Available online at www.sciencedirect.com

ScienceDirect

IFAC-PapersOnLine 49-7 (2016) 544–549

Modelling and Robustness Analysis of Model Predictive Control for Electrical Submersible Pump Lifted Heavy Oil Wells

Dinesh Krishnamoorthy [*] Elvira M. Bergheim [*] Alexey Pavlov [*] Morten Fredriksen [*] Kjetil Fjalestad [*]

[*] *Statoil Research Centre, Norway (e-mail: dikr@statoil.no, elvira@statoil.no, alepav@statoil.com, mofr@statoil.com, kjfa@statoil.com).*

Abstract: In this paper we consider the problem of automatic control of oil production wells equipped with Electric Submersible Pumps (ESP). To facilitate robustness analysis of automatic control algorithms for such systems, a high fidelity simulator of ESP lifted well producing heavy viscous crude oil, has been developed. Model Predictive Control strategy proposed by the authors in an earlier publication has been tested on this simulator with the main focus on controller performance and robustness. The results demonstrated sufficient robustness of the controller with respect to system nonlinearities, variations in operating conditions, disturbances and measurement noise.

Keywords: Model Predictive Control, Modelling, Artificial Lift, Optimisation

1. INTRODUCTION

Electrical Submersible Pump (ESP) in an oil producing well is an artificial lifting system that boosts production by providing additional pressure increase. ESP is a multistage centrifugal pump that is installed in a well several hundred meters below the surface (Fig 1). ESP is one of the widely used artificial lift technologies in the world and a natural choice for heavy oil reservoirs, see Takacs (2009) and Golan and Whitson (1991).

Currently, an ESP lifted well is operated by manually adjusting the ESP speed and the opening of the production choke at the top of the well. It can be a challenging task to find the optimal ESP speed and the production choke opening and maintain the operation within the operating limits. This becomes especially challenging in the presence of changing conditions and disturbances as described in Pavlov et al. (2014). A need for more sophisticated control system over the existing automation solutions for ESPs is justified in that paper.

Model predictive control strategy has been suggested for control and optimisation of ESP lifted oil wells and was presented in Pavlov et al. (2014). Similar work inspired by Statoil has been presented in Sharma and Glemmestad (2013) and Binder et al. (2014). Verification of the controller presented in these papers was done using simple hydraulic models, which did not allow thorough robustness analysis of the controller. Therefore we need a high fidelity simulator that captures the necessary dynamics to test and analyse the robustness of the proposed control strategy.

The main contributions of this paper are a high fidelity simulator model of an ESP lifted well, pumping live heavy crude oil, presented in Section 3 and the robustness analysis of the proposed Model Predictive Control strategy for ESP lifted oil wells, presented in Section 4.

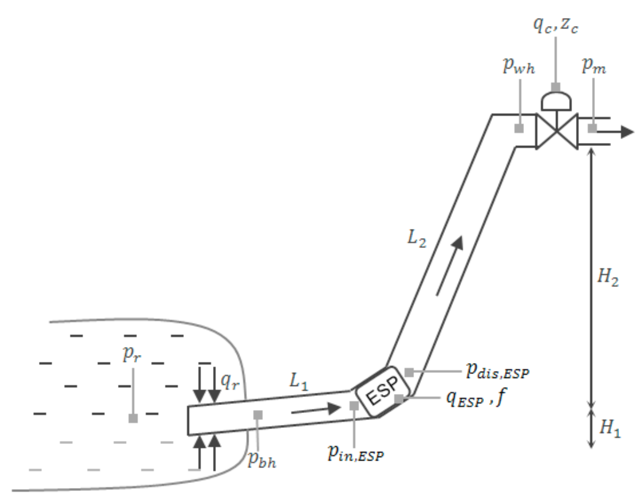

Fig. 1. Schematic of an oil producing well fitted with ESP

2. PROCESS DESCRIPTION AND PROBLEM FORMULATION

2.1 Process Overview

A schematic representation of an ESP lifted oil well is shown in Fig.1. Reservoir fluids (oil, water, and possibly gas) enter the well through perforations, flow to the ESP, which then lifts the fluids to the production choke at top of the well (also known as wellhead choke). Downstream the choke, the fluid enters a production manifold, which is connected to the topside process facility. The production from each well is generally controlled using the ESP speed and the production choke. Some wells may have more than

2405-8963 © 2016, IFAC (International Federation of Automatic Control) Hosting by Elsevier Ltd. All rights reserved.
Peer review under responsibility of International Federation of Automatic Control.
10.1016/j.ifacol.2016.07.399

one reservoir inflow branch. In such wells, reservoir fluids enter from each branch and meet upstream the ESP. Each branch may also have an additional valve known as Inflow control valve (ICV) to control or isolate the flow from each branch. A list of commonly available measurements that can be used for control is given in Pavlov et al. (2014).

The notations used in Fig.1 and in the subsequent equations are as follows: q_r is the total volumetric flow entering the well from the reservoir. q_{ESP} and q_c are the volumetric flow rates of the fluid through the ESP and the choke respectively. $p_{in,ESP}$ and $p_{dis,ESP}$ are the ESP inlet and discharge pressure respectively. p_r, p_{bh}, p_{wh} and p_m are the reservoir, bottomhole, wellhead and manifold pressure respectively. The ESP rotational frequency is depicted by f and the wellhead choke opening is denoted by z_c. L_1 and H_1 are the length and height of the pipe section upstream the ESP and L_2 and H_2 are the length and height of the pipe section downstream the ESP.

2.2 *Process constraints*

Production processes have a number of process and operating constraints that must be satisfied for safe operation and extension of the ESP and well lifetime. These include constraints on the ESP intake pressure, wellhead pressure, ESP current, ESP motor temperature, ESP speed and production choke etc. A detailed description of all the operating and process constraints for an ESP lifted well system is given in Pavlov et al. (2014).

Additionally, the operation of an ESP is constrained by an operational envelope, usually specified in terms of maximum and minimum admissible flow rates through the ESP. These constraints, known as upthrust and downthrust constraints are enforced to avoid excessive unbalanced thrust forces in the upward and downward direction respectively and avoid mechanical wear. More information on these constraints can be found in Takacs (2009). These constraints depend on both the ESP speed and the fluid viscosity and are expressed as:

$$q_0^{dt} c_q(\mu) \left(\frac{f}{f_0}\right) \leq q_{ESP} \leq q_0^{ut} c_q(\mu) \left(\frac{f}{f_0}\right) \quad (1)$$

where q_0^{ut} and q_0^{dt} are the upthrust and downthrust constraint on flow at reference conditions (at frequency f_0 and $1cP$ viscosity). These are corrected for the actual fluid viscosity using the viscosity correction factor for flow $c_q(\mu)$ and scaled to any arbitrary frequency f using the affinity laws, see Takacs (2009).

2.3 *Control and Optimisation Targets*

Since the drawdown from the reservoir is directly associated with the ESP intake pressure as in (11), controlling the ESP intake pressure to a desired setpoint gives direct control over the drawdown from the reservoir. At the same time, we would like to achieve this control target by keeping the production choke as open as possible to reduce energy losses across the choke.

Other control/optimisation targets can be formulated depending on the specific application.

3. DYNAMIC MODEL OF ESP LIFTED WELL

A simple dynamic model with two control volumes, average pump model and homogenous fluid under isothermal condition was presented in Pavlov et al. (2014). Although such a simple model was suitable for controller design, a more advanced model is required to test and verify the robustness of the control system in representative conditions. Hence a high fidelity simulator was developed using Modelica, see DassaultSystemes (2005).

The model consists of an oil well with many small control volumes, multistage ESP model, and live viscous crude oil. The different components that make up the model are as follows: live viscous fluid (with associated gas and water), reservoir inflow, ESP, ESP motor, production pipe and the choke. In this model, we assume no free gas enters the well from the reservoir. The simulator is modelled with the assumption that no mass or energy is stored in the system. The various components of the model are described in detail in the following sections.

3.1 *Fluid Model*

Heavy viscous crude oil with associated gas and water is modelled capturing various PVT and thermodynamic properties such as viscosity and density as a function of pressure and temperature in each control volume. The viscosity for each phase μ_{oil} and μ_{water} is given by (3). Mixing oil and water forms emulsions and the emulsion viscosity is given by Brinkmans correlation which depends on the watercut WC (2), see Brinkman (1949). The Oil-Water mixture viscosity follows Water in Oil emulsions (4) up to a certain watercut, known as the inversion watercut and thereon follows Oil in Water emulsions (5). The inversion watercut depends on the shear forces acting between the oil and water phases and generally occur between 30% and 50% watercut. For simplicity reasons, a fixed inversion watercut of 40% is chosen in this simulator.

$$WC = \frac{q_{water}}{q_{oil} + q_{water}} \quad (2)$$

$$\mu_{phase}(p,T) = \frac{\mu_{std}}{[1 + c_{\Delta T}(T - T_{std})][1 + c_{\Delta p}(p - p_{std})]} \quad (3)$$

$$\mu_{WiO} = \mu_{oil}(1 - WC)^{-2.5} \quad (4)$$

$$\mu_{OiW} = \mu_{water}(WC)^{-2.5} \quad (5)$$

where, μ_{std} is the viscosity of the phase at standard reference pressure p_{std} and temperature T_{std}. The thermal and pressure coefficients $c_{\Delta T}$ and $c_{\Delta p}$ are tuned using laboratory test data for each phase.

The density for oil and water is given by (6), see EngineeringToolbox (2005). The gas density is computed from ideal gas law equation as shown in (7). The mixture density is computed using the slip corrected mass fractions for each phase X_{oil}, X_{water} and X_{gas} as shown in (8)

$$\rho_{phase}(p,T) = \frac{\rho_{std}}{[1 + c_{\Delta T}(T - T_{std})][1 + c_{\Delta p}(p - p_{std})]} \quad (6)$$

$$\rho_{gas}(p,T) = \frac{p \cdot M_w}{T \cdot R} \quad (7)$$

$$\rho_{mix} = \frac{1}{\left(\frac{X_{oil}}{\rho_{oil}} + \frac{X_{water}}{\rho_{water}} + \frac{X_{gas}}{\rho_{gas}}\right)} \quad (8)$$