Hot Water Vapour Process (HWVP)

Field Trial Project

Final Report

December 13, 2013

Executive Summary

The HWVP technology is a new thermal EOR method for producing incremental oil from a depleted CHOPS reservoir. This is a cyclic technology that consists of an injection phase utilizing hot water vapour and a non-condensable gas (NCG) such as Nitrogen. Once a desired reservoir pressure has been reached, the well is placed back on production utilizing conventional pumping methods.

During the injection phase of this project a downhole pressure of 3,269 kPa was achieved after injecting 487 e^3m^3 of Nitrogen and 85.1 m^3 water. A maximum downhole temperature of 136°C was achieved. A soak period took place, to allow the well to cool slightly in order to run production equipment. Once the well was placed on production it produced an incremental 147 m^3 oil (925bbls), 144 m^3 water (902 bbl), and 13 m^3 solids. A total of 27% of the injected Nitrogen was recovered.

During the production period, the well suddenly lost inflow and despite numerous well interventions inflow could not be regained. As a result of the loss of inflow the test was ended. This process was shown to be capable of producing incremental oil volumes. However these volumes were not large enough to be able to claim that it is currently commercially viable.

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History of HWVP Technology Project

The Hot Water Vapour Process was first proposed in a report issued by PTAC (Petroleum Technology Alliance Canada) in 2008 and titled "Novel Low GHG Heavy Oil Recovery Process". The report describes the opportunity and technical challenges of increasing heavy oil recovery in the Lloydminster are oil fields. After reviewing a number of potential enhanced oil recovery approaches that had or could be tried, the report suggests designing and testing a novel EOR process that was called at the time "Flue Gas and Steam Stimulation". The process has since been re-named HWVP and was further described in subsequent PTAC reports to industry sponsors.

In 2010 a consortium was put together to field test the HWVP technology. In 2011 the consortium was finalized and funding agreements were signed. The consortium consists of: PTAC, PTRC (Petroleum Technology Research Centre), Devon Canada, and Husky Oil Operations Limited (Husky). Husky was thereafter retained as the main contractor for the project.

In March 2011 the well (10-04-050-24W3) was selected for the field test. Construction of the facility began in October 2011. First injection into the well was on March 21, 2012. The production phase for the first cycle started on July 13, 2012 and ended on December 22, 2012.

Thermal Technology in Heavy Oil

In the oil sands and in some other heavy oil formations, high temperature and pressure steam is injected into the reservoir to heat the oil and decrease the viscosity of the oil. Examples of such processes are Steam Assisted Gravity Drainage (SAGD), Cyclic Steam Stimulation (CSS) and steam floods. However, the injection of high temperature and pressure steam would not be optimal for the majority of Lloydminster oil formations due to the following considerations:

- Most Lloydminster reservoirs are relatively thin (less than 5 m)
- High pressure steam in thin payzones will present the risk of steam quickly escaping the reservoir into the overburden
- High temperature steam in thin payzones will result in unacceptable heat losses to the overburden and the underlying formation;
- Due to the high heat losses, a thin payzone will not support the high costs of building a steam plant and steam distribution network
- In order to minimize cost as much as possible there is a large incentive to use existing wellbores for an EOR process instead of incurring the cost of drilling new ones. Existing wellbores have not typically been thermally completed and are therefore not suitable for standard applications of high temperature and pressure steam.

Basic HWVP Technology Overview

In thin heavy oil producing areas there is no proven enhanced oil recovery technology. In the Lloydminster area most of the heavy oil production uses a process known as CHOPS (Cold Heavy Oil Production with Sand). The CHOPS process encourages the production of sand from the reservoir which results in streaks of high permeability in the reservoir which are commonly referred to as wormholes. The CHOPS process has allowed for greater economic production in the region, but it is generally accepted that only 10% of the PIIP (Petroleum Initially In Place) will be recovered. As a result new technologies are required to increase the recovery factor in thin heavy oil reservoirs.

The core idea of HWVP technology is the injection of a non-condensable gas (NCG) together with hot water vapour (in other words relatively low temperature and pressure steam) into heavy oil formations. HWVP generates hot water vapour using surface facilities and uses an available NCG (nitrogen for this test) to carry it into the formation. By utilizing the HWVP technology in a CHOPS well, we can take advantage of the wormholes (high permeability trends) in the reservoir to more efficiently deliver the hot vapour deeper into the reservoir. HWVP is therefore a thermal stimulation technology to be used for EOR in heavy oil reservoirs partially depleted by primary recovery. The thermal energy is conveyed to the reservoir by the enthalpy of evaporation of the water vapour. This thermal energy raises the temperature of the stimulated zone and reduces the heavy oil viscosity.

A non-condensable gas is required to carry the water vapour as the temperature/ pressure operating envelope is outside the steam envelope. The non-condensable gas has the added benefit of raising the currently depleted reservoir pressure towards initial reservoir conditions. The combination of hot water vapour combined with a non-condensable gas as an injection fluid has not been previously used. The injection fluid will provide incremental oil as this technology is to be used with wells which have no remaining primary reserves.

In HWVP, the thermal fluid injected into the reservoir is not steam but hot water vapour. Steam is a fluid entirely composed of water in the vapour state. Hot water vapour is water in the vapour state but carried by another gas. In other word, HWVP involves the injection of a hot gas (e.g. methane or nitrogen) saturated with water vapour. Steam and hot water vapour are chemically and thermodynamically identical and will carry the same amount of thermal energy into the reservoir.

The use of hot water vapour instead of steam reduces the temperature and pressure of the injection fluid. Therefore, hot water vapour can be injected under milder temperature and pressure conditions, allowing the use of existing wellbores and avoiding breakouts and excessive heat losses in the reservoir.

Figure 1 illustrates the difference between steam and hot water vapour. The operating limit of thermal injection using non-thermally completed wellbores is estimated at 140°C and pressure between 500 and 3,000 kPa. The steam curve does not pass through these conditions and any attempt at injecting steam would result in the injection of hot liquid water. It should be noted that hot liquid water is not an efficient thermal fluid because most of the thermal energy is associated with vaporization. For the same reason, a hot dry case is also not an efficient thermal fluid. The mixing of steam with a NCG shifts the effective steam curve to the left and allows it to pass through the operating envelope. Thus, with HWVP, it is possible to inject water in a vapour state at mild conditions and carry the thermal energy of the heat of vaporization into the reservoir.

For example, injection of 12,300 standard m^3/day (435,370 standard ft^3 /day) of dry gas at 140°C and 1,000 kPa will carry 1.9 GJ per day. Saturating this gas with water vapour will increase its thermal carrying capacity to 16.4 GJ per day. The additional energy is contained in the 5.3 tonnes per day of water vapour carried by the gas.

The amount of water vapour that can be carried by a hot gas depends primarily on pressure. The higher the pressure, less water vapour is carried. In the above example, if the gas pressure is doubled to 2,000 kPa, only 7.6 GJ per day would be carried by the gas (2.1 tonnes per day of water vapour). While it will be desirable to operate at low pressures, injection pressure will be controlled by reservoir injectivity. Injection pressure will likely start low and increase during the course of an injection cycle.

Figure 1: Water Vapour and Steam Comparison

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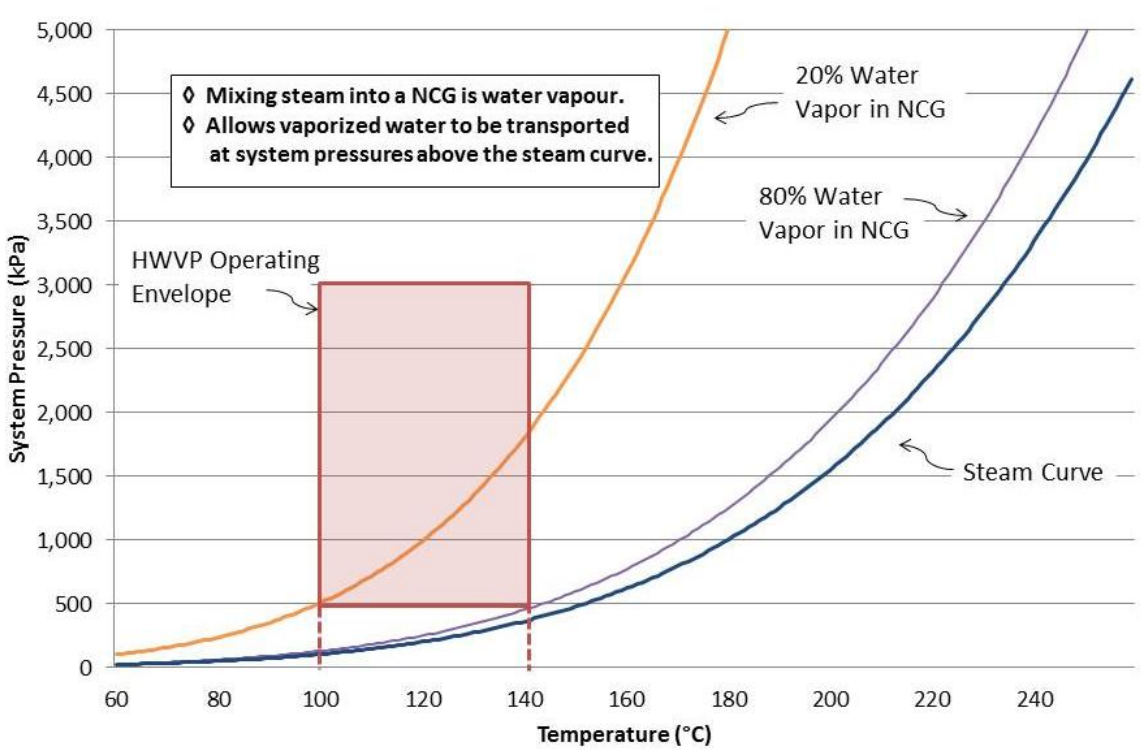


The co-injection of the NCG with hot water vapour will increase reservoir pressure and provide motive energy for pushing oil to the wellbore. Heating the oil simply reduces its viscosity and makes it easier to flow. However, a hydraulic force needs to be applied for flow to take place. In some cases, existing reservoir pressure may be sufficient. However, many Lloydminster reservoirs under primary production are pressure depleted and a new source of pressure needs to be put in place for economic production rates to happen.

Project Site Overview

The well that was selected for the testing of the HWVP technology is located at 10-04-050-24W3M. The well was rig released on January 3, 1997. It was initially completed in the GP and then Sparky formations prior to being completed in the McLaren formation, which is the formation that was tested with the HWVP. Table 1 below details the reservoir parameters for the McLaren formation in the 10-04-050-24W3M well.

Table 1: Reservoir Data for Husky Big Gully 10-4-50-24

Well	11/10-04-050-24W3/C
Formation	Lower McLaren
Net Thickness	1 m
Porosity	33%
Sw	25%
OOIP (1 LSD)	39,600 m^3
OOIP (9 LSD) – 1 Lsd surrounding 10-4	475,200 m^3
Initial Reservoir Pressure	3,500 kPa – average for area
Reservoir Pressure at end of Primary Production	1000 kPa

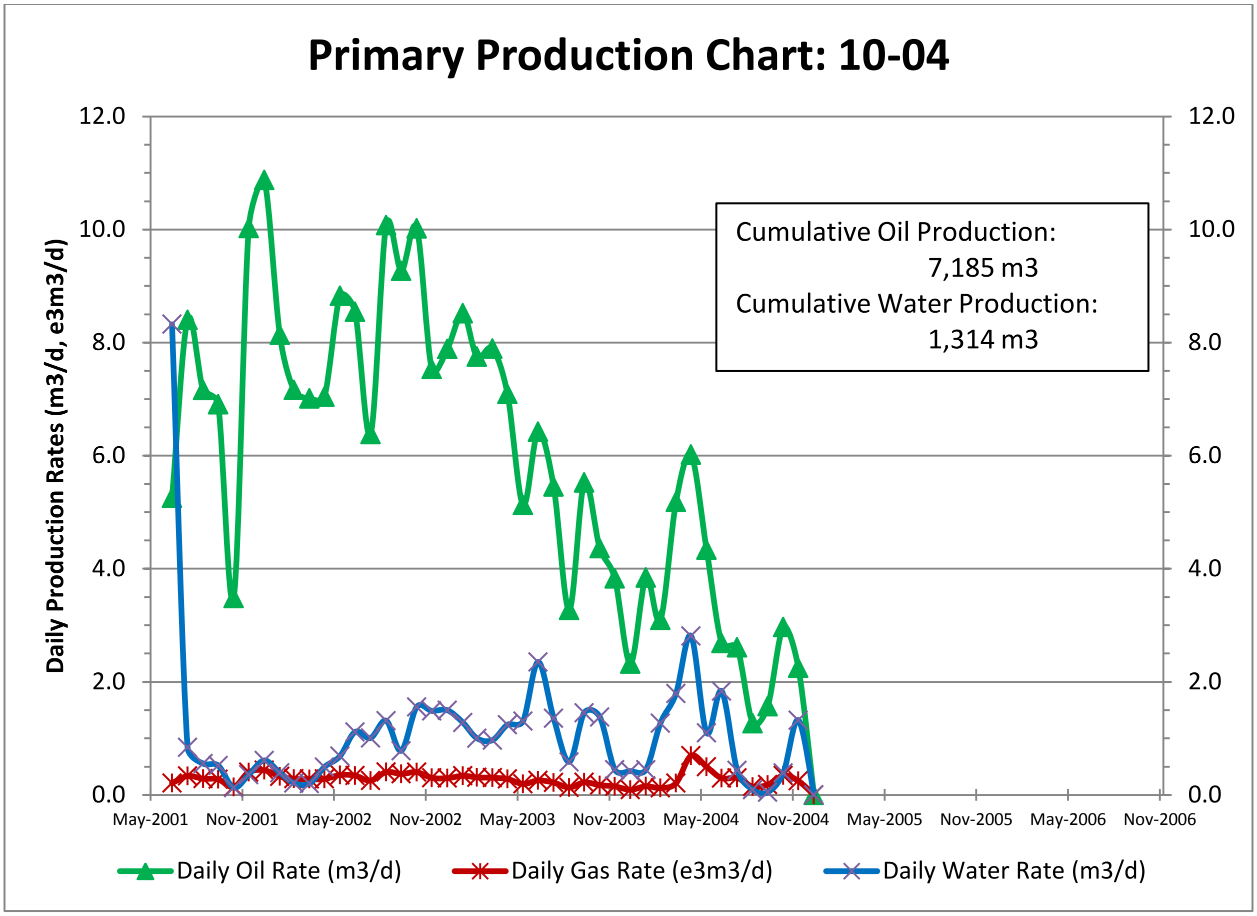
The fluid properties of the reservoir are included in Table 2.

Table 2: Fluid Data for Husky Big Gully 10-4-50-24

Well	11/10-04-050-24W3/C
Formation	Lower McLaren
Density @ 15 °C	977.8 kg/m^3
Density - API	13.1° API
Viscosity @ 20 °C	7,710 cP
Viscosity @ 50 °C	557 cP

In July 2001 11/10-04-050-24W3 was completed in the McLaren formation. Initial rates from the McLaren were: 8.4 m^3 opd and 0.9 m^3 wpd. 11/10-04 continued to produce from the McLaren formation until December 2004. The well was then shut-in after cumulative production of 7,185 m^3 oil and 1,314 m^3 water from the McLaren. Final rates (3 month average) at shut-in were 2.2 m^3 opd and 0.4 m^3 wpd. A plot of the primary production rates for the McLaren is shown in Figure 2.

Figure 2 : Primary Production Chart



Surface Equipment Design

The surface facility that was put in place for the HWVP test consisted of a number of pieces of equipment. The general process flow of the equipment is shown on the following page in Figure 3 along with a picture of the equipment in the field in Figure 4. Fresh water was brought to site from one of Husky's thermal projects and stored in a 1000 bbl tank where it was pre-heated. A Husky owned Nitrogen Generation plant was on site and produced Nitrogen through a membrane technology. The pre-heated fresh water and Nitrogen were mixed in a static mixer and then sent through a line heater to bring it up to temperature (120 – 140 °C). The heated water vapour and Nitrogen mixture was then sent through a water separator where liquid water was removed and sent back to the storage tank for later use. The hot water vapour and Nitrogen was injected into the well.

During the production phase of the HWVP test, the surface equipment used consisted of a typical heavy oil single well battery. This included a hydraulic pumping unit and single production tank. A small pop tank was placed in-line with the gas vent to ensure no liquids were discharged with the produced Nitrogen gas.

Figure 3 : General Process Flow

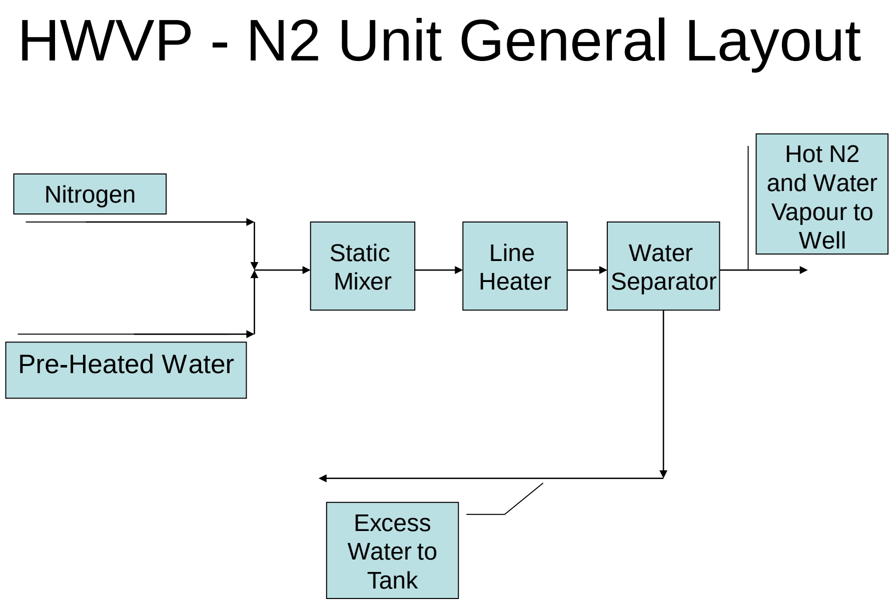


Figure 4 : Site Photo

Wellbore Design

One of the key goals for the HWVP is to utilize existing wells in a safe manner. The use of existing wells allows the HWVP technology access to the high permeability trends as well as making use of an existing asset. To that end further research was conducted into using heat in standard CHOPS wells.

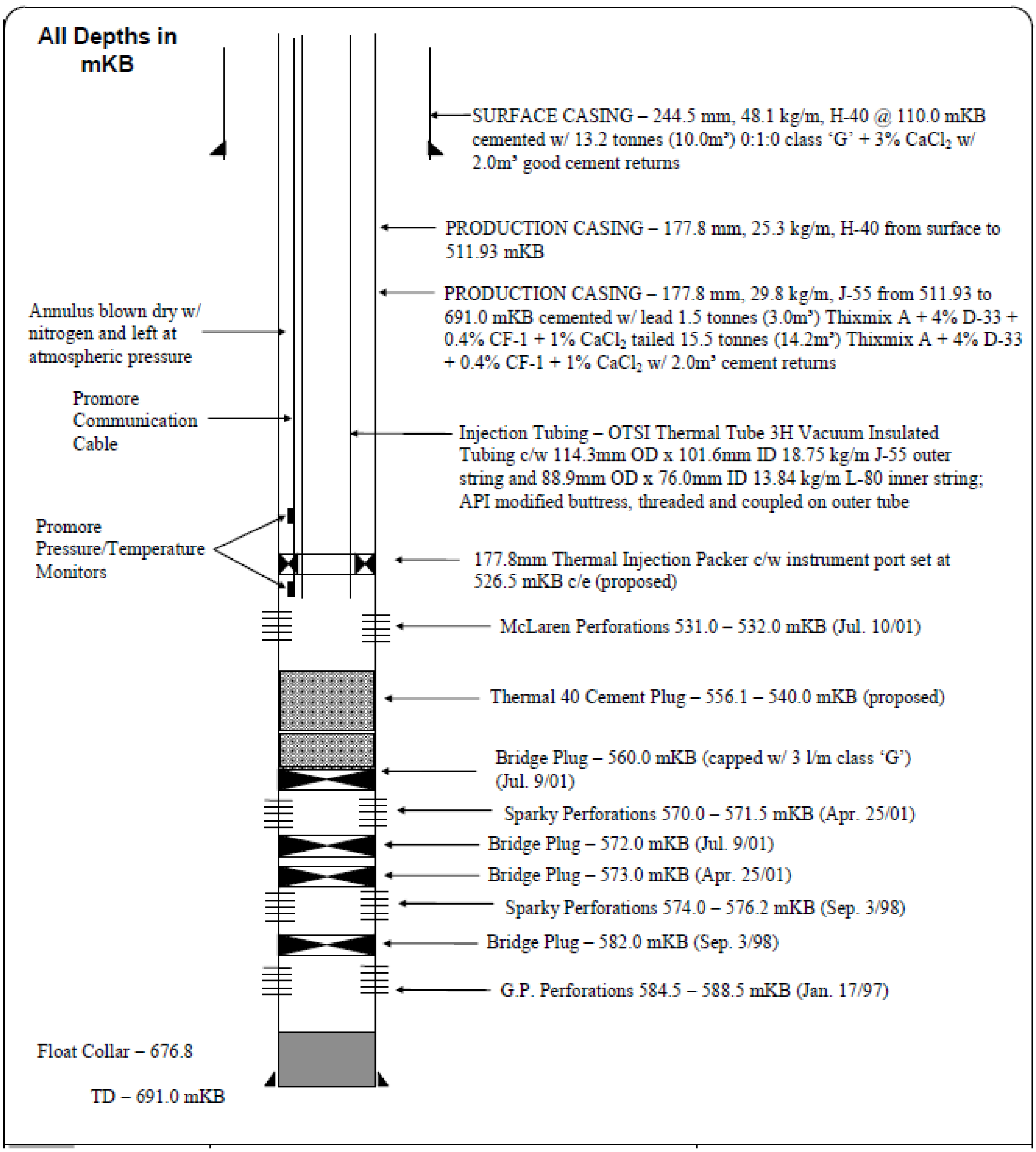
In order to understand the effects of heat on industry standard CHOPS well casing C-FER technologies was contracted to perform structural analyses on standard API ST&C casing connections. This report was previously distributed to member so the HWVP consortium. For a standard CHOPS well the temperature limit for casing with H40 pin with J55 coupling is 53°C.

In order to ensure that the casing temperature does not exceed it thermal limits various protective measures were investigated. The use of insulated tubing with a thermal packer during injection was determined to be a suitable means of keeping the casing below its thermal limits. Thermal modelling conducted by SimCal Consutling showed that after 10 days of injection at 200°C the casing was kept to a temperature of 41°C.

Additional measures were undertaken to protect the wellbore. These included setting a plug of thermal cement on top of the existing bridge plug to ensure that lower formations are protected from any heat transfer. The wellbore design also included temperature sensors above and below the thermal injection packer. The lower sensor was used to monitor the reservoir temperature. The upper sensor was used to monitor the temperature of the annular space between the casing and tubing. A schematic of the wellbore design is shown in Figure 5.

After the injection phase of the test was completed the reservoir temperature was monitored to determine the appropriate time to remove the injection equipment. Once the temperature had decreased to a safe level, the insulated tubing and thermal packer were removed from the wellbore. A conventional string of tubing was run in the well with a progressive cavity pump. One set of temperature and pressure sensors were run into the hole to monitor wellbore conditions.

Figure 5 : Downhole Equipment Schematic

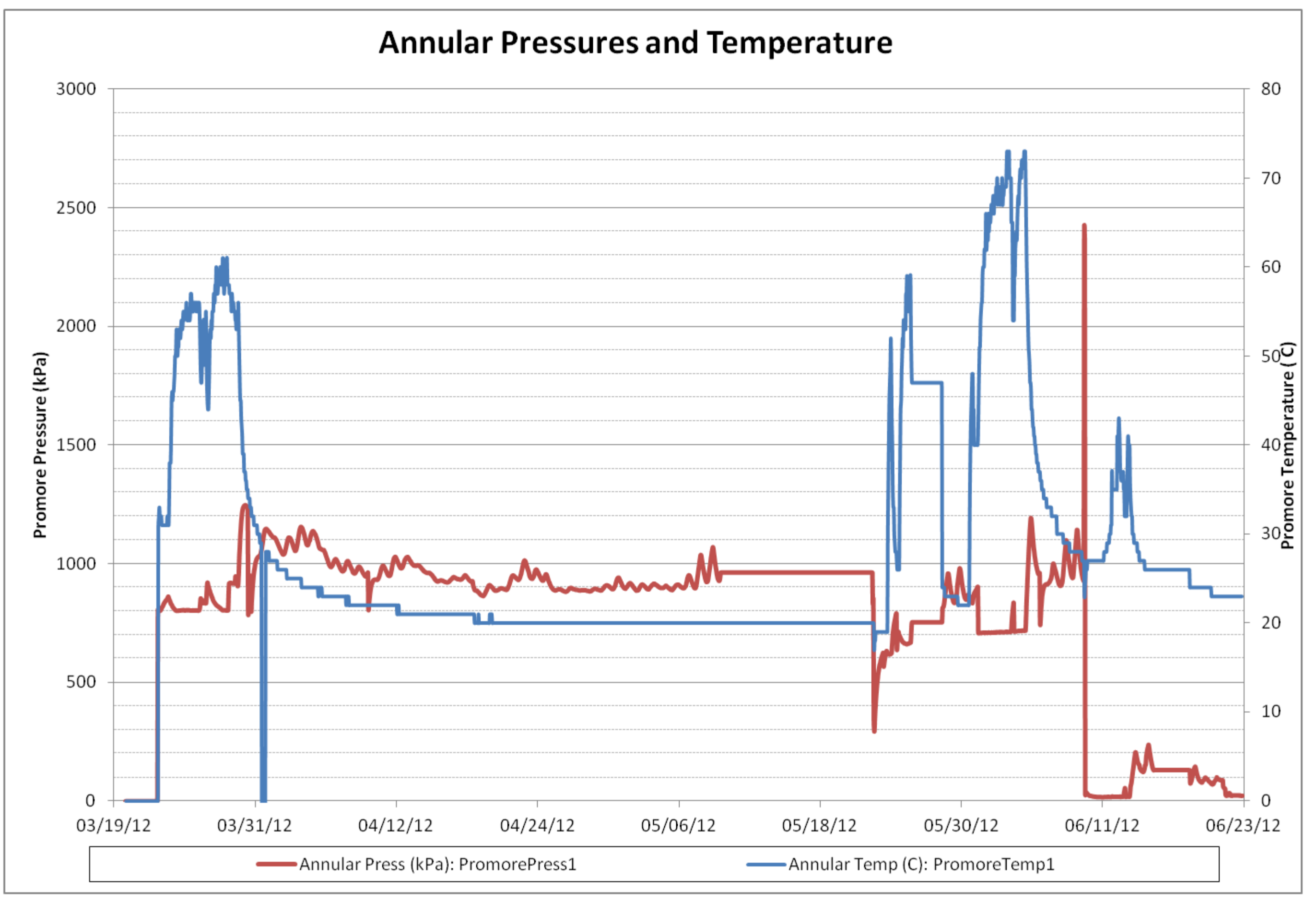


Injection Phase

The initial injection cycle began on March 21, 2012. Initial injection rates were set at 23 e3m3/d Nitrogen, 2.5 m3/d water, at a line heater temperature of 185 °C. The well was responding as expected (annular pressure and temperature were slightly elevated) when injection had to be shut down due to a vibrational issue in the surface equipment on March 29, 2012. A decision was made to shut down injection until this issue was resolved in order to ensure safe of operational staff and to maintain equipment integrity.

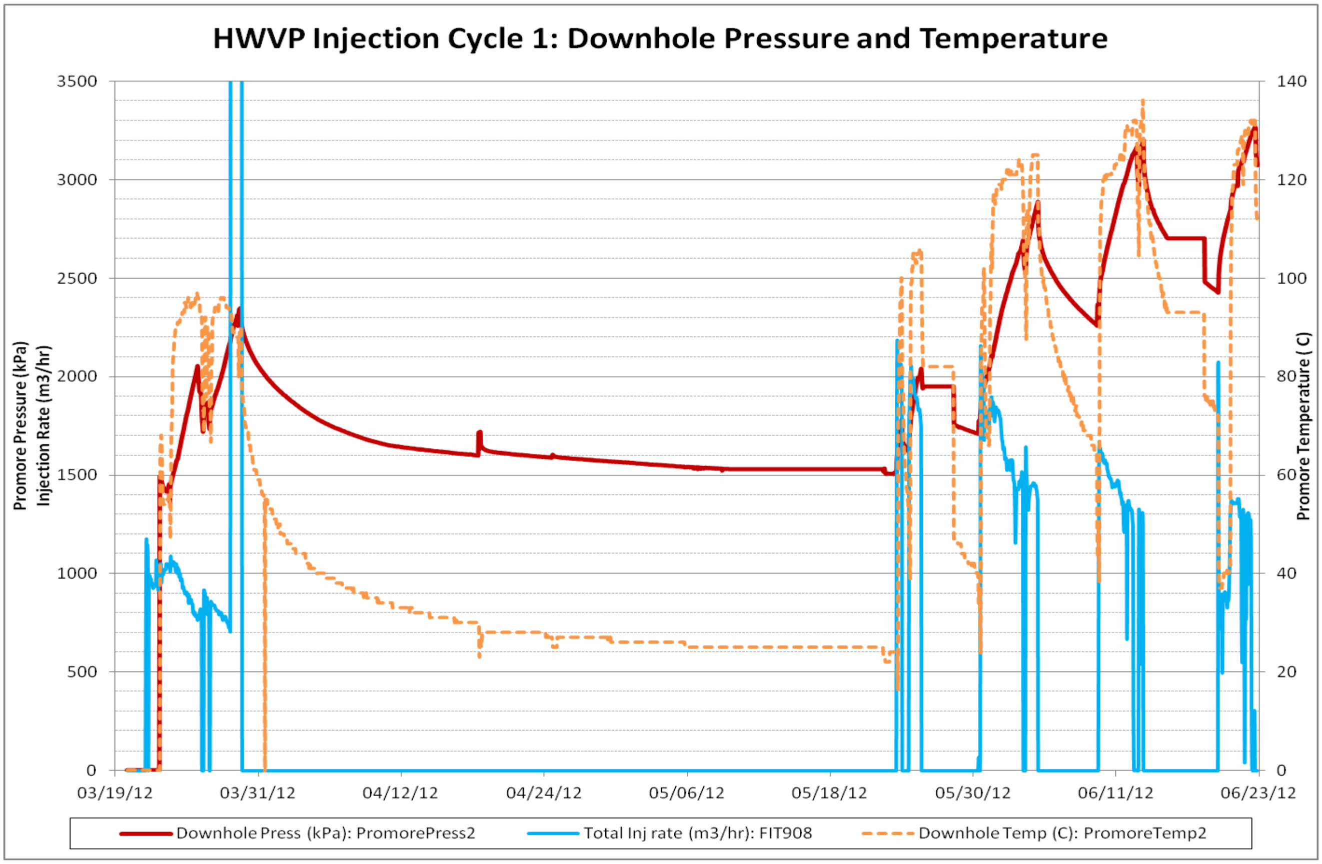
Once the vibrational issue was resolved with the surface equipment, the well was placed back on injection on May 23. During this part of the injection cycle the annular temperature rose quicker than was predicted from the numeric simulations. Work was done to understand this phenomenon and it was determined that a small amount of liquid water was in the annular space. Attempts to blow this water to surface were unsuccessful. A well workover was conducted on June 9 to blow the water into the formation and this drastically reduced the annular temperature for the duration of the injection cycle. The annular temperature and pressure during the injection phase is shown in Figure 6.

Figure 6 : Injection Cycle – Annular Measurements



The injection cycle was completed on June 22, 2012 after having injected 85 m^3 cold water equivalent and 487 e^3m^3 of Nitrogen at an average temperature of 115°C. A maximum downhole pressure of 3269 kPa and a maximum downhole temperature of 136°C was achieved. The downhole temperature and pressure during the injection phase is shown in Figure 7.

Figure 7 : Injection Cycle – Downhole Measurements



Production Phase

After a soak period which allowed the well to cool slightly in order to remove the injection packer. The well was placed on production on July 13, 2012. A conventional PC pump and rod system was installed in the well. At the time production was initiated the downhole temperature was 33 °C.

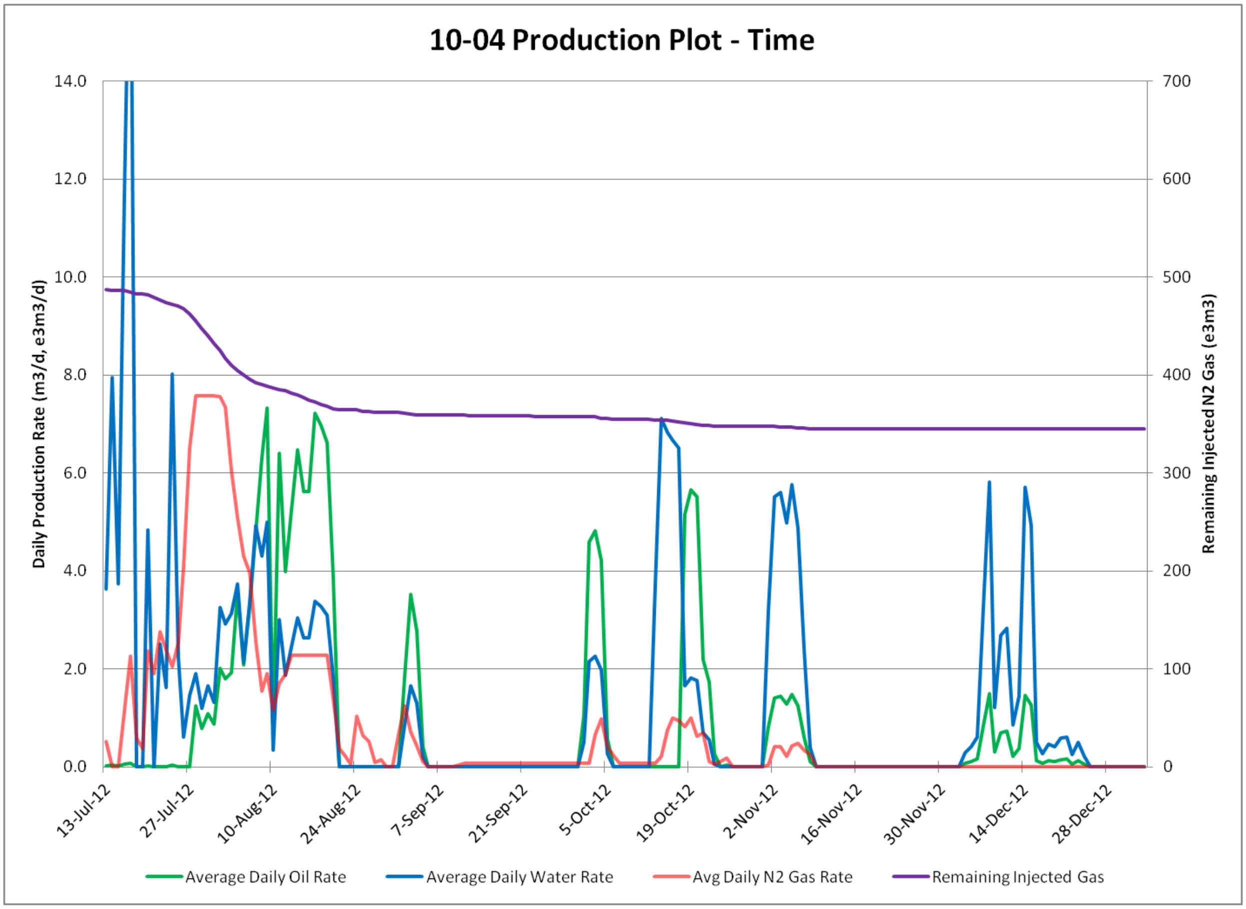
Initial production rates were erratic due to issues with balancing the gas vent rates to ensure fluid in the well. Production was stabilized on July 22 and the well began to produce steadily until August 20. Production had been steadily inclining to a rate of 10-11m^3 fpd with a BS&W of 36%. The net cumulative production was 95 m^3oil and 105 m^3 water. All of the injected water was recovered and approximately 27% of the N_2. On August 20th the well suddenly lost inflow. A number of well interventions were then taken to regain production.

Intervention History

- Following the sudden production decline on August 20th, the well was flushed and then loaded only pumping back the flush and load fluid.
- An injectivity test was conducted the morning of August 23rd to evaluate and attempt to re-establish communication with the reservoir. No surface pressure was encountered during pumping and a downhole pressure of 725 kPa was restored
- The well was re-started August 24th producing back 8m^3 before dropping off again. The well was loaded, flushed and loaded again making back only load fluid before being shut down on August 28th.
- A chemical soak was conducted on August 28th which restored the well to a measured downhole pressure of 856 kPa.
- The pump was started up on August 31st, the well produced fluid until September 3rd when it lost inflow (from 5 m3 fpd to 1 m3 fpd). Total injected volume 7m3 (1 m3 AS1, 6m3 water; total produced fluid 13 m3) Note: downhole pressure rapidly decreased starting at noon on September 2nd. The well was shut-in on September 4th. Shortly after shut-in, the downhole pressure began to rebuild.
- On September 23rd a Gamma Ray log was run to check for potential shale collapse in the near wellbore area. No change on the Gamma Ray was seen on the log. After the log was run, it was decided to do a production test on the well with a rig using a cup-down pump-to-surface configuration in an effort to surge the formation and remove any solids that were blocking the perfs. During surging the rig was getting a solids (sand/clay) cut of ~10% but this dropped back to 2% after a day. Once the PTS began to gas lock it was decided to run back in with a progressive cavity pump and the well was re-started on October 1st.
- The well produced sporadically until November 8th. It netted approximately 25 m3 of production (above load fluid) at a 50% cut.
- One last attempt to regain production was attempted in December 2012. A permanent Pump-To-Surface pumping system was installed on the well. Unfortunately the well was still unable to produce consistently. A decision was made to shut-in the well on December 22nd and to evaluate the potential for a 2nd cycle of injection.

Total net production from the 1st phase of the HWVP project was 147 m^3 oil (925bbls), 144 m^3 water (902 bbl), 13 m^3 solids, and 142 e^3m^3 N_2. Figure 8 shows the well production during the production phase.

Figure 8 : Production Cycle – Production over Time



Concluding Comments

The intent of this project was to demonstrate that the HWVP project could recover sufficient incremental oil to be viewed as an economically viable EOR technique. Despite achieving the goal of producing incremental oil (147 m^3) it was not in sufficient volumes during the first cycle to proclaim the process economically viable at this time.

Further work could be done with this technology as there were some positive outcomes from this test. This project showed that:

- Mild thermal processes can be undertaken in non-thermally completed wellbores with the proper downhole equipment
- Incremental oil can be achieved through the HWVP technology. Prior to losing inflow the oil rates were steadily increasing and came close to matching the peak rates achieved during CHOPS production.
- Production during the HWVP is quite sensitive to gas rate.

Further testing of this technology will be required to determine ways in which the process can be further optimized.