

**AND NOW FOR SOMETHING COMPLETELY DIFFERENT:
CONDENSATION INDUCED WATER HAMMER
AND
STEAM ASSISTED GRAVITY DRAINAGE IN THE ATHABASCA OIL SANDS**

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Abstract

Most people will have been exposed to some aspect of the debate about the Athabasca Oil Sands in North-Eastern Alberta and the significant role that the oil sands are expected to play in supplying conventional fossil fuels. Part of the bitumen is recovered from mines and part is recovered from in situ projects utilizing the Steam Assisted Gravity Drainage Process (SAGD). SAGD utilizes a considerable amount of steam, that is injected into geological formations. Hot water, bitumen and some vapour are recovered from the production wells. With significant steam generation, transmission and injection, there is the very real possibility of condensation induced water hammers.

There have been a number of catastrophic failures to date. Two major failures will be highlighted:

- MEG Energy had a steam distribution line fail at the Christina Lake project. Large parts of the pipe, weighing some 2500 kg, were thrown some 800 meters into the bush during the failure; and,
- Total had a steam release (blowout) at their Joslyn property due to a loss of caprock containment. A number of causes have been postulated. While it is agreed that there was sufficient downhole pressure to hydraulically fracture the formation, questions have been raised about the contribution that condensation induced water hammer made.

The situations that have occurred will be outlined, along with some preliminary thermal hydraulic work. The intent of the paper is to provide interesting background information on the in situ oil sands industry. More importantly, to show some interesting and broader applications of thermalhydraulics developed in the nuclear industry. The expertise developed may have potential markets, with some adaptation, to the oil sands industry. Finally, there has been some discussion about using nuclear power for steam generation in the oil sands.

Introduction

The majority of the oil sands are relatively shallow. About 20 percent of the oil sands have overburden that is sufficiently thin that it can be surface mined (the economic limit has historically been considered to be 45 meters). The majority of the oil sands, 80 percent, are too deep to be mined. Thus, the majority of the oil sand will have to be developed with in situ techniques, which at present means Steam Assisted Gravity Drainage (SAGD).

Basics of Steam Assisted Gravity Drainage (SAGD)

Higher density oils have been produced for some time utilizing steam as a driving agent. Traditional steam flood techniques have not proved to be effective in the very high viscosity bitumen found in the Athabasca tar sand. In north-eastern Alberta the bitumen is located between the sand grains and is mixed with water, which adheres to the sides of the grains of sand. The tar sands are particularly viscous – with typical initial in situ viscosities of approximately 1 million cp. In simplified terms, the bitumen is so viscous that it cannot move forward as the steam is injected. Figure-1 shows typical data.

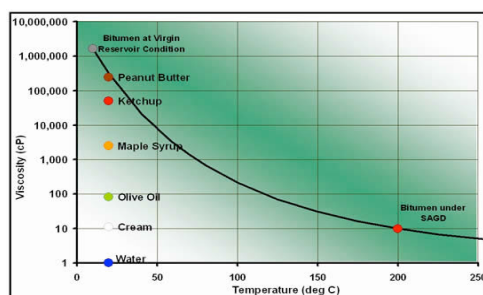


Figure 1 Typical Athabasca bitumen properties.

The original SAGD concept was conceived by Dr. Roger Butler and is a relatively recent development. There are three major steps – a circulation stage prior to starting SAGD, the actual production of oil (SAGD) and then a wind-down or abandonment phase. We start with two wells that are drilled down typically on a slant, followed by a long horizontal section of between 700 and 1500 meters.

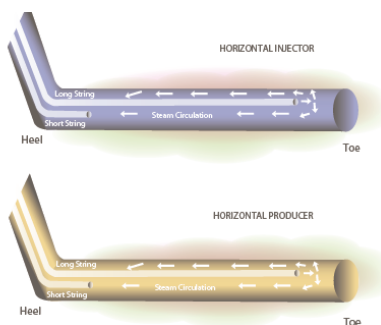


Figure 2 Arrangement of SAGD wells and circulation of fluids¹

Hot steam is circulated down both wells through steel tubing with the cold water returning up a second string of steel tubing. As the formation is heated, the temperature of the bitumen away from the well increases as heat is conducted away from the wellbore. The original temperature of the oil sands ranges typically from about 5 to 10 degrees Celsius. Note that the angled section of the well is constructed of intact pipe, while the lower horizontal section is constructed with a separate piece of pipe (called a liner) that has thin slots cut in the pipe. When the bitumen has become hot enough between the two wells that communication is well established, the next stage may begin. The thin slots allow fluid to move through the liner, but are thin enough to block the movement of sand.

In the next stage steam is injected under pressure into the upper well, which, by virtue of its low density rises. The oil segregates by gravity and is captured using the lower well. The well setup is shown in Figure 3, and the resultant process is shown in a lab experiment in Figure 4.

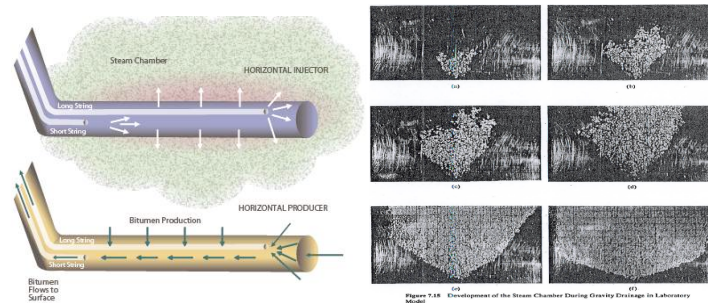


Figure 3 (left) Arrangement of SAGD wells during production phase¹; and, Figure 4(right) Cross Section of SAGD chamber development in a lab experiment²

The steam chamber from a 3D perspective looks something like Figure 5. This depiction is extremely simplified in that the reservoir is shown as being homogeneous sands. The reality is that there are a large number of interbedded low permeability shales that do not transmit fluids and the actual steam chamber would look in cross-section something more accurately in Figure 6.

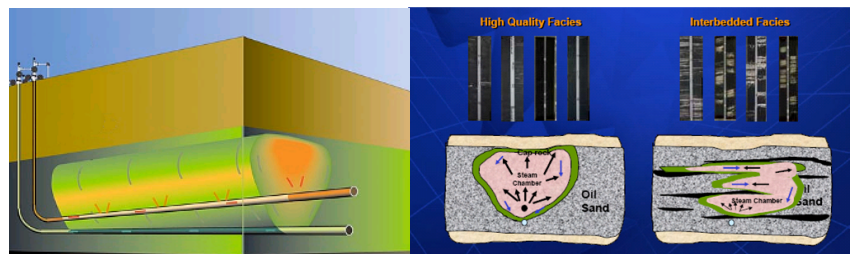


Figure 5 Three dimensional depiction of a SAGD chamber; and Figure 6 Effects of geological heterogeneities on SAGD chamber development³

The sand deposits cover quite large areas and a single well pair is not capable of draining an entire reservoir. Development consists of a series of steam chambers side by side. Wells are grouped by surface facilities into pads that contain anywhere from 3 well pairs up to about 10 well pairs. The pads are oriented to conform to the bitumen deposits. See Figures 7 and 8.

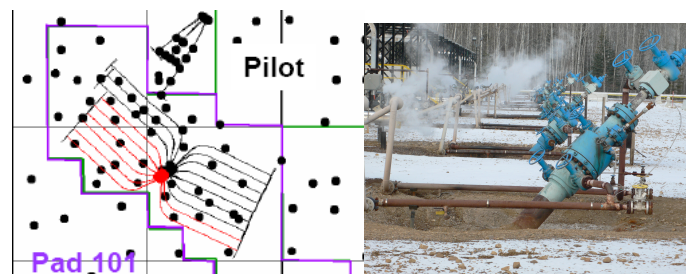


Figure 7 Arrangement of a pad with geological deposit⁵. Note small scale pilot and Figure 8 View down a producing pad, wells are produced with pumps

The final stage is called the wind down stage. To date there are few steam chambers that have been abandoned and this stage is just being reached by the first commercial projects. When steam injection ceases, the chambers will cool down and the steam inside the chamber will condense and contract. Since the chamber is comprised of sand with the interstitial bitumen removed, it will not physically collapse on abandonment. However, the original process envisaged using natural gas to

fill the chamber at operating pressure, since it would prevent unwanted steam losses from adjacent chambers.

The development of SAGD was originally implemented through the Alberta Oil Sands Research Technology Association, which was sponsored by the Province of Alberta. The UTF (Underground Test Facility) project was quite unusual in that a mine was dug and the horizontal wells were drilled out of mine tunnels. The project was a significant success. Subsequent phases utilized wells drilled from surface. Subsequent to the UTF there have been a series of commercial projects implemented. The efficiency of the SAGD process is customarily described by the amount of steam that must be injected to recover a barrel of oil. Generally speaking an SOR of 4 or less is required to remain economic. Not all projects have achieved this performance, although the majority have.

1. Operating a SAGD Project

From the proceeding, one may intuit that the manner in which the wells are operated can have a significant impact on performance. Starting with the circulation phase there is more than one way to circulate the wells. For instance, the steam can be circulated down the long string, with the steam exiting at the end of the well and being extracted up the short string, or possible with the fluid being recovered up both the short string plus up the annulus (i.e. from the casing directly). Alternatively the fluid flow can be reversed – with the steam going down the short tubing and the condensed water recovered up the long tubing. Of course there will be heat loss from around the casing on the way down and this heat is lost – it does no useful work. The annulus can also be filled with natural gas – which acts as an insulator. There is also heat transfer between the hot fluids going down the long string, with cooler fluids travelling past the hot tubing on their way back to surface. There are cost limitations on the tubulars and as a result there are real pressure drops along the well.

Although the cold bitumen does block most of the interstitial pore space in the oil sands, there is a film of water on the rock that does provide for some inherent water permeability. The sands in the Athabasca are not consolidated and this means that the sand grains can be re-arranged if the fluid pressures and applied loads change. There is therefore some fluid leak-off during the circulation stage. Although this fluid leak-off would appear to be a disadvantage, the conduction of heat through soils is quite slow. The transfer of heat by convection is faster and this leak-off actually helps heat up the formation more rapidly.

Ideally it would be possible to accurately calculate the exact amount of start-up or circulation time that is required. However, experience has indicated that this is not always possible since the exact geology and physical properties are never known with certainty. By operating the injector at a slightly higher pressure and monitoring the circulation returns in the producer, it should be possible to see if any oil is being produced – which would indicate that communication has been achieved between the two wells and the SAGD stage can begin.

After the circulation phase – in the SAGD phase, the producing wells are put on pump and the injection well injects steam into the formation. The two wells therefore operate differently. The steam inside the steam chamber rises up the middle, hitting the top of the formation and then spreading out towards the side of the formation. Ideally, the steam condenses as it hits the cold bitumen against the side of the chamber and releases its heat by condensing – melting the bitumen. There is therefore an inherent convection or circulation pattern within a steam chamber. This means the right amount of fluid must be drawn out of the producing well.

With the steam rising up to the top of the reservoir there will be a certain amount of heat that is lost to the overburden. In a typical SAGD application a bit under 15 percent of the heat is typically lost – assuming the cap rock has no inherent permeability. In practical terms this last assumption is not always true.

As can be seen in Figure 9, the interface between the steam and liquid water can vary within the steam chamber. If the water is too deep, the steam partially condenses on its way up to the top of the chamber. If the water interface is drawn down into the producer, steam may potentially short circuit from the injector directly into the producer – in which case no useful work is done. Ideally the interface between the steam and water would be located just above the producer, with maximum production occurring. The scale of the interstitial spaces within the reservoir sand are quite small. Sufficiently small that interfacial tension effects (capillary pressure) between the oil, water, hydrocarbon gases, steam, sand and fines become quite significant. Because of this sharp interfaces don't actually exist.

There are two ways of attempting to control this process. One is to use the temperature and pressure in the wellbore and compare this to a steam saturation curve. If the well can be operated below the saturation pressure, then no steam should be entering the well. Normally it is easier to measure temperature rather than pressure and the standard that has evolved is to express how far under the saturation pressure the fluids in the wellbore are in terms of temperature rather than pressure – the amount of “subcool”. Another alternative is to accept that complete optimization cannot be achieved and to use a small amount of steam production as an indicator of near optimal performance. In practice, since there are pressure drops along the well and there is considerable flashing of the wellbore fluids as hydrostatic pressure is released on the way to surface – making an accurate estimate at the formation difficult. Neither method is therefore easy to implement in practice.

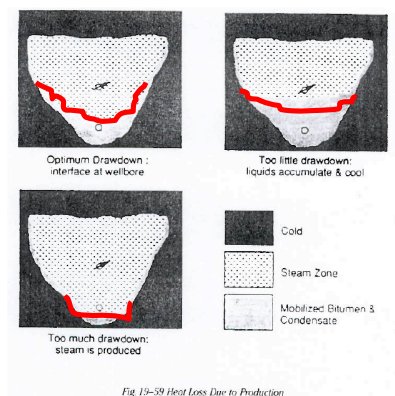


Figure 9 Steam – water interface variation as a function of operating conditions

In practice, the wells suffer some fines movement, scale and asphaltene deposition and there is a lower permeability zone around the wells that is normally referred to as a skin effect. This involves some pressure drop from the formation into the well. It also follows that a steady flow of fluids into the well would be optimal and this implies somewhat steady conditions in the production and injection wells. This later point is of great interest to those involved in thermalhydraulics.

2. Cap Rock Integrity and Hydraulic Fracturing

The steam chambers are operated at pressure. A SAGD project therefore requires enough dirt on top of it that the overburden doesn't get lifted off. Further, there must be sufficient strength that the overburden doesn't shear around the edges. In essence, a steam chamber will act as a distributed load under a plate. There must also be sufficiently low permeability that the steam doesn't simply flow up through the overburden. Steam will flow through sand quite well and this means the caprock has to be of low permeability i.e. the formation must have a high clay content.

There is another failure mode that is perhaps not quite as obvious; which is hydraulic fracturing. Hydraulic fracturing is most easily explained as a tensile failure around a borehole. I use the analogy of a concrete block to explain this, as shown in Figure 10:

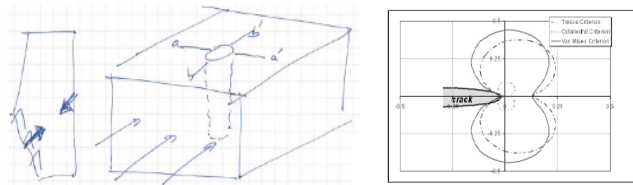


Figure 10 Fundamental mechanism – hydraulic fracture initiation and propagation

If we pump high pressure fluid into the hole in the middle of the concrete block, then eventually the outside of the bore hole is going to go into tension. Concrete has very little tensile strength (and soils even less) so this causes the borehole to crack along the side. I have shown a stress being applied to the concrete block. The block, if homogeneous, will crack preferentially along the b-b' line, since less stress has to be overcome than along the a-a' line. I have also shown a small map of Alberta and there are indeed significant natural stress variations in the earth, as evidenced by the Rocky Mountains. In general most rocks within a producing zone have some permeability and some allowance must be made for the fluid leak off, and the associated pressure distribution around the well.

Once the fracture has started the fracture is propagated by a completely different mechanism: stress concentration at the tip of the fracture. The fracture propagates as the material fails at the tip of the fracture. The direction in which the fracture propagates changes with the stress state and can change direction – if the stress conditions change. I have two quite nice pictures. The first is a clear plastic block that has been fraced in the lab in Figure 11. In this case the fracture has started horizontally. The second example is a series of large scale geological features resulting from a series of natural geological intrusion events in Figure 12. Note how the fractures change abruptly from vertical and then adopt a saucer or cup shape as they get close to surface.

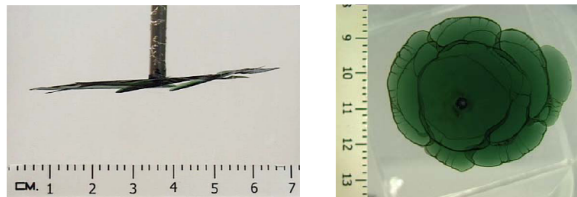


Figure 11 Hydraulic fracture induced in a clear plastic sample side and top view⁵

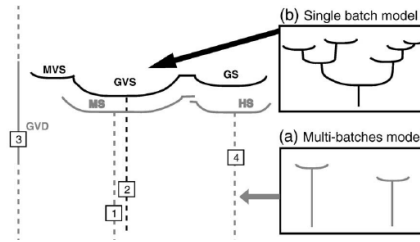


Figure 12 Cross-section through a series of dykes and sill in South Africa⁶

The system has the general appearance of a “bunch of flowers”. In simplified terms, if you put too much pressure inside an uncased or perforated wellbore, the formation will crack. It will then follow a complex path, as depicted above to surface.

Hydraulic fracturing is commonly used in the oil and gas industry using a very thick fluid to minimize fluid losses and to act as a sand carrying agent. Using timed breakers it is possible to create a large crack, fill it with sand, and then recover the (now broken) treatment fluids. The sand provides a conductive path which greatly enhances the productivity of oil and gas wells. This process is known colloquially as “fracking a well”. Most fracs result in vertically oriented fractures due to well depth.

Loss of drilling fluids due to hydraulic fracturing can occur if high pressure fluids are encountered in the lower section of the well. It is common to do a small fracture called an FIT (Formation Integrity Test). Small experimental hydraulic fractures can also be used to interpret the minimum stress state of formations, a process known as “mini-fracking” or “micro-fracking”. These and hydraulic fracturing well treatments (fracs) can all be used to measure or estimate the pressure at which a hydraulic fracture will be created.

3. Potential for Condensation Induced Water Hammer (CIWH)

The U.S. nuclear regulatory agency published NUREG/CR-6519⁷ Screening Reactor Steam/Water Piping Systems for Water Hammer, which was prepared by P. Griffith. The monograph provides a succinct guideline of conditions required:

1. The pipe must almost be horizontal.
2. The subcooling must be greater than 20° C.
3. The L/D must be greater than 24.
4. The velocity must be low enough that the pipe does not run full, i.e., the Froude number must be less than one.
5. There should be void nearby.
6. The pressure must be high enough that significant damage occurs, that is the pressure should be above 10 atmospheres.

Reviewing the above list we find:

1. The “horizontal wells” are steered through the formation and are not completely flat. It would be more accurate to say they have undulations. However, this criterion is substantially true.
2. On startup the natural formation temperature is between 5 and 10° C and the required temperature differential obviously exists. If there is a change of operating conditions – such as an injector shut-in (which does happen) the steam chamber is clearly going to cool over time. What is perhaps less obvious is that to work on the well fluid must be introduced in the wellbore to prevent the reservoir fluids from escaping. While it is possible to heat workover fluids to about 90° C, this is more than 20° C colder than the steam normally injected. More

generally it is known from downhole temperature monitors² that wellbore temperatures do vary by more than 20° C as shown in Figure 13.

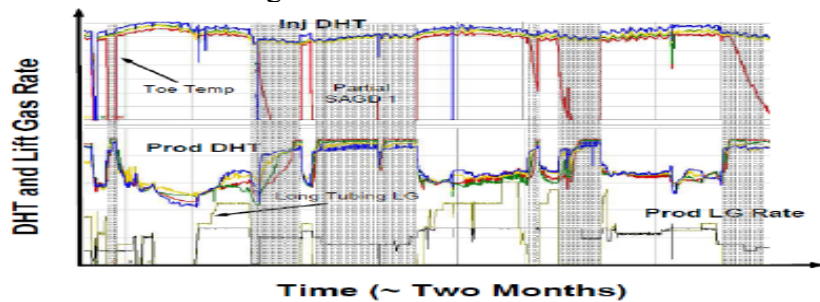


Figure 13 Temperature data from a SAGD operating wellpair¹

3. Most liners are about 177.8 mm in diameter and 1,000 meters long so the L/D is definitely met.
4. Initially the casing and tubulars are completely liquid filled. The Froude number requirement is therefore met. As time progresses this is not obvious. Modelling will be used in the following.
5. There is a void in the riser (diagonal) section of the horizontal well.
6. Most SAGD projects run in excess of 1000 kPa (10 bars) and thus the suggested pressure requirement is met. Although pipe burst strength is a criterion for surface piping, the horizontal section is slotted and for injectors and producers the maximum pressure limitation is the hydraulic fracturing pressure of the formation.

Those familiar with thermal hydraulics will quickly recognize that steam / water piping is frequently quite transient. This was recognized during the UTF⁸ project as shown in Figure 14.

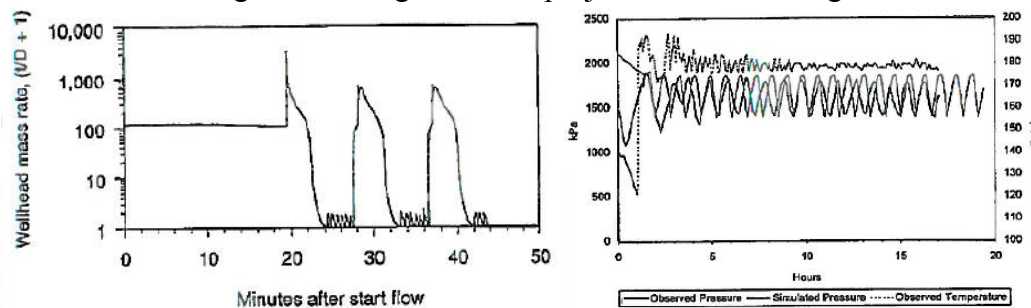


Figure 14 Calculations of wellhead rate and bottomhole pressures for different conditions.

The fluid flow results in slugs of flow from the horizontal section to surface, a process that has been dubbed “geysering”. Subsequently it has been called “Perco-Lift”. The UTF project was unusual in that the fluids were drained from the well into a mine tunnel and then pumped to surface using a centrifugal pump. Note the variations in well head rates which results in slugs in the surface facilities and the variation in bottomhole temperature and pressure. Fluids are brought to surface for operating SAGD well pairs using a variety of technologies, which include: gas lift, electric submersible multistage centrifugal pumps and progressive cavity pumps driven by a rotating steel rod to surface.

4. Modelling of an injection well using WAHA

Some preliminary modelling has been carried out using WAHA^{9,11} for an injection well utilizing an injection rate of 80 tonnes of steam a day with a 25° C temperature differential. The results are shown in Figure 15. The wellbore has been simplified, only the horizontal section has been modelled. The liner has been simplified in that all of the fluid exits at the end of the well, where in reality there would be a distributed leakoff into the formation. The pressures are shown 75 meters from the heel of the well. The input to the model (such as heat transfer coefficients) was not tuned and only the first minute

is shown. It strongly suggests that condensation induced water hammers should occur. The blue line represents the pressure. The well trajectory has been changed for the purple trace, with the objective of preventing CIWH. The red line represents the maximum pressure in the well. Above this pressure the formation will hydraulically fracture.

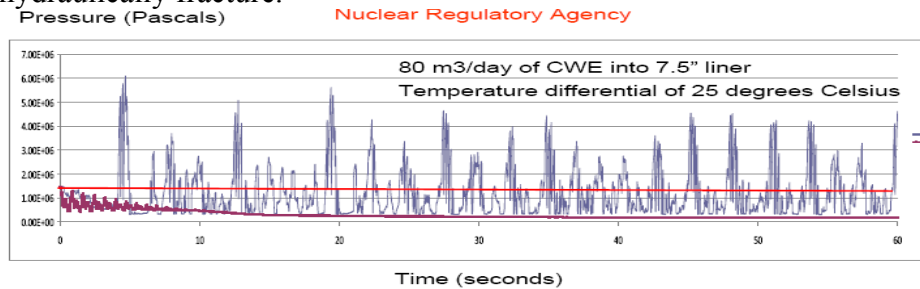


Figure 15 WAHA simulation of injection well – for first 60 seconds

It is also possible to build some fairly simple micro-models using some vinyl tubing and a wall paper steamer. All of which can be purchased at a local building store for a nominal cost. With a bit of epoxy putty, the tubular arrangements found in SAGD wells can be cheaply constructed. This demonstrates that the geometry definitely exists for water hammer. The latter experiments are, of course, at a very low pressure, approximately 4 kPag. The author believes that CIWH is not intuitively obvious and this visualization is critical.



Figure 16 Visual display of water hammer in a SAGD injector

Observed data does exist, which has an appearance similar to that shown in Figure 17. This data is problematical. The pressure sensors utilized were not sized to go to the pressure spike levels that can be predicted using the methodology from NUREG/CR- 6519 of 17,000 kPa. These gauges were also not designed to pick up short transients that last approximately 0.1 seconds, as suggested by the un-tuned WAHA model. In fact, downhole gauge reliability is a serious problem due to the high temperatures. It is quite likely that there is considerable physical vibration and shock from movement due to liquid slugging and tubular movement resulting from pressure spikes. The data is not a continuous output as the graph might suggest. The readings are spaced apart by about 4 to 5 minutes and are recorded digitally at a fixed sampling time. The WAHA model suggests that our recorded pressure has an element of chance associated with it – sometimes the gauge reads a spike, sometimes a void (which reads near zero pressure) and sometimes the approximate injection pressure. Because the riser section is typically gas (steam) filled, there is a large gas cushion effect and the downhole pressures do not manifest at surface. For instance, in the demonstration model shown in Figure-16, the wallpaper steamer operates continuously despite the downhole water hammers.

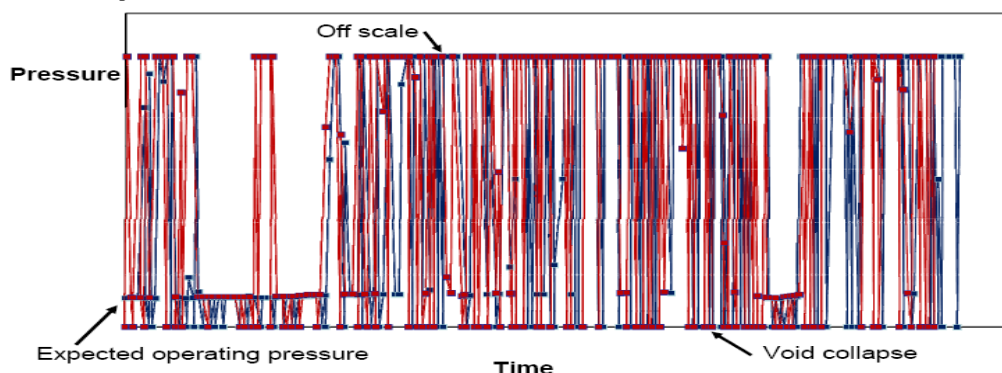


Figure 17 Cartoon of well pressure data. Red data is from heel, blue data is from toe

While conclusive proof is hard to draw from such data, the results obtained are not consistent with expectations.

The data indicates pressure spikes more than sufficient to induce a hydraulic fracture. These events would logically involve relatively small volumes of fluid since the spikes are so short. On the other hand, it is clear that the process is repetitive. The expected operating pressure is also a factor. The hydraulic fractures will heal with a return of cold fluids into the wellbore. This will tend to perpetuate the process. If the operating pressure is close to fracture pressure, the fracs will not heal and will steadily progress – a frac by a “thousand cuts”. Failure would therefore not be instantaneous. The Joslyn blowout lasted about 5 minutes. Accounting for steam expansion indicates the amount of condensate was not that large, about what would be expected from a fracture.

5. Significant Failures – Joslyn and Christina Lake

There are no pictures in the public domain for the MEG Energy surface line failure¹². The Energy Resource Conservation Board (ERCB), the agency responsible for regulating the oil and gas industry has produced a report IR 20080902 that documents their investigation. The following has been paraphrased from the report

At about 5:33 a.m. on Tuesday, May 5, 2007, MEG Energy Corp. (MEG) became aware of a potential release situation at its Christina Lake Regional Project when the control room operator noted an “electrical blip and a muffled pop sound.” Communication was lost between the Digital Control System (DCS) and Pad A (location of six horizontal well pairs) and a large plume of steam was observed rising in the direction of Pad A. ... MEG staff responded in the direction of the steam plume to confirm the location of the release but were stopped about half way to Pad A by sections of the aboveground 24-inch (610 millimetres [mm]) steam pipeline and downed power lines lying across the road.

The project was shut-in as a result of this failure. The steam line has now been repaired. Fortunately there was no one near the facility when it failed and there were no injuries.

The Province of Alberta also issued a report “ERCB Staff Report Joslyn Steam Release 2010-02”¹³. The following has been extracted from the report:

The steam release occurred near the heel of the first well pair in pad 204 (well pair 204-IIP1), and caused a surface disturbance about 125 metres (m) by 75 m, with rock projectiles travelling up to 300 m horizontally from the main crater and a plume of dust about 1 kilometre long stretching to the southwest of the release point. There was no loss of life or injury, and there were no harmful gaseous emissions.

The wellpair that failed and three adjoining well pairs were lost. Since this time the project has been abandoned. Two pictures have been extracted from the report as shown in Figure 18. The ERCB report was based on a significantly more detailed report prepared by Total¹⁴.

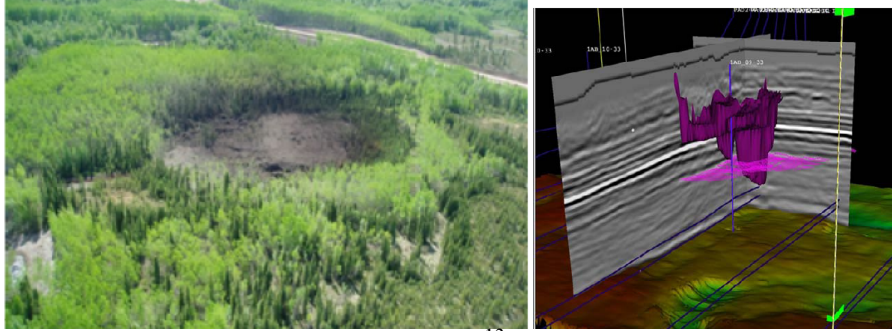


Figure 18 The crater from the Joslyn steam release¹³; and Figure 19 Geophysical interpretation made by Total of Joslyn steam release¹⁴

The report prepared by the operator and reviewed by the ERCB concluded that caprock failed in shear as the result of upward migration of pressure. This result is not consistent with combined reservoir simulation / geomechanical models prepared by the author. Condensation induced water hammer was not considered at the time as a possible failure mechanism. The pressure required to hydraulically fracture the oil sands is considerably below the pressure required to burst line pipe (no slots) as demonstrated by the Christina Lake steam distribution line failure. Note that the Joslyn failure occurred immediately after the circulation phase, in which cold fluids were introduced into the producing wellbore to install a pump. The injector was shut-in while this work was done. There will be a complex interaction between a production well liner and the formation containing the bitumen.

It is interesting to compare the morphology of the dykes in Figure 13 with the morphology derived from seismic shown in Figure 19.

6. Conclusion

The material above has been somewhat simplified. The petroleum industry has not commonly encountered condensation induced water hammer. Steam floods have been implemented in many places, however, the wells were traditionally vertical and this does not lend itself to the conditions for CIWH in the subsurface. Clearly the potential has existed in surface facilities for some time. This has been dealt with empirically using steam traps. The development of horizontal well technology during the late 1980's has changed this situation and the use of SAGD has introduced steam and horizontal wells together.

Complete understanding of CIWH is relatively recent, it did not occur until the early 1980's as a result of a series of events in the nuclear power industry and the research done at MIT by Bjorge¹³. This work was also subsequent to the geysering models that were created as part of the UTF project. The nuclear industry has responded with a series of guidelines and monographs, as well as the development of some sophisticated software such as RELAP, Cathare and WAHA⁹⁻¹¹.

The Joslyn failure is troubling in that it could easily be initiated by condensation induced water hammer. There have also been some serious surface facility failures as a result of CIWH, with very damaging results. U.S. regulatory experience from the web indicates that CIWH remains one of the most significant safety issues for the nuclear industry¹⁶⁻¹⁸.

Part of the intent of this paper is to provide some interesting information to those in a related energy industry. However, the author is also hoping that the expertise that has reached a high level of development within the nuclear industry can be adapted to the requirements of the in situ oil sands industry. Hopefully I piqued some interest¹⁹ to some of those researching and developing software for thermalhydraulics.

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