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Anti-slug control design: Combining first principle modeling with a data-driven approach to obtain an easy-to-fit model-based control

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ABSTRACT

The limit cycle is an unexceptional problem in the oil industry that may cause significant losses in production. Also called slug flow or slugging, the unsteady flow can be handled by feedback control, although nonlinear issues must be considered. As an oil well production valve is opened, its transfer function gain tends to decrease until it reaches zero, meaning that the valve actions lose effect against the system backpressure. Notwithstanding, this sensitivity loss can be compensated by adapting a suitable tuning according to the well operating point. In this work, a methodology to generate this control policy is proposed based on combining first principle modeling with a data-driven approach. The method aims at improving closed-loop performance through a gain scheduling curve resulting from an easy-to-fit model to plant data. A systematic procedure is defined and validated through an actual deployment in a Petrobras ultra-deepwater oil rig. As a result, it was possible to suppress unsteady flow and increase oil production by more than 9%. Although the method has been validated in a satellite offshore well, one expects that feedback control can be used in different scenarios successfully, regardless of the slugging mechanism.

1. Introduction

During an oil field life cycle of production, it is likely that problems related to stability occur. These problems originate in the multiphase flow features and are more common when the field reaches a mature stage. One can say the offshore upstream sector is frequently more affected by this kind of problem, once the subsea flowlines may trap gas due to terrain irregularities or negative declines between seabed lines and the riser. This occurrence creates a cyclic pattern of flow where gas is trapped by liquid accumulation, making the pressure increase until the liquid column is pushed away all the way through the production line. In the next step, a new incoming liquid joins the liquid that returns from the riser, and a new blockage occurs, beginning the cyclic phenomenon once again. If the pressure oscillation reaches high amplitude, this phenomenon is called severe slug flow, and it represents safety risks to facilities and/or disturbances to process plants. Several kinds of slugging mechanisms are widely discussed in Gilbert (1954), Yocum (1973), Schmidt et al. (1980), Taitel (1986), Bendiksen et al. (1986), Fuchs (1987), Torre et al. (1987), Fabre et al. (1990), Jansen et al. (1996), Hu (2004), Sinegre (2006), and Eikrem (2006).

Unstable wells result in production reduction. Yocum (1973) describes losses in production capacity of more than 50% in offshore oil field systems caused by poor design of two-phase flow risers. The author presents two real cases in which the slug flow formed in the vertical section was so severe that the flow capacity was reduced by approximately 60% and 70%. At that time, the offshore industry was experiencing its first severe troubles regarding slugging. Unfortunately, still nowadays, it is not possible to design an optimal oil rig because the production conditions substantially change along the field lifecycle.

Despite slugging is an old problem in the oil industry, its solution has not reached a consensus in the engineering community. One can sort the approaches to handle slugging into two groups (Pedersen et al., 2016): the passive and the active methods. Passive strategies basically refer to installing equipment to dampen the slug flow. This type of solution is

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more common in onshore environments, since this scenario requires more area and weight for installation, and the maintenance costs are much lower when compared with the ones in offshore facilities. On the other hand, active approaches consider the use of feedback control to address the stability problem and puts an end to all that passive solutions drawback. However, active solutions require a certain degree of instrumentation and automatic actuators.

Slug flow reduces production even if it does not harm safety. Hu and Golan (2003) reported around 20–40% of losses due to unstable gas-lifted system in their models. Still based on simulations, Diehl et al. (2018) experienced more than 40% oil production recovery by unsteady well stabilization through feedback control. In a laboratory scale at Shell R&D facilities, Kinderen and Dunham (1998) showed production rates increase of more than 40% by active control applied to an unsteady well. Considering a real scale test, Diehl et al. (2019a) depicted a feedback control deployment in a Petrobras ultra-deepwater well that obtained a 10% increase in oil production.

As a matter of fact, it is impossible to exactly assess a global average of production losses caused by unstable flow once this number relies on a lot of conditions, such as reservoir pressure, production index, water cut, gas-oil ratio, emulsion formation, and so on. In spite of this, it is possible to say that the problem is still underestimated and the potential locked behind it might be quite relevant to the industry.

Diehl et al. (2019b) present three active control strategies to slug flow: a linear PID; a nonlinear PID; and a linear MPC-PID. The MPC-PID strategy has shown smoother actions and transitions between set points, and it was validated in a real deployment present in Diehl et al. (2019a). The nonlinear PID has allowed the system to reach the lowest back pressures in well simulations, which results in higher oil production. Considering that the nonlinear PID compensation rule is not trivial to define, this paper aims at proposing a systematic methodology to nonlinear anti-slug control design. The procedure described making use of first-principles modeling coupled with a data-driven approach to offer a straightforward way to design a gain scheduling based anti-slug controller. As far as the authors know, this problem still was not addressed by this kind of approach in literature.

Therefore, this article proposes a new method to design anti-slug controllers based on first principles modeling and plant data. The major contribution of the method might be the ease to fit the proposed semi-empirical model to real data, which is usually a complex task in practical multiphase flow problems. As a result the whole well pressure steady states can be quickly mapped and used in the most diverse ways. In this work the main propose is to produce a control tuning compensation as close as possible to the nonlinear well behavior.

The control strategy aims to handle riser-induced slugging, once this mechanism usually induce the most severe unsteady flow patterns in an oil production system. However, the method might perform properly for any kind of slug flow mechanism. This is because the controller synthesis rely on the steady state well pressure and this behavior is independent of the slugging nature. The further field application reinforces this statement, since in actual production there is no way to be sure of the origin of the instability - here the slugging is likely a riser-induced type, but there are potential contributions from terrain-induced and hydrodynamic slugging as well. Regardless the slugging mechanisms and its combinations, the control strategy has shown suitable performance to deal with unsteady wells.

The paper is divided into five sections: (1) overview about active control in unstable wells; (2) description regarding the suggested control design systematic; (3) simulated control performance assessment; (4) validation deployment in a real oil rig, which has resulted in more than 9% increase in oil production; and (5) final considerations.

2. Background

Most oil wells will experience some types of instabilities at some point in their lives, whether in an onshore or offshore environment. In the 1950s, Gilbert (1954) reported what seems the most popular way to avoid unsteady flow in gas lifted wells: increasing its backpressure by choking the flow. In order to increase the flowrate of wells that have been beaned back to avoid slugging, the author mentions a device called "intermitter control". The intermitter control was a kind of mechanical device which opens or closes the production valve relying on the pressure in the gas annulus. Essentially, the idea consisted of moving the valve to an open position if the pressure was high and to a closed one if the pressure was low. Although the concept resembles a sort of sketchy feedback controller, according to Gilbert (1954), intermitters have been misapplied mostly by difficulties in selecting the setting ranges.

Subsequent years were concentrated on the development of correlations to predict and model slug flow (Yocum, 1973; Schmidt et al., 1980; Brill et al., 1981; Taitel, 1986; Bendiksen et al., 1986; Fuchs, 1987; Torre et al., 1987; Blick et al., 1988; Asheim, 1988). Mathematical demonstration for the success of choking to stabilize steady-state flow was also reported years later by Taitel (1986). Finally, by the end of 1980s, Blick and Boone (1986) and Blick and Nelson (1989) published a work that seemed to be the first one to approach the unsteady flow problem from the perspective of the feedback control theory. The instability addressed by these works is called heading and it is a flow regime characterized by cyclic changes in pressure at any point in the tubing string. The authors employed a simplified model of feedback-controller for unsteady flowing oil wells to evaluate stability through root locus analysis. The conclusions have shown that unsteady flowing oil wells could theoretically be stabilized with feedback control. Besides that, the authors stated that a PD controller is the most useful and effective configuration to stabilize oil wells.

Total SE company has developed an automatic operating strategy to eliminate riser-induced slugging phenomenon (Coubort, 1996). The strategy was applied in 1994 in a North Sea field and was based on throttling the pipeline sufficiently to maintain the pressure at a certain level to prevent liquid blockage at the riser base. In other words, they automated the choking method (Gilbert, 1954; Taitel, 1986) to prevent slugging. Besides, a bypass in the choke valve to deal with low flowrates, which consisted of a kind of passive method to handle the unsteady flow, had to be installed.

When field solutions were not based on production choking, they relied on gas lift rate increase (Jansen et al., 1996). Nevertheless, usually, those kinds of solutions were not accepted for a long time, due to limited gas availability or due to backpressure increase, which causes efficiency loss. Some works in the 1990s suggest ensuring stability through automatic gas lift relocation. Shell verified in a laboratory-scale rig a potential increase of 40% in production through a real-time strategy to automatically distribute lift gas to the wells to maintain the system stable (Kinderen and Dunham, 1998). Companies like Elf Aquitaine Production and Elf Congo reported results between 5 and 20% of oil increase using this strategy in an offshore field in Gabon (Lemeteyer et al., 1991; Gaurnaud et al., 1996). Jansen et al. (1999) brought to light more details regarding the concept behind the Gabon tested technology: a model-based controller aimed at positioning well(s) in a profitable stable equilibrium through concomitantly acting on the choke valve opening and the gas lift flowrate. Despite the elegant idea, this kind of strategy does not confront instabilities, but avoid them, leading the operating point to an open-loop stable region.

In the year 2000, the first feedback control was applied to an actual oil well managing to counteract the unsteady flow in its essence (Havre et al., 2000; Havre and Dalsmo, 2001). The deployment was done at a shallow water British Petroleum (BP) oil rig in the Hod field, North Sea, and was able to reduced riser-induced instability in a multiphase transport pipeline through active control. The control structure took into account flowrate and pressures as measurement variables and the topside choke valve as the manipulated one.

Skofteland and Godhavn (2003) have shown the application of three control structures proposed by Statoil to terrain-induced slugging suppression in a subsea manifold riser. The control structures make use of

(1) subsea pressure, (2) topside density and pressures, or (3) an association of all these measurements as the controller input and choke valve opening as the controller output. The strategies were evaluated experimentally both at a medium scale loop and in a real scale in Heidrun Field in North Sea. As a result, the authors showed that the strategies could suppress the slugging, and the flowline may be depressurized to some extent. Additional discussions and evaluations are conducted in Godhavn et al. (2005).

Another real interesting application was reported by Dalsmo et al. (2002) in Brage field, North Sea. Located in a shallow water zone, the Brage field was operated by the former Norsk Hydro ASA. Unlike the reported cases of BP and Statoil, the production system had experienced stability problems in satellite wells caused by terrain-induced slugging. That was the first time the feedback control solution was deployed directly to a production well. The control structure considered the downhole pressure as the controlled variable (CV) and the wellhead choke valve as the manipulated one (MV). Not many details regarding the control algorithm are shown in the paper. However, the results are well described. The controller allowed an increase in the choke valve opening and a decrease in the well downhole pressure, which resulted in a production increase. The authors estimated a reduction of about 75–100% on the oscillations while the controller was active.

The actual implementation accomplishment seems to have been the driving force for several theoretical studies reported in the literature over the last years. Indeed, those real deployment feedback control lacked a comprehensive analysis, and some works emerged to fill that gap. Based on controllability analysis, Storkaas (2005) thesis offers a relevant analysis about riser-induced slug flow highlighting the influence of the type and location of the measured variables used in the control structures considering the subsea pipeline up to the surface facilities. According to the author, the best controlled variables are the pressures located at subsea - inlet flowline or riser bottom - while combinations taking into account, the topside measurement can also be used. The second option is not as straightforward as the first one and usually requires non-conventional measures to achieve good performance (Silvertsen et al., 2008; Silvertsen et al., 2009; Silvertsen et al., 2010). Despite that, Jahanshahi et al. (2017) proposed a control strategy based on topside measurements where a virtual flow meter is used in a cascade with the choke valve pressure drop. As a result, the authors could conjugate a simple strategy and fair performance in a laboratory rig.

Eikrem et al. (2008) proposed different control structures to heading instability in a production column boosted by a gas lift system. The authors stated that bottom hole pressure and annular gas pressure could be directly used as a controlled variable with good results, whereas using only topside measurement produces poor performance. Hansen (2012) confirmed the bottom hole pressure as the best choice to stabilize a production column.

Problems regarding the maintenance of sensors in remote locations and difficulties with topside control structures have led to attempts in using state observers to estimate underwater measurements (Eikrem et al., 2004; Scibilia et al., 2008; Di Meglio et al., 2012). The results are positive at some point, but the system nonlinearity makes the problem nontrivial (Scibilia et al., 2008). The models may not be representative for a large range of operating points on a real well, and the stability may not be guaranteed (Di Meglio et al., 2012). According to Jahanshahi et al. (2017), if only topside pressures are available, the fundamental controllability limitation associated with the right half-plane (RHP) zeros cannot be bypassed by an observer.

Static nonlinearity has shown to be a relevant issue to anti-slug control robustness. For this reason, nonlinear control strategies to avoid slugging in offshore oil rig were proposed by Jahanshahi and Skogestad (2017). In Jahanshahi and Skogestad (2017) work, it was demonstrated that a gain-scheduling controller is more robust to deal with the unsteady flow than other strategies evaluated. Diehl et al. (2019b) compared a linear MPC-PID strategy against a nonlinear gain-scheduling PID. The results suggested that the nonlinear strategy may reach lower back pressures in the well. However, the MPC-based strategy showed less variability in the controlled and manipulated variables. Thus, the MPC was field applied in an ultra-deepwater well, and, as a consequence, the oil production was increased by 10%. These results are depicted in Diehl et al. (2019a). A nonlinear model predictive control (NMPC) was also addressed by Diehl et al. (2018) and Gerevini et al. (2018) and revealed an interesting potential related to multivariable acting simultaneously in the choke valve and gas lift flowrate.

Oliveira et al. (2015) present an interesting work where one propose a holistic approach to the anti-slug active control problem in a riser-induced slugging system. This solution is composed of an adaptive controller in the regulatory layer and a model-free optimizer in the supervisory layer that chooses the controllers' set point according to the system stability, aiming to lead the well to its limit. Still in the line of autonomous systems, Pedersen et al. (2014) and Pedersen (2016) proposed an alternative to reduce human intervention in unsteady wells operation through switching model-free PID controllers.

As the most recent studies point to nonlinear solutions as being the most promising for increasing production in case of slugging, we propose to treat the static well nonlinearity in the regulatory layer through a model-based control synthesis. The proposal will be evaluated in real and simulated environment in order to treat riser-induced slugging.

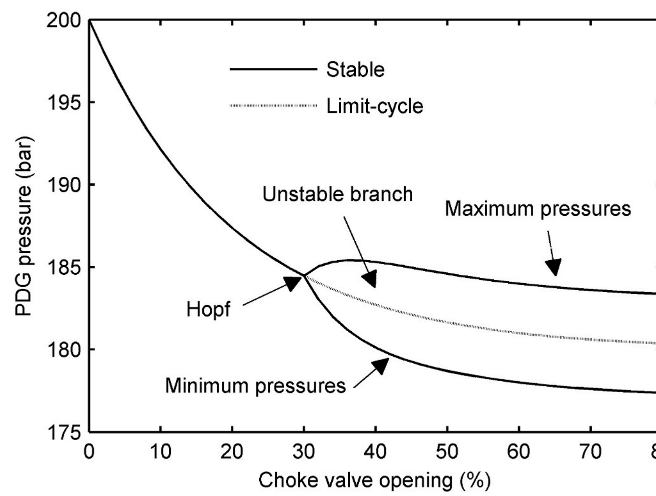

Fig. 1. Generic bifurcation diagram of an unsteady oil well.

3. Methodology

An unsteady oil well presents two main operating regions: one stable and another one featured by a limit cycle, which is characterized by permanent self-sustained oscillations caused by the slugging phenomenon. If a system changes its qualitative behavior to form a limit cycle when a parameter is varied, the singularity is called Hopf bifurcation (Bequette, 1998). The pioneer works of Storkaas et al. (2001) and Storkaas and Skogestad (2002) were the first to state this transition as a Hopf bifurcation in oil production. Besides, the authors emphasize the loss of process gain from input (choke valve opening) to output (well backpressure) with increasing valve opening, at the same time as a pole moves further into the right half plane. When this occurs it is practically impossible to stabilize the system with large valve openings.

A typical unsteady oil well bifurcation diagram is shown in Fig. 1, where PDG (Pressure Downhole Gauge) is the pressure close to the bottom hole and the bifurcation parameter is the choke valve. The loss of the pressure gain, throughout the production valve opening, is a static nonlinearity that becomes critical in unsteady flow wells, since the regions with the highest yields are located at the unstable branch. Although it is arduous to stabilize the system at large valve openings, it

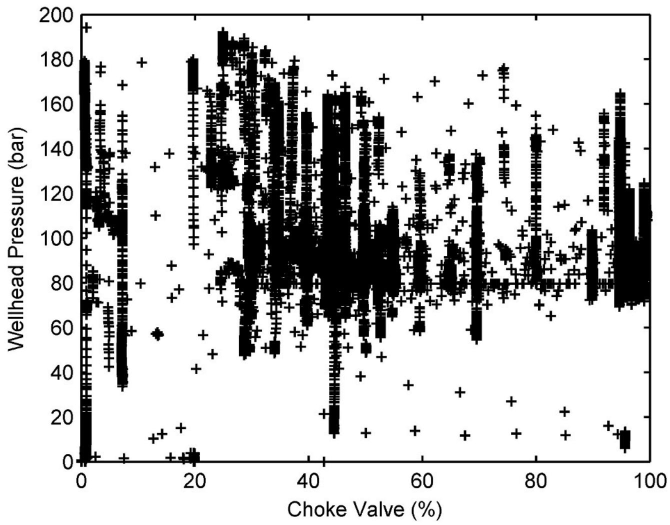

Fig. 2. Real well (ROY): two years of operating data from the wellhead Temperature and Pressure Transmitter (TPT).

is still possible to operate the well closer to the optimum point using feedback control. Hence, a nonlinear PID control can be applied to compensate the nonlinearity through online retuning according to the well operating point.

One way to define the control compensation policy is to obtain the system's equilibrium curve, compute its derivative, and use it to design the controller gain through direct synthesis. To generate this gain scheduling policy, it is necessary to know the well's behavior over a wide range of operational points. Traditionally, to obtain this global knowledge, several open-loop tests in the plant are required, which demands a long time producing in less profitable regions, resulting in financial losses that reduce the attractiveness of this type of approach. An alternative option is to apply numerical continuation techniques (Krauskopf et al., 2007; Kohout et al., 2002; Dhooge et al., 2006; Kasnyk et al., 2007) in a first principle model to approximate nonlinear solutions in order to build bifurcations diagrams and thereafter to obtain the system equilibrium curves. Unfortunately, fitting these models to a real global multiphase flow system is far from a straightforward task.

An alternative to overcome those difficulties would be to use the well's operational database as a source for reconstructing its whole steady-state equilibrium. A methodology based on data historian would make possible to avoid in situ tests and problems related to modelling a complex phenomenon. Although this idea is promising, the challenge of finding it in the midst of data is not trivial. For instance, Fig. 2 shows two years of raw data from an actual well, minute by minute, that we will call ROY well. It is not possible to obtain a clear perception of how is the well behavior, but somewhere in the data cloud is the equilibrium curve of the system.

In the next subsections of this paper, a proposal to map the entire pressure system equilibrium in order to support the nonlinear control policy design will be described. To illustrate the methodology step by step, real operating data from ROY, a gas lifted well with stability problems, will be used.

3.1. First principle model structure

Jahanshahi and Skogestad (2017) presented a pressure balance defined by Equation (1), from wellhead to topside, where P is the wellhead pressure (TPT), P_d is the choke valve downstream pressure, ΔP_v is the valve pressure drop, ΔP_{sh} is the static head contribution and ΔP_f is pressure loss by friction.

$$P = P_d + \Delta P_v + \Delta P_{sh} + \Delta P_f \tag{1}$$

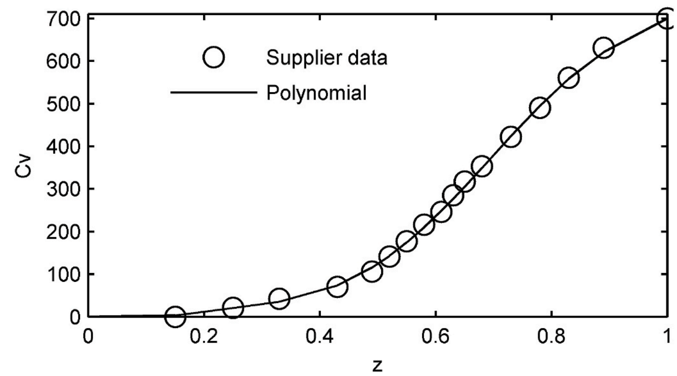

Fig. 3. Broadly employed choke valve type.

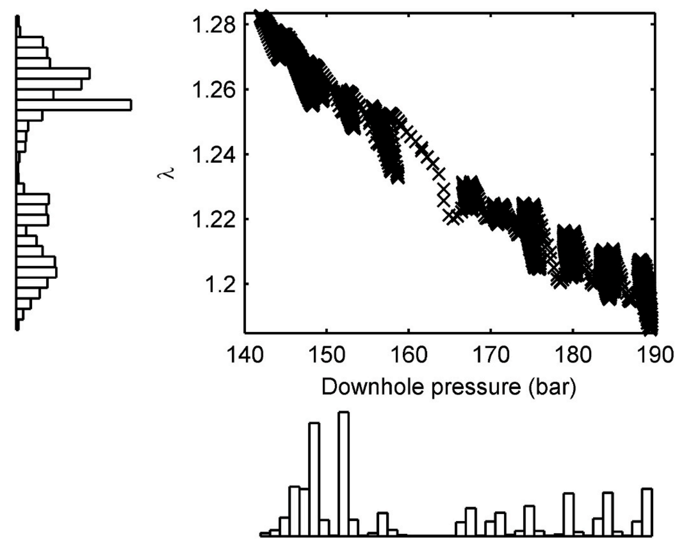

Fig. 4. λ behavior from the start to the minimum pressure of a well modeled in OLGA (the secondary bar represents the number of times the value is shown in the data set).

The authors assume P_d and ΔP_f as constant and derive the static gain model in Equation (2) to subcritical flow. In this equation, u is the valve characteristic curve, as defined Equation (3). Equation (4) presents λ, which is a parameter related to production system properties and flowrates at a steady state. In this equation, $(w_G)_{in}$ is the mass flowrate of gas at the inlet of the wellhead, w_{out} is the total mass flowrate in the system, ρ_G and ρ_{ss} are, respectively, the average density of gas and gas-liquid mixture, L is the riser length and g is the gravitational constant. Finally, c_1 comes from the ideal gas law (Equation (5)), so M_G is the gas molar weight, T is the inner average system temperature and R is the universal gas constant.

$$\frac{\partial P}{\partial u} = \lambda \frac{-2\Delta P_v}{u} \tag{2}$$

$$u = C_V(z) \tag{3}$$

$$\lambda = \frac{1 + \frac{gLc_1\rho_{ss}^2(\omega_G)_{in}}{\rho_G^3\omega_{out}}}{1 + \frac{c_1(\omega_G)_{in}\omega_{out}}{u^2\rho_G^2}} \tag{4}$$

$$c_1 = \frac{M_G}{RT} \tag{5}$$

Considering that the proposed model represent the steady state, the entire flow of gas lift provided by the topside facilities is incorporated into the fluids produced by the well for the λ estimation.

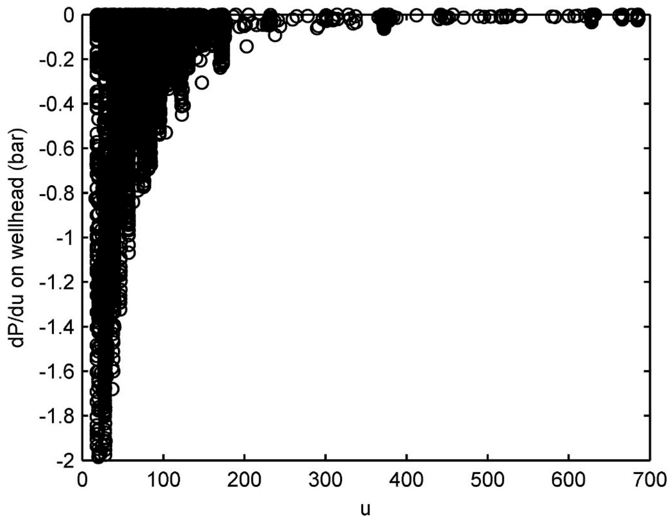

Fig. 5. Data cloud of estimated gains formed by 2 years of data from ROY well.

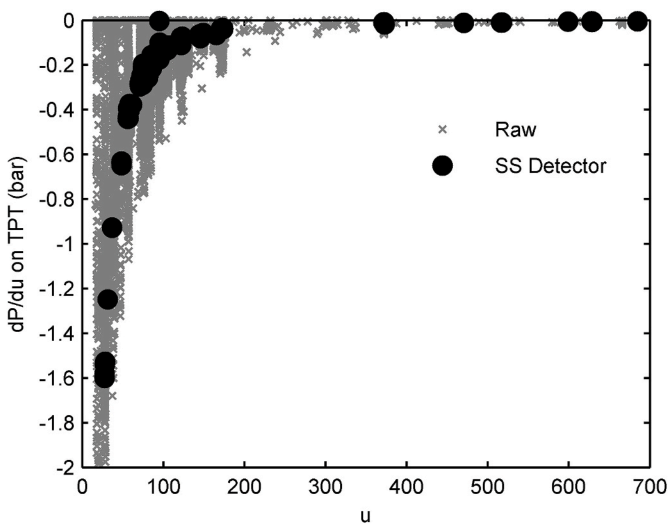

Fig. 6. System gain after steady states detection.

A typical choke valve characteristic curve is presented in Fig. 3. This kind of valve usually has a nonlinear behavior that can be approximated by a polynomial, as shown in Equation (6), or a sigmoid function, for example. In this case, the chosen polynomial has a degree (j) equal to 6. The polynomial coefficients are represented by the matrix a.

$$u = Cvf(z) = \sum_{i=0}^{i=j} a_i z^i \tag{6}$$

Short term observations using rigorous multiphase flow simulator OLGA reveal λ presents few variations even considering pressurized or depressurized operating zones. As shown in Fig. 4, changes of 50 bar in downhole pressure result in variations smaller than 0.1 in λ. So one can say λ may be approximated by a constant defined for an operating region of interest.

Considering as a start point $\lambda = 1$ and applying Equations (2) and (6) to ROY well operation data, as referred previously, Fig. 5 is obtained. As it can be seen, the data cloud assumes a kind of noisy exponential shape.

3.2. Steady-state detection

Since the system equilibrium curve is fundamentally a stationary behavior, it is important to remove the transient information from the dataset. There are several techniques in literature for steady-state identification. These techniques, however, do not share a common theoretical ground. They are based on different statistical and morphological aspects of the problem. In this context, one can find techniques based on the mean differences along with time intervals (Alekman, 1994; Schladt and Hu, 2007), on standard deviation thresholds (Jubien and Bihary, 1994; Kim et al., 2008), on detection of linear trends (Mahuli et al., 1992; Moreno, 2010; Önöz and Bayazit, 2003) and on the ratio of the mean square successive difference to the standard deviation (Von Neumann et al., 1941; Cao and Rhinehart, 1995; Bhat and Saraf, 2004).

In order to remove transient data from the well operation, we applied a steady-state detection based on the linear regression slope associated with the confidence bounds for coefficient estimates. The output subset generated is presented in Fig. 6, where it becomes evident the exponential behavior of the system static gain.

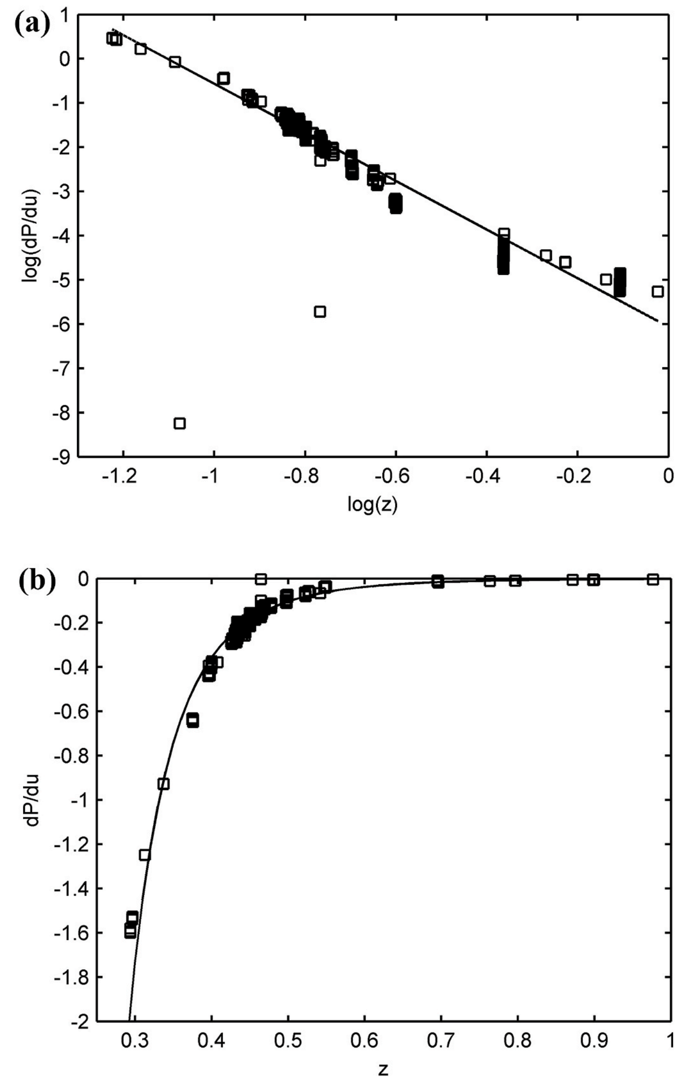

Fig. 7. Logarithmic domain of data (a) and static gain approximation by power law (b).

3.3. Pressure equilibrium correlation

Since the static gain behavior is an exponential feature, it can be approximated by the power-law Equation (7). A simple way to find the value of k and n is to apply a linear regression on the logarithmic data transformation, as illustrated in Fig. 7.

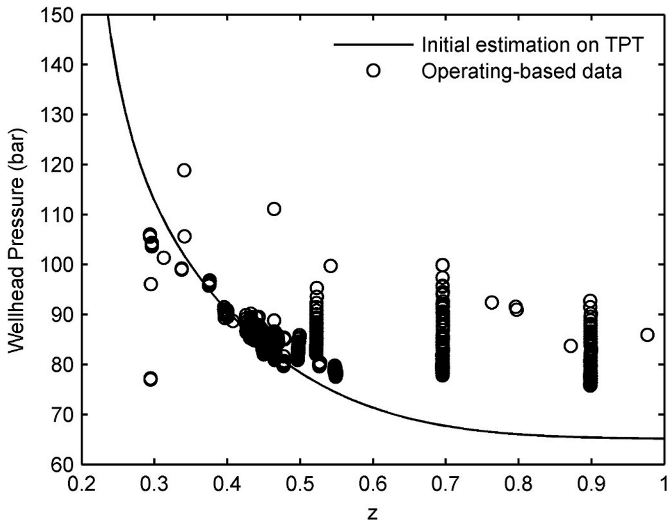

Fig. 8. Wellhead equilibrium curve based on Equation (15).

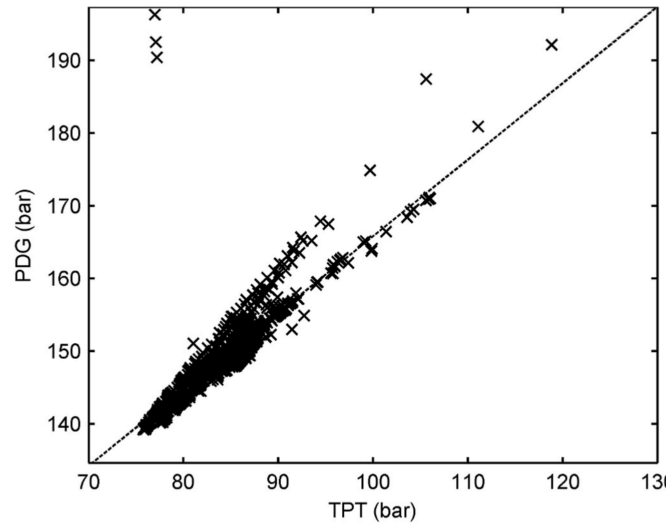

Fig. 9. Steady state linear correlation between pressures in wellhead and bottom hole.

$$\frac{\partial P}{\partial u} = kz^n \tag{7}$$

From the integration of the new static gain model Equation (7), it is possible to achieve the pressure equilibrium correlation in the wellhead. As the variable u is dependent on the choke valve opening z, as shown in Equation (3), it is necessary to change the partial pressure derivative from u to z, as indicated in Equation (8).

$$\frac{\partial P}{\partial u}\frac{\partial u}{\partial z} = kz^n\frac{\partial u}{\partial z} \tag{8}$$

Deriving Equation (6) concerning z Equation (9) is achieved.

$$\frac{\partial u}{\partial z} = \sum_{i=0}^{i=j} ia_i z^{(i-1)} \tag{9}$$

Replacing Equation (9) in Equation (8) results in Equation (10), which depicts the wellhead pressure variation directly related to the choke valve opening change.

$$\frac{dP}{dz} = k\sum_{i=0}^{i=j} ia_i z^{(i+n-1)} \tag{10}$$

Integrating Equation (10), as shown in Equation (11), results in the antiderivatives Equations (12) and (13).

$$\int dP = k\int \sum_{i=0}^{i=j} ia_i z^{(i+n-1)} dz \tag{11}$$

$$\Delta P = k\sum_{i=0}^{i=j} \frac{ia_i}{i+n} z^{(i+n)} + c \tag{12}$$

$$P_2 = k\sum_{i=0}^{i=j} \frac{ia_i}{i+n} z^{(i+n)} + (c+P_1) \tag{13}$$

The integration constant c and the pressure P_1 can be incorporated into $\boldsymbol{\beta}$, Equation (14). It gives a constant between the model and the plant.

$$\beta = c + P_1 \tag{14}$$

The pressure equilibrium correlation can then be described by Equation (15). Fig. 8 shows the equilibrium curve obtained by Equation (15) deployed to ROY well data set with $\lambda = 1$.

$$P = k\sum_{i=0}^{i=j} \frac{ia_i}{i+n} z^{(i+n)} + \beta \tag{15}$$

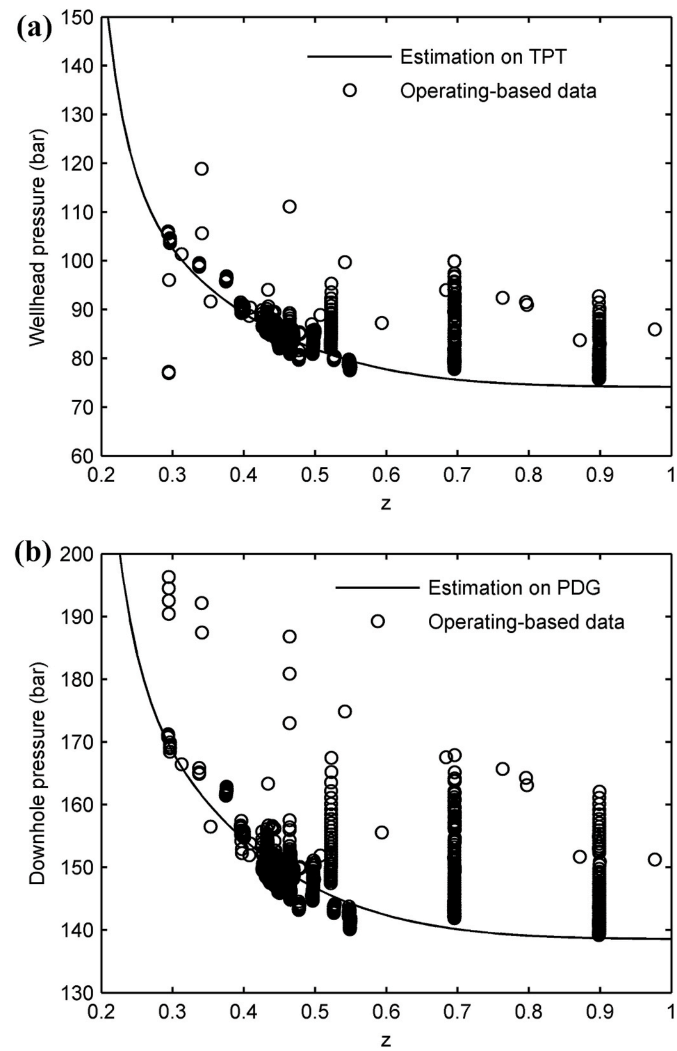

Fig. 10. Optimized equilibrium estimation at wellhead (a) and downhole (b).

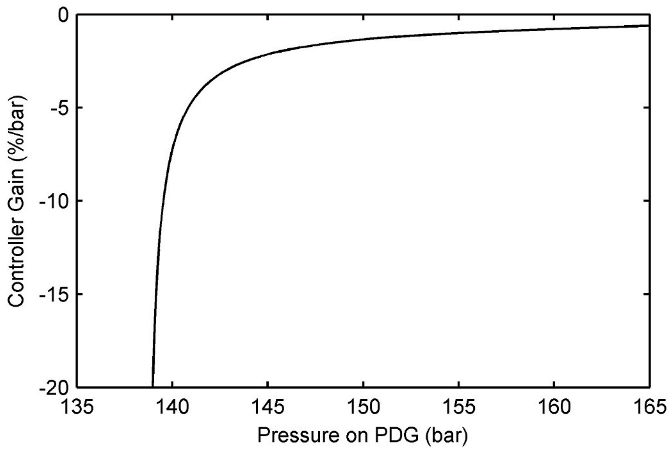

Fig. 11. Controller gain scheduling basis related to downhole pressure.

3.4. Fitting step

We have experienced that λ can assume a value between 0.5 and 1.5 for our case. This band is an empirical perception obtained through simulations and operating data evaluations from ROY well.

In order to find the best constant λ value, it is necessary to solve the minimization problem from Equation (16).

$$\min_{\{\lambda\}} \sum_{i=1}^{i=j} [P_e(z_i) - P_{ss}(z_i)]^T \varphi [P_e(z_i) - P_{ss}(z_i)] \tag{16}$$

In this optimization problem, P_e is the equilibrium pressure estimated for a specified λ and P_{ss} is the real plant steady-state pressure. For each valve position z there is a steady-state plant pressure (P_{ss}) and its corresponding estimated one (P_e). The sub index i refers to a measurement point considered in the problem and j is the total meters used to fit the equilibrium curve to actual data. It is common to have available up to three relevant pressure meters in an offshore well. These meters are usually located at the bottom hole, wellhead and upstream choke valve. Specifically, in this example, we are going to use the bottom hole ($i = 1$) and the wellhead pressure ($i = 2$) measurements in the cost function. In this case, the estimated pressures at the downhole may be approximated using a steady-state correlation between wellhead and downhole, as shown in Fig. 9. Note that the lowest pressure zone presents less dispersion between steady states, which is a positive fact, since it is desirable to operate the system in that region.

The weight matrix φ can take values according to the user's sense. For example, it is recommended to give more importance to the current operational data and less importance to data located after the Hopf bifurcation - if these data were not removed in steady-state detection stage - and so on. The index i represents the system production samples that one can take to fit the estimates to the plant observations.

The unconstrained optimization problem can be solved by Nelder-Mead algorithm, also called simplex search algorithm, and regarding this case study, the optimized λ is equal to 0.6. The optimized equilibrium set solutions are presented in Fig. 10.

3.5. Gain scheduling synthesis

The controller gain scheduling $K_{C,i}$ can be defined based on the inversion of the estimated equilibrium curve derivative, as defined in Equation (17). The parameter $\boldsymbol{\alpha}$ is a kind of acceleration factor to the controller that in practice increases its aggressiveness. It might be defined by SIMC rules (Skogestad, 2003), as shown in Equation (18), where $\boldsymbol{\tau}$ is the dominant lag time constant, $\boldsymbol{\tau_c}$ is the desired closed-loop time constant and $\boldsymbol{\theta}$ is the time delay (dead time).

$$K_{C,i} = \alpha \frac{1}{\frac{dP}{dz}} \tag{17}$$

$$\alpha = \frac{\tau}{\tau_c + \theta} \tag{18}$$

The static nonlinearity can be compensated in the input (z, choke valve opening) or in the output (P, PDG pressure). Fig. 11 shows the controller gain scheduling to ROY well considering $\boldsymbol{\alpha} = 1$.

A sensitivity analysis in λ shows that its fluctuation over the well lifetime have a considerable influence on the ideal controller gain as presented in Fig. 12. A λ adapting strategy might be important to a long term implementation. However, this issue is not going to be handled in this paper.

3.6. Systematic design procedure

The procedures to obtain the controller gain scheduling can be summarized by the following steps:

1. Define a model to the choke valve: we recommend to fit a polynomial to the valve characteristic curve as shown in Equation (6).
2. Create an initial cloud of the process gain: assume $\lambda = 1$ and estimate $\partial \boldsymbol{P} / \partial \boldsymbol{u}$ through Equation (2) and operational data.
3. Remove transient data: choose a steady state identification method and apply it to the cloud generated in the previous step.
4. Fit the steady states to a simple morphological structure: find the parameters from Equation (7) that approximate the system static data to a power law model.
5. Estimate the initial pressure equilibrium curve: apply Equation (15) in order to define the first wellhead pressure equilibrium curve.

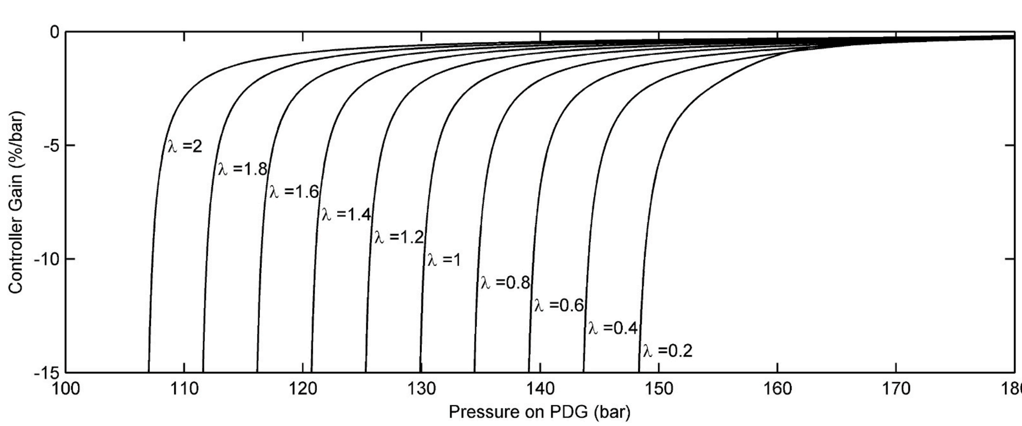

Fig. 12. λ influence in the controller gain scheduling.

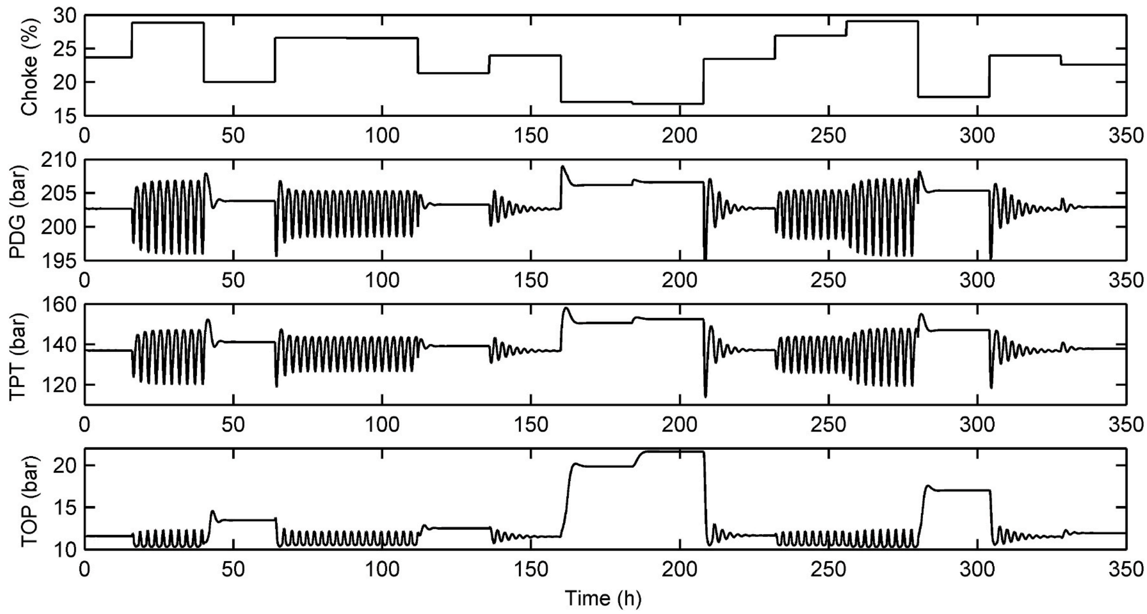

Fig. 13. Time domain series generated by random steps on the choke valve opening.

6. Tune the equilibrium to the plant data: solve the minimization problem in Equation (16) to find the best lambda value. Optionally, it is possible to include more than one well measurement relying on its availability. This step also allows to select more trustable and current subset of data according to the user experience. The answer is not unique and absolute since the well changes its behavior over the time.
7. Generate the controller: apply Equations (17) and (18) in the previous step data to produce the controller gain scheduling policy. It is recommended to use $\boldsymbol{\alpha} \leq 6$.

In steps 1 and 4 the models can be replaced by any other desired, conserving the main method concept, however Equation (15) will have to be redefined.

4. Method validation

In order to evaluate practical results from the methodology previously described, a validation stage through simulation is accomplished. Three pressures will be used as controlled variables in independent experiments: downhole pressure, wellhead pressure, and upstream choke valve pressure. Therefore a simplified ODE dynamic model was chosen to be the virtual production system. This model was published by Diehl et al. (2017), which is called FOWM (Fast Offshore Wells Model).

The case study addressed in the next sections corresponds to Well A described in Diehl et al. (2017) that is a deepwater satellite gas lifted well from Campos Basin, Brazil, with 1,639 m production columns, 2, 928 m flowline touching seabed, and 1,569 m subsea riser. The multiphase liquid produced from Well A (oil + water) has a density of around 900 kg/m^3 and 60% of water cut.

4.1. Fast Offshore Wells Model (FOWM)

The FOWM model (Diehl et al., 2017) aims at covering a gap in simplified production systems modelling: the whole architecture of satellite wells in deep and ultra-deepwater scenarios. FOWM is based on literature models coupling and it can be divided into three main parts:

- Reservoir-wellbore model: proposed by Vogel (1968) as an empirical correlation, the model consists of a two-phase Inflow Performance Relationship (IPR) used to calculate oil wells production performance. Vogel's model is widely used as wellbore-reservoir interface and it is generally a popular option in commercial flow simulators as boundary condition between reservoir and production column. Despite its static nature, IPR models are suitable options to boundary conditions in flow dynamic simulation if the model is focused on pipelines. This is a reasonable assumption because the flow-pressure response is much faster in pipelines than in the reservoir. So the short-term behavior in the interface reservoir-wellbore might be approximated by an IPR correlation.
- Wellbore-wellhead model: this section is modeled by Eikrem et al. (2008), that is a simple model to describe gas lifted wells from wellbore up to wellhead, in other words it represents the production column segment.
- Wellhead-topside model: consists in the subsea flowlines and riser. It is modeled based on Di Meglio (2011) ideas.

The combination of these works in a single model has resulted in the FOWM, given by Equations (19)–(24). In FOWM, the states represent the mass of gas and liquid in different sections of the system: m_{ga} is the gas mass in the gas lift annular, m_{gt} and m_{lt} are respectively the gas and liquid mass in the production column, while m_{gr} and m_{lr} are the gas and liquid mass in the subsea lines and finally m_{gb} is the mass of gas trapped by slugging phenomenon at the subsea production line (elongated buble).

$$\frac{\mathrm{dm_{ga}}}{\mathrm{dt}} = \mathrm{W_{gc}} - \mathrm{W_{iv}} \tag{19}$$

$$\frac{\mathrm{dm_{gt}}}{\mathrm{dt}} = \mathrm{W_r}\alpha_{\mathrm{gw}} + \mathrm{W_{iv}} - \mathrm{W_{whg}} \tag{20}$$

$$\frac{\mathrm{dm_{lt}}}{\mathrm{dt}} = \mathrm{W_r}\left(1 - \alpha_{\mathrm{gw}}\right) - \mathrm{W_{whl}} \tag{21}$$

$$\frac{\mathrm{dm_{gb}}}{\mathrm{dt}} = (1 - \mathrm{E})\mathrm{W_{whg}} - \mathrm{W_g} \tag{22}$$

$$\frac{\mathrm{dm_{gr}}}{\mathrm{dt}} = \mathrm{E}\ \ \mathrm{W_{whg}} + \mathrm{W_g} - \mathrm{W_{gout}} \tag{23}$$

$$\frac{\mathrm{dm_{lr}}}{\mathrm{dt}} = \mathrm{W_{whl}} - \mathrm{W_{lout}} \tag{24}$$

In essence, the FOWM is a mass balance-based model. Thus, the

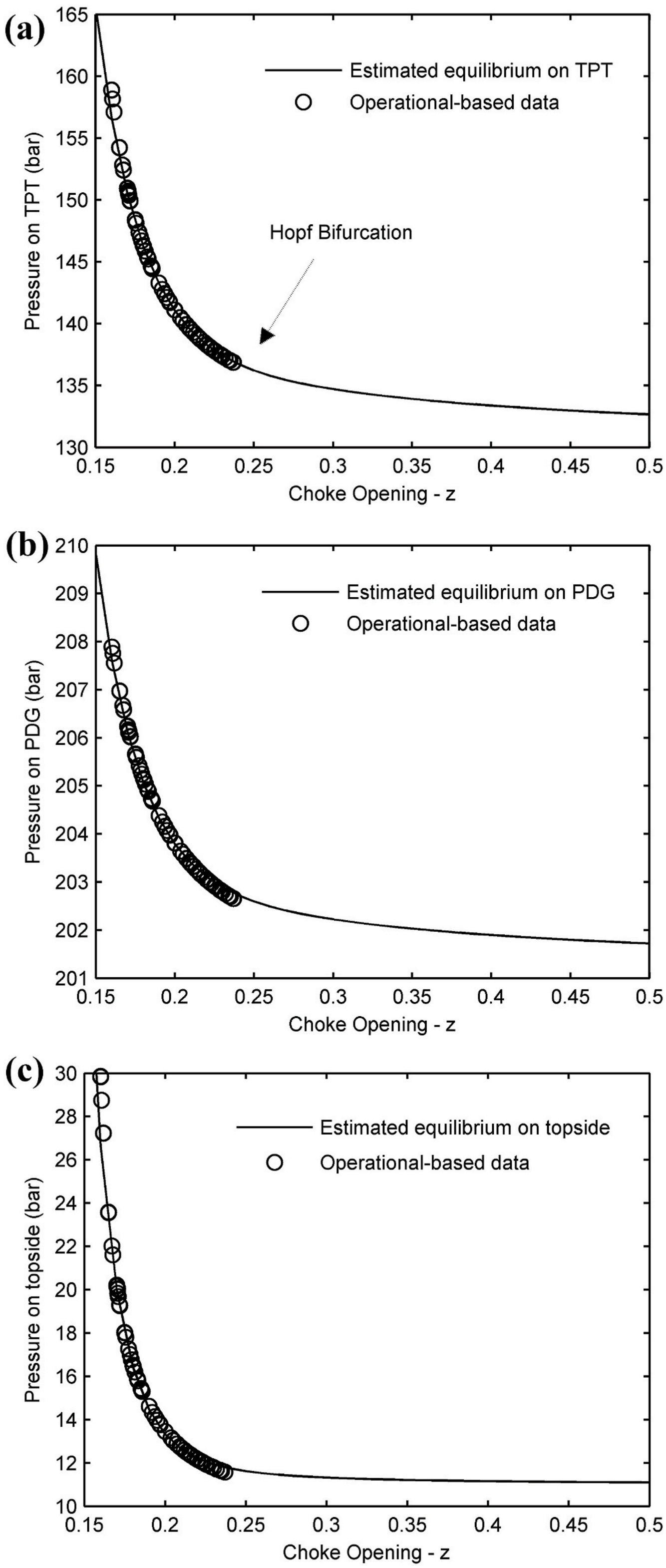

Fig. 14. Equilibrium pressure estimated in Well A: (a) wellhead, (b) downhole and (c) upstream choke valve.

differential terms are proportional to mass flow relationships, where W_{gc} is the gas lift mass flow entering in the annular, W_{iv} is the gas mass flow from the annular to the production column, W_r is the reservoir to the downhole flow estimation by the Vogel correlation, W_{whg} and W_{whl} are the gas and liquid mass flow at the wellhead, W_g is the flow at the Di Meglio's virtual valve, and W_{gout} and W_{lout} are the gas and liquid flows

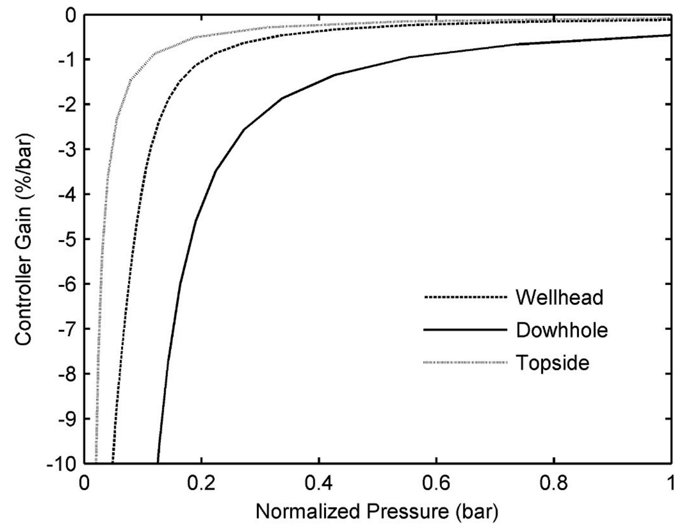

Fig. 15. Gain scheduling regarding three possibilities of controlled variables: pressure on the bottom hole, wellhead, and upstream choke valve at topside.

through the topside choke valve.

FOWM can be fitted to real data through a global unconstrained optimization based on the weighted least squares problem. When the model needs to fit into a limit cycle, an objective function that intends to penalize stable solutions is applied as proposed in Diehl et al. (2017). Despite this, achieve a good fit might not be a straightforward task, and complementary works as Rodrigues et al. (2018) and Apio et al. (2018) can be useful.

To better understand the FOWM model and its fitting to real data, we recommend reading the original paper (Diehl et al., 2017).

In order to compare open-loop and closed-loop performance, the production estimation will consider the linear Inflow Performance Relationship (IPR) described in Equations (25) and (26), where q is the volumetric liquid production, P_{Res} is the reservoir pressure, P_{BH} is the column production bottom hole pressure and PI is the well productivity index. The sub-indexes 1 and 2 refer to the well in open-loop and closed-loop situation, respectively. Well A has a reference liquid production of 2.923 m^3/d and a reservoir pressure of 225 bar.

$$q = PI(P_{Res} - P_{BH}) \tag{25}$$

$$\frac{q_2}{q_1} = \frac{P_{Res} - P_{BH,1}}{P_{Res} - P_{BH,2}} \tag{26}$$

4.2. Controller design

Over 3,500 simulation hours were generated with the objective of producing an artificial industrial data historian. Random steps on the choke valve opening were performed every 24 h, resulting in a rich collection of operating patterns. Three key variables were monitored: the downhole pressure (PDG), the wellhead pressure (TPT), and the upstream choke valve pressure (TOP). No noise was added to the data. Fig. 13 shows a sample of this database.

Well A presents a stability loss of around 24% of choke valve opening, which means that a Hopf bifurcation is located around this point. Valve openings over 24% presented a limit cycle pattern in the whole production system.

This database was used as an input to the methodology summarized in Section 3.6, which produces the estimated system equilibrium shown in Fig. 14. As it can be noted, only a stable system response was chosen in this validation. The idea is to verify the methodology extrapolation potential to the unstable branch of equilibrium.

Applying the controller design synthesis as defined in Equation (17), the gain scheduling profiles presented in Fig. 15 were obtained.

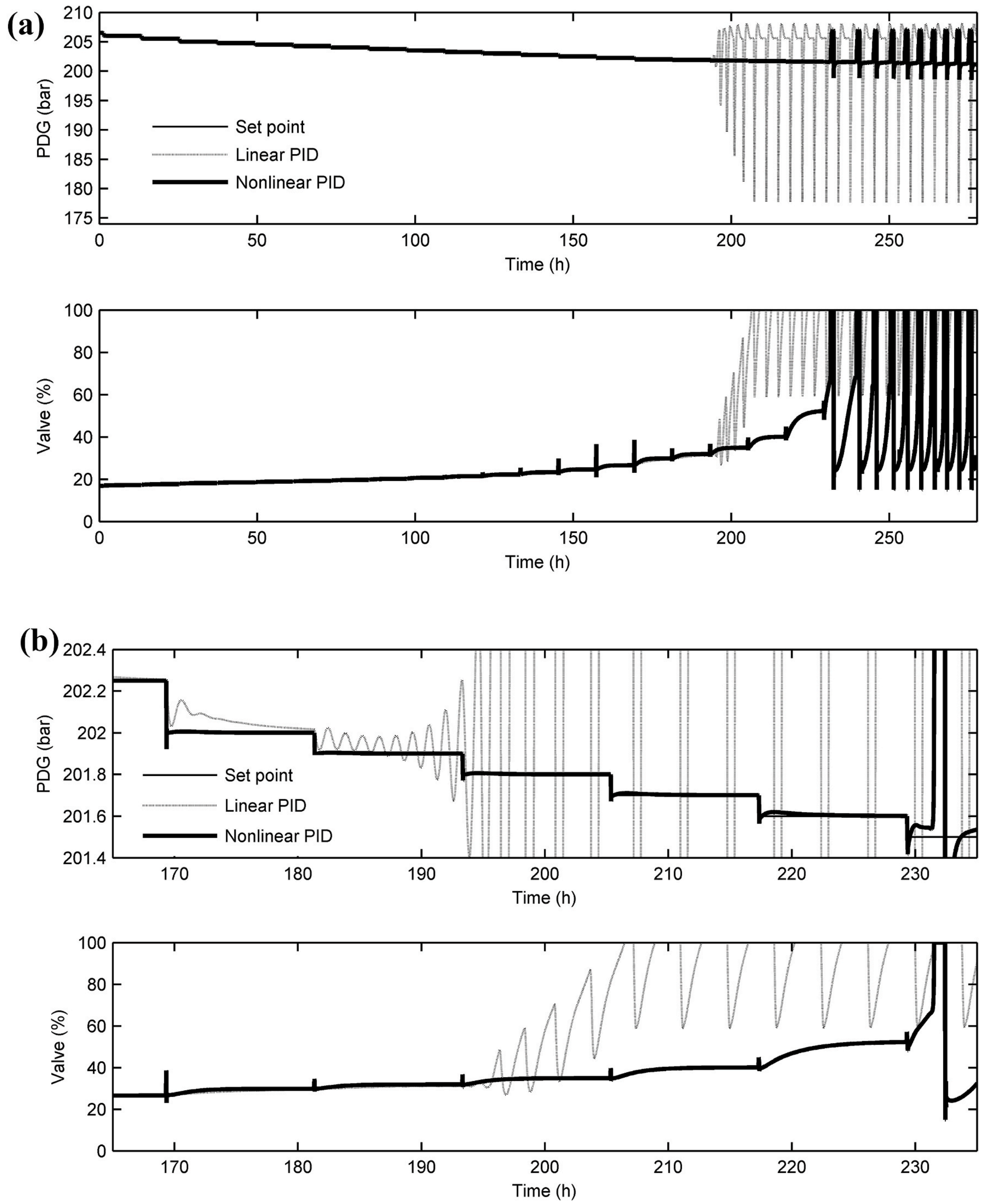

Fig. 16. Gain scheduling PID versus linear PID: (a) wide range of set points tested and (b) detail from system instabilization time window.

Particularly in this example, the acceleration factor was considered as $\alpha = 1$. The gain scheduling performance will be evaluated in the next sections.

Table 1
Control strategies performance comparison.

	Open-loop	Linear PID	Nonlinear PID
Stability changing: PDG pressure (bar)	202.6 (Hopf)	202.0	201.6
Stability changing: choke valve (%)	24 (Hopf)	29.5	52.0
Liquid production increase (%)	–	2.7	4.5
Oil production increase (bpd)	–	119	331
Potential additional profit (MM US $/year)	–	1.7	4.8

The PID integral (T_i) and derivative (T_d) terms have been set, respectively, as $T_i = \tau/4$ (where τ is the system lag time constant) and $T_d = 0$ (no significant time delay was verified). These terms were kept constant in all operational points.

4.3. *Downhole pressure as controlled variable*

The first control structure simulated considers the downhole pressure as the CV and the choke valve as the MV. For comparative performance evaluation, a linear PID tuned equally to its nonlinear version

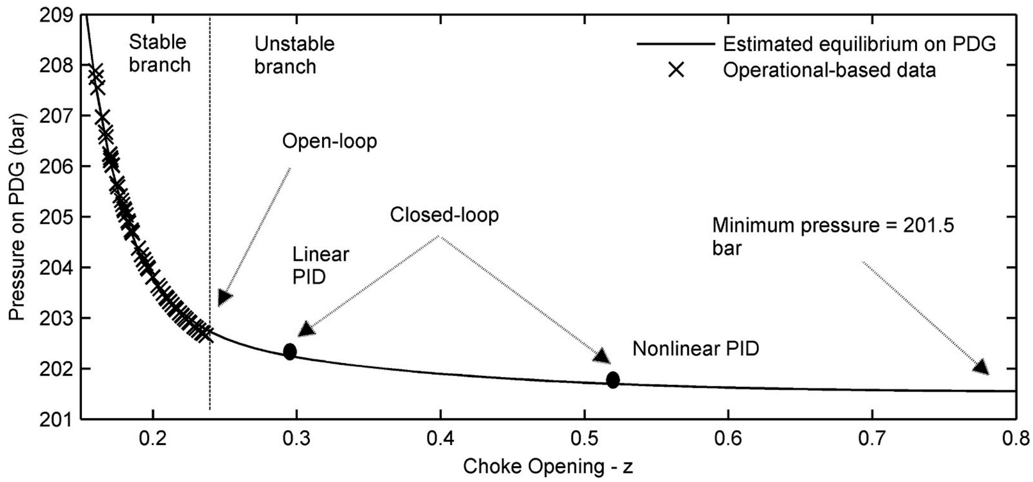

Fig. 17. Achievable operating point in stable condition (CV = downhole pressure).

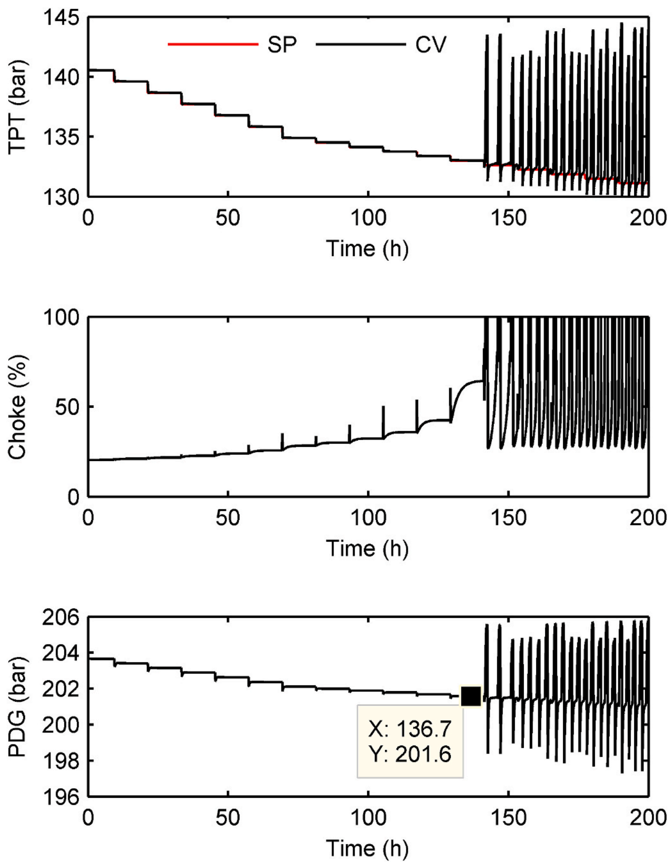

Fig. 18. Wellhead pressure-based control structure performance.

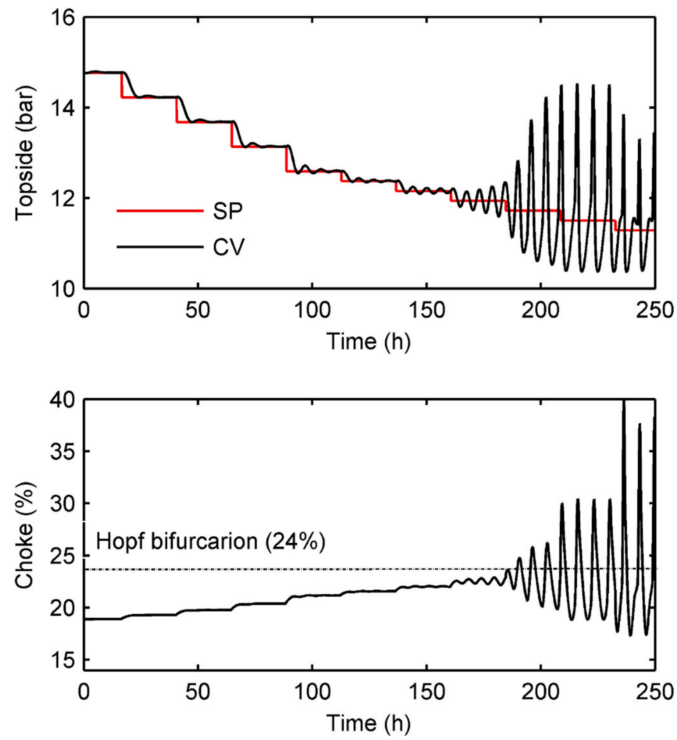

Fig. 19. Topside pressure-based control structure performance.

was used, but with a constant gain assumed to be equivalent to the gain scheduling observed at 21% of valve opening. This choice would be natural in a practical situation, once this operating point is stable and close to the Hopf bifurcation, which makes it feasible in a plant identification test.

Based on the equilibrium curve, the minimum downhole pressure theoretically achievable is around 201.5 bar. Therefore the simulation test target is to reduce pressure as lower as possible, keeping the system stable, since the lower the pressure at the bottom of the production column, the greater is the well production. The test is presented in Fig. 16, and the main results are summarized in Table 1.

The nonlinear PID based on gain scheduling was able to reduce the well pressure very close to its minimum at the same time that kept the system running stably. Obviously, when the minimum pressure limit is crossed, even the nonlinear controller loses stability.

Another point that draws attention is how far the choke valve can be unlocked. While the linear PID can open the production valve from 24% to 29.5%, the nonlinear PID allows the choke valve openings up to 52%, which increases about 3 times more in production. This difference can be viewed in the diagram shown in Fig. 17. Considering the oil price of US$ 50 per barrel, the gain scheduling control strategy has the potential to increase the well profit in 4.8 million dollars per year.

4.4. Wellhead pressure as controlled variable

The second control structure evaluated assumes the wellhead pressure as the CV and the choke valve as the MV. The gain scheduling

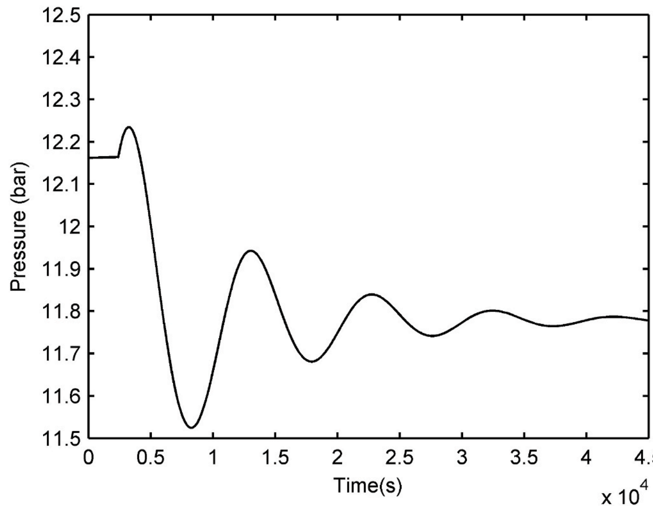

Fig. 20. Topside inverse response to unit step on choke valve.

design deployed corresponds to the curve fore mentioned in Fig. 15. Closed-loop performance is presented in Fig. 18.

As it can be seen, similar performance can be reached using wellhead pressure as CV when compared with previous results using downhole pressure in the loop. This means that using the gain scheduling design proposed makes it feasible to achieve the minimum pressure at well bottom hole (201.6 bar) even controlling the pressure measurement in a different point of the system.

4.5. Upstream choke valve pressure as controlled variable

The last control structure evaluated in this work takes into account the choke valve upstream pressure as the CV and the choke valve as the MV. The gain scheduling applied was previously described in Fig. 15, and the controller performance is shown in Fig. 19.

As a result, the closed-loop stability is guaranteed only in a narrow operating range. In fact, the stability is lost before the open-loop Hopf bifurcation, which means this strategy is not able to counter-attack the unsteady flow. The reason for that comes from the inverse response this structure presents. Fig. 20 shows the pressure response to a unit step on the choke valve at this location of the production system.

According to Storkaas (2005), the topside pressure measurement cannot be used for stabilizing control due to RHP limitations caused by unstable zeros. The author states that the flow measurement can be employed for stabilizing control if used in a cascate controller inner loop. Further investigations and contributions in this specific topic were performed by Silvertsen (2008), Silvertsen et al. (2009), and Silvertsen et al. (2010). Highlights for Jahanshahi and Skogestad (2017) work, where a simple flow inference was applied in order to achieve stability through a cascade control strategy. The results are promising, and the application requirements are quite low in terms of instrumentation. Therefore, when assuming topside measurement as the main controlled variable, we recommend considering this work as the current benchmark.

All these works presume that topside pressure inherently has a RHP limitation related to inverse response. This kind of behavior is strongly present in simplified models as FOWM or in rigorous models as OLGA simulator. Nevertheless, we could not see this limitation in actual facilities. Fig. 21 shows eight different real wells submitted to steps on the choke valve. It seems none of them show an inverse response in upstream choke valve pressure. Thus, it is considered that this issue requires further investigation.

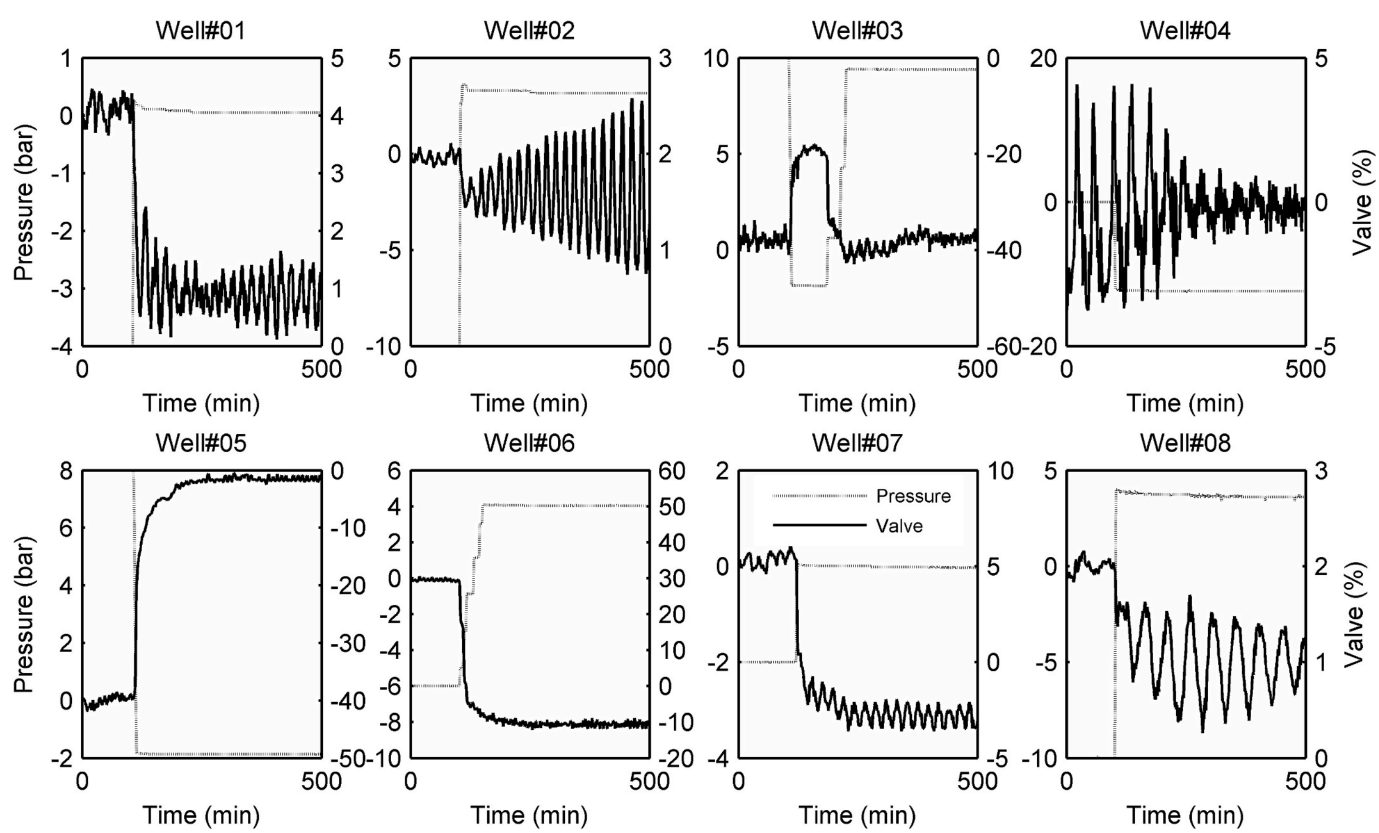

Fig. 21. Eight different real well response in topside pressure regarding steps on choke valve.

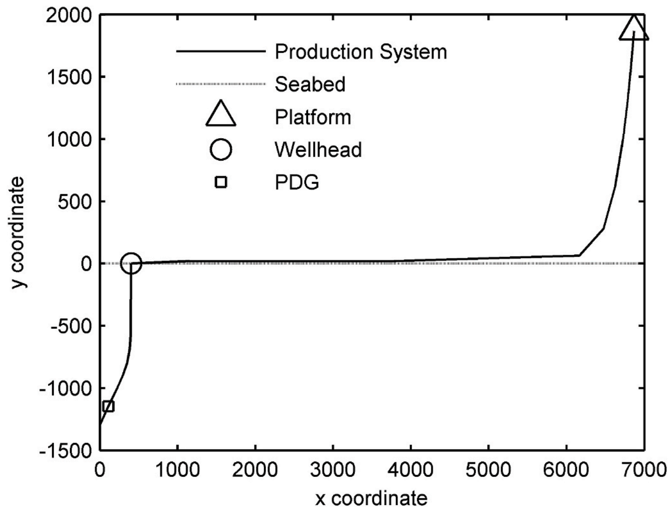

Fig. 22. ROY well: real production system dimensions in meters.

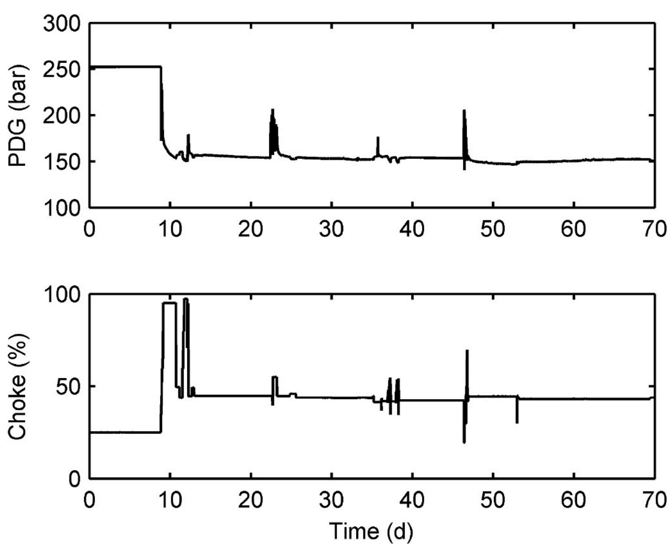

Fig. 23. Partially closed well in order to avoid unsteady state flow in oil rig.

5. Actual deployment

A real validation study was conducted in a Petrobras oil rig and it is described in this section. The Petrobras platform, located at 120 km from the Brazilian coast, has received an active control technology based on the ideas presented in this paper. The oil field where the platform is installed can be considered an ultra-deepwater facility once its depth is between 1,500–2,000 m. A set of satellite wells produces oil and gas using the gas lift as an artificial method for elevation.

Particularly, for this application, the production system corresponds to the ROY well, previously shown in the Methodology section of this paper. ROY produces an oil with 29 °API, 30% of water-cut and gas-oil ratio (GOR) of 120. Fig. 22 presents the ROY well architecture: the wellbore is located around 1,300 m below the seabed and connects the production column to a 6,000 m subsea flowline, followed by a 1,800 m riser line. Complementarily, the pipeline diameter is 6 in; the gas lift valve type is Venturi; the topside pressure in the separator is 9 bar, and the oil flow rate produced is around 1.200 Sm^3/d.

ROY is a choked well in order to avoid limit cycle formation. Fig. 23 shows two months of operation after a maintenance period. It is possible to see that, most of the time, the choke valve is partially closed around 42–43% to keep stability. This position is exactly where a Hopf bifurcation in the real system is. When operators try to open the valve above that limit, the slugging slowly starts to be formed. After some time, the instability grows to high amplitudes, forcing the operators to return the choke valve position to a more closed state to avoid safety issues. This pattern is shown in Fig. 24. Note how oscillation amplitude might be different in distinct points of the system.

The active control solution applied to ROY uses downhole pressure (PDG) as the CV and the choke valve opening as the MV. The gain scheduling was designed using the methodology described in this work, and the curve deployed is based on Fig. 25. Whereas there is no considerable dead time in PDG response, it was chosen as an acceleration factor of $\alpha = 4$ to allow a faster controller performance. The T_i and T_d terms were set as $T_i \cong \tau/4$ and $T_d \cong T_i/5$. Although there is no dead time, observations regarding derivative action showed it could lead to positive effects in limit cycle control. The rules applied to define this tuning were acquired heuristically by the authors' practical field experience in this specific phenomenon.

In the following sections, the control strategy performance will be presented, as well as its capacity to reject disturbance and its financial earning potential.

5.1. Actual closed-loop performance

The main goal of an active anti-slug control is to reduce the production system counter pressure safely. As lower the counter pressure is, the higher is the well flowrates, once the flow driving force is the pressure difference and the reservoir pressure is constant in medium term observations. So the well optimum point is the lowest pressure achievable. Fig. 26 presents four relevant moments in the anti slug-control performance in ROY well.

Firstly, the controller starts from one steady-state nearby Hopf bifurcation at the stable branch of equilibrium - Fig. 26 (a). While the flow pattern is stable, the set point is reduced little by little. The more the pressure decreases, the further "inside" the unstable zone the system is. This requires a MV action intensification. Hence, the variance increases on the choke valve opening, as shown in Fig. 26 (a) and (b).

Along the pressure minimization, the plant gain tends to get lower, and, as a consequence, the control actions increase. Fig. 26 (c) shows the controller suppressing the limit cycle amplitude in a low pressure level, around 5 bar from its begging in open loop.

According to Fig. 25 and its plant inversion prevision by $\alpha = 1$, this level of pressure drop is around the minimum feasible pressure in the production system. This means that the controller is very close to its limit in terms of robustness, which tends to be critical to stability. Indeed, the following set point reductions induce a complete loss in the closed-loop performance, and, as result, an instability emerges when the pressure is below 145 bar. Fig. 26 (d) shows the stability loss and recovery through increasing the well counter pressure, which actually moves the system toward a stable region and retrieves the controller robustness.

Finally, it took 5 days for the controller to reach the minimum system pressure.

5.2. Disturbance attenuation

The main disturbances that a gas lifted satellite well might be submitted to correspond to the gas flow rate supply variation and topside pressure discharge fluctuations. Definitely, the gas lift flow rate has a strong impact on the wells, and it is desirable to reduce the effects of its variance on the production.

The oil rig that ROY is connected to makes use of subsea manifolds in order to distribute the gas lift to wells. The gas provision of ROY comes from a subsea manifold that feeds the other three wells, which means operational maneuvers in those wells cause a disturbance in ROY gas supply.

One example of this kind of disturbance can be viewed in Fig. 27,

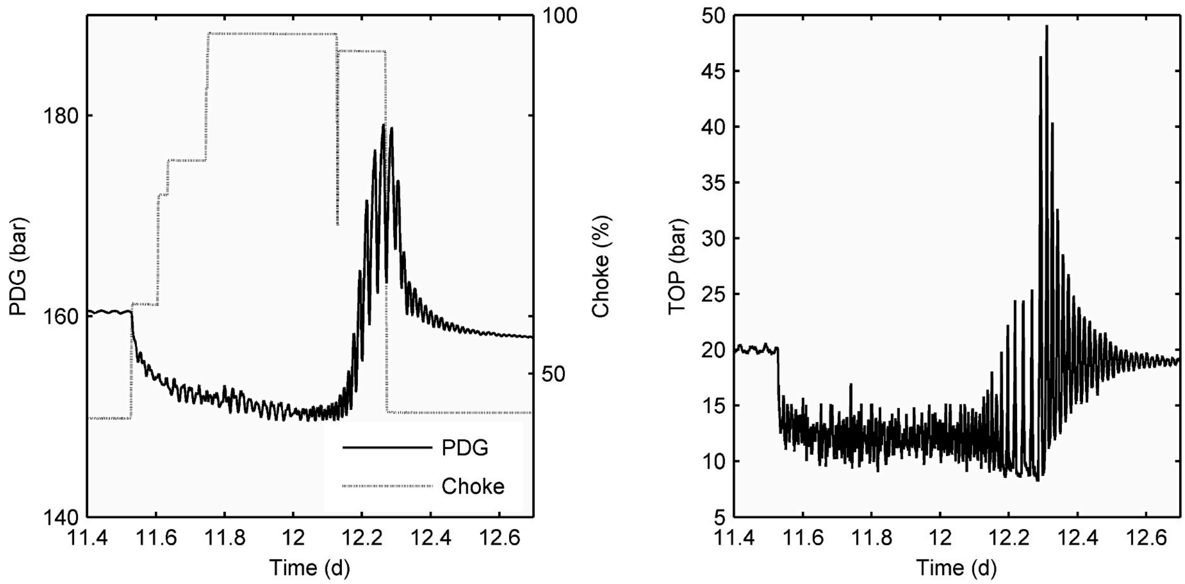

Fig. 24. ROY instabilization/stabilization through choke valve opening: (a) downhole and (b) upstream choke valve pressure.

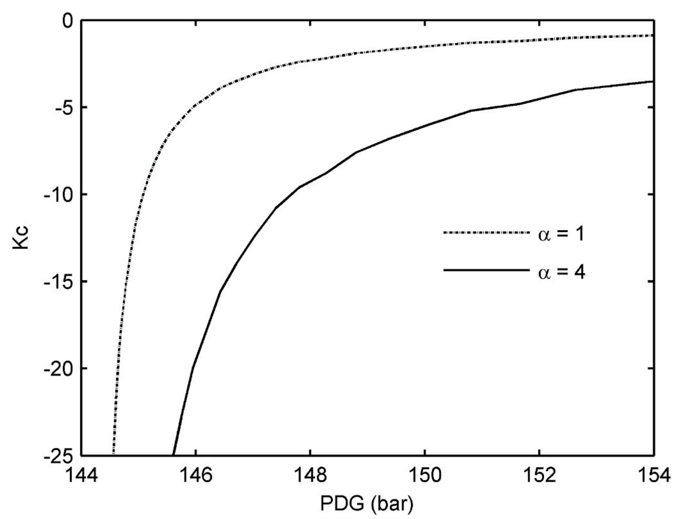

Fig. 25. Gain scheduling designed based on data for $\alpha = 1$ and $\alpha = 4$.

where the subsea manifold pressure suddenly drops for about 3 h. In this period, the gas availability was reduced, inducing a static head increase and leading the flow to a more unstable state. Despite the reduction of 31 bar in the manifold pressure, that is, 14% of pressure drop, the controller handled the disturbance and kept the system in a profitable zone.

A second and even more critical example is shown in Fig. 28. In this case, there was a pressure loss of around 42 bar in the subsea manifold. In other words, a restriction of 19% in the supply pressure. Once again, the controller handled the disturbance avoiding losses in production.

Disturbance impact and its rejection ability by the active control solution are more enlightening through Fig. 29 comparison. The graph shown corresponds to the second disturbance described in this section. Nevertheless in this analysis, an open-loop well called ROZ, which is directly linked to the same subsea manifold as ROY, was added. The difference between maximum and minimum pressures during the disturbance shows ROZ suffered much more than ROY with the gas lift pressure drop. Specifically, ROY presented up to 12 times less variation in downhole pressure (PDG) amplitude if compared to ROZ, while the ROY upstream choke valve pressure (TOP) amplitude is up to 65% less than ROZ. The controller allows ROY to operate more safely and profitably when compared with its quite identical well ROZ.

5.3. Profit report

Financial aspects of the closed-loop tests were estimated based on the IPR described in Section 4.3. Considering that the lowest pressure reached was 144.5 bar, the oil production increase associated with this level of pressure is around 725 barrels per day, which is equivalent to an increment of more than 9% in the well production. Assuming US$ 50 as the oil price reference, the well unlockable potential is in the range of 13 million dollars per year.

Taking into account that the pressure meter and the automatic choke valve are already available, it is required a simple computer to deploy this solution, which means that the CAPEX is virtually zero. The financial results and other details are presented in Fig. 30 and in Table 2.

6. Conclusions

In this work, a systematic procedure for nonlinear anti-slug control design was proposed. The controller synthesis is based on direct plant inversion, and for this reason, it is required to map the static system equilibrium. For that, the method uses a simple semi-empirical model and the plant database to generate a controller gain scheduling relationship in order to compensate nonlinearities in well operation. This task is not straightforward once the unsteady state equilibrium branch is not the kind of information easily obtained from available well data. In this sense, adding correlations derived from first principle modeling can definitely help.

The methodology was evaluated in two offshore wells: (1) a virtual well represented by FOWM model and (2) a real ultra-deepwater well, both installed on the Brazilian coast. The results showed good capability in getting close to the theoretical minimum well back pressure and, therefore, to the maximum production achievable while rejecting disturbance in the gas lift supply. A point of attention is that the lower the system gain is, the less robust is the controller, even with high compensation in the controller gain. At a limit gain, any noise could unstabilize the well. Finding out this limit in an online deployment is still an open issue and an important matter for future works.

Further, the method can be applied successfully in all control structures based on conventional subsea and bottom pressure measurements, i.e., downhole pressure and wellhead pressure.

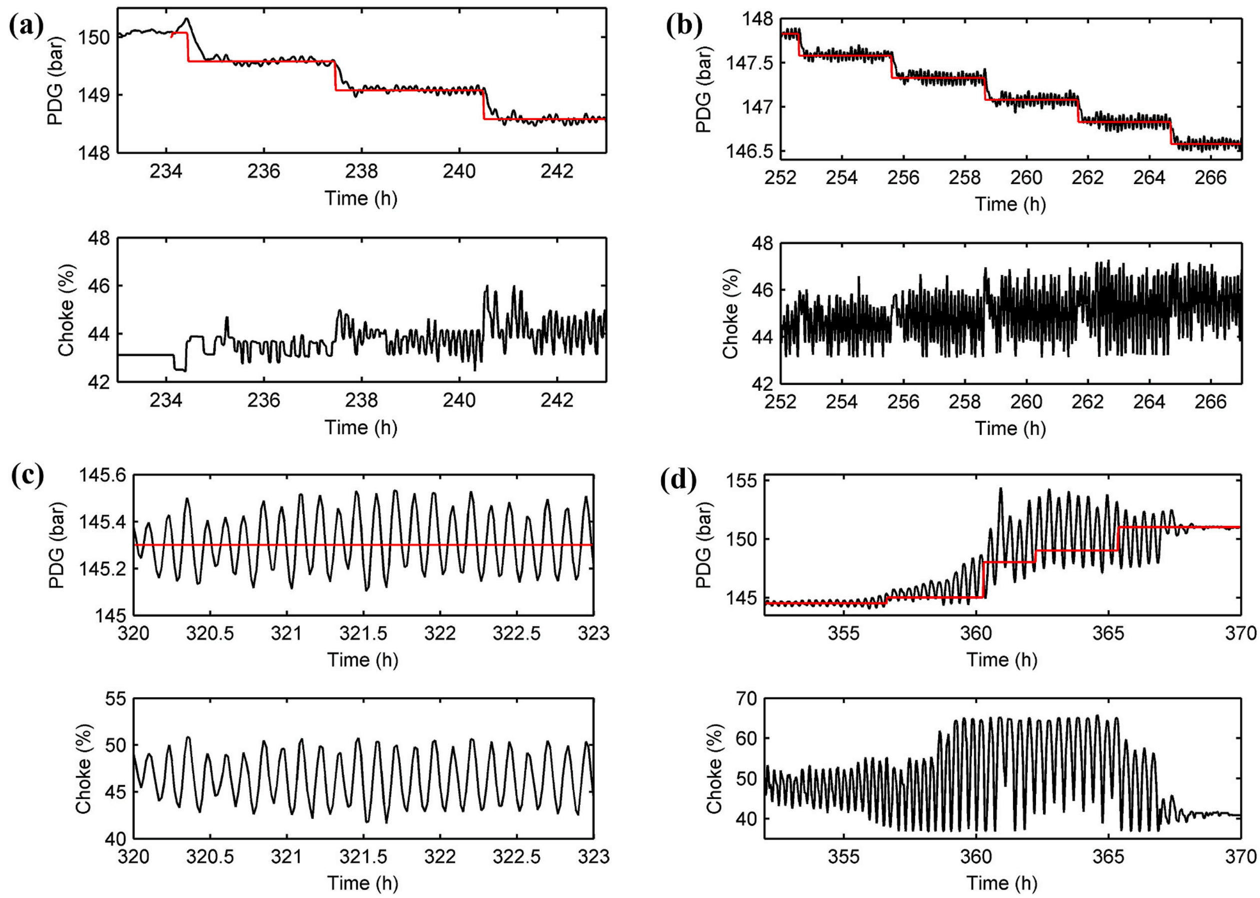

Fig. 26. Gain scheduling-based controller applied to the actual production system ROY: (a,b) pressure reduction forward Hopf bifurcation; (c) the controller counter attacking slugging; (d) robustness loss due to low system gain, followed by an instabilization and, after that, a stability recovery through pressure fallback.

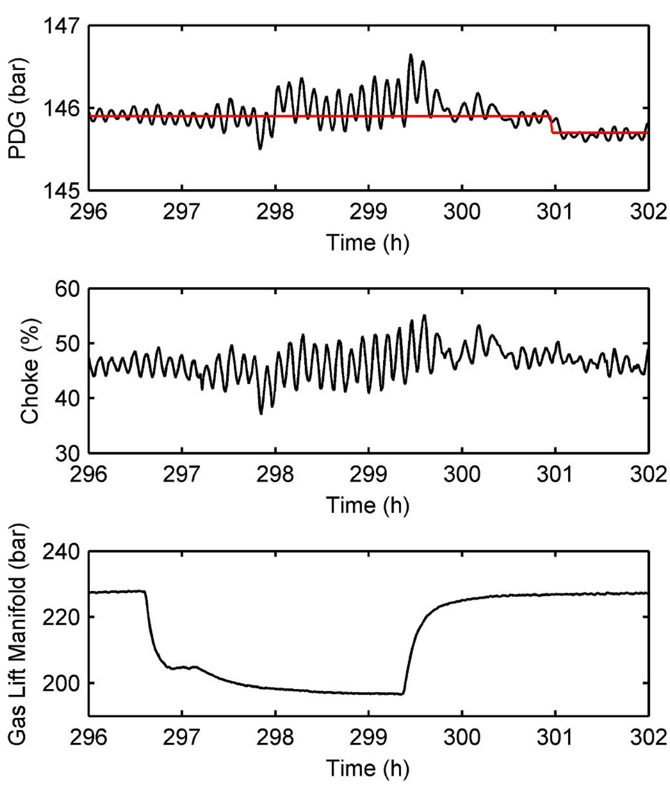

Fig. 27. More than 30 bar pressure loss in the subsea manifold gas lift supply.

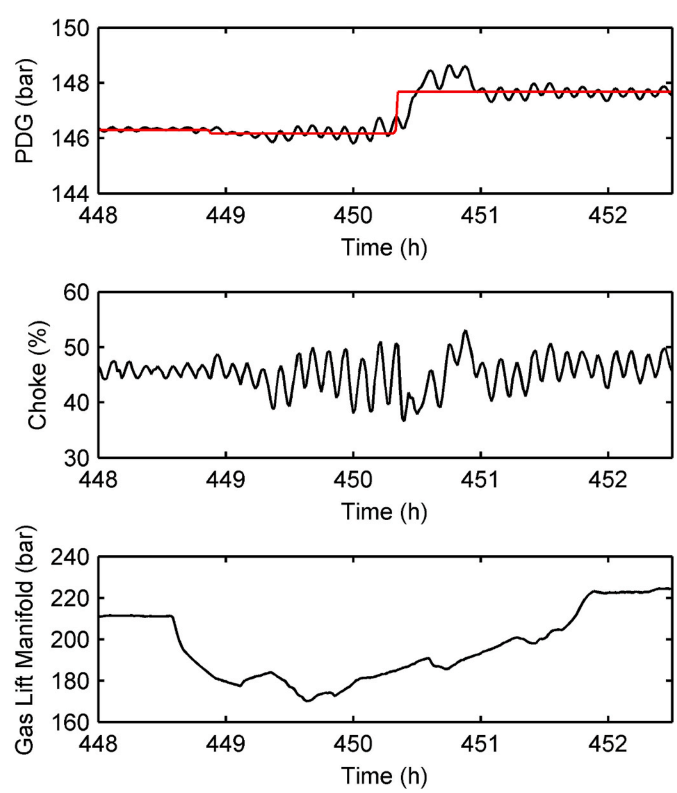

Fig. 28. More than 40 bar pressure loss in the subsea manifold gas lift supply.

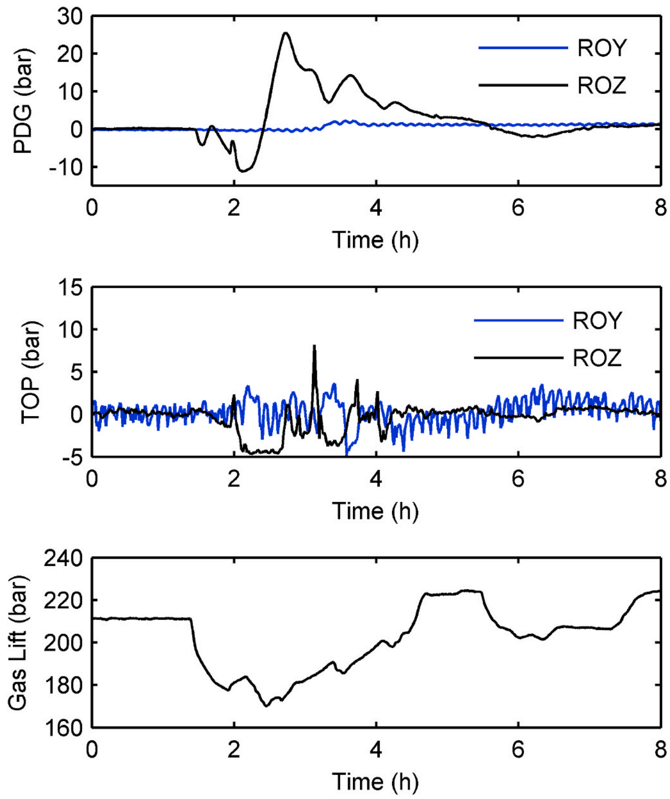

Fig. 29. Gas lift disturbance effect in closed-loop (ROY) and open-loop (ROZ) production system.

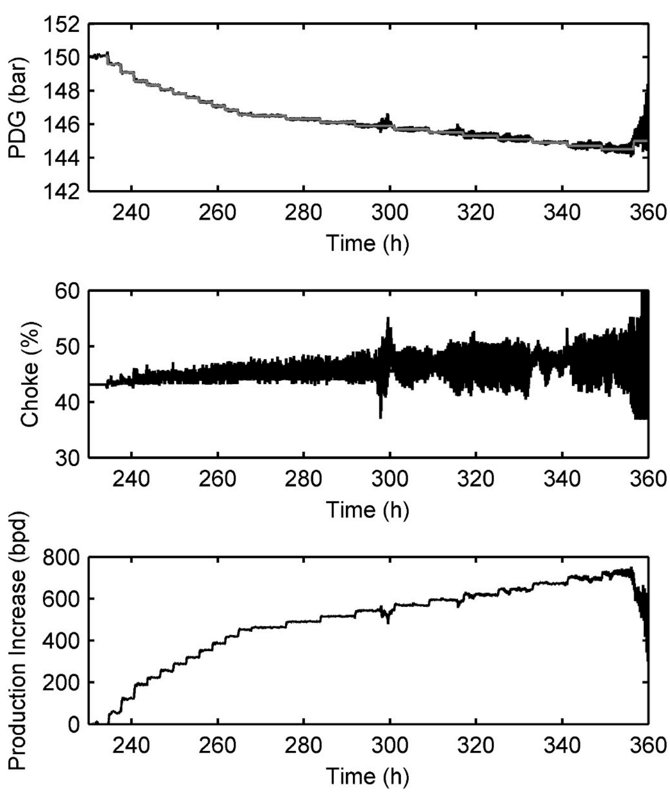

Fig. 30. Oil production increase during the tests.

Table 2
Deployment performance summary.

Feature	Value
Hopf bifurcation pressure (bar)	150
Lowest pressure achieved (bar)	144.5
Highest oil production increase achieved (%)	9.3
Highest oil production increase achieved (bpd)	725
Potential earning[a] (million US$/year)	13.2
Reduction ratio in disturbances spread: downhole	12
Reduction ratio in disturbances spread: topside	2/3

[a] Considering highest profit reached and oil barrel price of US$ 50.

Regarding financial aspects, the method presented increased oil production through active feedback control solution substantially. In the reported field deployment, the oil flowrate was increased by more than 9%, which represents a potential of US$ 13 million per year for that specific well – considering an oil barrel price of US$ 50.

Author contributions

Fabio C. Diehl: Conceptualization, Methodology, Simulation, Plant Deployment, Analysis, Writing and Editing. Giovani G. Gerevini, Tatiane O. Machado, Tiago Bitarelli, Fulvio Serpentini and José R. F. de Azambuja: Plant Deployment. Thiago K. Anzai: Review. André D. Quelhas and Esmaeil Jahanshahi: Conceptualization. Marcelo Farenzena, Jorge O. Trierweiler and Sigurd Skogestad: Supervision and Review.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Glossary of acronyms and abbreviations

BPD	Barrels per day
CAPEX	Capital expenditure
CV	Controlled variable of a closed-loop system
ODE	Ordinary Differential Equations
FOWM	Fast Offshore Wells Model
GOR	Gas-oil ratio
IPR	Inflow Performance Relationship
NMPC	Nonlinear Model Predictive Control
MPC	Model Predictive Control
MV	Manipulated variable of a closed-loop system
PDG	Pressure close to well downhole measured by a sensor named Pressure Downhole Gauge
PID	Proportional-Integral-Derivative controller
ROY	Fictitious name of a real oil well where the methodology proposed in this work was tested
ROZ	Fictitious name of a real oil well that operates in open-loop
R&D	Research and Development
TOP	Pressure upstream the topside choke valve
TPT	Pressure on the wellhead measured by a sensor named Temperature-Pressure Transmitter

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