Final Report

Numerical Modelling of SCV Process — Application in Post-CHOPS Reservoirs

Prepared for Petroleum Technology Alliance Canada (PTAC)

By Zhiguo Wang and Muhammad Imran
Energy Division/EOR Field Development

REPORT

SRC Publication No. 13849-1C15

November 2015

129 – 6 Research Drive, Regina, SK, Canada S4S 7J7

Disclaimer

This report was prepared by the Saskatchewan Research Council (SRC) for the sole benefit and internal use of Petroleum Technology Alliance Canada (PTAC). Neither SRC, nor any of its employees, agents or representatives, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, reliability, suitability or usefulness of any information disclosed herein, or represents that the report's use will not infringe privately owned rights. SRC accepts no liability to any party for any loss or damage arising as a result of the use of or reliance upon this report, including, without limitation, punitive damages, lost profits or other indirect or consequential damages. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favouring by SRC.

Abstract: Numerical simulation studies were performed to evaluate the oil recovery potential of a novel process involving cyclic injection of hot steam and flue gases generated by a submerged combustion vaporizer (SCV) into reservoirs that had undergone cold heavy oil production with sand (CHOPS). SRC's wormhole model and CMG's STARS reservoir simulator were used to history match the CHOPS process and generate wormhole networks. The history-matched reservoir model was then used for the post-CHOPS SCV process simulation. Simulation results suggest that injecting hot steam and flue gases generated by the portable SCV unit could boost oil recovery. One simulation showed an increase in oil production of 116% over the CHOPS analogue for one well. Further simulation studies are recommended for SCV process optimization and development; and some recommendations are also suggested for a future SCV process field trial.

EXECUTIVE SUMMARY

This project was carried out under a contract with PTAC by the EOR Field Development group in the Energy Division of Saskatchewan Research Council between May 2015 and October 2015.

Under this proof of concept project, the potential of using a submerged combustion vaporizer (SCV), or the SCV process, was evaluated by performing numerical simulation studies.

The application of the SCV process is a potentially effective enhanced oil recovery technology for reservoirs after years of operations of cold heavy oil production with sand (CHOPS). In this process, the steam and flue gas mixture is generated on the surface through a compact portable SCV system using the submerged combustion principle; and the steam and flue gas mixture is introduced into the reservoir through a vertical injection well once the portable SCV system is connected to the wellhead. The SCV process typically involves an injection period, a soaking period and a production period. It takes advantage of both thermal and solvent effects (CO_2 and N_2 in flue gases) to enhance oil recovery.

In this simulation study, a field-scale reservoir model with seven vertical wells and with dimensions of 1,207×1,207×6 (L×W×H) meters was used. The reservoir properties were taken from an actual reservoir in western Canada that was undergoing CHOPS. SRC's multi-well CHOPS model was used, together with the Computer Modelling Group's (CMG's) STARS simulator, to history match sand and fluid productions of the CHOPS process and to generate corresponding wormhole networks in the reservoir. The history-matched model with a CHOPS production period of ~3,000 days was then used for the post-CHOPS SCV process simulation.

Multiple cases using the post-CHOPS SCV process up to five cycles (~5.5 years) were simulated using CMG's STARS simulator. Simulation results suggest that the application of the SCV process could substantially boost oil recovery. The best case scenario of the SCV process (Case 12A) produced 24,760 m^3 of oil from Well #4 during a period of ~5.5 years, i.e., 9.18% original oil in-place (OOIP) recovery; and this represented an oil production increase of 116% over the CHOPS-only case. The best case scenario was the one with a maximum injection capacity of ~80% of a 5 MMBtu/hr SCV system for one of the wells, and with an injection period of 30 days, a soaking period of 1 day, a production period of 365 days.

The simulation results suggest that SCV process application is not limited to the suspended CHOPS wells or to the reservoirs which are completely pressure depleted. Even if this process is applied to the CHOPS reservoirs that are still producing, the potential oil recovery from SCV could be much more attractive than the CHOPS pressure depletion.

The SCV process simulation for a period of ~5.5 years was conducted for evaluation purposes only. The injection and production cycles of the SCV process can be extended for many more years that would result in higher %OOIP recoveries than calculated for 5.5 years. Further simulations will be required to estimate the process performance for extended production.

ACKNOWLEDGMENTS

The authors want to express their sincere thanks to PTAC for its financial support of and participation in this project.

PROJECT TEAM

Muhammad Imran, MASc, P. Eng., Business Unit Manager
Zhiguo Wang, PhD, P. Eng., Research Engineer

TABLE OF CONTENTS

List of Tables

Page

LIST OF FIGURES

1. BACKGROUND AND OBJECTIVES

1.1 Background

Cold heavy oil production with sand (CHOPS) is a non-thermal process in which heavy oil is produced from unconsolidated sand reservoirs through pressure depletion. A characteristic of this process is that sand is produced along with oil, water, and gas, thus leaving behind open channels – referred to as wormholes – and dilated halos around them. The wormholes can have diameters ranging between 1 and 10 cm. The surrounding halo structures can have diameters of up to 1 meter, an enhanced porosity of 5 to 15 units higher and an enhanced permeability of 1.5 to 3 times higher compared with the original reservoirs. During the CHOPS process, a network of wormholes is created within the reservoir and can often intersect with high water saturation zones or pressure-supported aquifers, resulting in diminished oil production and leaving behind 85 to 90% of the original oil in place (OOIP). Currently there are more than 10,000 suspended CHOPS wells in western Canada. These CHOPS reservoirs offer the opportunity for the application of potential enhanced oil recovery (EOR) methods to recover these tremendous oil volumes left in the reservoirs.

FERST-CSI Technologies Inc. (Calgary, AB) developed the concept of using a submerged combustion vaporizer (SCV) for enhanced oil recovery from depleted heavy oil reservoirs through suspended CHOPS wells. As the foundation of the SCV application process (or SCV process), a compact portable SCV system uses the submerged combustion principle to generate steam and flue gases on the surface; the mixture of steam and flue gases is then injected into the reservoir once the portable SCV system is connected to the wellhead. The SCV process typically involves an injection period, a soaking period and a production period; and it will take advantage of both thermal and solvent effects (carbon dioxide and nitrogen in the flue gases).

There are several advantages of using the SCV for the steam generation:

1. Combustion energy that is normally wasted through the emission of hot flue gases could be exploited through the co-injection of steam and hot flue gas; as a result, high energy efficiency could be achieved.
2. While steam serves as the major heat-carrying medium, CO_2 and N_2 (flue gases) serve to repressurize the reservoir and provide a blanket against heat loss to the overburden, which is a problem for most thermal processes in thin Lloydminster-type heavy oil reservoirs. In addition, CO_2, and to a small extent N_2, provides the additional benefit of reducing the oil viscosity by dissolving in the heavy oil.

3. No water treatment is required for the steam generation. The SCV is not prone to scaling or fouling; therefore, produced water could be directly reused for the steam generation.
4. The SCV system can be made compact enough to fit in a truck, to be portable, and to allow quick and cheap redeployment.

Based on certain assumptions, FERST-CSI Technologies Inc. estimated a voidage of 13,300 m^3 left in the reservoir by a typical mature CHOPS well. It was also estimated that a 5 MMBtu/hr SCV system operated at its designed capacity for 30 days could produce sufficient fluids to repressurize the above-mentioned reservoir voidage up to 3,300 kPaa, and increase the oil temperature by 45°C. The authors suggested that with this temperature increase, the viscosity of the dead oil would be reduced by a factor of 40 to 100. In addition, the dead oil viscosity could be further reduced due to the dissolution of CO_2.

Based on certain assumptions, it was also estimated that an incremental of 50,000 barrels of oil could be recovered over a period of one year (FERST-CSI Technologies Inc. 2014).

The above estimates were very attractive; however, they were very rough, since the oil recovery was based on many assumptions, especially the assumption of producing all the heated oil. Therefore, it is very important to test the proof of concept of injecting the mixture of steam and hot flue gases into a depleted reservoir and evaluate the increase in the reservoir temperature and pressure, along with the oil production rate and recovery factor.

Numerical simulation is the best tool for proving the concept of an EOR process without the risk of incurring a large expense for testing the process in the field. This work investigated the potential applications of the SCV process in depleted CHOPS reservoirs through proof-of-concept numerical simulation studies.

1.2 Objectives

The overall objective of this study is to help the oil industry to develop a post-CHOPS EOR process that can potentially be applied to CHOPS wells that possibly connect with fully developed wormhole networks. These wells and wormholes provide access to the reservoir, and offer huge savings on capital costs. A robust and economically feasible EOR process is the key to reactivating these suspended wells and generating billions in revenue from the remaining oil in place left in CHOPS reservoirs: the SCV process could be such a potential EOR technology.

The specific objectives of this study were to evaluate the recovery performance of the SCV process applied to CHOPS-depleted reservoirs (with wormhole networks) with defined injection, soaking and production periods using the proposed 5 MMBtu/hr SCV system.

The primary technical objectives were to perform the following two tasks:

Task 1 – CHOPS Wormhole Modelling: Numerically simulate the wormhole network for a post-CHOPS reservoir for which the reservoir petrophysical and fluid properties are available. Build a reservoir model with L×W×H of 1,207×1,207×6 meters and seven vertical wells; history match the oil, water and sand productions during the CHOPS process; tune the CHOPS model and generate a wormhole network using SRC's multiwell CHOPS model and CMG's STARS simulator.

Task 2 – Post-CHOPS SCV Process Modelling: Use the history-matched CHOPS model results up to 3,000 days (from Task 1) and simulate the SCV process performance for five cycles (~5.5 years) with defined injection, soaking and production periods. Also investigate the wellbore casing temperature with vacuum-insulated tubing (VIT) as the high temperature fluid injector, and investigate the possibility of using a cooling fluid to control the wellbore casing temperature below 60^{o}C.

The following sections of the report present the detailed results for each of the tasks summarized above.

2. TASK 1 – CHOPS WORMHOLE MODELLING

2.1 CHOPS Reservoir Model

Under this task, a numerical model was developed to simulate the wormhole network for a Lloydminster post-CHOPS reservoir with dimensions of L×W×H of 1,207×1,207×6 meters **(Fig. 2.1)** and equipped with seven vertical wells separated by ~40 acre spacing **(Fig. 2.2)**. This typical reservoir was selected because SRC had access to ~2,000 days' production data for each of these wells for oil, water, gas, and specifically, sand. The actual physical data were used for the numerical model to generate the wormhole network associated with each vertical well. This tuned model was then used to predict the fluid production and wormhole networks for an additional 1,000 days; the objective was to generate wormhole networks, and oil, water, gas and sand distributions for a CHOPS operation period of ~3,000 days. It was postulated that 3,000 days of CHOPS operation would provide sufficiently long wormholes that would provide access to the majority of the reservoir.

The history matching or the tuning of the numerical model was done by using SRC's multiwell CHOPS model and CMG's STARS simulator. The size, length and placement of the wormholes and the sand production were estimated from SRC's CHOPS model, and the fluid productions were estimated from the STARS simulator. SRC's multiwell CHOPS model can generate a maximum of eight wormholes branching off a vertical well at 0, 45, 90, 135, 180, 225, 270, and 315 degrees on each layer along the K direction (thickness of the reservoir). The pressure at each wormhole tip is calculated at each time step, which determines the growth rate of the wormhole branch. The technical details of SRC's wormhole model can be found elsewhere (Tremblay et al. 1997; Tremblay 2005, 2008, 2009a, 2009b).

The following procedures were followed to perform the CHOPS modeling and tune the numerical model:

1. Both the SRC CHOPS model and CMG's STARS reservoir model were set up using the parameters listed in **Table 2.1**.
2. The SRC CHOPS model was run and the sand production was matched mainly by adjusting the wormhole diameters.
3. Once a reasonable history match of sand production was obtained, the data file prepared for STARS in the first step was then updated through the SRC CHOPS model interface, with all well information coming from the simulation results of the SRC CHOPS model.

4. The updated data file was then run in CMG's STARS simulator, and the oil and water productions were simulated and matched by adjusting the k_r curves.
5. The SRC CHOPS model was run again with changes in k_r curves. The sand production was again history matched by adjusting the wormhole diameters. Once a reasonable history match of sand production was obtained, the data file used by STARS was updated again.
6. Steps 4 and 5 were usually repeated many times before reasonable history matches of oil, water and sand production were achieved.

Note that the initial model permeability, oil and water saturations were estimated from well log data.

Table 2.1—Major Model Parameters

Parameters and Units	**Value**
Porosity (%)	33
Permeability (μm^2)	0.137~10.85
Initial Water Saturation S_w (%)	15.62~16.10
Initial Model Pressure (kPaa)	3,100
Model Temperature (°C)	15
Dead Oil Viscosity at 15°C and 101.3 kPaa (mPa·s)	~20,575
Dead Oil Density at 15°C and 101.3 kPaa (kg/m^3)	~989
Gas/Oil Ratio at 15°C and 3,100 kPaa (sm^3/sm^3)	~6.8
Model Dimensions, L × W × H (m)	1,207 × 1,207 × 6
Gridblock Size (m) x Number - (I Direction)	1,207 m in Length – 38.93 x 31
Gridblock Size (m) x Number - (J Direction)	1,207 m in Width – 38.93 x 31
Gridblock Size (m) x Number - (K or Well Direction)	6 m in Height – 0.667 x 9
Producer Minimum Bottomhole Pressure (BHP) (kPaa)	316.5

Figs. 2.3 to 2.5 present 3D images of the initial reservoir model permeability, oil saturation and water saturation.

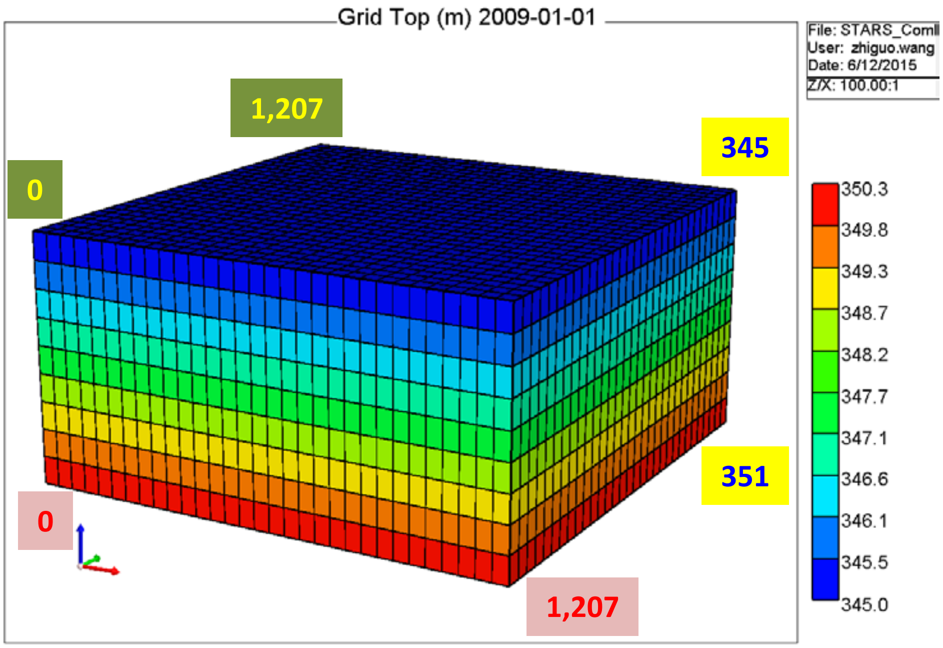


Fig. 2.1—Reservoir model.

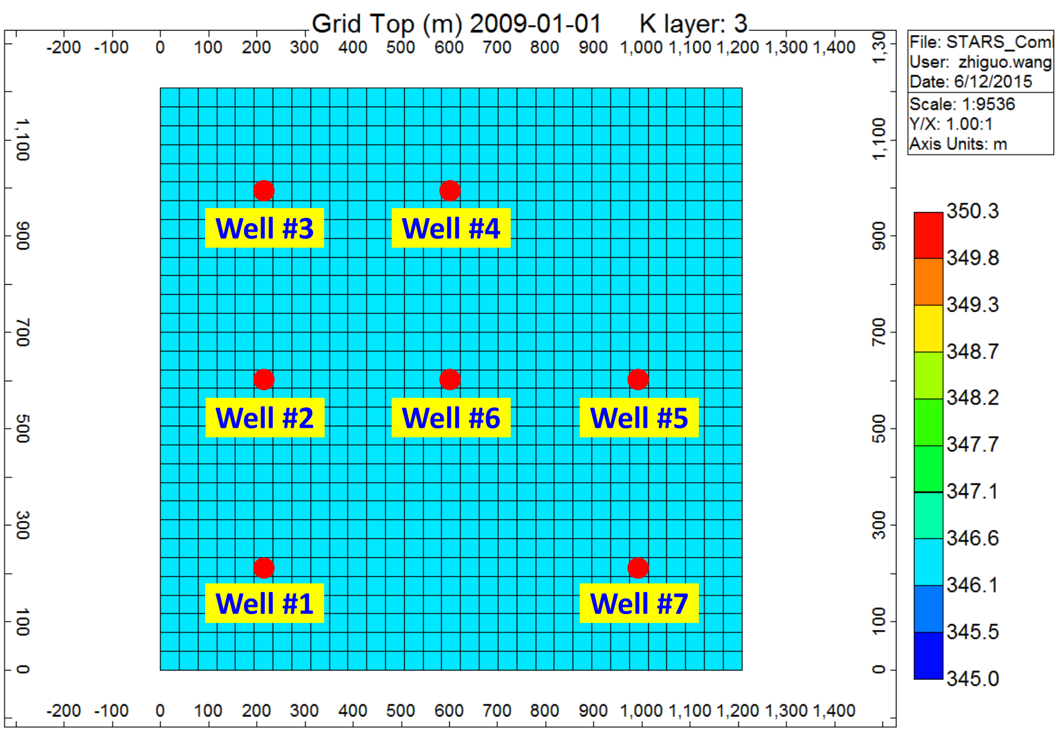


Fig. 2.2—Well locations.

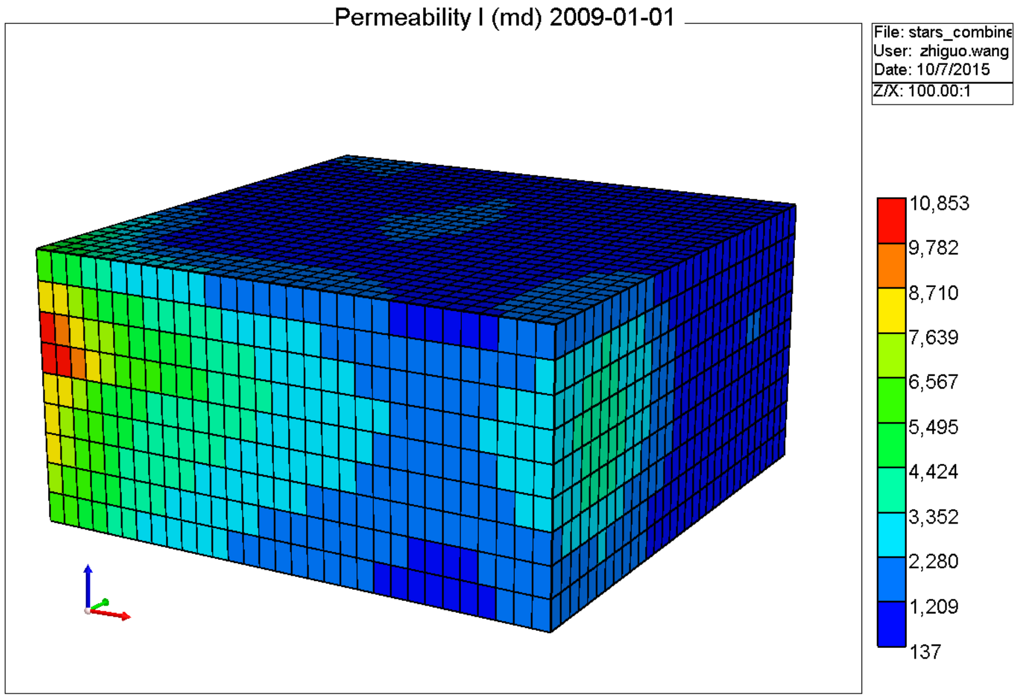


Fig. 2.3—Reservoir permeability distribution.

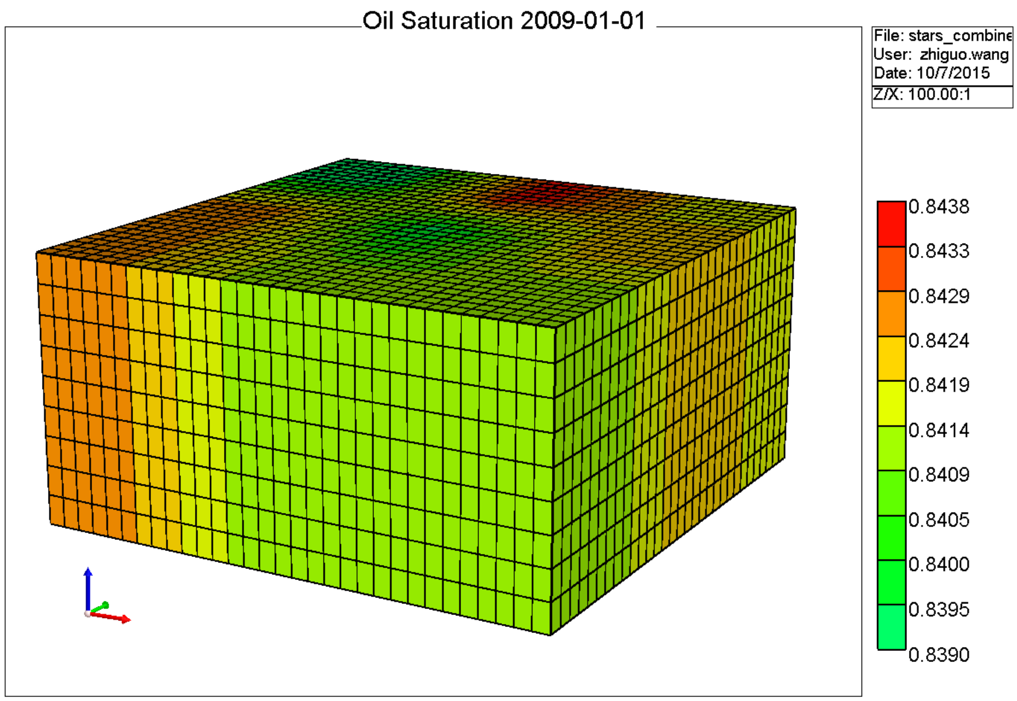


Fig. 2.4—Oil saturation distribution.

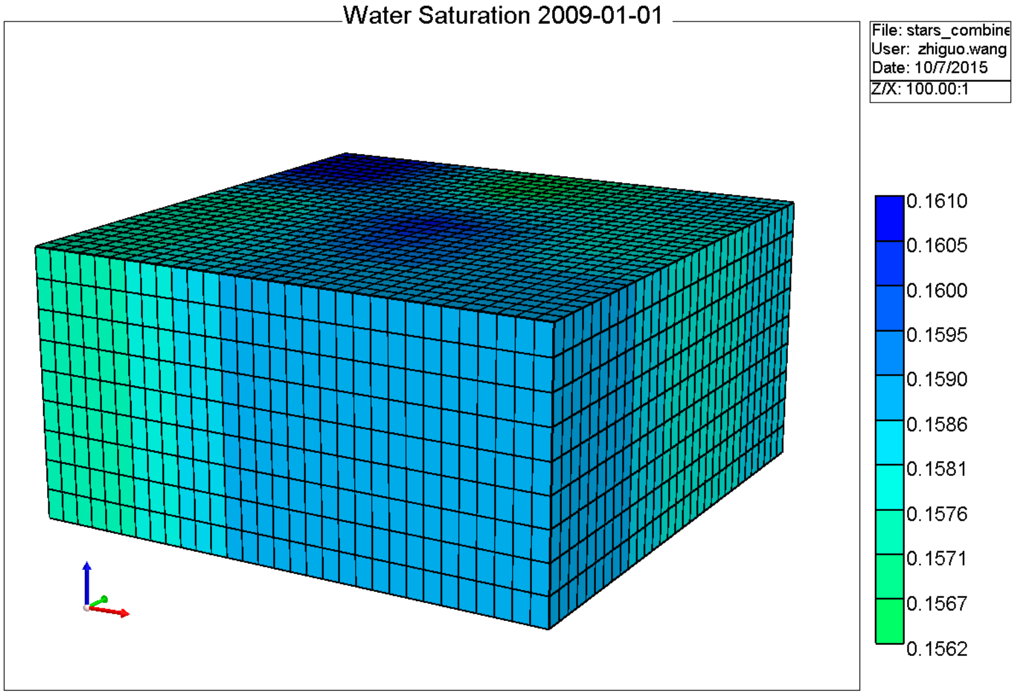


Fig. 2.5—Water saturation distribution.

2.2 CHOPS Modelling Results (Six-Well Case, 3,000 Days)

Since there was negligible fluid and sand production from Well #7, the results for this particular well are not included in the report and analysis.

2.2.1 Tuned Relative Permeability Curves

Figs. 2.6 and 2.7 present the tuned relative permeability curves that provided the best history match of the oil and water production during the CHOPS process simulation. To simulate the foamy oil behaviour during the CHOPS process, a very low gas relative peremability was used in the model.

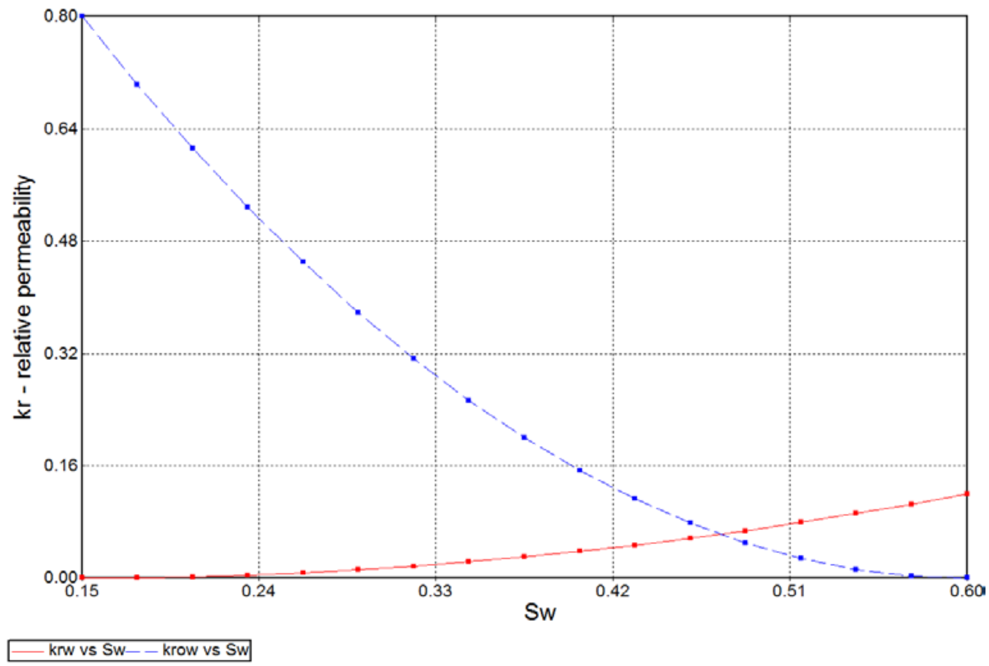


Fig. 2.6—Relative permeability curves for k_{rw} and k_{row}.

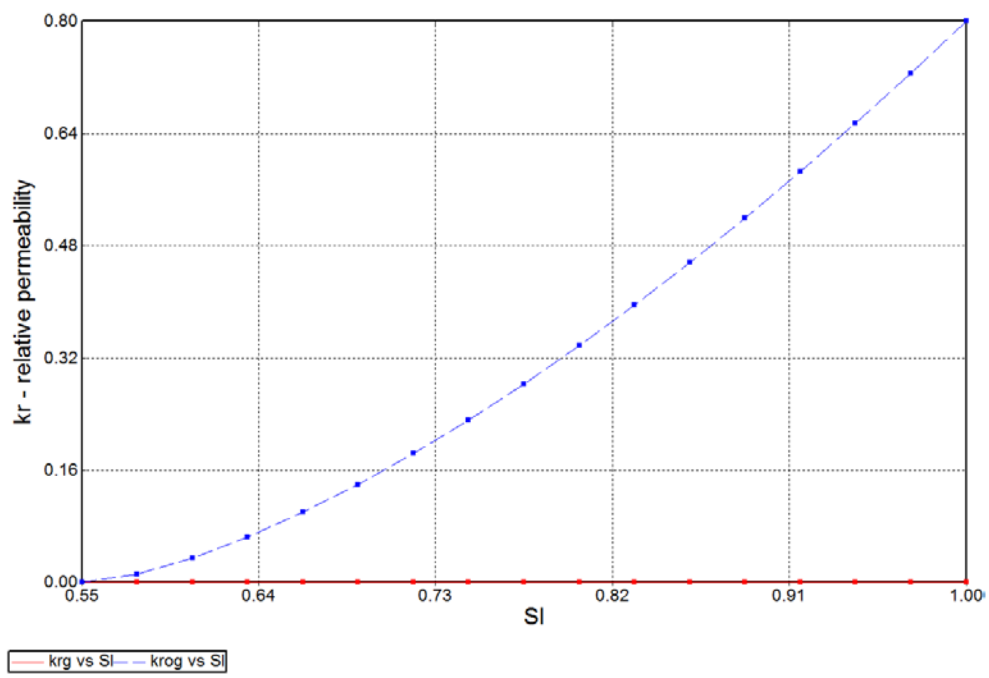


Fig. 2.7—Relative permeability curves for k_{rg} and k_{rog}.

2.2.2 History Matched Sand Production

Fig. 2.8 presents the simulation results for sand production over a period of 3,000 days for six vertical wells. Note that the comparison of the actual data with the simulation results can be done within the first ~2,000 days. Although the simulated sand production for some of the wells showed a bit of deviation from the field data during the first 2,000 days of the CHOPS process, the endpoint sand production for all of these wells was matched fairly well with an overall relative error of 1.4% (1,848 m^3 in the field vs. 1,874 m^3 from the simulation). The deviation between the simulation results and the field data probably arose because some assumed simulation conditions – for example, the production pressure – could be different from the actual production conditions.

2.2.3 History Matched Oil Production

Fig. 2.9 presents the simulation results for oil production over a period of 3,000 days for six vertical wells. Overall, the model matched the oil production data fairly well for all six wells within the first ~2,000 days, with an overall relative error of 0.7% (53,821 m^3 in the field vs. 53,425 m^3 from the simulation).

2.2.4 History Matched Water Production

Fig. 2.10 presents the simulation results for water production over a period of 3,000 days for six vertical wells. Overall, the model matched the water production data for all six wells within the first ~2,000 days, with an overall relative error of 3% (8,399 m^3 in the field vs. 8,152 m^3 from the simulation).

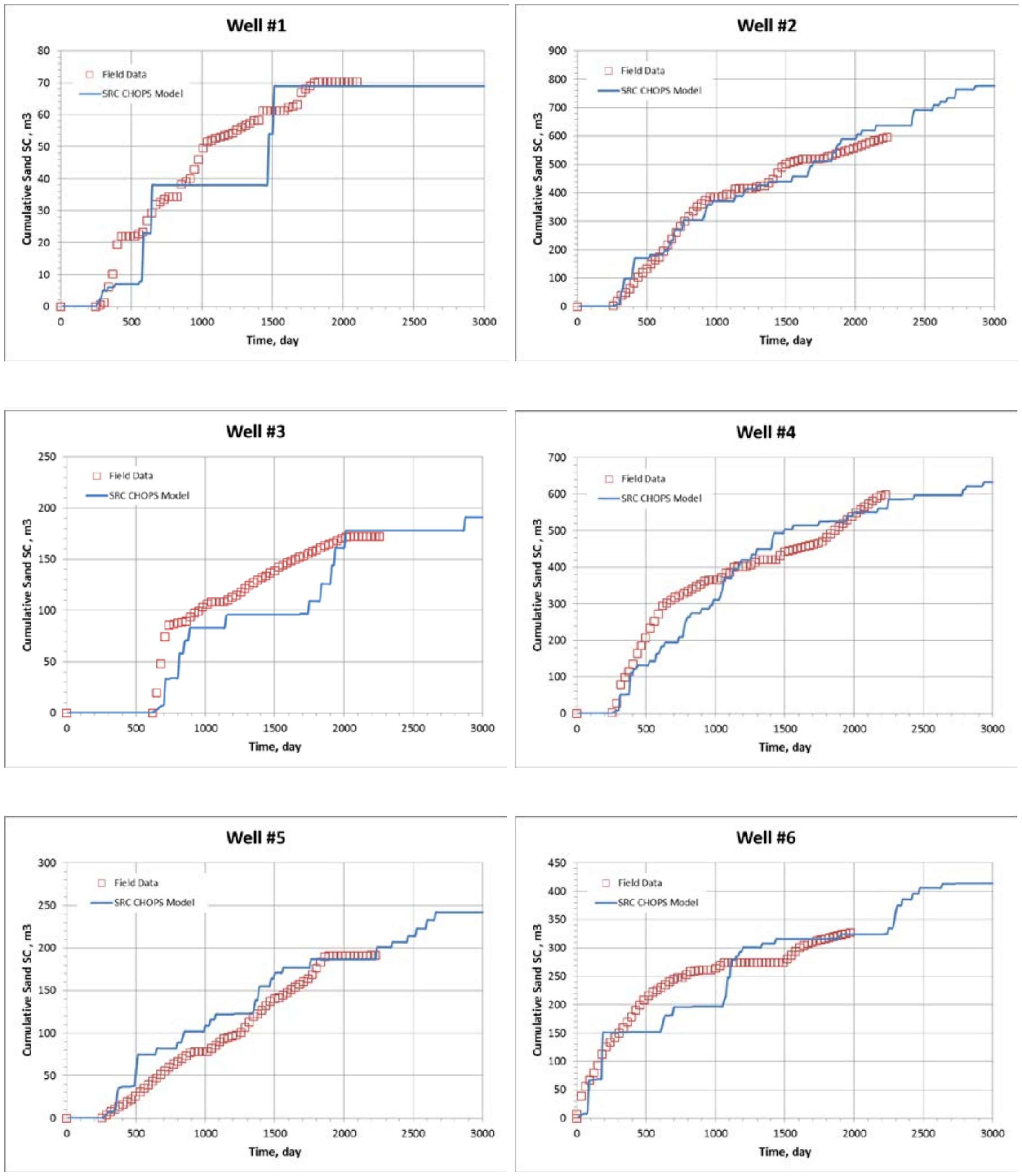


Fig. 2.8—History matched sand production for Wells #1–6.

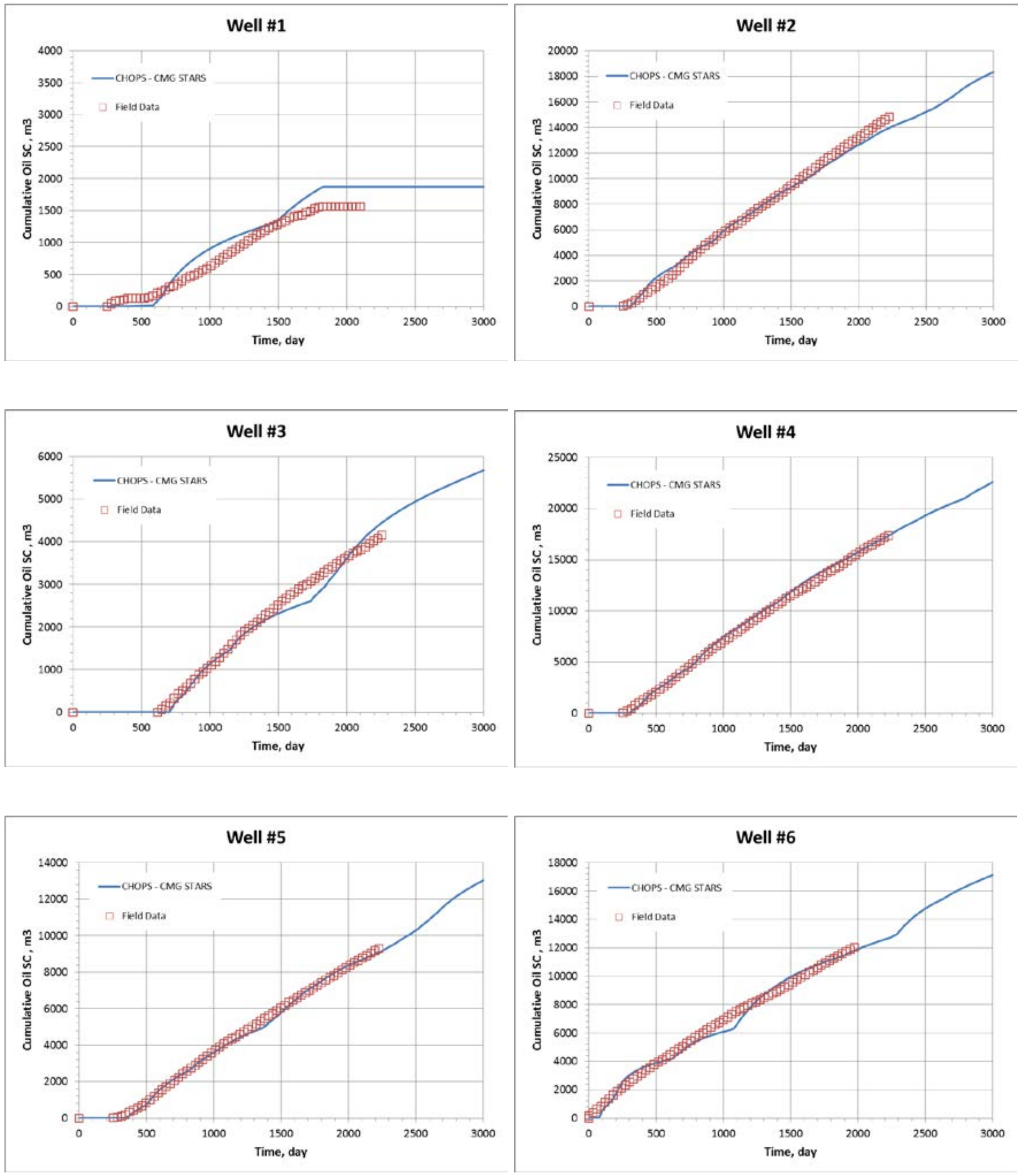


Fig. 2.9—History matched oil production for Wells #1–6.

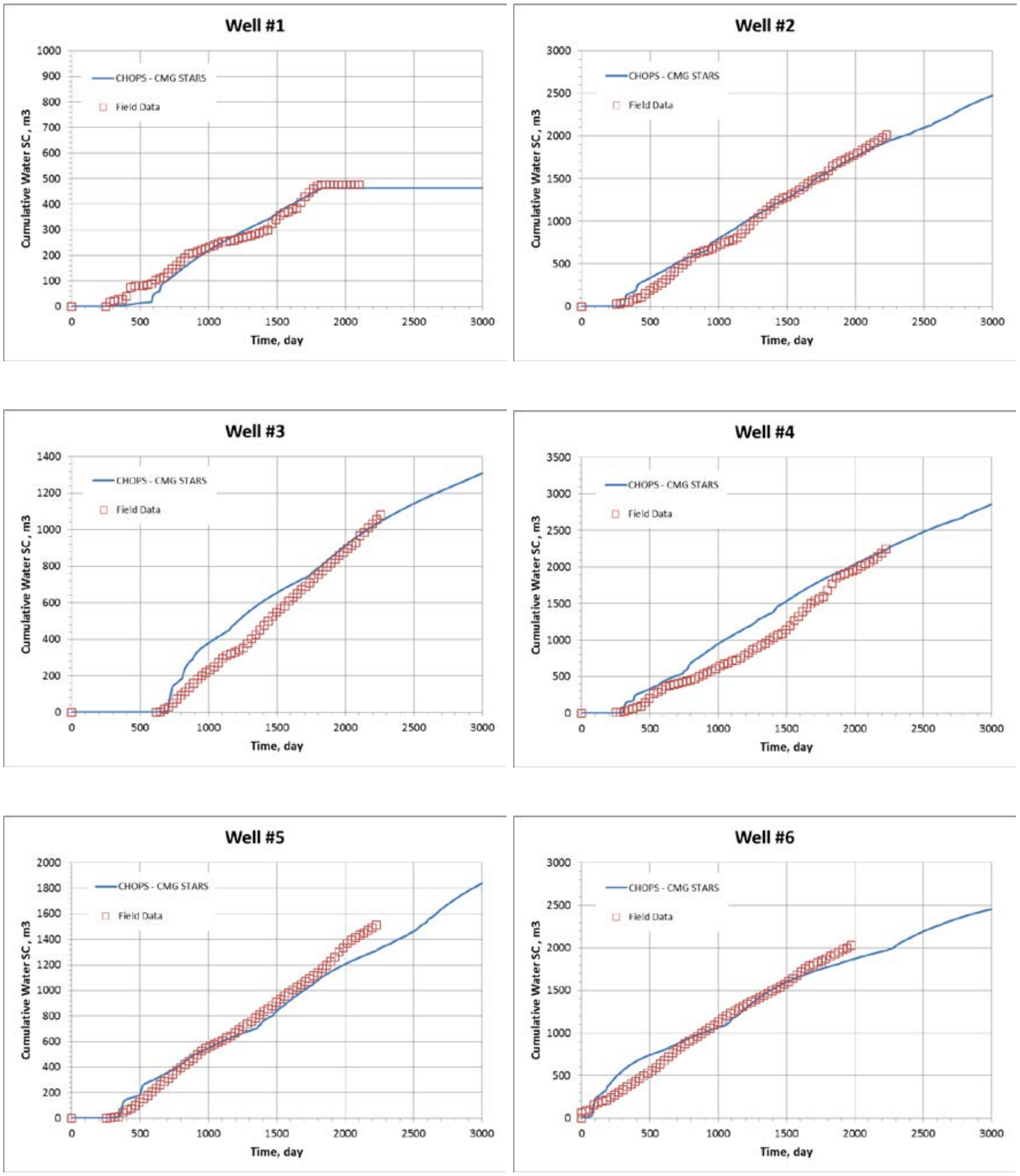
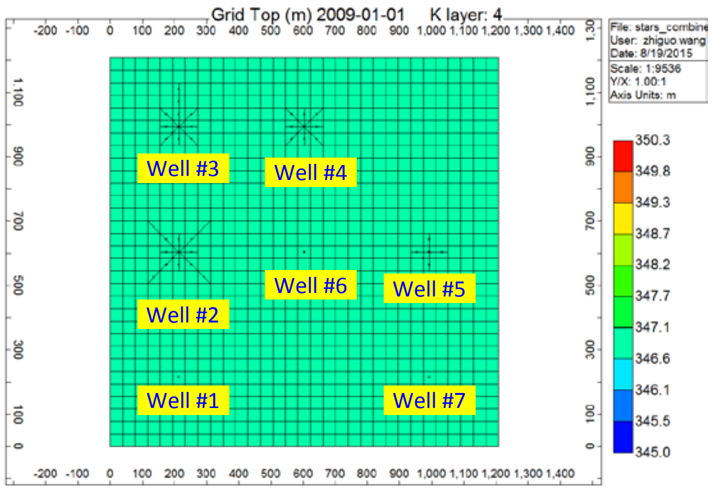


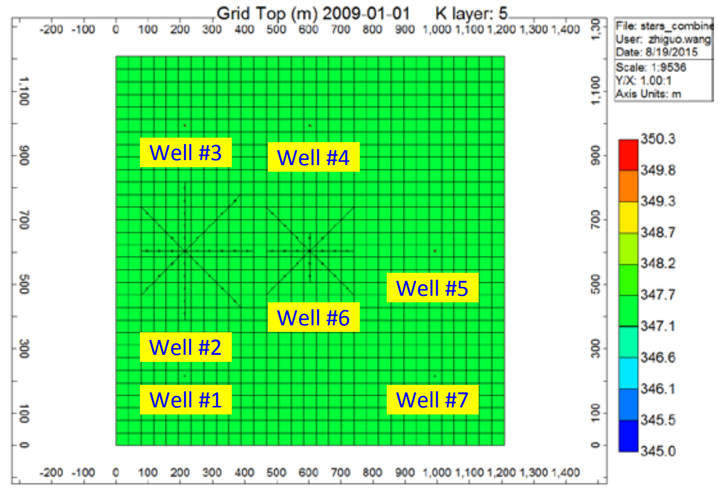
Fig. 2.10—History matched water production for Wells #1–6.

2.2.5 Wormhole Network

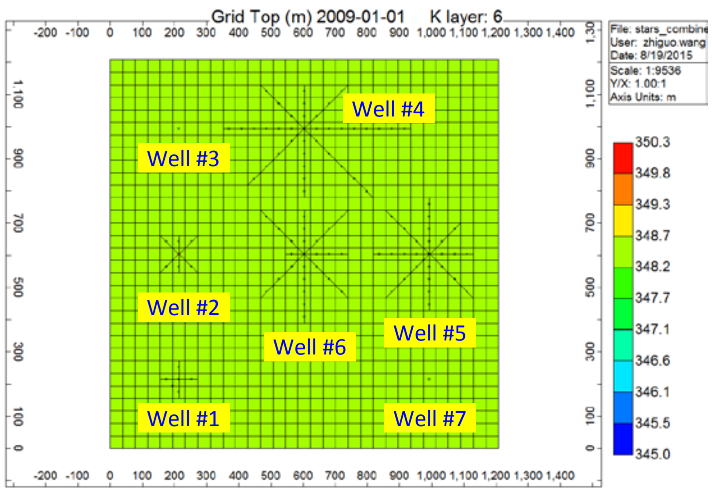
Fig. 2.11 presents the wormhole network after 3,000 days of the CHOPS process. Among the perforated layers 2 to 8, the model showed that the wormhole networks developed between layer 4 and layer 7, and that Wells #2, 4 and 6 had more wormhole branches and longer wormholes.



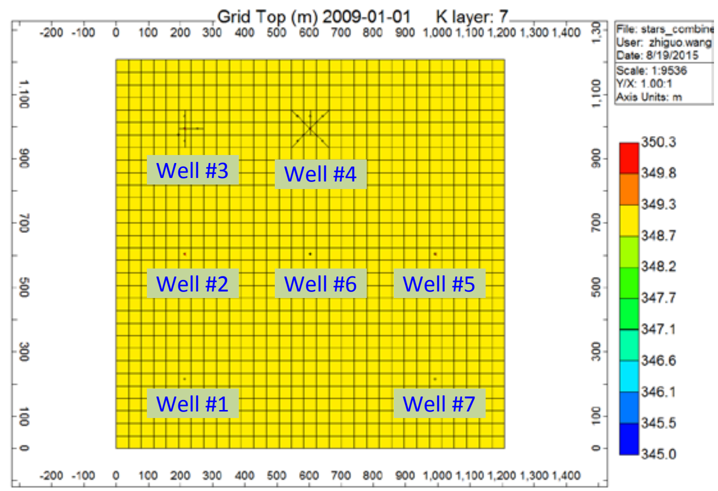
Layer 4



Layer 5



Layer 6



Layer 7

Fig. 2.11—Wormholes in layers 4-7.

2.2.6 Pressure Distribution

Analysis of the pressure distribution in the model after 3,000 days of production suggested that the pressure depletion was facilitated through the wormhole network **(Fig. 2.12),** whereas outside the wormhole-affected areas, the virgin reservoir pressure was preserved due to the lack of fluid mobility in the cold reservoir.

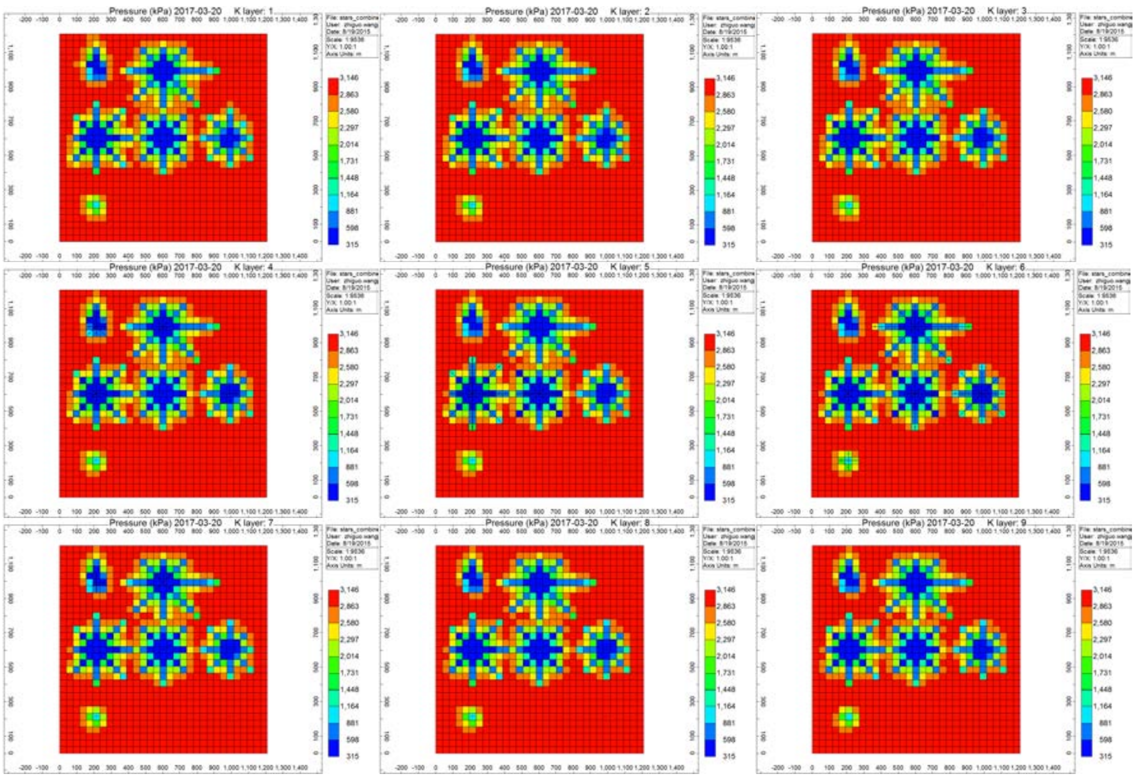


Fig. 2.12—Pressure distribution by layer.

3. Task 2 – Post-CHOPS SCV Process Simulation

Under this task, simulations were performed to prove the concept of the application of the SCV process in CHOPS reservoirs. The numerical model with the wormhole networks obtained from Task 1 was used to perform these simulations.

3.1 Modelling Procedure, Conditions and Constraints

The SCV process simulations were performed in a cyclic manner: the simulations were performed for five cycles; and each cycle included an injection period of 30 days, a soaking period of 1 day and a production period of 365 days. A linear pressure decline period of 30 days at the beginning of each production period (the wellbore pressure dropped from reservoir pressure to 316.5 kPaa within 30 days) was selected. Flue gases and steam, the product of a portable SCV unit with a capacity of 5 MMBtu/hr, were injected into all six wells.

ChemCAD simulation of the SCV process provided the composition of the effluent stream as 3.76, 36.06, and 60.18 mol% of CO_2, N_2, and H_2O, respectively; and the maximum fluid injection rate was 40,061 m^3/day at the surface conditions. In the CMG simulation model, the injection fluid was superheated, at 239^oC and 3,300 kPaa (used as the maximum injector BHP), and it was applied to the first perforation in the reservoir. The minimum producer BHP was set to 316.5 kPaa.

In addition, considering that the flue gas consisted of CO_2 and N_2, the pressure/volume/temperature (PVT) phase behaviour model used for the SCV process also considered the solubilities of CO_2 and N_2 in the oil phases, which were derived from previous SRC experimental data.

3.2 Preliminary Post-CHOPS SCV Process Simulation

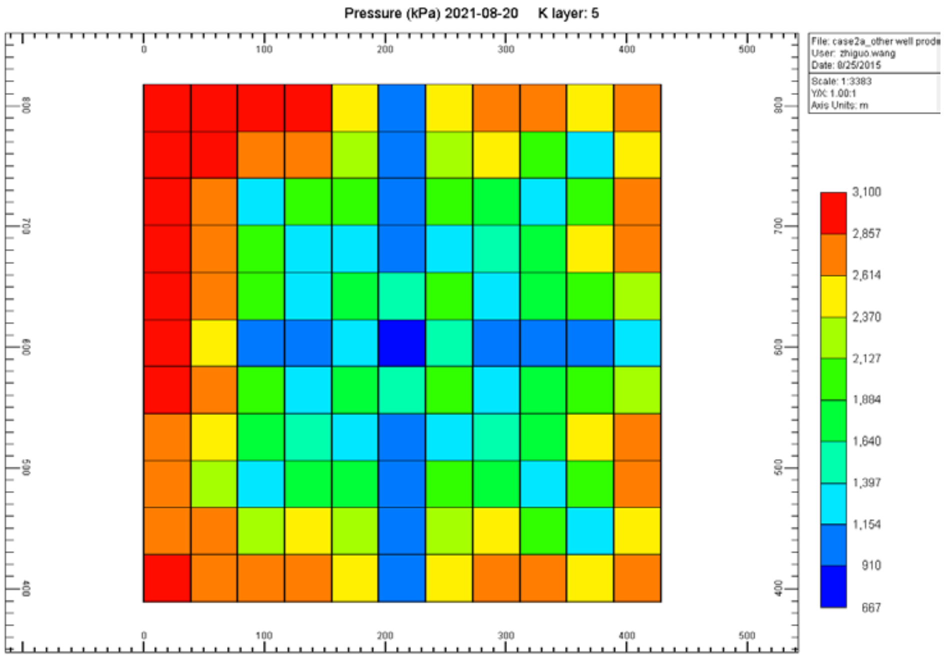
During the post-CHOPS SCV process simulations with the aforementioned constraints and conditions, it was found that 100% injection capacity for the steam and flue gas mixture (i.e., 40,061 m^3/day at the surface conditions) could never be achieved if the set of relative permeability curves applied for the CHOPS model was used. Only ~10% of the injection capacity from a 5 MMBtu/hr SCV unit was usable. The primary reason for this low fluid injectivity was because of the very low relative permeabilities of water and gas being used. These low relative permeability curves resulted in the limited penetration of the injected fluid in the wormholes, limited the pressure dissipation in the reservoir, caused the wellbore pressure to reach its maximum pressure constraint of 3,300 kPaa, and eventually resulted in the low fluid injection rate (or fluid injectivity). The details of these simulations and results can be found in the interim report provided to PTAC in July 2015 and are not repeated here for the sake of brevity.

To improve the fluid injectivity, it was first decided to simulate the post-CHOPS SCV process using smaller gridblocks. It was anticipated that smaller gridblocks could possibly allow a faster dissipation of the pressure and temperature to the adjacent gridblocks and thus improve the fluid injectivity. The attempts with finer gridblocks also failed to enhance the fluid injectivity. Although using smaller grid blocks resulted in higher pressures and temperatures near the wellbore and wormhole networks **(Figs. 3.1 and 3.2)**; the refined gridblocks resulted in lower oil recovery.

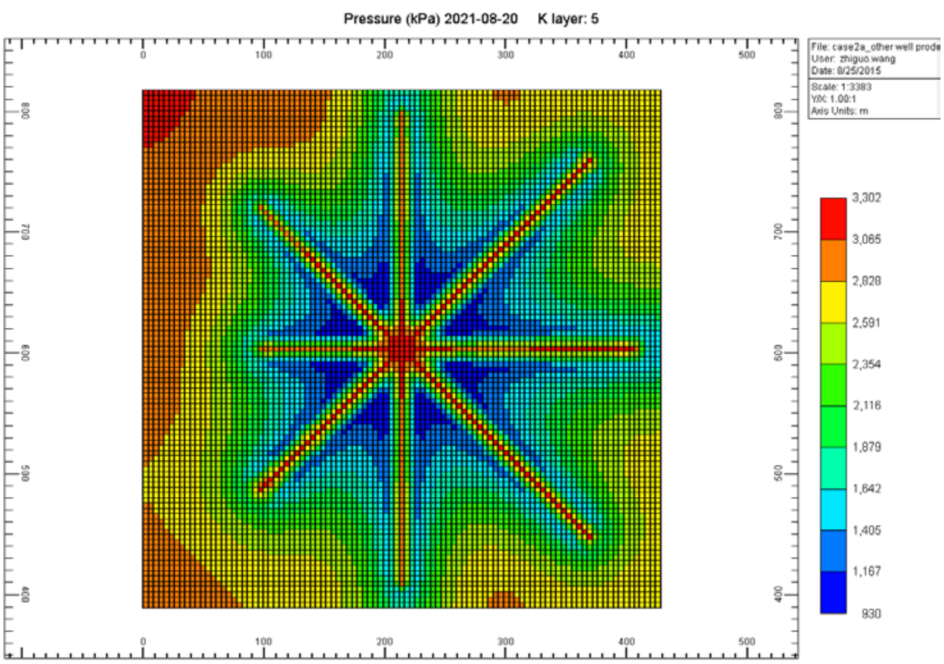
This was because only the smaller volumes in the grid blocks contained highly mobile oil due to viscosity reducing effects of temperature and gas dissolution, whereas when using larger grid blocks, larger volumes of increased mobility oil was available for production. Even though the overall mobility of the oil in the large grid blocks was less than that in the small grid blocks, more oil was produced from the larger grid block system.

Without having the actual field data for an SCV process application the characteristic injection response in a wormholed reservoir was unknown, and it was thought any adjustment to the numerical model to arbitrarily increase injectivity would lead to arbitrary results. Therefore, this approach was avoided. Fortunately, after considerable discussions both internally at SRC and with PTAC representatives, it was determined that some data was available for an analogous process where hot gases were injected in combination with water/steam. One such process was the hot water vapour process (HWVP) in which non-condensable gas (i.e., N_2) was injected in combination with hot water into post-CHOPS reservoirs. The details of the HWVP field trial can be found in the corresponding reports (Husky Oil Operations Limited, 2013, 2014).

Fig. 3.3 shows the wellbore pressure and the fluid injection rate during the HWVP field trial (Husky Oil Operations Limited, 2013). According to this figure, the pressure response [dP/dt/(fluid injection rate) or dP/(volume injected)] within the first selected region was ~6.48 Pa/m^3; the pressure response within the second selected region was ~6.94 Pa/m^3; and the average pressure response for HWVP was ~6.71 Pa/m^3.

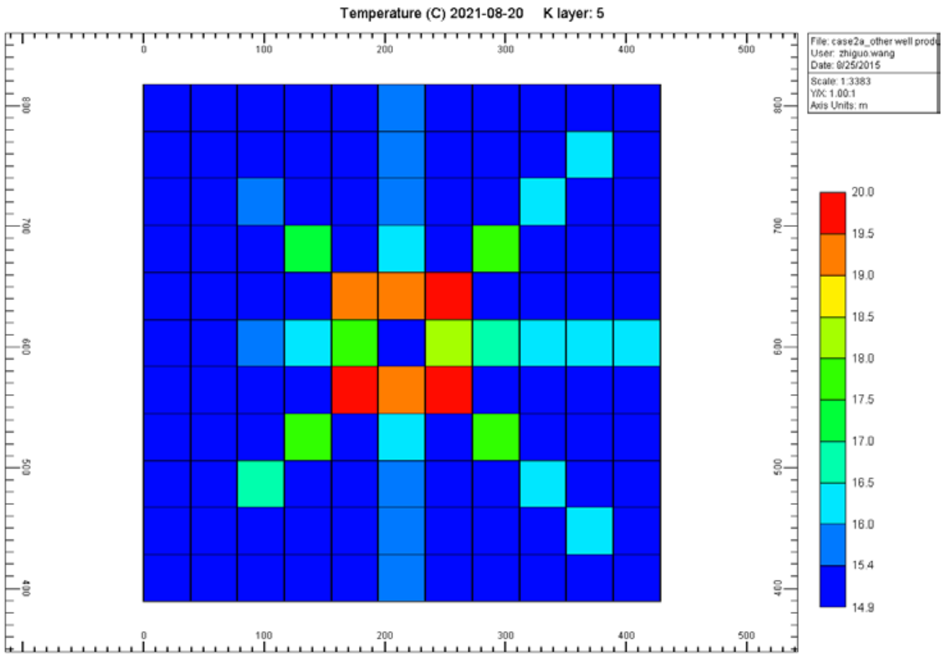


(a) Large gridblocks.

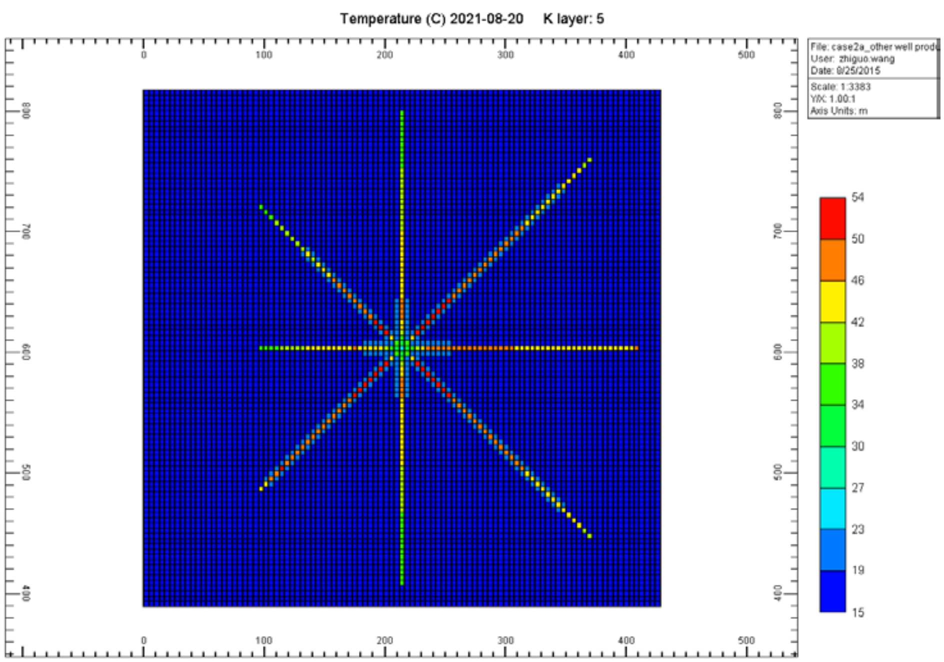


(b) Fine gridblocks.

Fig. 3.1—Pressure distribution around Well #2.



(a) Large gridblocks.



(b) Fine gridblocks.

Fig. 3.2—Temperature distribution around Well #2.

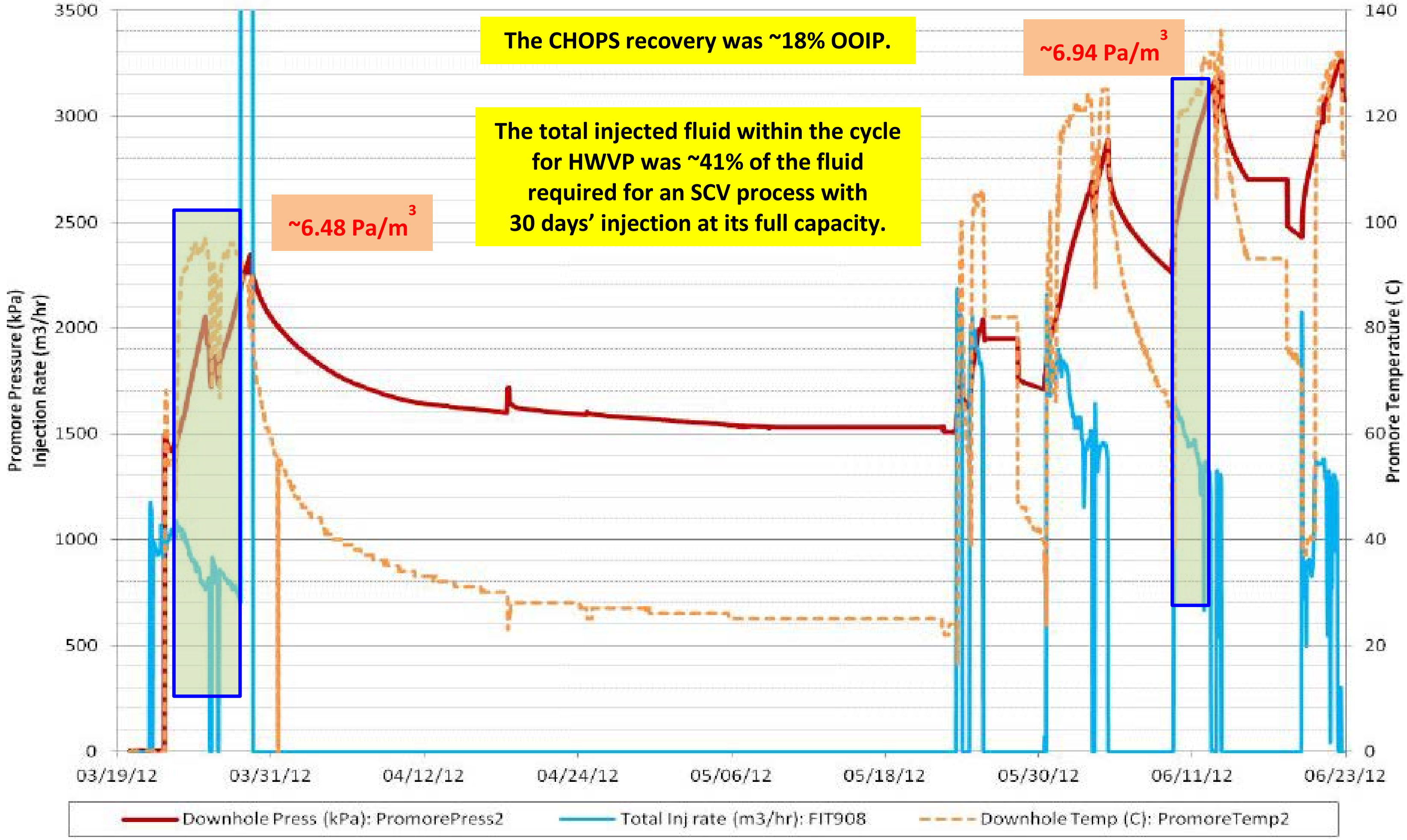


Fig. 3.3—HWVP injection cycle 1: downhole pressure and temperature (Husky Oil Operations Limited, 2013).

In addition, several options were considered to dynamically modify k_r curves during the simulation run, and it was found that making them functions of both temperature and solvent composition represented the best petrophysics of the process. It also turned out that these dynamic k_r curves could result in significant increases in both injectivity and oil production. CMG's optimization software CMOST was used to find the best set of relative permeability curves, such that the well injectivity was maximized, and was reasonable as compared to the HWVP field tests.

With this set of relative permeability curves, relative permeability values within each individual gridblock would be estimated through either interpolation or extrapolation using the temperature and solvent concentration within the gridblock. When there was no temperature change and no solvent in the reservoir, for example, during the CHOPS process, the estimated permeability values would be the same as those used for the CHOPS process. When there was a temperature change and solvent in the reservoir, for example, during the SCV process, the better defined dynamically modified permeability values would be used.

Once the best set of k_r curves was obtained, this set of k_r curves was employed to simulate the SCV process with the maximum fluid injection rate constraint of 40,061 m^3/day (Case 12A) to generate the best case-scenario results for the SCV process. In addition, this set of k_r curves was also employed to simulate the SCV process with a lower maximum fluid injection rate constraint (Case 12B) such that most wells had a similar pressure response as the HWVP field trial; and it was estimated that this reduced maximum fluid injection rate constraint was 15,350 m^3/day.

Section 3.3 of this report presents the best case-scenario results of Case 12A; **Section 3.4** of the report presents the results of Case 12B, where the injection rate was constrained to simulate the wellbore pressure response similar to the one observed during HWVP.

3.3 Post-CHOPS SCV Process Simulation Results (Case 12A)

This section of the report presents the simulation results of the SCV process at its maximum achievable fluid injectivity for an SCV unit with a capacity of 5 MMBtu/hr; the set of k_r curves used was obtained using CMG's optimization software CMOST with the objective of maximizing the fluid injection.

Fig. 3.4 compares the wellbore pressure response of Case 12A with that of the HWVP. Note that the well pressure response is a measure of the fluid injectivity. The fluid injectivity for Wells #2, 4, 5 and 6 were better than what was observed during the HWVP field trial. The lower fluid injectivity in Wells #1 and 3 was attributed to the smaller number and shorter length of wormholes (Fig. 2.11).

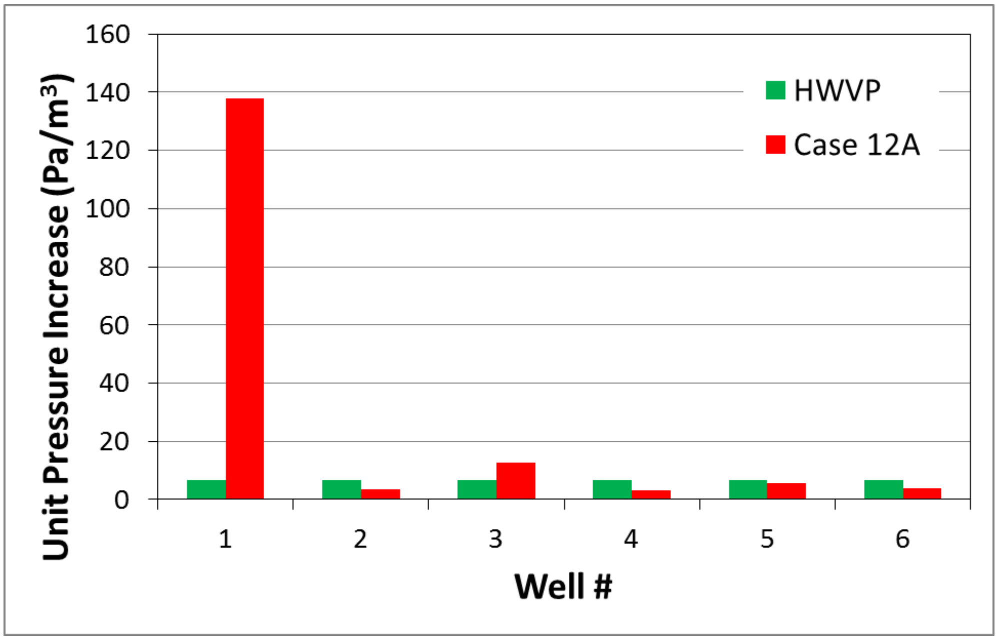


Fig. 3.4—Pressure response comparison between Case 12A and HWVP.

Figs. 3.5 and 3.6 present the cumulative gas and water injection for all six wells during the ~2,000 days of the SCV process. It can be seen that different wells had different percentages of injection capacity based on an SCV unit with a capacity of 5 MMBtu/hr; the maximum of 79.5% injection capacity occurred for Well #4. **Fig. 3.7** presents the cumulative oil produced for all six wells during the ~2,000 days of the SCV process; Wells #2, 4, 5 and 6 clearly produced more oil, with the highest oil production coming from Well #4. Based on Fig. 2.11, it was clear that differences in the fluid injection and oil production were mainly due to different wormhole networks around wells.

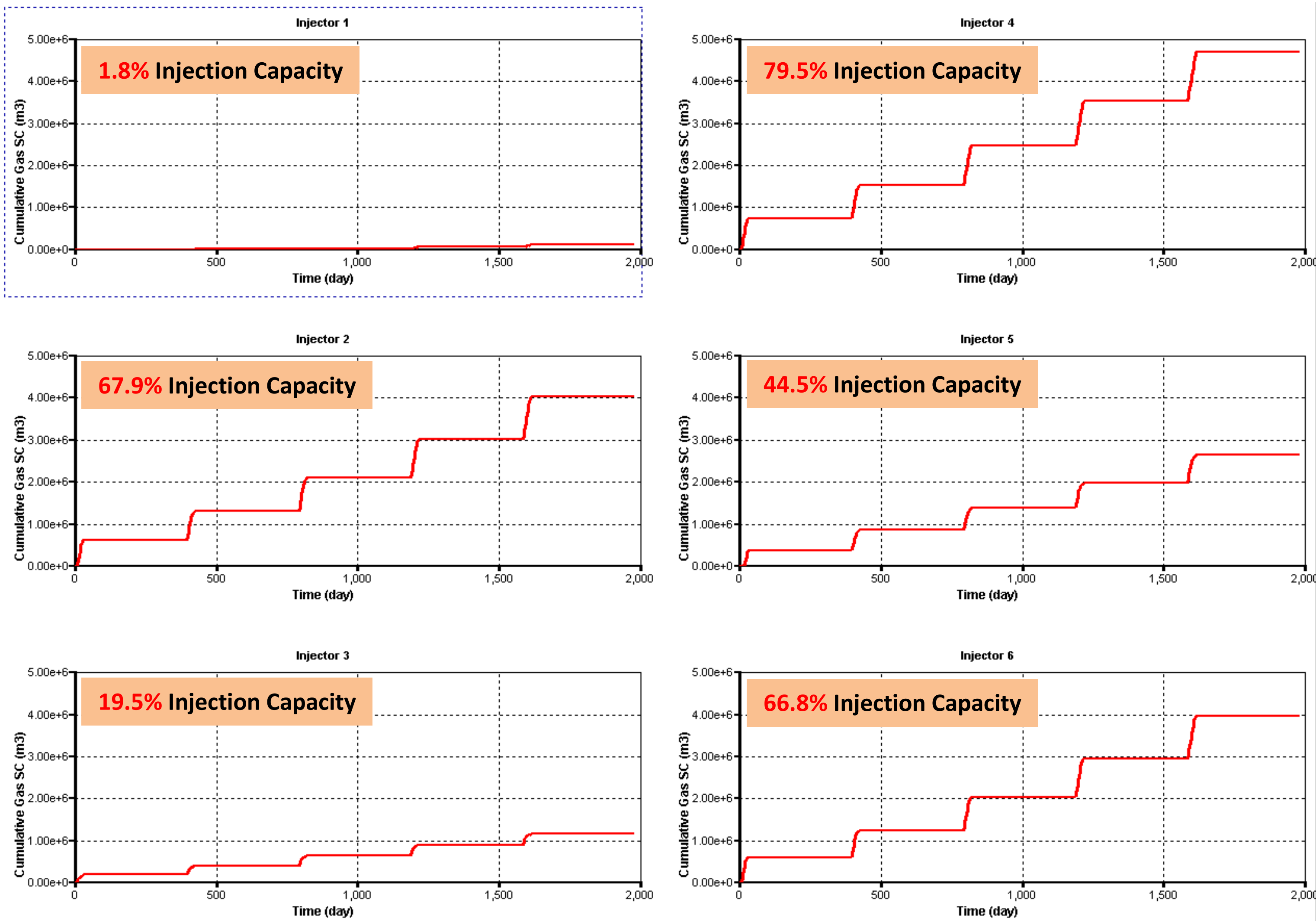


Fig. 3.5—Cumulative gas injected for Wells #1–6 (Case 12A).

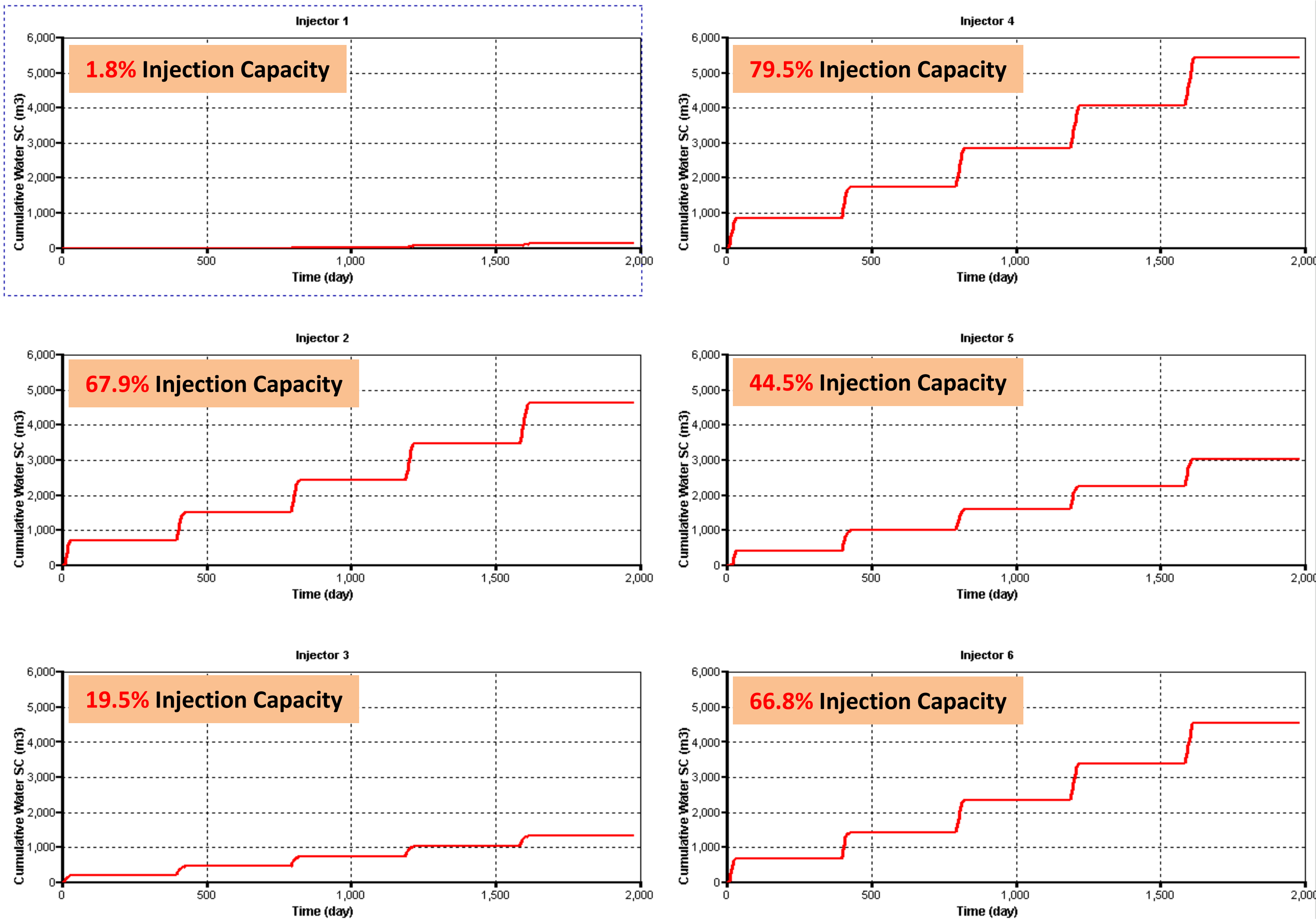


Fig. 3.6—Cumulative water injected for Wells #1–6 (Case 12A).

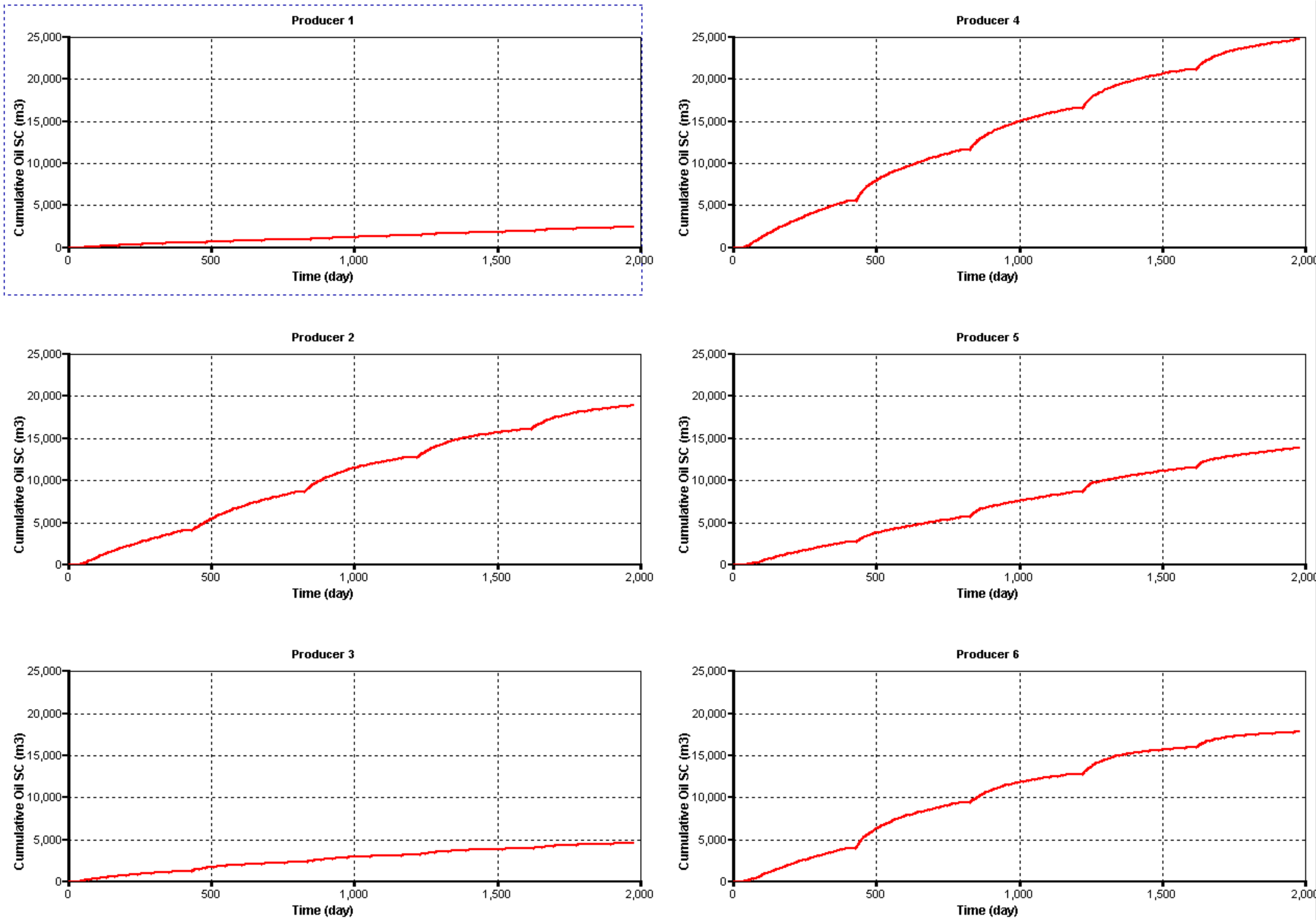


Fig. 3.7—Cumulative oil produced for Wells #1–6 (Case 12A).

In order to compare the SCV process performance with the CHOPS process, the CHOPS model was also run for a total of ~5,000 days to generate more CHOPS simulation results for comparison. Note that the k_r curves were the same as those employed for the CHOPS simulation; and this particular case was referred to as “CHOPS-only”.

In comparison to the CHOPS-only case, the post-CHOPS SCV process (Case 12A) significantly increased the oil production, especially for Wells #2, 4, 5 and 6 **(Fig. 3.8)**; **Table 3.1** shows the detailed simulation results of these two cases. For example, Well #4 – the CHOPS-only case – produced 11,450 m^3 oil, i.e., 4.25% OOIP. On the other hand, the SCV process (Case 12A) produced 24,760 m^3 oil, i.e., 9.18% OOIP. This represents an increase in the oil production of 116% over the CHOPS-only case.

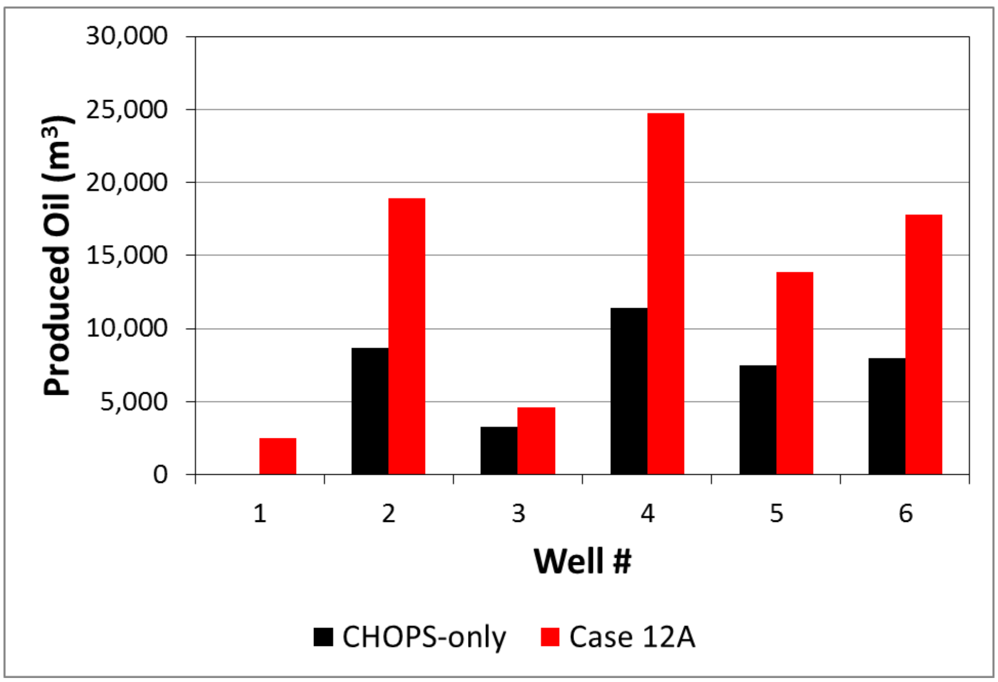


Fig. 3.8—Oil production comparison between Case 12A and the CHOPS-only case.

Table 3.1—Comparison of Case 12A and CHOPS-Only Case

	CHOPS-only (from 3,000 to 4,980 days)		SCV Process (Case 12A) Varied k_r Curves (1,980 days)		
	Produced Oil (m^3)	**Oil Recovery (%OOIP)**	**Produced Oil (m^3)**	**Oil Recovery (%OOIP)**	**% Increase in Produced Oil**
Well #1	0	0.00%	2,469	0.92%	NA*
Well #2	8,691	3.22%	18,961	7.03%	118.2%
Well #3	3,278	1.22%	4,589	1.70%	40.0%
Well #4	11,450	4.25%	24,760	9.18%	116.2%
Well #5	7,464	2.77%	13,899	5.15%	86.2%
Well #6	7,984	2.96%	17,825	6.61%	123.3%

* During CHOPS Well #1 stopped production during the first 1,900 days of pressure depletion.

Fig. 3.9 presents the pressure distribution within the reservoir model after the injection period of the fifth cycle. For Case 12A, pressures around all wells and wormholes reached their highest value of ~3,300 kPaa due to a better fluid injectivity. **Fig. 3.10** presents the temperature distribution within the reservoir model after the injection period of the fifth cycle. The highest temperature in the reservoir for Case 12A was ~63°C.

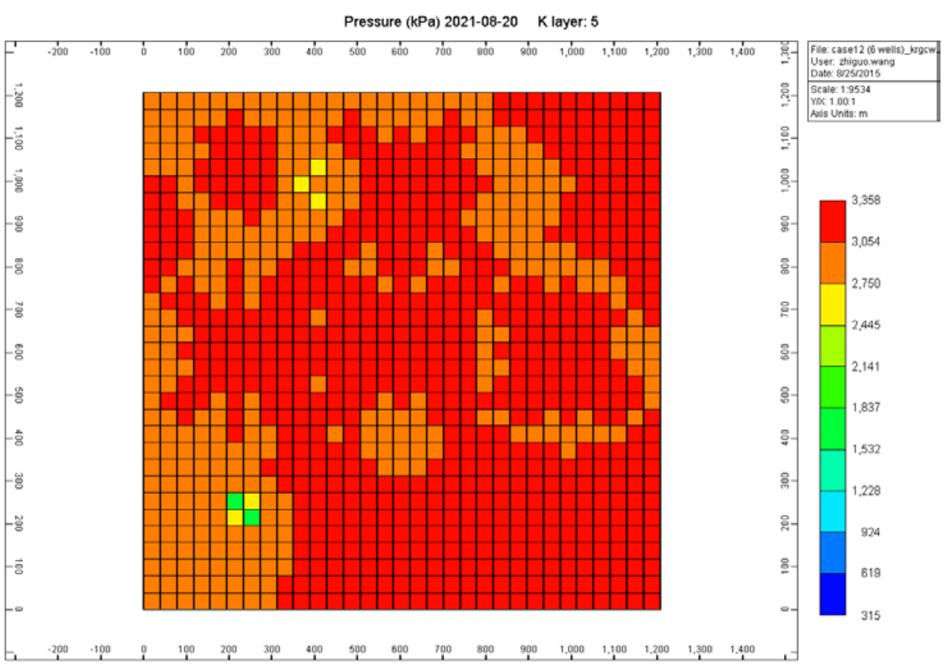


Fig. 3.9—Pressure distribution after the fifth injection period (Case 12A).

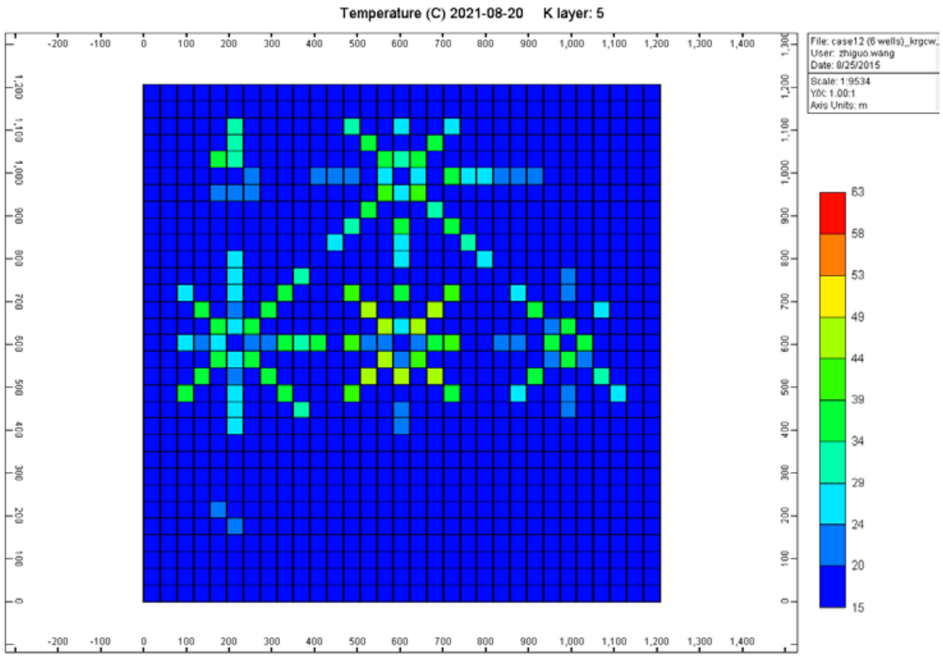


Fig. 3.10—Temperature distribution after the fifth injection period (Case 12A).

Please note that, although only five cycles were simulated, this does not limit the application of the SCV process to this number. For this particular study, the selection of five cycles was for evaluation purposes only. For the SCV process application, the number of cycles can be more than what was used during this study. More cycles mean longer than ~5.5 years' application of the SCV process, and it would result in higher oil recovery. Further simulations can be performed to evaluate the period after which the oil production rate from an SCV process starts to decline.

The simulation results also suggest that SCV process application is not limited to the suspended CHOPS wells or to the reservoirs which are completely pressure depleted. Even if this process is applied to the CHOPS reservoirs that are still producing, the potential oil recovery from SCV could be much more attractive than the CHOPS pressure depletion.

3.4 Post-CHOPS SCV Process Simulation Results (Case 12B)

This section of the report presents the simulation results of the SCV process with the reservoir pressure response similar to what was observed during the HWVP field trial.

Fig. 3.11 compares the wellbore pressure response of the SCV process (Case 12B) with that of the HWVP. The fluid injectivity values for Wells #2, 4, 5 and 6 were similar to what was observed during the HWVP field trial. The lower fluid injectivity in Wells #1 and 3 was attributed to the smaller number and shorter length of wormholes (Fig. 2.11).

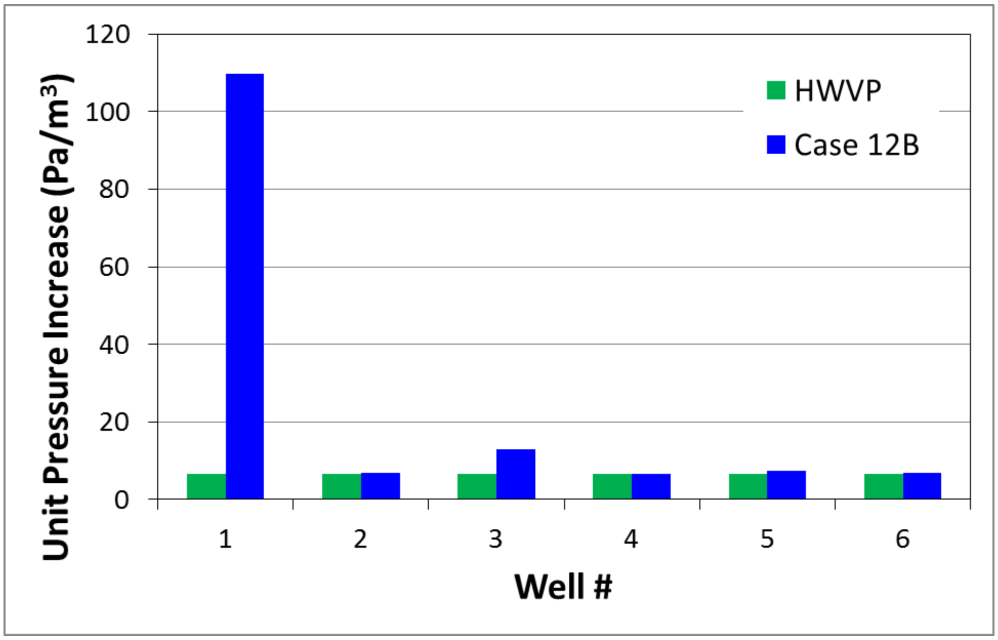


Fig. 3.11—Pressure response comparison between Case 12B and HWVP.

Similar to Case 12A, **Figs. 3.12 and 3.13** present the cumulative gas and water injection for all six wells of Case 12B during the ~2,000 days of the SCV process. It can be seen that different wells had different percentages of injection capacity based on an SCV unit with a capacity of 5 MMBtu/hr, and a maximum of 37.3% injection capacity for Well #4.

Fig. 3.14 presents the cumulative oil produced for all six wells of Case 12B during the ~5.5 years of the SCV process; Wells #2, 4, 5 and 6 clearly produced more oil, with the highest oil production coming from Well #4. Based on Fig. 2.11, it was clear that differences in the fluid injection and oil production were mainly due to the differences in the wormhole networks that developed around wells.

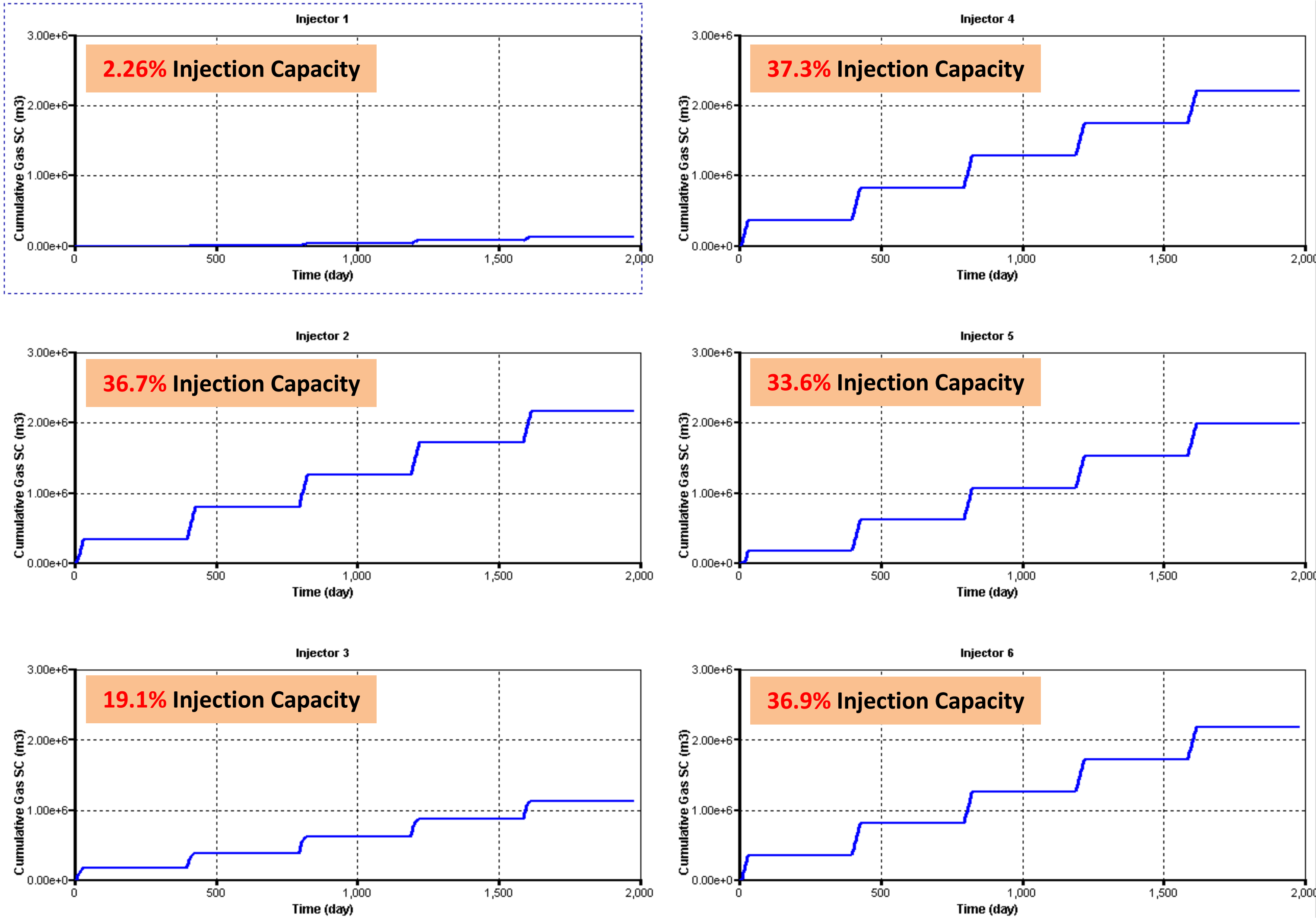


Fig. 3.12—Cumulative gas injected for Wells #1–6 (Case 12B).

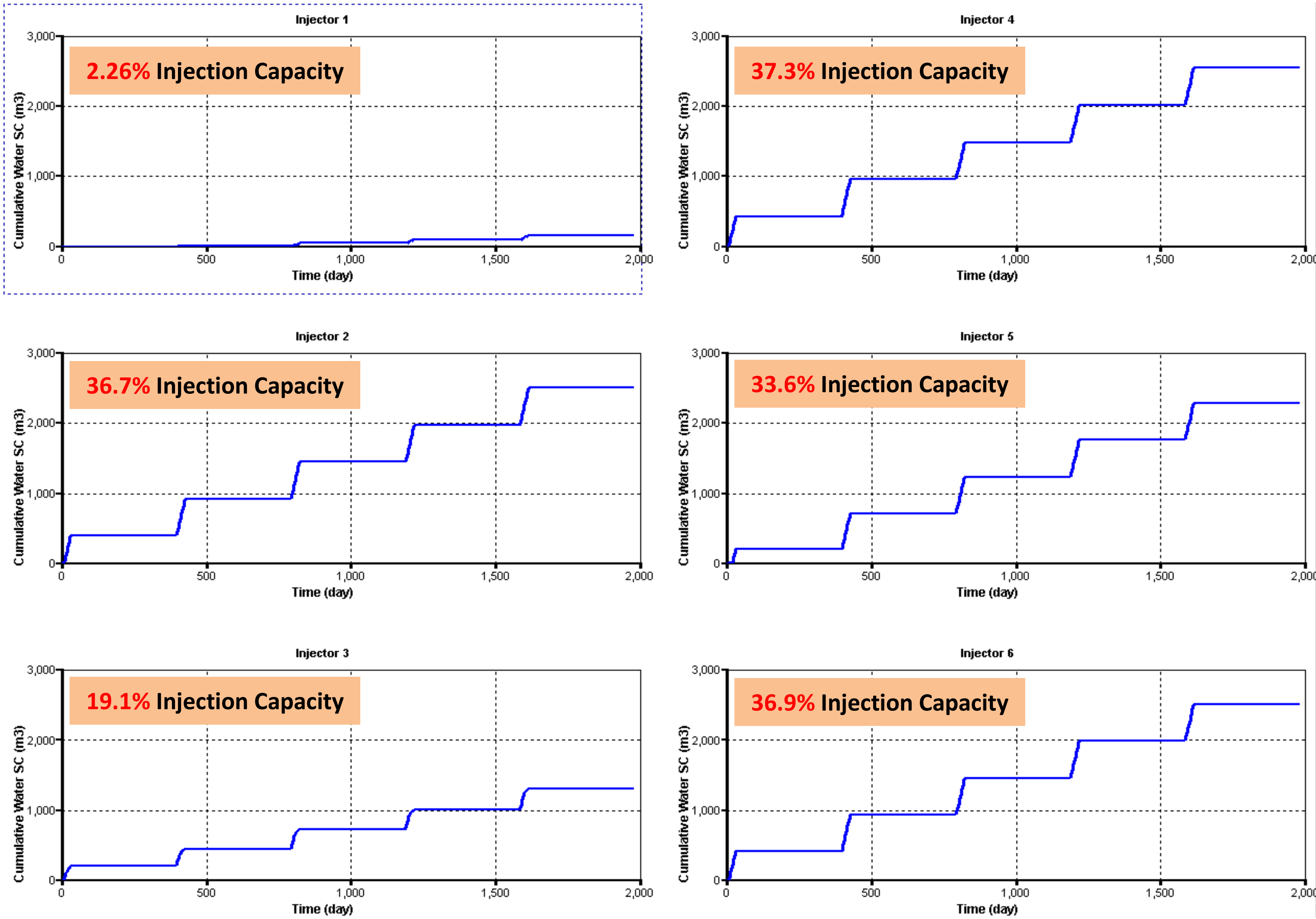


Fig. 3.13—Cumulative water injected for Wells #1–6 (Case 12B).

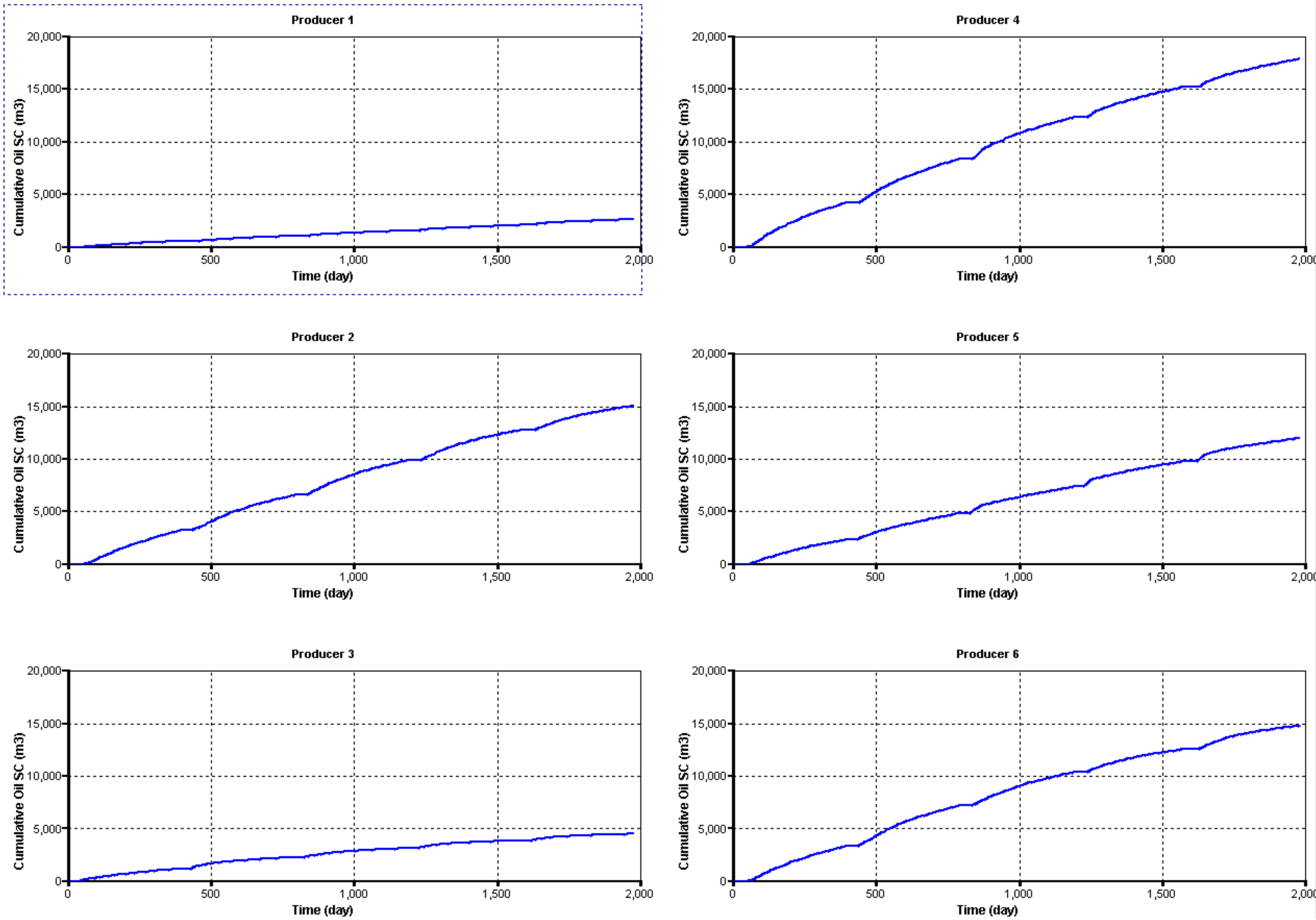


Fig. 3.14—Cumulative oil produced for Wells #1–6 (Case 12B).

In comparison to the CHOPS-only case mentioned in the last section, the post-CHOPS SCV process (Case 12B) also significantly increased the oil production, especially for Wells #2, 4, 5 and 6 **(Fig. 3.15)**; **Table 3.2** shows the detailed simulation results of these two cases. For example, Well #4 – the CHOPS-only case – produced 11,450 m^3 oil (4.25% OOIP). By contrast, the SCV process (Case 12B) produced 17,921 m^3 oil (6.65% OOIP). This represents an increase in oil production of 56.5% over the CHOPS-only case.

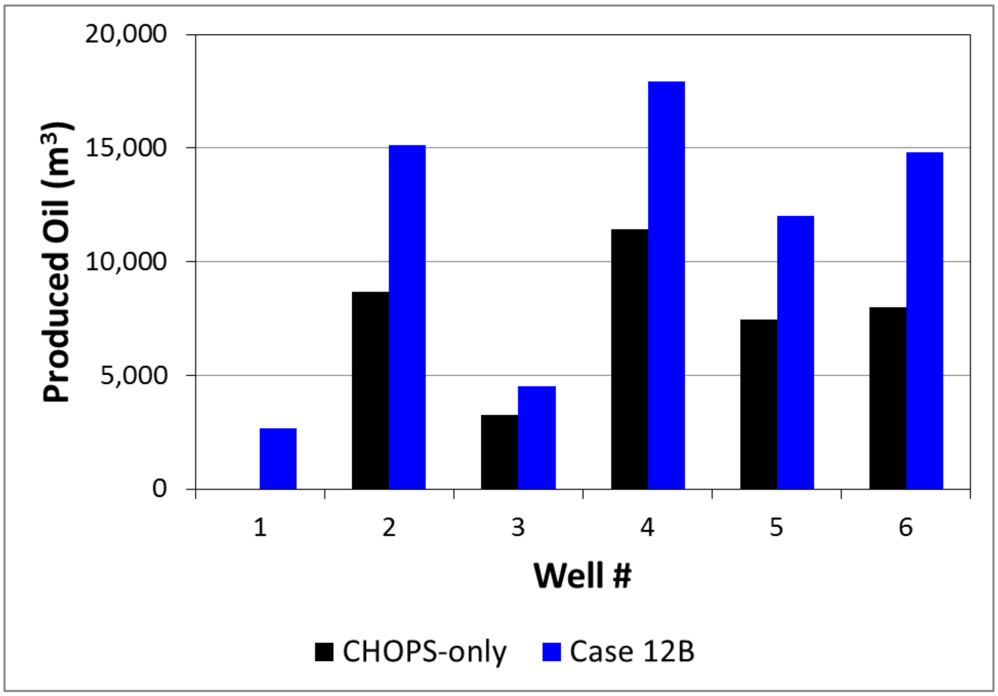


Fig. 3.15—Oil production comparison between Case 12B and the CHOPS-only case.

Table 3.2—Comparison of Case 12B and the CHOPS-Only Case

	CHOPS-only (from 3,000 to 4,980 days)		SCV Process (Case 12B) Varied k_r Curves (1,980 days) and Lower Injection Rate Constraint		
	Produced Oil (m^3)	Oil Recovery (%OOIP)	Produced Oil (m^3)	Oil Recovery (%OOIP)	% Increase in Produced Oil
Well #1	0	0.00%	2,663	0.99%	NA*
Well #2	8,691	3.22%	15,113	5.60%	73.9%
Well #3	3,278	1.22%	4,535	1.68%	38.3%
Well #4	11,450	4.25%	17,921	6.65%	56.5%
Well #5	7,464	2.77%	12,014	4.45%	60.9%
Well #6	7,984	2.96%	14,834	5.50%	85.8%

* During CHOPS Well #1 stopped production during the first 1,900 days of pressure depletion.

Fig. 3.16 presents the pressure distribution within the reservoir model after the injection period of the fifth cycle. For Case 12B, pressures in the vicinity of most wells reached ~2,400 kPaa due to better fluid injectivity. **Fig. 3.17** presents the corresponding temperature distribution within the model at this point. The highest temperature in the reservoir for Case 12B was ~57°C.

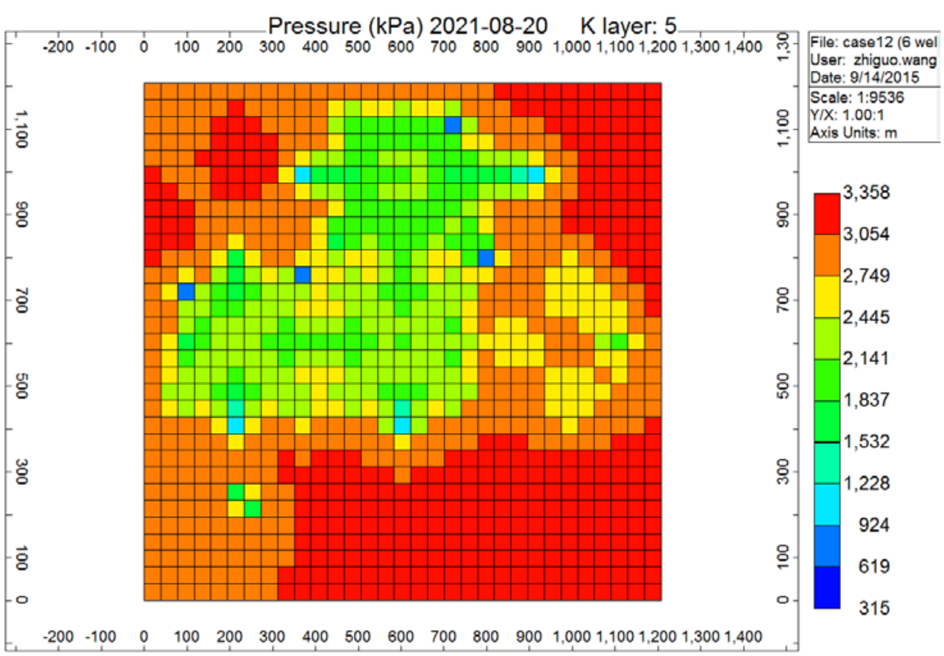


Fig. 3.16—Pressure distribution after the fifth injection period (Case 12B).

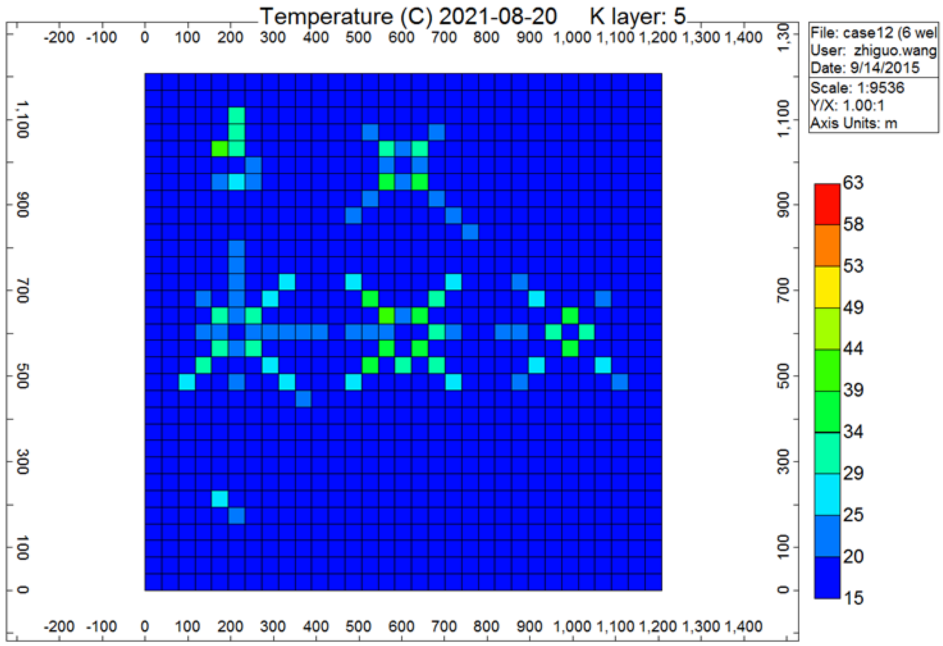


Fig. 3.17—Temperature distribution after the fifth injection period (Case 12B).

The simulation results also suggest that SCV process application is not limited to the suspended CHOPS wells or to the reservoirs which are completely pressure depleted. Even if this process is applied to the CHOPS reservoirs that are still producing, the potential oil recovery from SCV could be much more attractive than the CHOPS pressure depletion.

3.5 Post-CHOPS SCV Process Wellbore Modelling

Under this subtask, a standalone model was formulated to model the casing temperature of the wellbore during the SCV process. To more accurately model the vertical wellbore within the overburden, CMG's Flex wellbore model was used, and a pseudo reservoir was attached to the bottom of the overburden section to obtain the required injectivity. This unique approach was adopted because of some CMG software limitations, for example, the Flex wellbore model cannot model very complex wormholes.

3.5.1 Pseudo Reservoir Model

As shown in **Fig. 3.18**, the cooling concept that appeared as Figure 3 in the presentation provided by FERST-CSI Technologies Inc. (2014) was applied. In this cooling concept, the cooling fluid or coolant was injected into the annulus through the tubular injector opening just above the packer, and then flowed upward and exited the annulus from its top. The central vacuum-insulated tubing (VIT) was the hot fluid injector, and there was no opening above the packer;

however, there were openings below the packer for the hot fluid injection into the reservoir. Since the coolant in the annulus was in intimate contact with the casing, its temperature would be accurate enough to represent the casing temperature.

Table 3.3 lists major well parameters used for the wellbore modelling. The thermal properties of the vacuum insulation layer of the VIT were estimated using ChemCAD, since they were the most important parameters for proper cooling and only the conductivity was available from the VIT manufacturers. The other thermal properties used default values provided by CMG's STARS simulator.

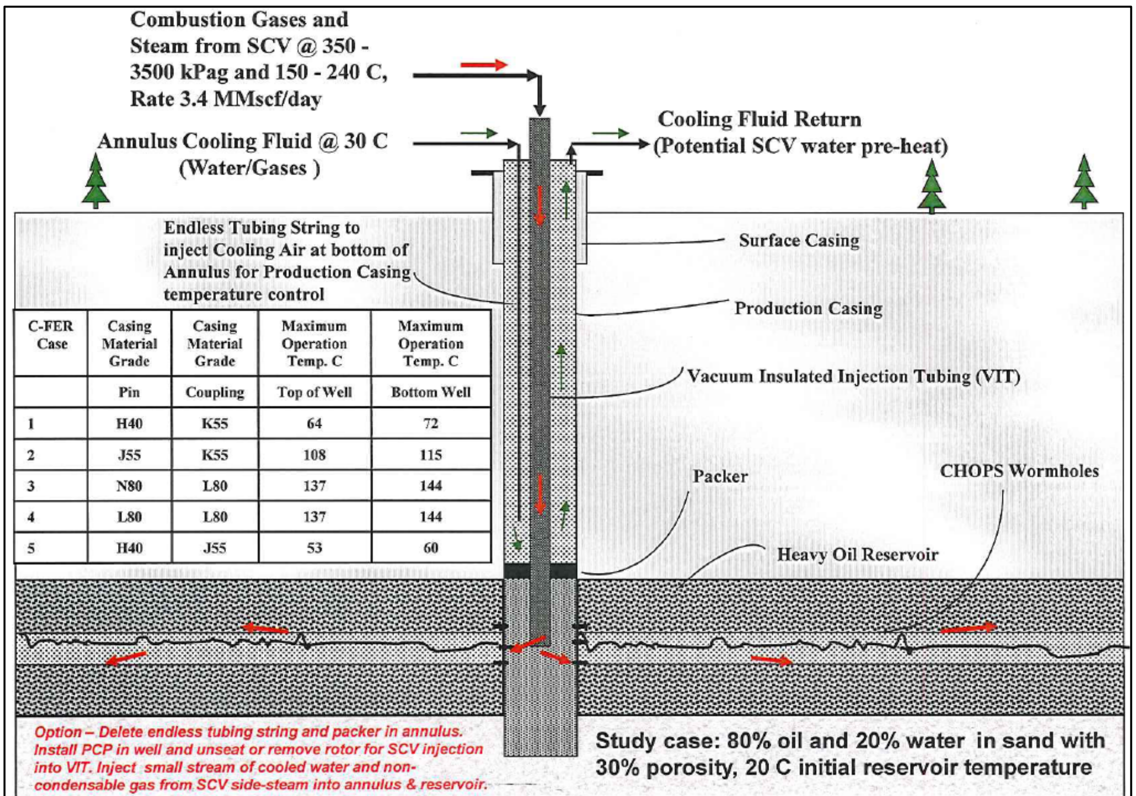


Figure 3
SCV Combustion Gas and Steam Injection
into CHOPS Well with Annulus Cooling

Fig. 3.18—SCV process application concept
(FERST-CSI Technologies Inc. 2014)

To estimate the heat capacity and thermal conductivity of the vacuum layer using ChemCAD, a simple vacuum system consisting of air at a pressure of 1 kPaa was used; as a result, the thermal conductivity was estimated to be 0.0247 W/(m·°C); this was within the range of 0.002 ~ 0.08

W/(m·°C) from the manufacturer [Continental Steel Corporation (CSTL) 2015]. The estimated heat capacity of VIT was 12.132 J/(m^3·°C).

Table 3.3—Major Well Parameters

Flue Gas Injector	Inside Diameter (ID), m	0.076
	Outside Diameter (OD), m	0.0889
	Tube Well Heat Capacity, J/(m^3·°C)	3.63E+06
	Tube Well Conductivity, J/(m·day·°C)	3.74E+06
	Insulation ID, m	0.101
	Insulation Layer Heat Capacity, J/(m^3·°C)	12.132
	Insulation Layer Conductivity, J/(m·day·°C)	2134.08
Coolant Injector	ID, m	0.019
	OD, m	0.027
	Tube Well Heat Capacity, J/(m^3·°C)	3.63E+06
	Tube Well Conductivity, J/(m·day·°C)	3.74E+06
Casing	Casing ID, m	0.164
	Casing OD, m	0.178
	Casing Material Heat Capacity, J/(m^3·°C)	3.63E+06
	Casing Material Conductivity, J/(m·day·°C)	3.74E+06
Cement Layer	Cement Layer OD, m	0.222
	Cement Heat Capacity, J/(m^3·°C)	1.85E+06
	Cement Conductivity, J/(m·day·°C)	1.73E+04

3.5.2 Casing Temperature Modelling Results

Simulations were run to estimate the casing temperature for the base case and for the case where water was used as the coolant. For the base case, a gas blanket was created in the annulus of the wellbore, and Nitrogen was used. For the proper model convergence, the gas flow rate had to be above zero; and an injection rate of 1.0 m^3/day for nitrogen was eventually selected.

Fig. 3.19 shows the annulus temperature (or casing temperature) along the vertical direction for the case using a gas blanket. Between the bottom end of the coolant injector (342.5 m below the surface) and the packer top (345 m below the surface), there was a stagnant zone; as a result, the annulus temperature in this region was higher than 60°C. However, above this region, the annulus temperature remained below 60°C.

Fig. 3.20 shows the annulus temperature (or casing temperature) along the vertical direction for the case using water cooling. Although there was a stagnant zone in the same region as noted above, the annulus temperature above the packer top could always be well controlled below 60°C with an injection rate of 1.0 m^3/day for water.

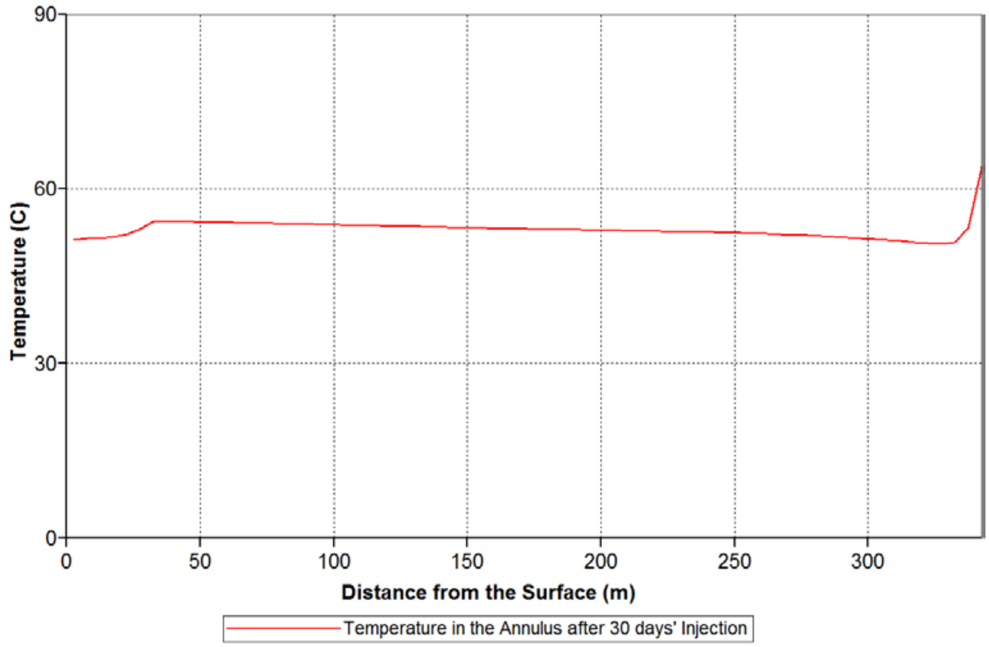


Fig. 3.19—Annulus temperature along the vertical direction (using gas blanket).

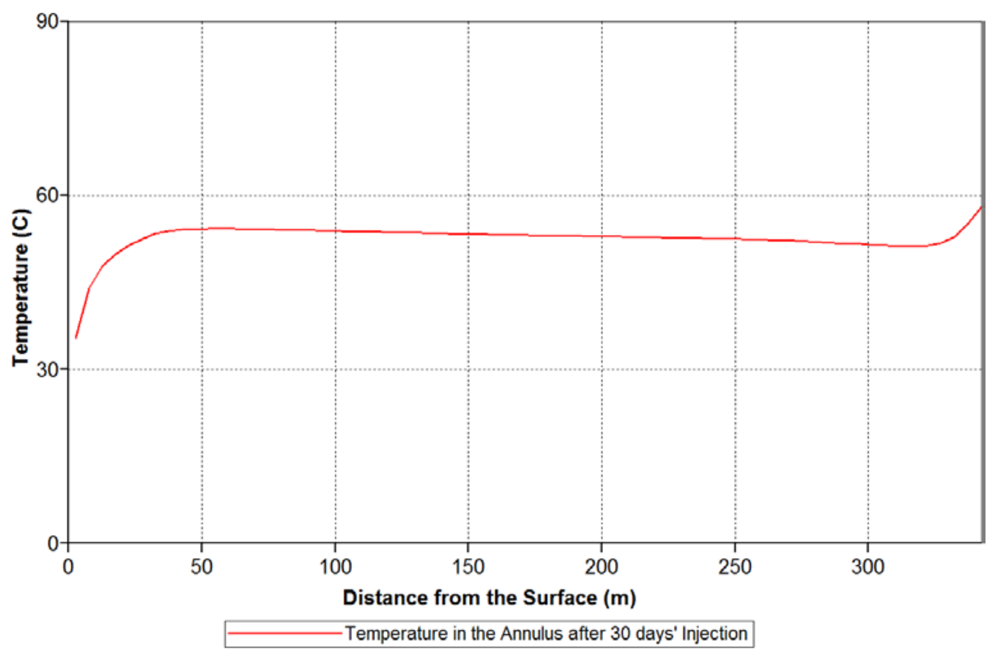


Fig. 3.20—Annulus temperature along the vertical direction (using water cooling).

4. Conclusions and Recommendations

4.1 Conclusions

Based on simulations of both the cold heavy oil production with sand (CHOPS) process and the post-CHOPS submerged combustion vaporizer (SCV) process conducted under this project, the following major conclusions can be drawn:

- Wormholes generated by CHOPS provided access for injecting the steam and flue gas mixture; as a result, the reservoir pressure could be restored to provide drive to enhance the oil recovery.
- The extent of the wormhole network connected to an individual well was positively correlated with that well's performance.
- Using the SCV process as a follow-up to the CHOPS process or replacing the CHOPS process early could result in improved oil recovery compared to CHOPS.
- Using a smaller gridblock size could more accurately capture distributions of temperature, pressure and solvent composition near the wellbore; however, computing time could increase significantly. The oil recovery factor could also change from that obtained with the larger gridblock case. This suggests that, if a refined gridblock is used for the post-CHOPS process simulation, the same gridblock should also be used for the CHOPS process modelling.
- The post-CHOPS hot water vapour process (HWVP) field trial was conducted on a well that had recovered ~18% of the original oil in place (OOIP) during CHOPS. However, in the current model, the maximum single-well CHOPS recovery was 8.38% OOIP (Well # 4 up to 3,000 days). Higher CHOPS recovery could result in a more extensive wormhole network, which in turn could be beneficial for the post-CHOPS SCV process.
- The best case scenario (Case 12A) had a maximum injection capacity (in terms of flue gases and steam) of ~80% of a 5 MMBtu/hr SCV system for Well #4, and with an injection period of 30 days, a soaking period of 1 day, a production period of 365 days, and a pressure decline period of 30 days at the beginning of the production period. The best case scenario produced 24,760 m^3 of oil from Well #4 during a period of ~5.5 years, i.e., 9.18% original oil in-place (OOIP) recovery; and this represented an oil production increase of 116% over the CHOPS-only case.
- Based on the casing temperature estimations, the casing temperature can be controlled below 60°C using a water cooling scheme.

4.2 Recommendations

As summarized above, the current simulations have shown significant benefits of the SCV process as a post-CHOPS EOR technology; however, taking the steps suggested below could go beyond this proof-of-concept study and confirm these benefits or reveal additional ones:

- In the current project, the post-CHOPS SCV process was started after 3,000 days' CHOPS production. The oil recovery after these 3,000 days was relatively low (< 8.38% OOIP); most parts of the reservoir still had a relatively high pressure; and the wormholes still had the potential to grow. Longer primary production could result in a more extensive wormhole network and provide better reservoir access for hot fluids. Therefore, additional modelling and economic evaluation is recommended to find the optimum CHOPS recovery factor and/or best candidate wells for the post-CHOPS SCV process.
- Additional numerical and economics modelling is recommended to optimize the injection/soak/production cycles and ultimate economic recovery. This optimization should be based on steam/oil ratio, energy balance, minimum economic oil rate, operating costs, net present value, etc.
- In the current project, five cycles of the SCV process was simulated. More cycles mean a longer production time of the SCV process, and it could result in higher oil recovery; therefore, further simulations are recommended to evaluate the feasible operating period for the SCV process, during which the oil production rate could still be economically viable.
- The SCV process could also be applied in thin reservoirs where the injection of pure steam is an issue because of the heat loss to the overburden. Using the SCV process, the non-condensable portion of the injected fluid will tend to rise to the top of the reservoir, and provide an insulating blanket of gas that will reduce the heat loss to the overburden; therefore, to further develop the SCV process, it is recommended to conduct some simulations on the application of the SCV process in thin reservoirs.
- A potential bottomwater effect was outside the scope of this study. It should be considered in the future because bottomwater has proven to be detrimental to steam-based EOR processes, and bottomwater is not uncommon in the Lloydminster heavy oil reservoirs. In addition, wormholes often tend to accelerate and exacerbate water breakthrough in heavy oil reservoirs.
- A more detailed investigation, including physical experiments, into the temperature and concentration dependence of relative permeability curves is recommended. The details of the physical modeling work can be refined after discussions.

Important aspects to consider for a future field trial are as follows:

- *CHOPS well selection.* A larger wormhole network is likely beneficial. In the absence of sand production data, the target wormhole network could be indicated by large recovery factor, high peak oil rates (relative to the reservoir thickness), and frequent pump changes. Wells indicating the presence of bottomwater or communication with an active aquifer (well logs, high water cuts) should be avoided.
- *Interwell communication.* Pressure communication between CHOPS wells at 40 acre spacing is not uncommon, especially after many years of production. Wormhole networks are often responsible for fast interwell transmissions. For the post-CHOPS SCV process, it will be important to recognize possible interwell communications and to take advantage of such knowledge.
- *Tuning of the numerical model from field trial data*. Once a field trail for SCV process has been planned, it is highly recommended to gather the data for the important process parameters and use this data to construct a numerical model and tune it to evaluate the relative permeability curves. Once tuned, this model can be used to perform optimization and sensitivity analysis in order to further improve the SCV process performance. The important process parameters information that can be gathered from the field is: fluid injection rate, fluid injection pressure, fluid injection temperature, injected fluid composition, wellbore pressure, temperature within the reservoir, oil production, gas production, water production, gas composition, and so forth.

5. References

Continental Steel Corporation (CSTL). 2015. Vacuum Insulated Tubing (VIT). Date accessed: July 2015. Available at: http://www.cstl.ca/products/vacuum-insulated-tubing-vit/.

FERST-CSI Technologies Inc. 2014. Submerged Combustion Vaporizer NRCan UOSE-018 R&D Project — High Capacity EOR Pressuring and Heating Heavy Oil Reservoirs. Confidential Presentation on June 30, 2014.

Husky Oil Operations Limited. 2013. Hot Water Vapour Process (HWVP) Field Trial Project - Final Report. Available at: http://www.ptac.org/projects/64.

Husky Oil Operations Limited. 2014. Hot Water Vapour Process (HWVP) Field Trial Project - Final Technical Report for the SPRI Program (Saskatchewan Petroleum Research Incentive). Available at: http://www.economy.gov.sk.ca/adx/aspx/adxGetMedia.aspx?DocID=10290,10289,3384,5460,2936,Documents&MediaID=6580e85a-7e18-4981-b5ed-70065b5cc6d7&Filename=Husky+Hot+Water+Vapour+Process.pdf.

Saskatchewan Research Council. 2015. Numerical Modelling of Submerged Combustion Vaporizer Process — Application in Post-CHOPS Reservoirs. Interim report delivered on 16 July, 2015.

Tremblay, B., Sedgwick, G., and Forshner, K. 1997. Simulation of Cold Production in Heavy-Oil Reservoirs: Wormhole Dynamics. *SPE Reservoir Engineering* **12** (2):110–117.

Tremblay, B. 2005. Modelling of Sand Transport through Wormholes. *J. Cdn. Pet. Tech.* **44** (4): 51–58.

Tremblay, B. 2008. Multi-Well Cold Flow Numerical Model. SRC Publication No. 12276-1C08.

Tremblay, B. 2009a. Multi-Well Cold Flow Numerical Model: Waterflooding Cold Produced Reservoirs. SRC Publication No. 12276-3C09.

Tremblay, B. 2009b. Cold Flow: A Multi-Well Cold Production (CHOPS) Model. *J. Cdn. Pet. Tech.* **48** (2): 22–28.