. The horizontal portions of the well are equipped with a specially designed liner system, which allows for fluid movement in and out of the well while preventing any significant reservoir sand production.

Typically a thermal well requires some type of initial steam stimulation to heat up the near wellbore region, allowing the oil to become mobile. The overall success of this initial stimulation has a significant impact on determining the overall performance of a wellpair and can be detrimental to the well if certain reservoir heating goals are not met. The two most common start-up strategies for SAGD wellpairs are a steam bullhead and steam circulation; the method employed is determined by the reservoir and operational characteristics.

Upon completion of the initial stimulation, the well is then operated as a typical SAGD wellpair, where steam is injected into the injector only, and fluid is produced from the producer. A steam chamber will begin to grow vertically, and as it does, it transfers heat to the formation to mobilize the heavy oil, allowing oil and condensed steam to drain to the producer.

CO-INJECTION

After the steam chamber is grown to a certain size, the most common operational enhancement process is co-injection, where a gas or hydrocarbon liquid is injected simultaneously with the steam into the reservoir. The most commonly utilized fluids are gas and solvents. Gas typically refers to a fluid that is in a gaseous state prior to injection, where solvent is often a liquid (such as diluent or condensate) prior to mixing with the steam.

Among the co-injection cases, more SAGD well pairs have injected natural gas than any other alternatively injected fluid stream as a way of reducing the volume of steam required to operate a SAGD wellpair. The steam that is saved is then directed toward new SAGD wellpairs or infill wells, as often a steam constraint exists within the facility. Natural gas is the most commonly injected gas due to its low cost and the relatively low capital required for implementation. CO_2, butane, propane and air have also been trialled.

Gas co-injection has historically been a transition phase to a full blowdown phase where only gas is injected to a well, but it is now being utilized much earlier in the life of many SAGD wells in some projects. The overall success of gas co-injection is typically determined by the volume of gas injected (and steam volume offset) and how early in the life cycle of the wellpair that it occurs. Gas injected in the late stage of a well's life typically has less of an impact on the overall oil production from any given well.

Solvent co-injection trials are becoming more common, and this is one of the most discussed alternative enhancements to typical SAGD operations. Solvent co-injection can increase the produced oil rate due to the solvent's ability to dilute and further mobilize the draining oil. The process can potentially reduce the residual oil saturation within the steam chamber, increasing ultimate recovery. It can also reduce the steam requirements for the operation and reduce its energy intensity, which in turn decreases greenhouse gas emissions.

The biggest disadvantages associated with solvent co-injection are the cost of the solvent, the large capital requirement for facility modifications and the potential for solvent losses within the reservoir. Facilities will typically undergo major modifications in order to properly capture the solvent for reuse and to mitigate the amount of solvent that is burned in the boilers. Due to the cost associated with the solvent, mitigating the volume of lost solvent within the reservoir is critical. This means that any well that is being considered for solvent co-injection must not have the potential of substantial loss to thief zones, and likely has operational history that proves little to no steam losses throughout regular SAGD. Performing various solvent co-injection trials is typical, as each formation and oil type reacts differently to various solvent streams and concentrations.

OUTLOOK

The ongoing development of new technologies and operational philosophies will not only have a large impact on existing SAGD operations, but will be critical to the success of many of the future's challenging reservoirs. Due to the variety of heavy oil reservoirs now utilizing SAGD, it has become much more difficult to simply apply a technology or operational principle that may have been successful elsewhere. Each resource needs to be optimized on its own, which makes it extremely important to understand how variation in reservoir and operation will impact the overall project.

It is critical that the industry transparency and information sharing continues and realistic expectations are put forward for each particular resource.

Trevor Phenix is a production and reservoir engineer consulting for Top Analysis.