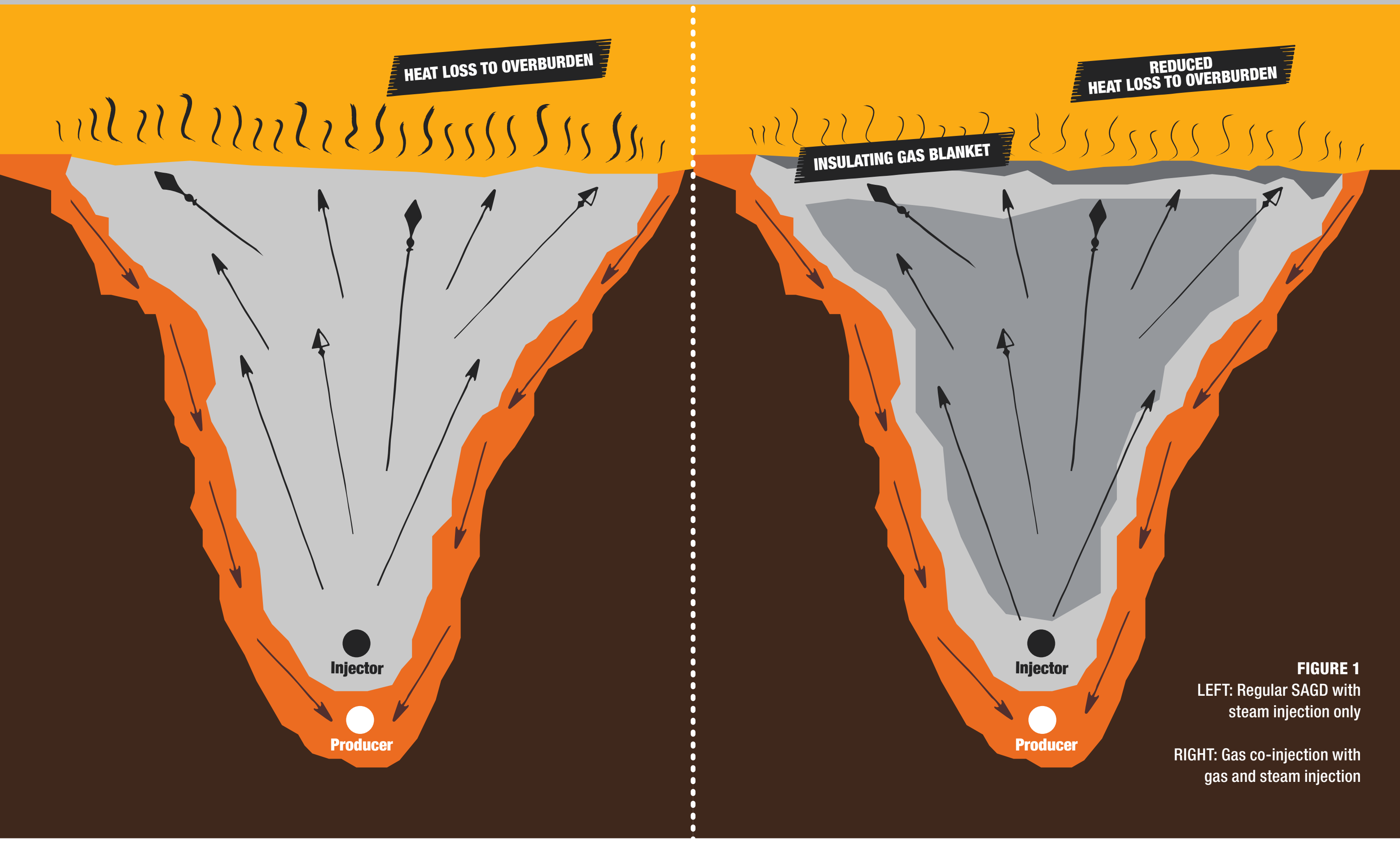


FIGURE 1
LEFT: Regular SAGD with steam injection only

RIGHT: Gas co-injection with gas and steam injection

Gas co-injection

The evolution of the most common SAGD enhancement

By Trevor Phenix, TOP Analysis

The rapid development of SAGD projects in Alberta and Saskatchewan has significantly increased societal awareness of the recovery method. Technological advancement in facility design, drilling and completion techniques along with actual operational experience has supported rapid growth of SAGD projects. Once an enhanced recovery method, SAGD is now more of a standard technology in which enhancements are being trialed and commercialized. Not all technology and operating procedures work in every formation, and it is common to see various strategies being applied in the same field.

Co-injection is the most common enhanced operational process for SAGD wellpairs, where a gas, hydrocarbon liquid or surfactant is injected simultaneously with the steam into the reservoir. Co-injected gas refers to a fluid in a gaseous state prior to injection, which is typically natural gas. Co-injected solvent, such as diluent or condensate, is often in a liquid state prior to mixing with the steam. Among co-injection cases, more SAGD wellpairs have injected methane than any other injected fluid stream. This is likely due to the low cost of natural gas and minimal capital requirements associated with facility modifications. Due to the perceived benefit and historical precedence, gaining regulatory approval for methane injection in operating strategy has become relatively common.

With natural gas co-injection, the volume of injected steam is reduced, and an equivalent volume of methane is introduced such that the original target steam chamber pressure is maintained (with less steam). Typically, the steam that is no longer injected is directed toward wells that will have a lower steam to oil ratio (SOR) such as a new wellpair or an infill well. In a sense, it can be treated as a type of steam expansion with minimal capital requirements.

Gas co-injection was historically viewed as a late-stage transition phase to full blowdown where only

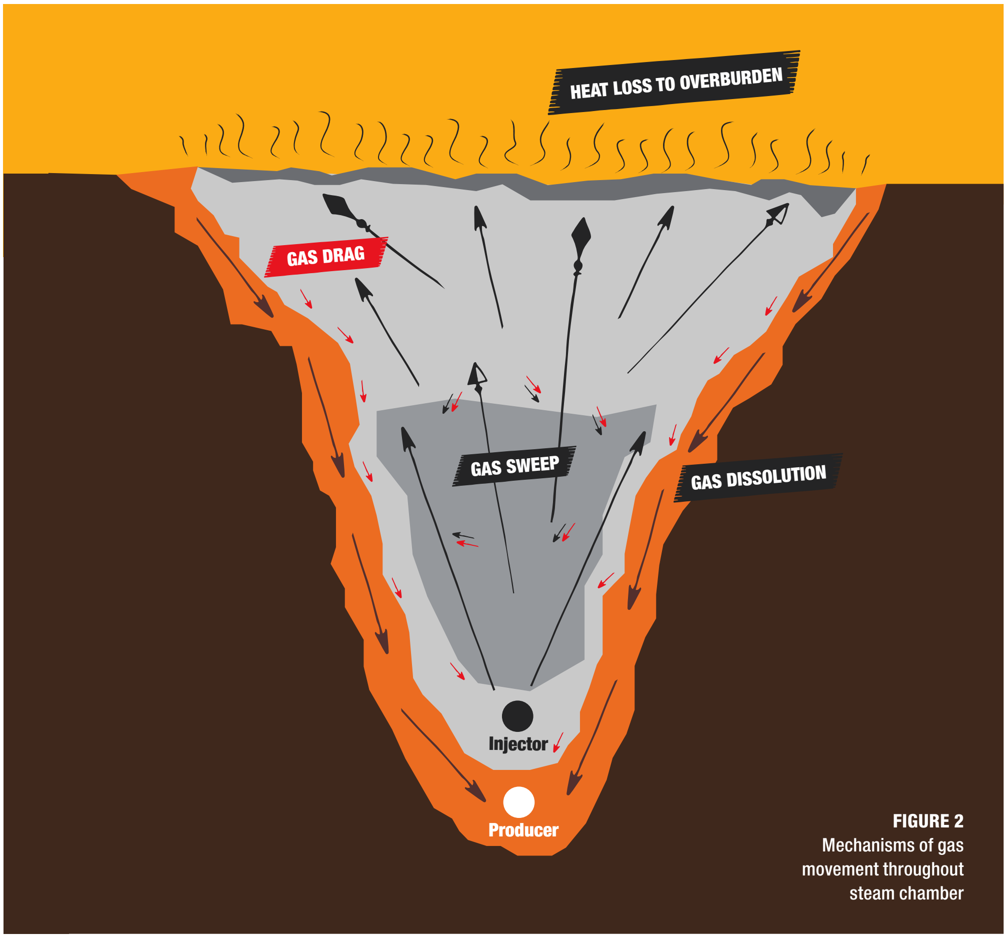


FIGURE 2
Mechanisms of gas movement throughout steam chamber

gas was injected for pressure support, with the intent of extending the economic life of a well. This would reduce operating costs associated with burning gas to generate steam and increase the recovery from that well. Recently, gas co-injection has shifted from a process of economic well life extension to an earlier strategy to accelerate production. Operators are applying for gas co-injection on less mature wellpairs that are showing signs of an increasing SOR so that steam can be redirected toward new wellpairs or infill wells that will have a lower SOR. The economic driver is to immediately deliver more oil for the incremental steam. Less emphasis is directed to extension of economic life and ultimate recovery of waning wellpairs.

WHY GAS CO-INJECTION WORKS

The predominant argument for natural gas co-injection is that gas that accumulates at the roof of the steam chamber creates an insulating effect by reducing the partial pressure of the steam and associated temperature of the steam chamber. The drop in temperature at the top of the steam chamber reduces the temperature difference between the steam chamber and the overburden, reducing the volume of steam that condenses against the overburden and reducing the heat lost to the non–oil bearing rock. The steam that is replaced by gas at the contact of the steam chamber roof and overburden does not provide significant incremental oil, and the oil rate should be relatively unaffected by the reduction in the injected steam.

The other perceived benefit has been the subject of numerous studies of gas movement into lower-permeability oil-bearing regions that the steam chamber could be in contact with. Regions such as inclined heterolithic stratification that are warmed up by conductive heating could utilize injected gas to unlock resource that may not otherwise be accessible. These areas of the reservoir have such a slow rate of penetration that steam is likely to condense prior to displacing draining oil, although significant heat transfer still does occur by conduction. Conductive heat mobilizes the trapped oil, and gas can then fill void space associated with draining oil. The impact of such a process would be very slow and is a potential long-term strategy for increasing ultimate recovery.

In either case, the success of gas co-injection revolves around the gas staying within the reservoir upon injection and accumulating at the roof of the steam chamber once it has spread laterally [Figure 1].

When gas is injected into the injector well of the wellpair, a large portion of gas is produced quickly, often within hours. The time it takes for gas to be produced is a function of the location of gas injection within the reservoir, the fluid level above and along the producer (referred to as subcool), or the operating pressure of the injector and associated pressure of the producer. The most commonly accepted mechanisms of gas transportation toward the producer are dissolution of gas within draining oil and condensed steam; a drag force on the gas from fluid draining down the sides of the steam chamber creating a foamy emulsion; and the gas moving within the steam chamber from higher-pressure to lower-pressure regions, or gas sweep [Figure 2].

STEAM CHAMBER PRESSURE AND TEMPERATURE

Operating at a lower steam chamber pressure is generally regarded to be associated with more gas retention in the reservoir. This may contribute to the minimal impact on oil production during late-stage co-injection and blowdown as operating pressure is typically lowest by design later in the life of the wellpairs. A higher steam chamber pressure results in a higher temperature, both of which promote gas movement down the steam chamber walls. A higher operating pressure coincides with gas having an increased density, and contrary to liquids, the increase in temperature results in an increased viscosity of the gas. Gas that accumulates at the roof and gas that spreads along the edge of the steam chamber may be reduced as a result of dissolution and drag and thereby reduce the insulating effect between the steam and overburden.

Pressure variations occur across the steam chamber and are most notably associated with hydraulic inconsistencies near producer wellbores. Producer completions are designed to promote even inflow through hydraulic optimizations, but irregularities are inevitable. Varying drainage rates across the wellpair occur as a result of wellpair hydraulic design and reservoir phenomena such as a low reservoir roof or zones of reduced permeability as the steam chamber moves upward. In general, areas with a lower drainage rate result in a ►

lower fluid level above the producer and a subsequent region of lower pressure. The pressure difference promotes steam movement toward the low-pressure areas, and steam sweeps the injected gas toward the producer. Injecting more gas near the regions of lower pressure and operating with a lower fluid level will affect how much and how quickly gas is produced. The impact of a low-pressure area is considerable, as it minimizes the likelihood of gas moving significant distance into the reservoir [Figure 3].

The gas within the steam vapour mixture reduces the steam chamber temperature by lowering the partial pressure of the steam. Cooling occurs not only within the chamber where gas may be accumulating or be swept but also within the producer wellbore. However, various temperature profiles within the chamber can form depending on the volume of gas present in different parts of the chamber.

The significant portion of gas accumulating at the edges of a steam chamber and bitumen interface will result in a localized cool-down. This phenomenon, may further reduce the likelihood of lateral steam chamber conformance in an already struggling region of development. The reduction in conformance reduces the potential economic recovery due to a decrease in oil rate and associated higher SOR in the late stages of the wellpair life.

The cooling effect can also negatively influence typical producer optimization, as the increase in gas composition can result in an ill-advised increase in production rate and inadvertent steam production. The increased fraction of gas within the fluid that moves into the producer wellbore will drop the temperature at any thermocouple or fibre point. This temperature drop in the producer will falsely increase the perceived fluid level above the producer (or subcool) as if more fluid is actually pooling than is really there. If the operator chooses to attempt to maintain the same calculated subcool value, the production rate will be increased even though the fluid drainage rate has not increased. Eventually, the consequence of little to no fluid level above the producer can be a steam event into the producer, and ultimately a slowdown in rate when the apparent flush fluid is gone. This fluid level provides protection to

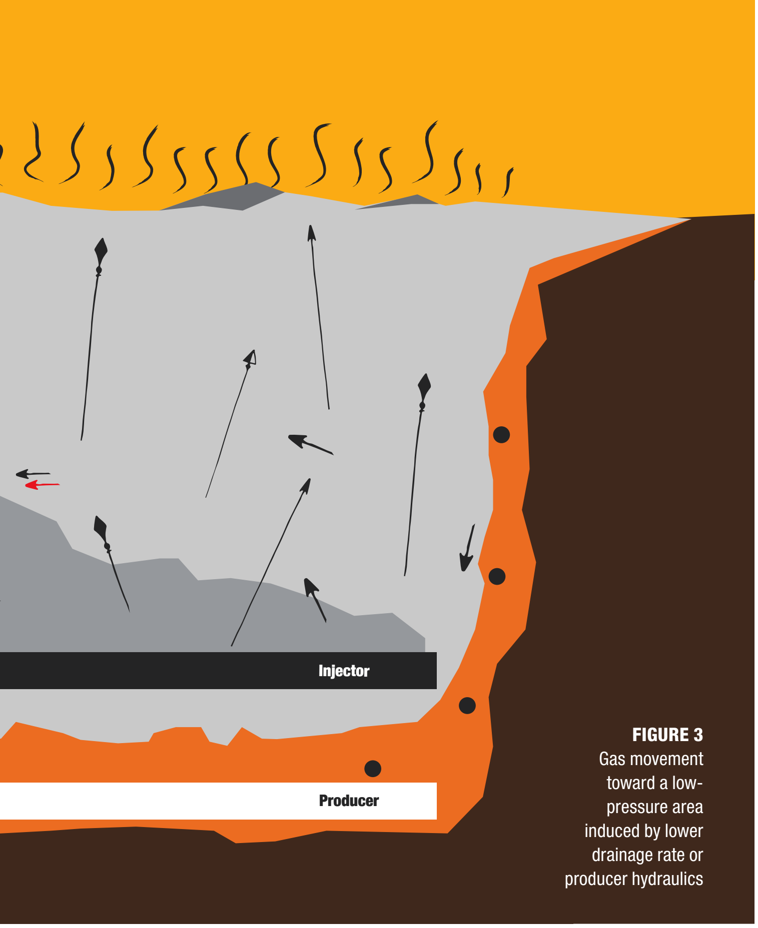


FIGURE 3
Gas movement toward a low-pressure area induced by lower drainage rate or producer hydraulics

the producer slotted liner or screen, artificial lift equipment and potentially surface facilities.

MODELLING INACCURACIES AND INDIVIDUAL WELLPAIR ANALYSIS

Although extensive numeric simulation of various types of gas (solution gas and injected gas) within a SAGD reservoir has been modelled, there has been minimal success of matching modelled results to field results of gas co-injection. The importance of proper modelling of the impact of co-injected gas is significant due to the potential positive impact on ultimate recovery and its application for less-mature wellpairs. In most models, very little gas is actually produced, and a significant portion of the gas accumulates at the edges of the steam chamber as steam sweeps the gas to the condensing steam front.

In contrast to modelled predictions, in field results the majority of solution gas and co-injected gas is produced. However, in modelling practices the accumulation of gas at the steam front causes considerable impedance on steam chamber development and significantly reduces the performance of the wellpair. To achieve more realistic model results, modellers generally manipulate relative permeability curves, reduce gas-oil ratios or eliminate solution gas.

The biggest impact from modelling inaccuracy is the inability to understand and forecast the true impact of gas co-injection on resource recovery. This results in the majority of operators applying multiple resource optimization strategies. The ability to properly understand the impact of each optimization strategy on its own is critical.

Although there are more than 130 instances of natural gas co-injection in Alberta, analyzing individual wellpair results is a challenge. The impact of infill wells, of inconsistent operating strategies, of planned and unplanned maintenance, and of allocation and reporting issues make analysis of gas co-injection difficult. However, analysis of each wellpair does allow for general understanding of the impact associated with gas co-injection.

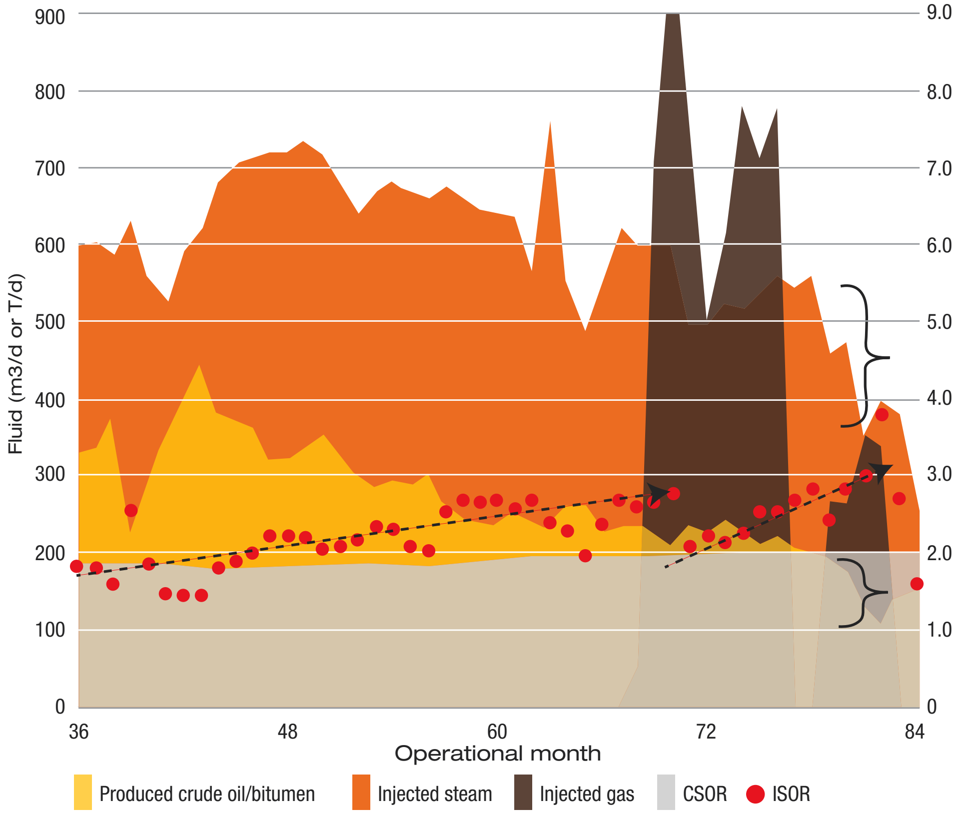
OPTIMIZING GAS CO-INJECTION

Generally, co-injecting gas will not result in a long-term reduced SOR in a wellpair. The SOR appears to ►

drop for a short period, but typically returns to the pre-co-injection value and begins to increase at a similar rate as previous to co-injection. This is likely associated with the induced effects of various partial pressures. This means that the oil rate will drop in proportion to the steam rate drop and return to the pre-co-injection SOR. The case below [Figure 4] demonstrates that if an insignificant reduction in steam injection rate occurs, the SOR and oil decline rate will continue on the pre-co-injection trend.

The negative impacts appear to be reduced with lower natural gas injection volumes and shorter injection cycles. Although any gas injection will have some negative effect on incremental recovery, in most cases natural gas co-injection appears to be a suitable solution for short-term periods of reduced steam (such as during boiler maintenance). Continual cycling of gas injection appears to increase the negative impact of future gas cycles. In a mature wellpair, the rock is likely able to sustain enough heat to show little impact on the overall

Figure 4: ISOR and oil rate response to gas co-injection (DVN|JFE|A|A3)



SOURCE: TOP ANALYSIS

> ***Gas co-injection has shifted from a process of economic well life extension to an earlier strategy to accelerate project production.***

production with reduced co-injection volumes and cycle time.

There are a few wellpairs with late-stage gas co-injection and associated blowdown. From these late-stage co-injection wells, it appears that once significant communication occurs within a pattern, and with considerable associated heat present in the reservoir, reductions of steam injection volumes have less impact on oil drainage rates. This is encouraging. Longer well life and greater ultimate well recovery can be anticipated in late-stage co-injection wells with the utilization of properly designed mechanical lift systems.

The utilization of gas co-injection requires the operator to have a clear understanding of the true intention of the enhanced recovery method and its potential long-term impact. The immediate benefit of co-injection is clear: For the same volume of facility-generated steam, an incremental increase of oil rate will occur. The potential downside of gas co-injection is the overall impact on ultimate recovery factor as a result of the reduction in late-stage performance of the associated wellpair. Later-stage gas co-injection ensures that a high ultimate recovery does take place but potentially results in a reduced asset value due to the time value of money. Gas co-injection will increase the immediate asset value, although metrics of timing, development strategy, and oil and gas price will significantly impact the overall benefit of either accelerated production or an increase in ultimate recovery.

Continued development of new technologies and operational philosophies such as gas co-injection will have a large impact on existing SAGD operations. These strategies will be critical in the future success of many challenging reservoirs. As SAGD operators continue to move wellpads toward lower-quality resources to sustain production rates and new projects targeting lower-tier assets come online, the importance of enhancements to current SAGD strategies will have a significant impact on the future growth in the industry. It is important that transparency of industry and sharing of information continues and that realistic expectations are put forward for each particular resource and mode of recovery enhancement. ▮

Trevor Phenix is a production and reservoir engineer consultant for Top Analysis. Over 10 years, he has held various engineering roles in reservoir, production and development positions, most recently as a consultant to various SAGD operators on the numerous aspects of thermal pilot and commercial projects. Trevor has an extensive background in thermal operations and has been directly involved in 12 operating projects that exploited uniquely different reservoirs in Alberta and Saskatchewan.

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