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IFAC-PapersOnLine 48-6 (2015) 140–146

Estimation of Flow Rate and Viscosity in a Well with an Electric Submersible Pump using Moving Horizon Estimation ⋆

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Abstract: A Moving Horizon Estimator (MHE) is designed for a petroleum production well with an Electric Submersible Pump (ESP) installed for artificial lift. The focus is on estimating the flow rate from the well, the viscosity of the produced fluid, and the productivity index of the well. The software package ACADO is used to implement a Moving Horizon Estimator using a third-order nonlinear model. Simulation results show that the implemented estimator is able to estimate the desired variable and parameters. The resulting C-code solver is very fast, admitting real-time implementation.

Keywords: Petroleum Production, Electric Submersible Pumps, Estimators, Moving Horizon Estimation, Flow Rate Allocation, Production Optimization

1. INTRODUCTION

Information about the flow rate and phase fractions from individual wells in an oil field is important for flow rate allocation and production optimization. Measurements of these have traditionally been performed with specialized and costly instrumentation. Multi-phase flow metering has been a challenge for offshore applications, both due to the complexity of such fields, and space requirements, costs and uncertainties associated with such instrumentation (Varón et al., 2013). Moreover, for fields producing oil with a high viscosity, multi-phase flow meters may not be very reliable.

The Electric Submersible Pump (ESP) is one of the most widely used methods for artificial lift in the oil industry (Takacs, 2009; Varón et al., 2013). There are a number of variables that affect the life-time of ESP installations, such as power consumption, flow rate, pressure, temperature, thrust forces and vibration. Operation outside of certain limits on these variables may lead to failure or reduced life-time of the ESP, which has a huge economic impact, both due to the costs of replacing the pump, and the loss of production.

Reliable measurements are difficult to obtain for many important variables and parameters in ESP-lifted wells. As a lot of instrumentation is usually included in ESP installations, using the ESP as a flow meter has recently been investigated. Extensive testing of both flow meters and ESPs for flow allocation purposes was performed in Beall et al. (2011). It was shown that flow meter accuracy is highly dependent on correct fluid characterization, specifically viscosity and phase fractions are important parameters. In Olsen et al. (2012) the ESP tests and flow rate allocation was further discussed, and the results from the ESP tests were used to develop an algorithm that estimates flow rates based on measurements from the ESP system and fluid properties, combined with models of the ESP system components. The flow rate measurements depend on the pump speed, ESP head or brake horsepower, and the viscosity of the fluid. Promising results with this approach were reported. Uncertainties in the flow rate measurements by using the ESP as a flow meter were investigated in Varón et al. (2013), where it was shown that this depends on the pump speed and fluid viscosity. This reveals that a main limitations in this approach is that it depends heavily on correct information about certain parameters, such as the viscosity of the produced fluid.

Estimators (observers) are usually implemented to estimate unmeasured states in a system model that is used for control and monitoring purposes. The Kalman Filter is an efficient solution to the estimation problem for linear systems, but the estimation of nonlinear systems is still a challenging problem. Various nonlinear extensions of the linear Kalman filter has been developed, including the Extended Kalman Filter (EKF) and the Unscented Kalman

⋆ This work is funded by the Research Council of Norway and Statoil through the PETROMAKS project No. 215684: Enabling High-Performance Safety-Critical Offshore and Subsea Automatic Control Systems Using Embedded Optimization (emOpt)

10.1016/j.ifacol.2015.08.022

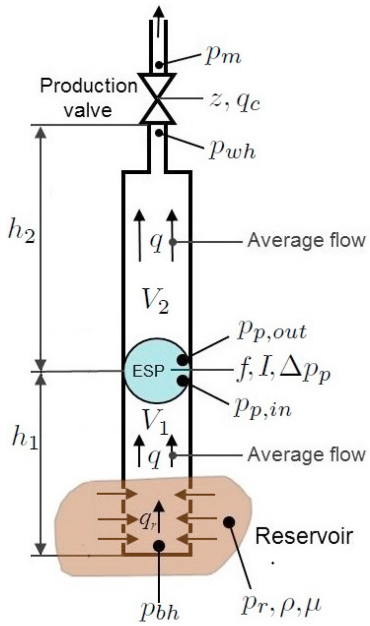

Fig. 1. ESP-lifted well

Filter (UKF), the EKF probably being the most commonly implemented estimator for nonlinear systems (Julier and Uhlmann, 2004). The Moving Horizon Estimator (MHE) (Rao et al., 2003) is an optimization-based method for nonlinear estimation that works on a limited number of past measurements (a 'window' or 'horizon'). The main advantages of MHE is the explicit consideration of state and parameter constraints, optimality of the estimates (in a least-squares sense), and the stability properties (Kühl et al., 2011).

In the recent years, several researchers have investigated estimation in petroleum wells based on dynamic models of the wells. Estimation in gas-lifted wells was investigated e.g. in Bloemen et al. (2004); Eikrem et al. (2004); Aamo et al. (2005), and for drilling applications in e.g. Siahaan and Nygaard (2008); Paasche et al. (2011); Kaasa et al. (2012); Nikoofard et al. (2014); Hasan and Imsland (2014).

In this paper, MHE is implemented for a well with an ESP and a production choke valve, as shown in Fig. 1. The focus is on estimating the flow q from the well, the viscosity μ of the produced fluid, and the productivity index PI of the well, based on measurements that typically are available in such systems. Both flow rate of the produced fluid and the well productivity index (PI) are very important parameters for flow rate allocation and production optimization, and both flow rate and viscosity of the produced fluid are needed to determine whether the ESP has safe operating conditions.

A main feature of the approach presented in this paper is that not only a model of the ESP, but a dynamic model of the entire well is used to get better estimates of the unknown parameters. This includes models of the pressure drop in the well between the ESP and the production choke, the pressure drop over the production choke, and the inflow from the reservoir. Moreover, the estimations are based on measurements from a certain time window (estimation horizon), which adds up to reliability and accuracy of the estimates.

Table 1. Model variables

Inputs		**Unit**	**Meas**
f	ESP frequency	Hz	yes
z	Production choke valve opening	-	yes
Pressures		**Unit**	**Meas**
p_m	Manifold pressure	Pa	yes
p_{wh}	Wellhead pressure	Pa	yes
$p_{p,out}$	ESP outlet pressure	Pa	yes
$p_{p,in}$	ESP inlet pressure	Pa	yes
Δp_p	Pressure difference across ESP	Pa	yes
p_{bh}	Bottomhole pressure in well	Pa	no
Δp_f	Frictional pressure drop in the well	Pa	no
F_1	Frictional pressure drop below ESP	Pa	no
F_2	Frictional pressure drop above ESP	Pa	no
Flow rates		**Unit**	**Meas**
q	Average flow rate in well	m^3/s	no
q_c	Flow rate through production choke	m^3/s	no
q_r	Inflow from reservoir into well	m^3/s	no
ESP		**Unit**	**Meas**
I	Electric current in ESP motor	A	yes
H	Head developed by ESP	m	no
P	ESP brake horsepower (BHP)	W	no

2. SYSTEM MODEL

The estimation in this paper is based on a dynamic model of the well and the ESP. The estimation also depends on available system information, such as measured variables, known model parameters and empirical test data. In this section, the model that is used in the estimator is presented, and the information assumed to be available is outlined.

2.1 Model Variables

The considered well is shown in Fig. 1. (A vertical well is depicted, but the model also describes deviated wells.) These are the main variables in the system:

- The control inputs to the system are the rotational frequency f of the ESP, and the production choke valve opening denoted z.
- p_m denotes the manifold pressure, which is treated as a disturbance in the model.
- The wellhead pressure is denoted p_{wh}, and the bottomhole pressure is denoted p_{bh}.
- $p_{p,in}$ and $p_{p,out}$ denote the pressures at the inlet and outlet of the ESP, and $\Delta p_p = p_{p,out} - p_{p,in}$ the pressure increase provided by the ESP.
- I denotes the electric current supplied to the ESP motor.
- q denotes the average flow rate in the well, q_c the flow rate through the production choke valve, and q_r the inflow from the reservoir.

A complete list of variables that are used in the model is given in table 1. Model parameters are described in sections 2.4 and 2.5.

2.2 Measurements

The following assumptions are made regarding available measurements in the system: