Preprints of the
9th International Symposium on Advanced Control of Chemical Processes
The International Federation of Automatic Control
June 7-10, 2015, Whistler, British Columbia, Canada

Model-Predictive-Control (MPC) of Steam Trap Subcool in Steam-Assisted Gravity Drainage (SAGD)

Sagar N. Purkayastha, Ian D. Gates, and Milana Trifkovic

University of Calgary, Calgary, AB T2N 1N4, Canada (e-mail: spurkaya, idgates, mtrifkov@ucalgary.ca).

Abstract: For thermal technologies for heavy oil and oil sand reservoir extraction, such as cyclic steam stimulation and steam-assisted gravity drainage (SAGD), suboptimal steam conformance leads to recovery factors between 25-50%. Although preliminary research using Proportional-Integral-Derivative (PID) control in SAGD operations has proved beneficial towards steam conformance, PID control is responsive only to deviation from set-points and lacks constraint-handling capabilities. This results in suboptimal actuation signals that are sometimes unattainable. This paper summarizes research on a Model-Predictive-Controller (MPC) with proactive adjustments of steam injection rate. The steam injection rate was determined based on recursive parameter updates of a suitable time varying dynamic model describing the implicit relationship between the subcool temperature difference and the input heat rate, to achieve optimal steam conformance. Furthermore, the steam injection rate was constrained such that the pressure with which the steam impinged on the formation, called well bottom hole pressure (BHP), was below the formation fracture pressure of 4500 kPa at all times. The real time control study was made possible by establishing a bidirectional communication link between the Computer Modelling Group (CMG) STARS^{TM}, and MATLAB/Simulink software. The three-dimensional heterogeneous reservoir model, developed in STARS^{TM} acted as a virtual plant and the MPC, developed in MATLAB/Simulink, acted as an onsite controller. Results show 35.7% improvement in oil recovery and a more efficient cumulative steam-to-oil ratio (cSOR) profile in comparison to the base case of steam injection at a constant BHP of 4000 kPa.

Keywords: Automatic process control (closed loop), Predictive control, Set-point control, SISO, Process models, Process parameter estimation, Recursive estimation, Recursive least squares, Constrained parameters, Steam-Assisted Gravity Drainage.

1. INTRODUCTION

The majority of the 1.7 trillion barrels of heavy oil and extra heavy oil in Western Canada (Burrowes et al. (2011)) are formed of extra heavy oil or bitumen, having viscosities in the order of millions of cP under normal reservoir conditions. Therefore, unconventional techniques of oil recovery, such as thermal recovery of bitumen, have proved to be the most efficient. Thermal recovery techniques pertaining to heavy oil recovery can broadly be said to consist of two steps; the first involves heating the bitumen such that its viscosity falls from millions of cP to around 20 cP, thus mobilizing it and the second involves directing the mobile bitumen towards a production well (Gotawala et al. (2009) and Gotawala et al. (2012)). The most current and widely used technologies for the fluidization of bitumen are Cyclic Steam Stimulation (CSS) and Steam-Assisted Gravity Drainage (SAGD) (Butler (1994)), both of which use steam.

The performance of any steam-based thermal recovery process of heavy oil is governed by its ability to efficiently deliver steam into the oil sands formation. This enables the steam to deliver its latent heat to the bitumen to mobilize it. For example, ideally in SAGD (Fig. 1), the steam from the rising steam chamber transfers its latent heat to the bitumen at the edges of the depletion chamber. The latent heat of steam then mobilizes the bitumen, which then flows, under the influence of gravity to the base of the depletion chamber above the production well. This process, currently, typically requires the lengths of the upper injection and lower production wells to be between 500 and 1000 m and the vertical spacing between the two wells to be between 5 and 10 m (Edmunds and Gittins (1993), Singhal et al. (1998), Komery et al. (1999)).

Additionally, steam delivery to the formation, and steam conformance within the formation needs to be optimal to maximize bitumen recovery. However, in reality, as shown in Fig. 2, reservoir heterogeneity, both fluid compositional and geological, hinders proper steam chamber growth, which in turn leads to suboptimal steam delivery and conformance (Larter et al. (2008)). As a result, present day technologies such as CSS and SAGD are able to recover between 25 and 50% of the oil from reservoirs.

One way to improve uniform steam delivery and conformance is by using steam trap control (Edmunds (1998) and Gates and Leskiw (2010)). Steam trap control prevents injected steam from being produced by maintaining a liquid

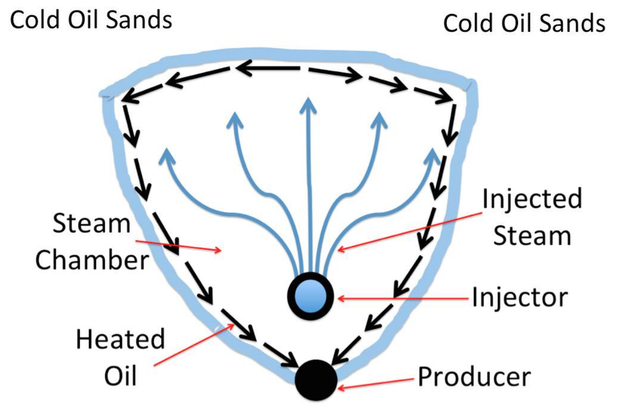

Fig. 1. Cross sectional view of a SAGD steam chamber: The latent heat of steam delivered at the edges of the rising steam chamber mobilizes the bitumen, which then drains along the edges of the steam chamber and accumulates above the producer to form the liquid pool for steam-trap control.

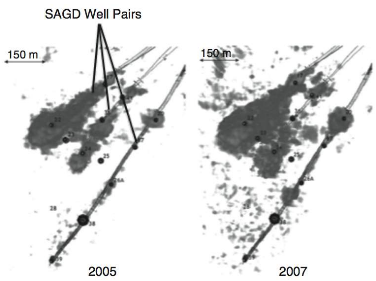

Fig. 2. Seismic images of the Surmount SAGD pilot picture (ConocoPhillips (2008)) shows non uniform steam conformance along the three SAGD well pairs after steam injection started in 1998.

pool above the producer (Sharma et al. (2011)). The height of the liquid pool is proportional to the subcool, which is the temperature difference between the injected steam and the produced fluids (Le Ravalec et al. (2009), Gates and Leskiw (2010), Gotawala et al. (2012)). Therefore, a small subcool leads to a small liquid pool height and subsequent live steam production, while a large subcool leads to the liquid occupying most of the steam chamber, resulting in suboptimal steam chamber growth. It is thus important to maintain an optimal subcool to enable steam trap control and maximize production (Gates and Leskiw (2010) and Patel et al. (2014)).

At present, subcool control at a typical SAGD well site is carried out either by manual or through PID control (Patel et al. (2014)). It is assumed that the entire liquid pool temperature, T_P, is constant and same as that of the produced liquid. In manual control, any deviation from the Set-point (SP) of T_P or the Control Variable (CV) is regulated by manual adjustments of the Manipulated Variables (MV), which in this case is the steam injection rate ($\dot{q}_S$), expressed as cold water equivalent. However, manual control is suboptimal and inefficient.

Although preliminary research and some field implementations have suggested that PID control based techniques is an improvement over the open loop manual control (Gotawala et al. (2009) and Gotawala et al. (2012)), there still remains the inability of PID controllers to handle constraints and calculate optimal control gains for the MV. The process of achieving the desired subcool by increasing T_P through injection of superheated steam and mobilizing the bitumen has a high time constant (τ). To compensate for the high τ, a high gain PID control can be used. However, a high gain PID control can increase BHP and thereby not only fracture the formation and make it unstable, but also increase the production cost. Therefore, constraint handling abilities are of paramount importance for this process.

This paper documents research on the novel utilization of a Model-Predictive-Controller (MPC) with proactive adjustments of $\dot{q}_S$ for the control of a SAGD process. The use of MPC is not new to the petroleum industry (Saputelli et al. (2005)). However, the use of MPC in SAGD operations is scarce (Patel et al. (2014)). Although Patel et al. (2014) use MPC for subcool control, the authors rely on using system identification techniques to determine the internal model of the MPC. As a result, offline tests were run to determine a process model. The same process model was used for the entire operation. Although using the same process model is sufficient in case of a MPC, frequently updated process models result in faster convergence. Lastly, Patel et al. (2014) use SEPTIC (Strand and Sagli (2003)), STATOIL's in-house MPC software, which is not publicly available.

The work described in this paper involves, recursive parameter updates of a transient model describing the implicit relationship between the subcool temperature difference, which in turn is a function of T_P, and the input heat rate ($\dot{Q}$). The real time control study was made possible by establishing a bidirectional communication link between the Computer Modelling Group (CMG) STARS^{TM}, and MATLAB/Simulink software.

The paper is presented as follows: Section 2 describes the heterogeneous reservoir model followed by Section 3, which presents the control architecture, the parameter estimation and a brief description of the bidirectional communication link between CMG STARS^{TM} and MATLAB/Simulink. Following Section 3, Section 4 presents the results and discussions, which is followed by Section 5, which has the concluding remarks.

2. RESERVOIR MODEL

The reservoir simulation model used here has properties typical of that of a McMurray Formation oil sands reservoir as would be found in the Athabasca deposit in the Northeastern region of the province of Alberta, Canada. It is a three-dimensional model representing a 93 m section of the SAGD well pair. The average porosity is equal to about 0.3 and the horizontal permeability is equal to about 4 D with a vertical permeability to horizontal permeability equal to 0.25. The vertical permeability distribution is displayed in Fig. 3. The average oil saturation of the model is equal to 0.8 with a solution gas-to-oil ratio equal to about 3 m^3/m^3. The viscosity of the oil is as follows: at 12°C, it is roughly equal to 2 million cP whereas at 220°C, it is equal to about 12 cP. The relative permeability curves were taken from Gates and Leskiw (2010). Prior to

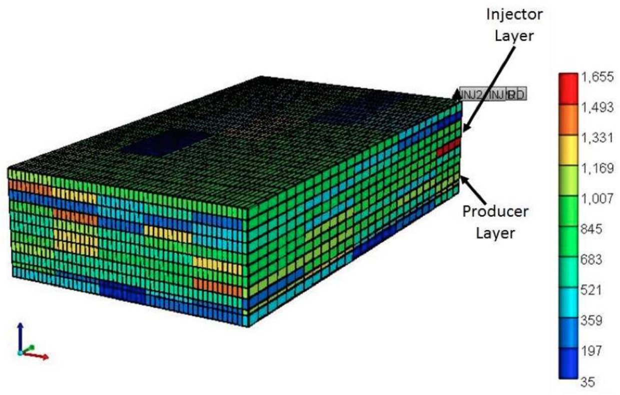

Fig. 3. Three-dimensional heterogeneous oilsands reservoir model, showing the vertical permeability, had 50 grid blocks along the X direction, 28 grid blocks along the Y direction and 11 layers in the Z direction with layer 4 being the injector layer and layer 9 being the producer layer. The well pair ran for 28 grid blocks along the Y direction.

SAGD operation, the wells operate as line heaters for five months to mimic steam circulation as done in the field. Steam circulation is used to heat the region between the wells to about $80°C$ prior to SAGD mode. This enables the creation of the steam chamber when SAGD operation starts. All injection and production rates are linked to the length of the well pair in the model, that is, 93 m. To get the equivalent rates for a 700 m long well pair, the rates should be multiplied by 7.53.

3. METHODS

This section presents the recursive parameter estimation and dynamic model update method, the control architecture, and the bidirectional communication between CMG STARS^{TM} and MATLAB/Simulink.

3.1 Parameter Estimation

As presented in Gotawala et al. (2012), the one dimensional Ordinary Differential Equation (ODE) implicitly relating $T_P(t)$ and $\dot{Q}(t)$ from the advancing steam chamber to the surface of the liquid pool, is given by Equation (1):

$$\frac{dT_P(t)}{dt} + A(t)(T_P(t) - T_R) = B(t) + T(t) \tag{1}$$

$T_P(t)$ is assumed to be constant throughout the liquid pool at any given point in time. The initial temperature of the oil sands formation is assumed to be T_R. The revised expressions for the time varying constants, $A(t)$, $B(t)$ and $T(t)$ are expressed in Equations (2) through (4) below:

$$A(t) = \frac{q_S(t)}{V_o(t)} \left[\frac{\frac{1}{SOR(t)} + \frac{f\rho_w C_{pw}}{\rho_o C_{po}}}{1 + \frac{C_{pw}(T_S - T_R)}{\eta_{eff}\eta_S\lambda_S}} \right] \tag{2}$$

$$B(t) = \frac{q_o(t)}{V_o(t)}(T_S - T_R) \tag{3}$$

$$T(t) = \frac{\dot{Q}(t)}{\rho_o V_o(t) C_{po}\left(1 + \dfrac{C_{pw}(T_S - T_R)}{\eta_{eff}\eta_S\lambda_S}\right)} \tag{4}$$

$V_o(t)$ is the time varying volume of oil in the liquid pool, above the production well. The time varying oil volumetric flowrate entering the liquid pool from the surrounding formation is $q_o(t)$. The densities of oil and water are given by ρ_o and ρ_w respectively, while *SOR(t)* is the time varying steam-to-oil ratio of the process expressed as cold water equivalent. C_{p*} is the heat capacity of Phase $*$. The entire steam chamber is assumed to be at the saturation temperature of the injected steam, T_S, and η_S is the quality of the injected steam. The factor, f, as stated in Gotawala et al. (2012), lies between 0.9 and 1.1 depending on the presence or absence of water within and around the formation.

The solution of Equation (1) is given by

$$T_P(t) = \frac{B(t) + T(t) - \gamma e^{-A(t)t} + A(t)T_R}{A(t)} \tag{5}$$

where γ is the constant of integration.

At $t = 0$, if there is any liquid pool in the formation then it is assumed to be at the original temperature of the formation, T_R. Therefore, $T_P(0) = T_R$.

Substitution of the initial conditions in Equation (5) leads to,

$$\gamma = B(t) + T(t) \tag{6}$$

Substituting the value of γ back in Equation (5) leads to Equation (7), which is the one dimensional non linear Equation required to estimate $T_P(t)$ at any given time.

$$T_P(t) = \frac{B(t)(1 - e^{-A(t)t})}{A(t)} + \frac{T(t)(1 - e^{-A(t)t})}{A(t)} + T_R \tag{7}$$

Therefore, after every three time steps, amounting to three simulation weeks, the parametric values of $A(t)$, and $B(t)$, in Equation (7), are estimated by using non-linear least squares and the value of $T(t)$ was used from the previous simulation time step. The T_P was computed in MATLAB by taking the mean temperature of the producer layer, thereby assuming that the producer layer constituted the liquid pool.

3.2 Control Architecture

A time varying dynamic process model derived from the physics relating T_P and $\dot{Q}(t)$ was used. The derivation of the model is presented in Gotawala et al. (2012). In Fig. 4, which shows the control architecture, the MV is $\dot{q}_S$, CV is T_P and the SP is $230°C$. The SP was chosen to maintain the subcool at $20°C$, which was previously found to be optimal for steam conformance (Gates and Leskiw (2010)). The objective function and the constraints of the MPC, used to minimize a finite horizon control and performance index, are given by Equations (8) and (9).

$$\min_u J(x(t), u(t), t) = \begin{cases} \displaystyle\sum_{k=1}^{H_P} [\hat{y}(k) - y(k)_{ref}]^2 \\ \displaystyle + \sum_{k=1}^{H_C} \lambda(k)[\Delta u(k|k+1)]^2 \end{cases} \tag{8}$$

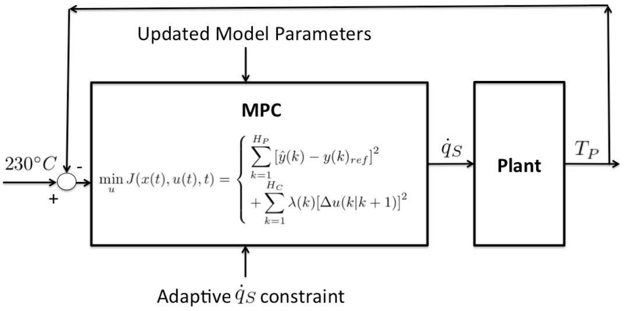

Fig. 4. The closed loop control block diagram. (Maintaining a SP of $230°C$ ensured a subcool of $20°C$)

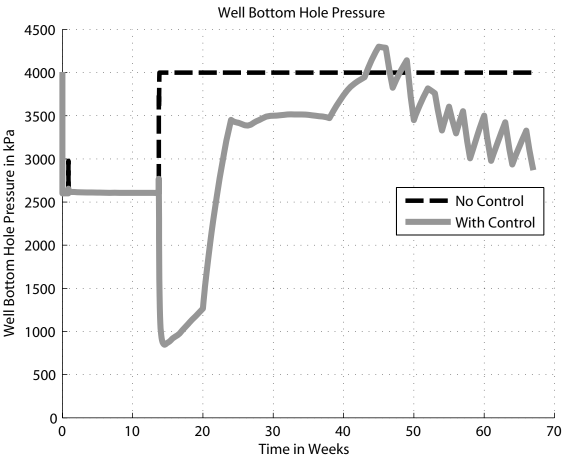

Fig. 5. Comparison of the BHP after 50 simulated weeks of operation between the "no control" case and the MPC case.

$$
subject\ to: \begin{cases} u \le 35 & t \le 6 \ \ \& \ \ 21 < t \le 25 \\ u \le 30 & 7 < t \le 20 \\ u \le 40 & 26 < t \le 30 \\ u \le 45 & t \ge 31 \\ u = 5 & e(t) = 0 \\ \lambda = 1 & e(t) < 20 \\ \lambda = 0.91 & e(t) \ge 20 \end{cases} \tag{9}
$$

For this study, the prediction horizon, H_P and the control horizon, H_C were kept constant at 10 and 1 respectively. The values for H_P and H_C were chosen such that they could be used to compensate for the high time constant of the process, thereby ensuring a more aggressive control strategy. In Equation (8), the predicted future and reference states are given by $\hat{y}(k)$ and $y(k)_{ref}$ respectively. The value for the reference state or T_P was chosen to be $230°C$ so that a subcool of $20°C$ could be attained. The control input, u or $\dot{q}_S$ was was carefully constrained to comply with the fracture strength (BHP of 4500 kPa) of the near well bore area. The profile for the upper bound of $\dot{q}_S$ was chosen in this manner because the near well bore area is not able to sustain a high initial $\dot{q}_S$. However, a few weeks of operation leads to a substantial growth of the liquid pool, with the liquid serving as a cushion resulting in no further increase in BHP even if $\dot{q}_S$ is increased. This phenomenon is evident in Fig. 5, where after Week 50 of the simulation, which is actually 30 weeks following the commencement of the SAGD operations, the BHP starts to decrease even though $\dot{q}_S$ is higher than at any time prior to that. Once the desired subcool was achieved, $\dot{q}_S$ was maintained at $5m^3/day$ instead of stopping the steam injection completely. This lower bound of $5m^3/day$ was selected to prevent wear and tear of the valve due to high frequency actuation signals leading to shutting and reopening of the valves. A penalization factor, λ, was used in excess of a $20°C$ error to ensure a bounded control.

The relationship between $T(t)$ and the injection rate or flowrate of steam $\dot{q}_S(t)$ are given by Equations (10) and (11):

$$
\dot{Q}(t) = T(t)\rho_o V_o(t) C_{po}\left(1 + \frac{C_{pw}(T_S - T_R)}{\eta_{eff}\eta_S\lambda_S}\right) \tag{10}
$$

$$
\dot{q}_S(t) = \frac{\dot{\widehat{V}}_S \dot{Q}(t)}{\eta_{eff}(\eta_S \widehat{H}_S + (1-\eta_S)\widehat{H}_L)} \tag{11}
$$

where $\widehat{V}_S$ is the specific volume of saturated steam at $250°C$ and 4000kPa, $\widehat{H}_S$ and $\widehat{H}_L$ are the specific enthalpies of steam and liquid water at $250°C$ and 4000kPa. The temperature of the injected steam was $250°C$ and the BHP for the "no control" case was 4000kPa. Since the efficiency of the process lies between 25 and 50%, η_{eff} was taken as 30%. The steam quality, η_S was maintained at 95%. It was assumed that the volume of oil produced (V_P) at any given time was 70% of V_o. The V_P was calculated in MATLAB by Equation (12):

$$
V_P(t) = \frac{N_P(t) M_{Bitumen}}{\rho_o} \tag{12}
$$

where $V_P(t)$ and $N_P(t)$ are the time varying volume of oil and the total moles of oil, produced per week, $M_{Bitumen}$ is a representative molecular weight of bitumen (Domin et al. (1999)) and ρ_o is the density of oil.

3.3 Bidirectional Communication

The real time control study was enabled by establishing a bidirectional communication link between the CMG STARS^{TM}, and MATLAB/Simulink software as shown in Fig. 6. The three-dimensional heterogeneous reservoir model, developed in CMG STARS^{TM}, acted as a virtual plant and the MPC, developed in MATLAB/Simulink, acted as an onsite controller. After each computational time step, the simulation in CMG STARS^{TM} was paused, and the total moles of oil produced (N_P) and the temperature of every grid in the formation block (T_F) was automatically imported into MATLAB/Simulink from CMG STARS^{TM}. This information was used to compute $\dot{q}_S$, which was automatically directed back to CMG STARS^{TM} from MATLAB/Simulink and the simulation in CMG STARS^{TM}, resumed. The simulation was run for a total of 50 simulation weeks.

The entire simulation was run on a single computer having 8 GB RAM and a 64 bit version of Windows 7.

4. RESULTS AND DISCUSSIONS

The MPC scheme was tested and compared with the "no control" scheme. The "no control" scheme involved running the simulation independently in CMG STARS^{TM}

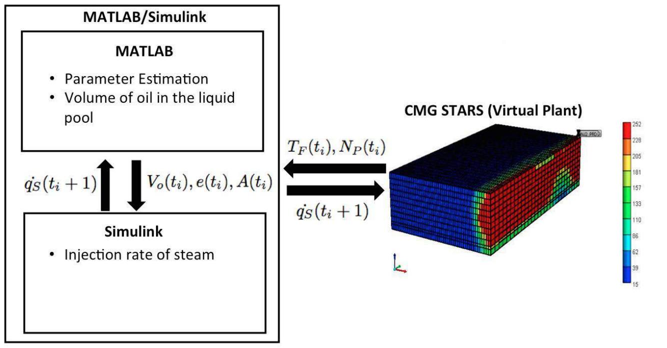

Fig. 6. The control architecture. (After every computational step, the simulation in CMG STARS^{TM} was paused and the necessary states were imported into MATLAB/Simulink, followed by the computation of the steam injection rate for the subsequent step, which sent back to CMG STARS^{TM} for the resumption of the simulation in CMG STARS^{TM})

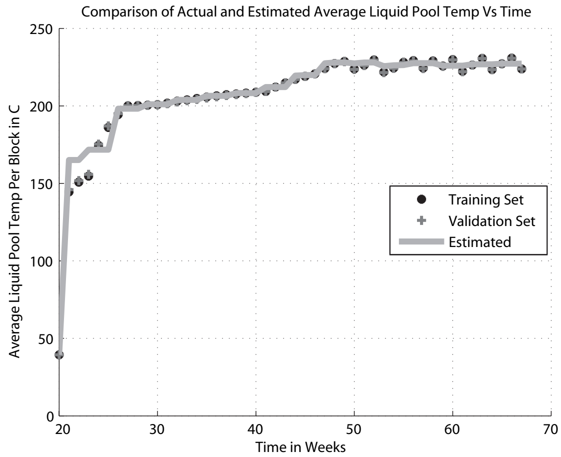

Fig. 7. Evolution of the estimated T_P for 50 simulated weeks of operation.

under constant BHP control of 4000 kPa. It should be noted that the SAGD operation commenced from Week 20 of the simulation, while the first 20 simulated weeks constituted the pre-heating period. As a result, in Fig. 7 and Fig. 8, which show the parameter estimation, the control effort and the error for when the SAGD operations started, start from Week 20.

The parameter estimation results in Fig. 7, indicated minor plant/model mismatch prevalent at the start of the steam injection process, in Week 20 and once the desired subcool of $20°C$ was attained, around Week 50 and later. Both the deviations from the actual plant model can be attributed to impulsive changes in $\dot{q}_S$ in excess of $20m^3/day$, geared towards minimizing the control effort and error, resulting in a sudden increase or decrease in temperature. However, the error due to the plant/model mismatch was within 10% at the beginning and within 2% for the rest of the simulation. Furthermore, the MPC was able to counter this plant/model mismatch.

The control effort in Fig. 8, shows that the steam injection rate was operating at the upper bound of the adaptive constraint for $\dot{q}_S$. This upper bound of the adaptive constraints, corresponded to values stated in Equation (9) for the specified time periods, until the error was nullified to zero close to Week 50 of the operation. Thereafter, the control effort oscillated between its upper and lower bounds based on the value of the error which oscillated between 0 and about $7°C$. The oscillation was due to the fact that $\dot{q}_S$ was updated once every week. Therefore, the reduction of $\dot{q}_S$ to $5m^3/day$, resulted in the decrease in T_P and accumulation of error until the next computational step (in a week), when it was compensated. The aggressive control strategy used, ensured faster convergence within 30 weeks of the start of the SAGD operations, in spite of the high τ of the process.

The cSOR profile in Fig. 9, shows that for the "no control" case shows a higher value at the start of the operation

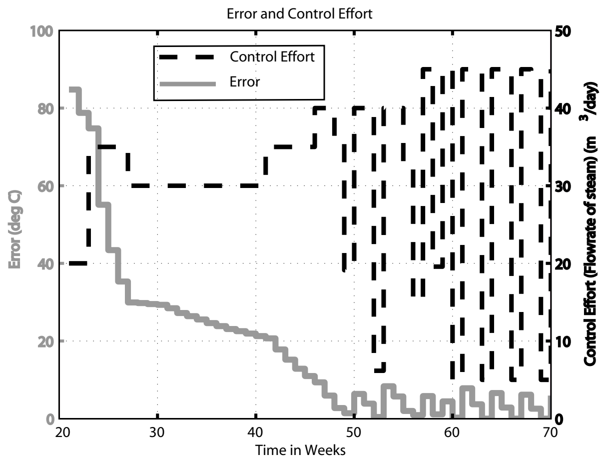

Fig. 8. Evolution of the error in T_P and the control effort or the steam injection rate for 50 simulated weeks of operation.

compared to the MPC case. This is an indication of lower process efficiency for the "no control" case in comparison to the MPC case. Apart from that, a high cSOR profile leads to high production costs.

Lastly, as shown in Fig. 10, the cumulative oil produced after 50 simulated weeks of operation was 1017.74 m^3 for the MPC case and 749.98 m^3 for the "no control" case. Therefore, the MPC case produced 35.7% more oil and hence proved to be more superior than the "no control" case.

5. CONCLUSION

In this paper, a linear MPC was designed in MATLAB/Simlulink to maintain a subcool temperature difference of $20°C$ by controlling steam injection into a reservoir model developed in CMG STARS^{TM} . During the course of the experiment, the parameters of the dynamic model implicitly relating T_P and $\dot{Q}$ were recursively estimated, thus enabling the accurate calculation of $\dot{q}_S$. A bidirectional communication link was established between CMG STARS^{TM} and MATLAB/Simulink, which made the real

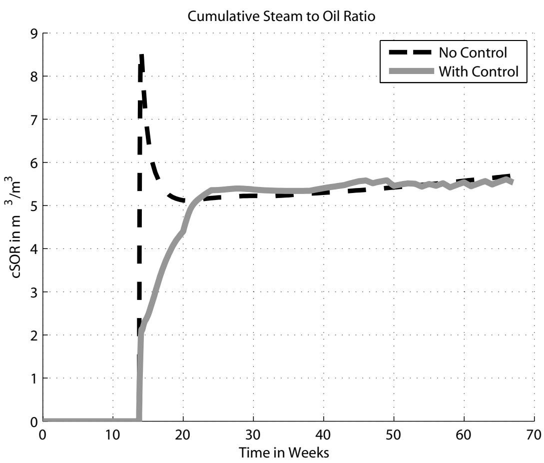

Fig. 9. Comparison of cSOR after 50 simulated weeks of operation between the "no control" case and the MPC case.

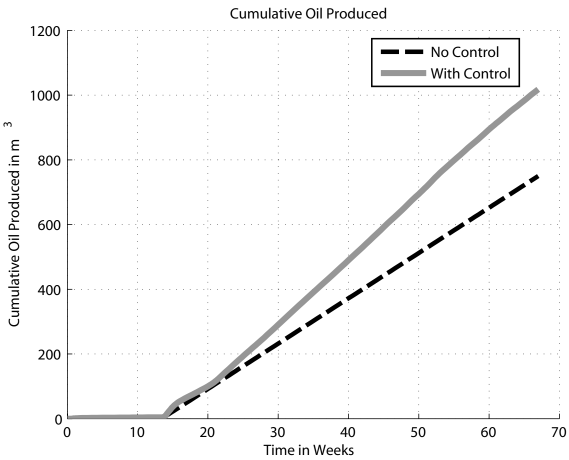

Fig. 10. Comparison of cumulative oil produced after 50 simulated weeks of operation between the "no control" case and the MPC case.

time control study possible. From the results, it is evident that the MPC was superior in comparison to the "no control" case. Additionally, the MPC was able to efficiently handle the minor plant/model mismatch, resulting mainly from the impulsive changes in temperature due to sudden changes in steam injection geared towards minimizing error and control effort. The results indicated a 35.7% increase in oil production when the MPC was used as compared to the "no control" case.

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