Gas-lift Optimization and Control with Nonlinear MPC

A. Plucenio * **D. J. Pagano** * **E. Camponogara** * **A. Traple** * **A. Teixeira** **

* *Departamento de Automação e Sistemas, Universidade Federal de Santa Catarina, 88040-900 Florianópolis-SC, Brazil*
e-mail: {plucenio, daniel, camponog, traple}@das.ufsc.br
** *CENPES-Petrobras, Rio de Janeiro, RJ, Brazil*
e-mail: alex.teixeira@petrobras.com.br

Abstract: More than 70% of the oil production in Brazil employs gas-lift as the artificial lift method. An effort is being done by some operators to complete new gas-lift wells with down hole pressure gages. This paper proposes a Non-Linear MPC algorithm to control a group of wells receiving gas from a common Gas-Lift Manifold. The objective is to maximize an economic function while minimizing the oscillations of the pressures at the manifold and at the bottom of the wells.

Keywords: Gas-Lift, Nonlinear MPC,

1. INTRODUCTION

Advanced Control Techniques like Nonlinear MPC have not arrived yet at the upstream processes of the oil industry. Many gas-lift wells with significant daily production are operating with manual driven gas injection and production chokes. In the last few years some Petroleum Exploration and Production companies have initiated efforts to introduce automation and control techniques in the operation of production wells. These initiatives resulted in technical approaches with names as smart wells, intelligent wells, smart fields or Digital Oilfield Management-GEDIG in Petrobras, Campos et al. (2006). The introduction of Information Technology in the oil production system is slow mainly due to the prohibitive cost of well intervention to install new sensors and actuators. Apart from that, sensors and actuators to be used in oil wells will have to cope with very harsh conditions caused by high pressure, temperatures and vibrations. There are several important works related to modeling, control and optimization of gas-lift wells operations like Boisard et al. (2002), Eikrem et al. (2004), L. Singre and Lemetayer (2006), Imsland et al. (2003), Camponogara and Nakashima (2006), Plucenio et al. (2006) to cite only a few. Not all control and optimization techniques discussed in the literature will be ready to be applied with the present instrumentation level of most gas-lift wells. This work discuss the automation of gas-lift wells equipped with downhole pressure measurement sensor, gas injection control valve and manually operated production choke. This is a realistic scenario in Brazil for new gas-lift wells. To our knowledge this is the first work that attempts to control the Gas Lift Manifold and the wells connected to it using Nonlinear MPC (NMPC). Section 2 discusses the NMPC formulation, section 3 presents and discusses the main results and section 4 concludes the paper.

⋆ A. Plucenio and A. Traple are supported by *Agência Nacional do Petróleo, Gás Natural e Biocombustiveis* under project PRH34-ANP/MCT. Daniel J. Pagano and E. Camponogara are supported by CENPES-Petrobras under the project *Development of control algorithms for artificial lifting*. A. Teixeira is a researcher at CENPES-Petrobras

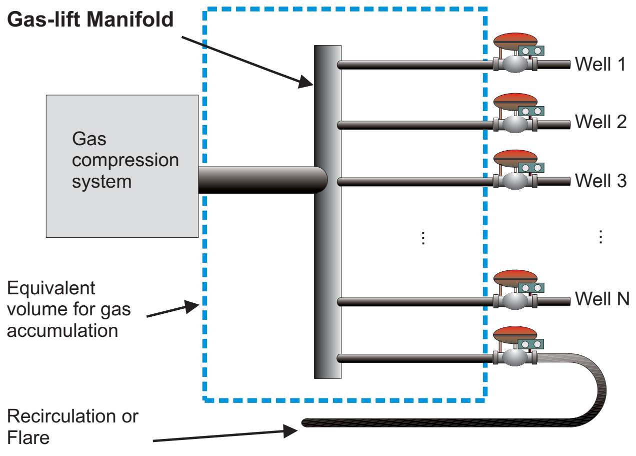

Fig. 1. Gas-lift Manifold

2. THE NMPC FORMULATION

We deal with a system where N gas-lifted wells with downhole pressure measurement and gas injection valves receive gas from a common Gas-lift Manifold (GLM). Gas from the compressor system enters the GLM and is distributed to the gas-lift wells and to an output which can be directed to the flare or to the recirculation of the compressor system. This output is a mechanism which allows gas to be discharged in cases where the gas flow-rate entering the GLM is higher than what is needed to operate the wells at their unconstrained optimum. This will be referred in the paper as the excess gas flow rate. The pressure at the GLM has to be kept at level high enough to allow injection in the annular of all gas-lift wells. For such a system shown in Figure 1 we wish

- to keep the GLM pressure close to a set-point designed according to the needs of the gas-lift wells,
- to distribute the gas flow-rate delivered by the compressor system among the gas lift wells in a way that maximizes an economic objective and

- to minimize the production oscillations caused by changes in the gas injection flow-rates. These oscillations cause problems to the separation process.

Some constraints should be introduced.

- To keep the gas injection flow rate of each well above a minimum value.
- To keep the pressure at the GLM between an upper and lower bound.

Table 1 presents the nomenclature used.

Table 1. Nomenclature

Symb.	Variable description	Unit
qo_i	Well i oil flow rate	std m$^3.d^{-1}$
$qliq_i$	Well i liquid flow rate	std m$^3.d^{-1}$
qw_i	Well i water flow rate	std m$^3.d^{-1}$
qg_i	Well i gas flow rate	std m$^3.d^{-1}$
p_{wf}	Bottom hole pressure with well flowing	kgf.cm^{-2}
$\bar{p}$	Average reservoir pressure	kgf.cm^{-2}
p_{sat}	Oil saturation pressure	kgf.cm^{-2}
q_{sat}	Liquid flow rate at $p_{wf} = P_{sat}$	std m$^3.d^{-1}$
q_{max}	Maximum well liquid flow rate (p$_{wf} = 0$)	std m$^3.d^{-1}$
qo_{max}	Maximum well oil flow rate	std m$^3.d^{-1}$
$qinj_i$	Well i gas injection flow rate	std m$^3.d^{-1}$
q_{exc}	GLM excess gas flow rate (flare or recirc.)	std m$^3.d^{-1}$
P_m	Gas Lift Manifold Pressure	kgf.cm^{-2}
P_{msp}	Gas Lift Manifold Pressure set point	kgf.cm^{-2}
p^*_{wf}	Value of p_{wf} used for normalization	kgf.cm^{-2}
$qinj^*$	Value of $qinj$ where $p_{wf} = p^*_{wf}$	std m$^3.d^{-1}$
q_{out}	Mass flow rate exiting the GLM	kgs^{-1}
q_{in}	Mass flow rate entering the GLM	kgs^{-1}
$\tilde{x}$	Predicted or modeled value of x	
Symb.	**Constants**	**Unit**
V	Equivalent GLM volume	m^3
R	Universal Gas Constant, 8.314472	Pa.m$^3/Kmol$
M	Gas molecular weight	kg.mol^{-1}
BSW	Water saturation	-
GOR	Gas Oil Ratio	-

2.1 The NMPC Cost Function

The NMPC Cost Function should be tailored in such a way that its minimization provides the objectives discussed previously. There are several economic objectives that can be introduced in the Cost Function. A more general economic objective should express the net economic result of the gas lift operation taking into account the revenue from the oil production, gas production and the costs associated with the gas compression, water treatment, etc. Every well i has a maximum attainable oil production rate, qo_{maxi} , which can be obtained with an unique gas injection flow rate. Since there is a cost to implement the gas injection flow rate it becomes interesting to consider an economic objective which takes into account the gas compression cost and the revenue due to the oil produced. This is done at every sample time kTs computing the total amount of oil that will not be produced and the total amount of gas that will be injected between the actual time kTs and the future time T defined by the prediction horizon p and the sampling time Ts, $T = (k+p)*Ts$. An expression for the revenue loss due to oil production below unconstrained optimum is

$$L = P_o \sum_{i=1}^{N} \sum_{j=1}^{p} \left[qo_{maxi} - qo_i(k+j) \right] Ts, \text{ where} \quad (1)$$

P_o is the oil price per 1 $stdm^3$. The gas injection compression cost can be expressed as

$$C_{comp.} = C_c \sum_{i=1}^{N} \sum_{j=0}^{p-1} \left[qinj_i(k+j) \right] Ts, \text{ where} \quad (2)$$

C_c is the cost to compress $1stdm^3$ of gas to the GLM nominal pressure P_{msp}. The economic objective can be obtained by determining for every well i the vector

$$\Delta \mathbf{Q}inj_i = \left[\, \Delta qinj_i(k) \;\; \Delta qinj_i(k+1) \; \ldots \; \Delta qinj_i(k+m-1) \, \right]^T, \quad (3)$$

that minimize the objective function J_1, or,

$$\min_{\Delta \mathbf{Q}inj} J_1 \quad (4)$$

$$J_1 = \sum_{i=1}^{N} \sum_{j=1}^{p} \left[qo_{maxi} - qo_i(k+j) \right] + \frac{p}{m} \frac{C_c}{P_o} \sum_{i=1}^{N} \sum_{j=0}^{m-1} \left[qinj_i(k+j) \right]$$

The factor $\frac{p}{m}$ compensates the fact that the accumulated production loss is computed along an interval of time pTs while the total gas injected is computed along the time mTs where p and m are respectively the prediction and control horizon length. This formulation, in the absence of constraints is equivalent to the equal slope method, Kanu et al. (1981). One way to implement the cost function in matrix representation is to define for each well i the oil production loss qo_{Li},

$$qo_{Li} = qo_{maxi} - \tilde{qo}_i(p_{wfi}), \quad (5)$$

where $\tilde{qo}(p_{wf}))$ is computed with the predicted p_{wf}. We assemble the vector $\mathbf{Q}\tilde{\mathbf{o}}_L$ with the difference between the maximum attainable oil flow rate and the predicted flow rate for every well i along the prediction horizon p.

$$\mathbf{Q}\tilde{\mathbf{o}}L = \left[\, qo_{L1}(1) \; \cdots \; qo_{L1}(p) \; \cdots \; qo_{LN}(1) \; \ldots \; qo_{LN}(p) \, \right]^T \quad (6)$$

In order to damp the production oscillations we propose to minimize the sum of the time differential square of the production losses of all wells along the prediction horizon.

$$J_2 = \sum_{i=1}^{N} \sum_{j=1}^{p} \left(\frac{dqo_{Li}(k+j)}{dt} \right)^2 \quad (7)$$

The time differential is obtained using the matrix T equivalent to the $\Delta = 1 - z^{-1}$ operator.

$$T = \begin{bmatrix} -1 & 1 & 0 & 0 & \cdots & 0 \\ 0 & -1 & 1 & 0 & \cdots & 0 \\ \vdots & \vdots & \vdots & \vdots & \cdots & 0 \\ 0 & 0 & 0 & \cdots & -1 & 1 \end{bmatrix} \quad (8)$$

The final Cost Function used is

$$J = \mathbf{W_1}\mathbf{Q}\tilde{\mathbf{o}}_L + \mathbf{W_2}\mathbf{Qm_{out}} + (\mathbf{P}_{msp} - \tilde{\mathbf{P}}_m)^T \mathbf{W}_3 (\mathbf{P}_{msp} - \tilde{\mathbf{P}}_m) + \left(\mathbf{T}\mathbf{Q}\tilde{\mathbf{o}}_L \right)^T \mathbf{W}_4 \left(\mathbf{T}\mathbf{Q}\tilde{\mathbf{o}}_L \right) + \Delta\mathbf{Qm}_{out}^T \mathbf{W}_5 \Delta\mathbf{Qm}_{out}, \text{where}$$

$$\mathbf{Qm}_{out} = \left[\, \mathbf{Q}inj_1; \; \mathbf{Q}inj_2; \; \cdots \; \mathbf{Q}inj_N; \; \mathbf{Q}_{exc.} \, \right], \text{ and}$$

$$\mathbf{Q}_{exc.} = \left[\, q_{exc}(k) \;\; q_{exc}(k+1) \; \ldots \; q_{exc}(k+m-1) \, \right]^T \quad (9)$$

The first two terms implement the economic objective, the third term forces the pressure at the GLM to its nominal value or set-point, the fourth term minimizes the production losses oscillation and consequently the oil production rate oscillations and the fifth term minimizes the changes in the gas injection flow-rates. The vectors $\mathbf{W}_1$ and $\mathbf{W}_2$ can be adjusted to implement the economic objective in steady state. The matrix $\mathbf{W}_3$, $\mathbf{W}_4$ and $\mathbf{W}_5$ must be adjusted to weight the dynamic response objectives against the economic objective. There is no doubt that the optimum gas distribution is reached in steady state since in this case terms 3, 4 and 5 vanish but a proper tuning should provide optimization also during production transients. An excessive requirement for the oil production oscillation attenuation may induce a production loss compared to softening this objective.

2.2 Prediction models

The main purpose of applying automatic control to a group of gas-lift wells is to maximize an economic objective. That means to distribute the available gas flow rate entering the GLM among the wells in order to maximize the oil production for instance. Using the available downhole pressure measurements, the parameters of the Inflow Performance Relationship (IPR) of each well as well as parameters like BSW and GOR, it is possible to estimate the oil production flow rate entering the well. For under-saturated reservoir (formation pressure above the bubble point pressure),

$$qo = J(\bar{p} - p_{wf}), \tag{10}$$

where J is the productivity index, p_{wf} is the well flowing pressure in front of the perforated zone, $\bar{p}$ is the static pressure, and qo is the oil flow rate produced by the well. For saturated reservoirs, Vogel's formula Vogel (1968) gives

$$qo = qv_{max}\left[1 - 0.2\frac{p_{wf}}{\bar{p}} - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2\right], \tag{11}$$

where qv_{max} is the maximum oil flow rate (for $p_{wf} = 0$). Defining the bubble pressure as p_{sat}, Patton and Goland (1980) proposed an expression considering the case where $\bar{p} > p_{sat}$ and the well operating with $p_{wf} \geq p_{sat}$ or $p_{wf} < p_{sat}$:

if $p_{wf} \geq p_{sat}$

$$q_{liq} = \frac{q_{sat}}{\bar{p} - p_{sat}}(\bar{p} - p_{wf}), \tag{12}$$

if $p_{wf} < p_{sat}$

$$q_{liq} = q_{sat} + (q_{max} - q_{sat})\left[1 - 0.2\frac{p_{wf}}{p_{sat}} - 0.8\left(\frac{p_{wf}}{p_{sat}}\right)^2\right]$$

$$qw = BSW q_{liq.} \tag{13}$$

$$qo = (1 - BSW)q_{liq}, \tag{14}$$

$$qg = RGOq_o \tag{15}$$

where q_{liq} is an IPR relationship that accounts for liquid flow rate in saturated and under-saturated wells, qw is the water flow rate, qo is the oil flow rate and qg is the gas flow rate. Other IPR models are found in Fetkovich (1973), Richardson and Shaw (1982), Raghavan (1993), Wiggins et al. (1996), and Maravi (2003). Due to the difficulty to have on line measurements for oil, water and gas flow rate of each well, and taking advantage of the availability of downhole pressure measurements an effort was done to derive an empirical model relating steady state gas injection flow rate to downhole pressure. For a real application the cost to obtain steady state values of downhole pressure and gas injection rate is significant since the well will have to operate at downhole pressures which translate into lower oil flow rate. Therefore it is highly desirable that the steady state model relating $p_{wf} = f(q_{inj})$ could be adjusted with measurements close to the point (p^*_{wf}, q^*_{inj}) where the production loss is minimum. A mathematical model with good extrapolation capability is most welcome. Most gas-lift wells do not produce naturally and for those the knowledge of the average reservoir static pressure, even with some uncertainty, gives an important information that can be used in the model since $p_{wf}(q_{inj} = 0) = \bar{p}$. In order to avoid numerical problems the relationship proposed uses normalized variables. Downhole pressure and injection flow rate are normalized to the pair (p^*_{wf}, q^*_{inj}). This would be an operational point corresponding to an observed lowest downhole pressure. The exact point chosen to normalization is not too important as long as the curve adjustment can use points to the right and left of (p^*_{wf}, q^*_{inj}).

$$\begin{aligned} u &= \frac{q_{inj.}}{q^*_{inj.}} \\ y &= \frac{p_{wf}}{p^*_{wf}} \\ y &= \Theta_1 e^{-\Theta_2 u^m} + \Theta_3 + \Theta_4 u^2 \\ \tilde{p}_{wf} &= p^*_{wf} y. \end{aligned} \tag{16}$$

A simplified SQP algorithm was developed for the curve fitting

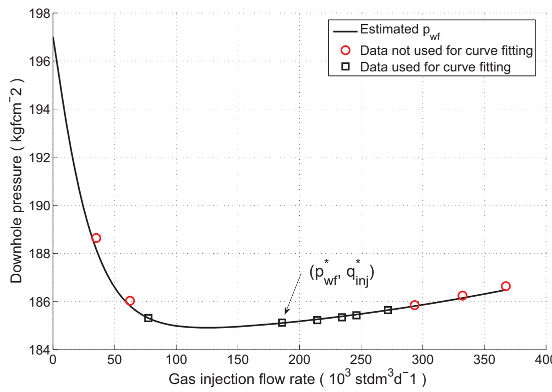

Fig. 2. Estimated p_{wf}

which uses the information about the average reservoir static pressure and its uncertainty. Figure 2 shows an example of curve fitting for data obtained from a rigorous steady state gas lift simulator. In order to verify the model extrapolation capability some points with lower values of downhole pressure were not used for the curve parameters adjustment. All points are plotted to show that the model adjusts well to the data even with a narrow data range used for the curve fitting. The points used for the curve fitting present downhole pressure close to the minimum which means that the production loss for obtaining these measurements would be minimum. Because one of the control objectives is to damp the oil production flow rate oscillations caused by changes in gas injection flow rates, it is also important to have a dynamic model for prediction. Since the main objective is economic, the dynamic prediction model needs to exhibit a very accurate steady state relationship. Modern wells are being completed with Venturi gas-lift operating valves. These valves can provide critical flow for the injection gas at very low pressure drops (about 10% of the upstream pressure). This is normally enough to make sure that the gas-lift flow will be critical for most of its operating range. Critical flow in the gas-lift operating valve eliminates the heading phenomena but does not help to avoid the density wave oscillations, Hu (2004). In order to take advantage of the steady state model developed for $p_{wf} = f(q_{inj.})$ a Hammerstein model is proposed to be used for prediction. Figure

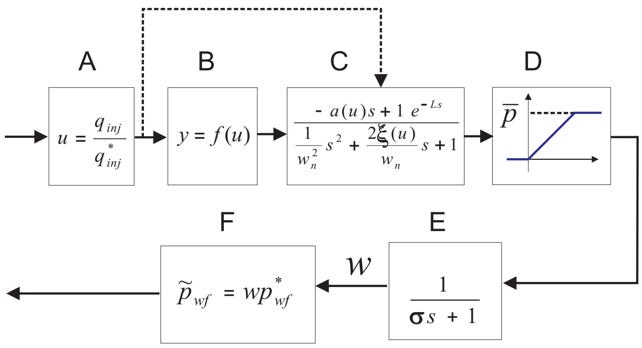

Fig. 3. Hammerstein dynamic model $p_{wf}(t) = f(q_{inj}(t))$

3 shows the dynamic model structure. Block A performs the normalization to the gas injection flow rate, block B applies the steady state function shown in equation (16), block C is a second order transfer function with transport delay and an adaptive zero and damping factor. Block D applies a saturation limiting the pressure values between zero and static pressure $\bar{p}$. Block E filters the saturation effect and block F multiplies the incoming signal by p^*_{wf} to recover the final estimated $\tilde{p}_{wf}$. It is assumed that the operating valve is working in critical mode so the gas flow rate crossing it is approximately the same gas flow rate that entered the casing head L seconds earlier. An approximate expression for L, ξ and the zero a are

$$L = \frac{H}{\sqrt{\frac{\gamma R T}{M}}},$$
$$\xi = k_1(.99 - e^{-3u(t-L)^2}) \text{ and}$$
$$a = \frac{k_2}{k_3 + u(t-L)}, \text{ where} \tag{17}$$

H is the distance from the casing head to the operating valve, γ is the gas ratio $\frac{c_p}{c_v}$, R is the universal gas constant, T is the gas temperature, $u(t-L)$ is the normalized gas injection flow rate at the casing head L seconds before the actual time and the constants k_1, k_2 and k_3 need to be tuned for each well together with the natural frequency w_n. In order to develop this empirical model several well cases were simulated with the OLGA^{TM} [1]. The pressure at the manifold, (P_m) is modeled as the pressure of a volume (V) filled with gas that results from the balance of gas that arrives from the compressor system and gas leaving to the wells and to the flare or to recirculation depending on the setup. The volume V is the sum of the internal volumes of all pipes between the compressor system and wells casing head. The pressure at the GLM is modeled as

[1] http://www.sptgroup.com/Products/olga/

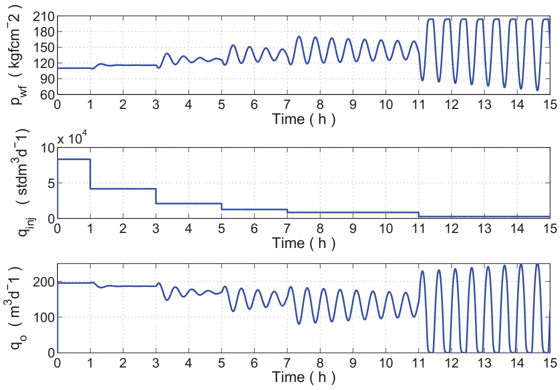

Fig. 4. Dynamic model response

$$\dot{P}_m = k_{GLM}(q_{in} - q_{out}),$$
$$k_{GLM} = \frac{RT}{MV}, \text{ where} \tag{18}$$

T is the gas temperature, R is the gas universal constant and M is the gas molecular weight. The compressibility factor is assumed to be one. It is assumed that the gas mass flow rate entering the GLM is measured.

3. RESULTS AND DISCUSSION

In order to test the strategy proposed a total of 4 wells were modeled. These wells were simulated with a rigorous steady state simulator and the parameters of the empirical model given by equation (16) were tuned. The wells details are shown in table 2. A hypothetical dynamic model was added according to the model structure shown in figure 3. The Nonlinear MPC

Table 2. Well data

$Parameter$	$Well\ 1$	$Well\ 2$	$Well\ 3$	$Well\ 4$
$qmax[\frac{m^3}{d}]$	871.38	7.739e+003	5.177e+003	1.558e+003
BSW	0.341	0.676	0.03	0.488
$p^*_{wf}[kgf/cm^2]$	110.0	185.1	182.9	146.5
$q^*_{inj}\ [m^3/d]$	8.33e+4	1.859e+5	2.661e+5	9.98e+4
$\bar{p}\ [kgf/cm^2]$	203.7	199	217.2	205
a_1	.9038	0.067	0.4003	0.3885
a_2	3.5039	8.0042	0.6133	5.8235
a_3	0.9666	0.9972	0.7751	0.9972
a_4	0.0075	0.0026	0.0082	0.0052
m	0.56	1.11	0.09	1.04

algorithm used is discussed in Plucenio et al. (2008b) and with more details in Plucenio et al. (2008a). The NMPC algorithm, named PNMPC, employs a continuous linearization technique where the vector of the predicted variable $\tilde{\mathbf{Y}}$ is represented by

$$\tilde{\mathbf{Y}} = \mathbf{F} + \mathbf{G}\Delta\mathbf{u} + \Gamma. \tag{19}$$

The matrix $\mathbf{G}$ is the Jacobian of $\tilde{\mathbf{Y}} = f(\Delta\mathbf{u})$ and is obtained by a numerical procedure realized in two steps at every iteration. The first step uses the matrix $\mathbf{G}$ of the previous iteration to produce an intermediate $\Delta\mathbf{u}$. Next, another matrix $\mathbf{G}$ is obtained using the $\Delta\mathbf{u}$ just computed. The matrix $\mathbf{G}$ used to compute the final $\Delta\mathbf{u}$ is an average of the two matrix. The vector Γ represents the correction factors which are an explicit version of the CARIMA error treatment.

3.1 NMPC Tuning

One way to tune the NMPC objective function weights is to start by the economic function as described by equation (4). Next the other weights are tuned to balance production oscillation attenuation with the economic objective. For numerical efficiency it may be interesting to multiply all weights by a common factor. The tuning parameters are shown in table 3. Controlling the system composed by the GLM and the wells

Table 3. NMPC Tuning Parameters

Symb.	Variable description	Value
Ts	Sampling time	5s
p	Prediction horizon for qo_L	150
p_1	Prediction horizon for P_m	18
w_1	Element of vector $\mathbf{W}_1$ $1 \times 4p$	.020
w_2	Element of vector $\mathbf{W}_2$ $1 \times 5m$	5e-4
w_3	Diagonal element of Matrix $\mathbf{W}_3$ $p_1 \times p_1$	(1)
w_4	Diagonal element of Matrix $\mathbf{W}_4$ $4p \times 4p$	(2)
w_5	Diagonal element of Matrix $\mathbf{W}_5$ $5m \times 5m$	(3)

(1) $w_3(i)$ varies linearly from 1 to 10 for $i = 1:18$

(2) w_4 is a linear function of the filtered and normalized gas mass flow rate q_{in} entering the GLM. 1 for $q^*_{in} = 1$ and 12 for $q^*_{in} = 0.25$

(3) $\mathbf{W}_5(i,i) = 1x10^{-5}$ for i=1:12. For Δu_{flare}, $\mathbf{W}_5(i,i)$ for i=13:15, a linear function of the filtered and normalized gas mass flow rate q_{in} entering the GLM was used. $\mathbf{W}_5(i,i)$ goes from $1x10^{-5}$ for $q^*_{in} = 0.25$ to $15x10^{-5}$ for $q^*_{in} = 0.25$.

has a great advantage of eliminating the gas lift availability constraint. Many gas-lift optimization studies consider gas lift availability as a constraint while this information is not always available. Another advantage is the possibility to apply optimization during the transients which can be more or less frequent depending on the setup used. On the other hand the GLM pressure dynamic behavior is highly dependent on the associated pipe internal volume and it will be normally faster than the downhole pressure. This requires the sampling time to be adjusted based on the GLM pressure dynamics. To overcome a bit the problem the qo_L predictions were done every 3 sampling time resulting in a prediction horizon p equal to 150. A constraint was used to make sure that the excess gas flow rate would be always positive. Besides, a minimum flow rate was imposed to all wells to avoid entering in the density wave limit cycle. A constraint was used to imposed a limit on the GLM Pressure deviation from the set point at +- 5%.

3.2 Results obtained

In order to test the control strategy proposed an operation of 24 hours was simulated covering different gas-lift availabilities. It was assumed an equivalent volume for the GLM (sum of all associated pipes internal volume) equal to 1 m^3. The initial gas injection flow rate was the sum of all gas flow rates values which corresponded to the values used for normalization. This value was considered as the nominal input GLM flow rate. Next the gas entering the GLM was changed to 50%, 25% and 110% of nominal value as shown on figure 5. Figure 6 top shows all the wells downhole pressure (normalized values) and the GLM pressure (normalized to the set-point value). It can be noticed that they change smoothly. The GLM pressure presents a small deviation from its set-point at moments of significant ramp type changes on the gas flow rate entering

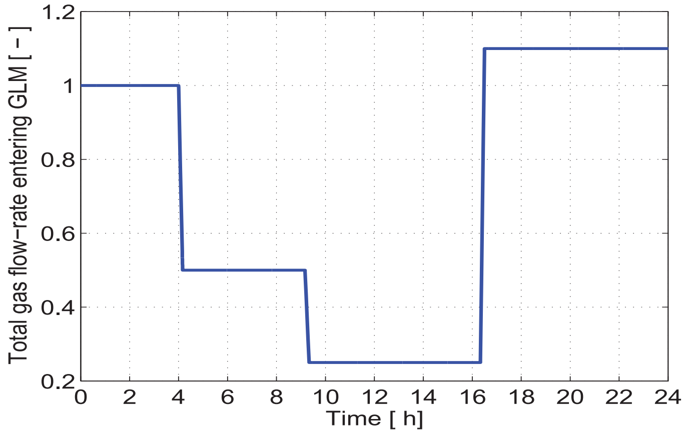

Fig. 5. Normalized gas flow-rate entering the GLM

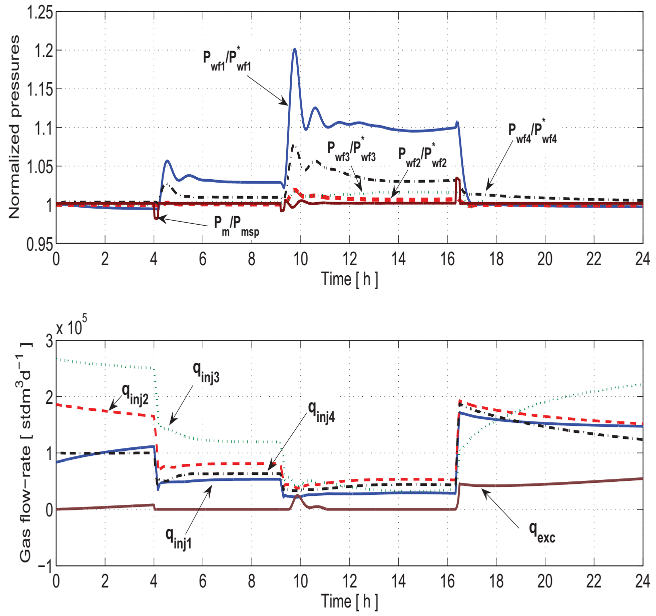

Fig. 6. GLM and gas lift wells behavior

the GLM although not enough to exceed the constraints. The bottom plot of figure 6 shows all the gas injection flow rates for the four wells and the excess gas flow rate. It is interesting to observe that when the gas flow rate entering the GLM goes to 110% of the nominal value the excess gas flow rate rises to keep the GLM pressure at its reference and to avoid production losses. When the gas entering the GLM decreases from 50% to 25% of the nominal value, the excess gas flow rate helped on avoiding too much change in the wells gas injection flow rate what would cause excessive oil production oscillation. This behavior can be controlled by tuning the Cost Function parameters. Figure 7 shows the evolution of the total oil production flow rate as the gas entering the GLM was changed. Both, 100% and 110% of nominal GLM input flow-rate give the same total oil production flow-rate. The gas flow rate not used for injection in the wells returns on the recirculation line as excess gas as shown in figure 6. The oil production flow rate of all the four wells is shown in figure 8. The solid lines were obtained with the simulation including the

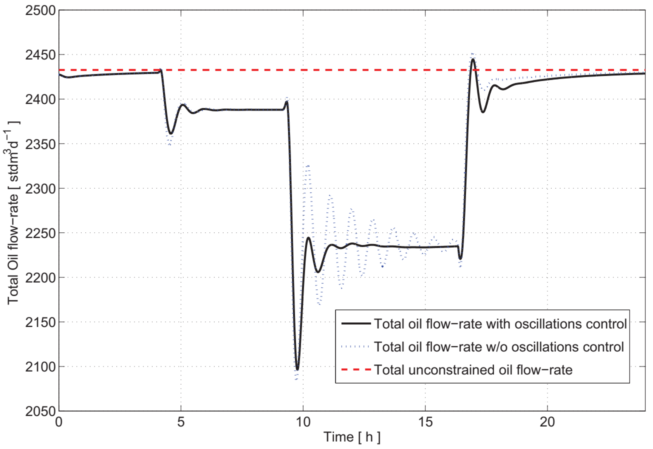

Fig. 7. Total oil production flow rate

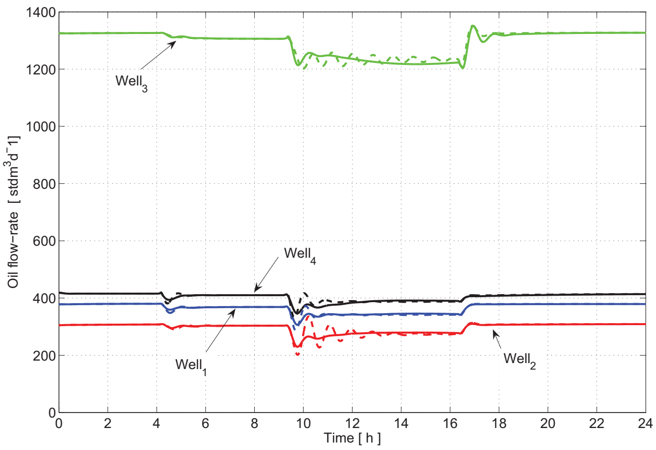

Fig. 8. Oil Production flow rate for all wells

oscillation attenuation control while the dashed lines not. The well 3 is the main producer. It is interesting to notice that the production decay is not much affected by the decrease in the total gas injection flow rate due to the appropriate gas allocation made by the NMPC algorithm. Despite the limited degree of freedom (only gas injection flow-rate manipulation) all the objectives are met; optimum gas distribution, GLM pressure control and attenuation of oil production oscillations.

4. CONCLUSION

Downhole permanent pressure measurement is becoming a reality for new wells. This work proposes the utilization of the PNMPC control technique discussed in Plucenio et al. (2008b) and demonstrates its applications on the control of 4 gas-lift wells using simulation. More work has to be done to investigate the quality of the empirical gas lift well dynamical model proposed.

ACKNOWLEDGEMENTS

The authors also acknowledge Scandpower for providing an academical OLGA2000 software license.

REFERENCES

Boisard, O., Makaya, B., Nzossi, A., Hamon, J., and Lemetayer, P. (2002). Automated well control increases performance of mature gas-lifted fields, Sendji case. In *Proc. 10^{th} Abu Dhabi International Petroleum Exhibition and Conference*. Abu Dhabi,. Paper SPE 78590.

Camponogara, E. and Nakashima, P.H.R. (2006). Optimizing gas-lift production of oil wells: Piecewise linear formulation and computational analysis. *IIE Transactions*, 38(2), 173–182.

Campos, S.R., Junior, M.F.S., Correa, J.F., Bolonhini, E.H., and Filho, D.F. (2006). Right time decision of artificial lift management for fast loop control. In *SPE Intelligent Energy Conference and Exhibition*. Amsterdam, Netherlands.

Eikrem, G.O., Imsland, L., and Foss, B. (2004). Stabilization of gas-lifted wells based on state estimation. *Proc. of International Symposium on Advanced Control of Chemical Processes-ADCHEM, Hong Kong*.

Fetkovich, M. (1973). The isochronal testing of oil wells. In *Proceedings of the SPE Annual Fall Meeting*. Las Vegas, Nevada.

Hu, B. (2004). *Characterizing gas-lift instabilities*. Master's thesis, Department of Petroleum Engineering and Applied Geophysics, Norwegian University of Science and Technology University, Trondheim, Norway.

Imsland, L., Eikrem, G.O., and Foss, B. (2003). State feedback control of a class of positive systems: Application to gas lift control. *Proc. of European Control Conference, Cambridge*.

Kanu, E.P., Mach, J., and Brown, K.E. (1981). Economic approach to oil production and gas allocation in continuous gas lift. *Journal of Petroleum Technology*, 33, 1887–1892. Paper SPE 9084.

L. Singre, N. Petit, T.S.P. and Lemetayer, P. (2006). Active control strategy for density-wave in gas-lifted wells. *International Symposium on Advanced Control of Chemical Processes-ADCHEM*, 2(ADCHEM 2006), 1075–1080.

Maravi, Y.D.C. (2003). *New Inflow Performance Relationships for Gas Condensate Reservoirs*. Master's thesis, Department of Petroleum Engineering, Texas A&M University.

Patton, D. and Goland, M. (1980). Generalized IPR curves for predicting well behavior. *Petroleum Engineering International*, 52(7), 74–82.

Plucenio, A., Mafra, G.A., and Pagano, D.J. (2006). A control strategy for an oil well operating via gas-lift. *International Symposium on Advanced Control of Chemical Processes-ADCHEM*, 2(ADCHEM 2006), 1081–1086.

Plucenio, A., Normey-Rico, J.E., Pagano, D.J., and Bruciapaglia, A.H. (2008a). Controle preditivo não linear na indústria do petróleo e gás. *IV Congresso Brasileiro de P & D em Petróleo e Gás - PDPetro*.

Plucenio, A., Pagano, D.J., Bruciapaglia, A.H., and Normey-Rico, J.E. (2008b). A pratical approach to predictive control for nonlinear processes. *NOLCOS 2008*.

Raghavan, R. (1993). *Well Test Analysis*. Prentice Hall, Englewood Cliffs, NJ.

Richardson, J.M. and Shaw, A.H. (1982). Two-rate IPR testing – a practical production tool. *Journal of Canadian Petroleum Technology*, 57–61.

Vogel, J.V. (1968). Inflow Performance Relationships for Solution-Gas Drive Wells. In *JPT*.

Wiggins, M.L., Russel, J.E., and Jennings, J. (1996). Analytical development of vogel-type inflow performance relationships. *SPE Journal*, 355–362.