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Dynamic Oil and Gas Production Optimization via Explicit Reservoir Simulation

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Abstract

Dynamic oil and gas production systems simulation and optimization is a research trend with a potential to meet the challenges faced by the international oil and gas industry, as has been already demonstrated in a wide variety of publications in the open literature. The complex two-phase flow in reservoirs and production wells governs fuel transport, but is mostly handled by algebraic approximations in modern optimization applications; the true reservoir state variable profiles (initial/boundary conditions) are not known. Integrated modeling and optimization of oil and gas production systems treats oil reservoirs, wells and surface facilities as a single (yet multiscale) system, focusing on computing accurate reservoir and well state variable profiles, useful for optimization. This paper discusses a strategy for interfacing reservoir simulation (ECLIPSE®) with equation-oriented process optimization (gPROMS®) and presents a relevant application.

Keywords: oil and gas production, modeling, multiphase flow simulation, optimization.

1. Introduction and Motivation

In an era of globalized business operations, large and small oil and gas producers alike strive to foster profitability by improving the agility of exploration endeavors and the efficiency of oil production, storage and transport operations (Economides et al., 1994). Consequently, they all face acute challenges: ever-increasing international production, intensified global competition, price volatility, operational cost reduction policies, aggressive financial goals (market share, revenue, cash flow and profitability) and strict environmental constraints (offshore extraction, low sulphur): all these necessitate a high level of oilfield modeling accuracy, so as to maximize recovery from certified reserves. Straightforward translation of all considerations to explicit mathematical objectives and constraints can yield optimal oilfield network design, planning and operation policies. Therefore, the foregoing goals and constraints should be explicitly incorporated and easily revised if the generality of production optimization algorithms is to be preserved. This paper provides a summary of a strategy towards integration of equation-oriented process modeling and multiphase reservoir computational fluid dynamics (CFD), in order to include the dynamic behavior of reservoirs into oil and gas production models.

The problem of fuel production optimization subject to explicit oilfield constraints has attracted significant attention, documented in many petroleum engineering publications. A comprehensive literature review by Kosmidis (2003) classifies previous algorithms in 3 broad categories (simulation, heuristics, and mathematical programming methods) and underlines that most are applied either to simple pipeline networks of modest size, relying on heuristic rules of limited applicability, only suitable for special structures. Reducing the computational burden (focus on natural-flow wells or gas-lift wells only, or reducing well network connectivity discrete variables) is a crucial underlying pattern.

Dynamic oil and gas production systems simulation and optimization is a research trend which has the clear potential to meet the foregoing challenges of the international oil and gas industry and assist producers in achieving business goals and energy needs. Previous work (Lo, 1992; Fang and Lo, 1996; Kosmidis et al., 2004, 2005) has addressed successfully research challenges in this field, using appropriate simplifying correlations (Peaceman, 1977) for two-phase flow of oil and gas in production wells and pipelines. A series of assumptions are adopted to achieve manageable computational complexity: the fundamental one is the steady-state assumption for the reservoir model, based on the enormous timescale difference between different spatial levels (oil and gas reservoir dynamics evolve in the order of weeks, the respective ones of pipeline networks are in the order of minutes, and the production optimization horizon is in the order of days). The decoupling of reservoir simulation from surface facilities optimization is based on these timescale differences among production elements (Peaceman, 1977; Aziz, 1979). While the surface and pipeline facilities are in principle no different from those found in any petrochemical plant, sub-surface elements (reservoirs, wells) induce complexity which must be addressed via a systematic strategy that has not been hitherto proposed.

The complex two-phase flow in production wells governs crude oil and gas transport. Despite intensive experimentation and extensive CFD simulations towards improved understanding of flow and phase distribution, commercial optimization applications have not benefited adequately from accurate sub-surface multiphase CFD modeling, and knowledge from field data is not readily implementable in commercial software. model integration can enable the employment of two-phase reservoir CFD simulation, towards enhanced oil or gas production from depleted or gas-rich reserves, respectively.

The concept of integrated modeling and optimization of oil and gas production treats oil reservoirs, wells and surface facilities as a single (albeit multiscale) system, and focuses on computing accurate reservoir state variable profiles (as initial/boundary conditions). The upper-level optimization can thus benefit from the low-level reservoir simulation of oil and gas flow, yielding flow control settings and production resource allocations. The components of this system are tightly interconnected (well operation, allocation of wells to headers and manifolds, gas lift allocation, control of unstable gas lift wells). These are only some of the problems that can be addressed via this unified framework.

Figure 1 presents the concept of integrated modeling of oil and gas production systems.

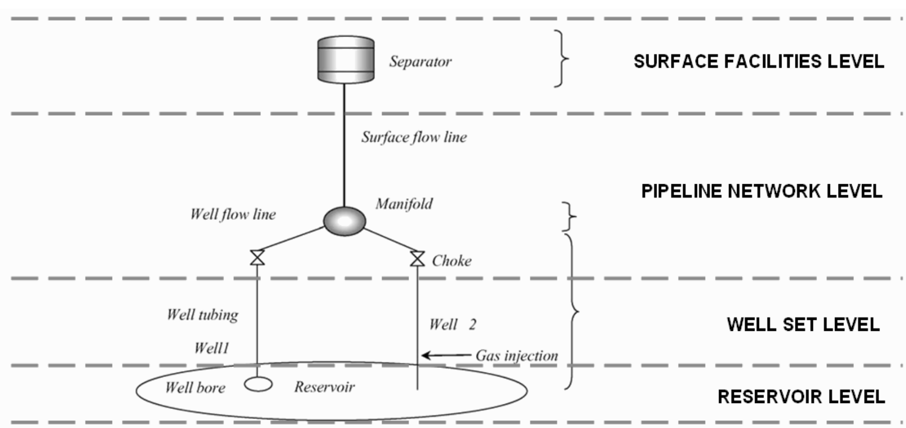

Figure 1: Integrated modeling concept for oil and gas production systems optimization: illustration of the hierarchy of levels and production circuit elements (Kosmidis, 2003).

2. Previous Work and Current Challenges

A number of scientific publications address modeling and simulation of oil extraction: they either focus on accurate reservoir simulation, without optimization considerations (Hepguler et al., 1997; Litvak et al., 1997), or on optimal well planning and operations, with reduced (Lo, 1992; Fang and Lo, 1996; Stewart et al., 2001; Wang et al., 2002) or absent (Van den Heever and Grossmann, 2000; Saputelli et al., 2002) reservoir models. Computational Fluid Dynamics (CFD) is a powerful technology, capable of elucidating the dynamic behavior of oil reservoirs towards efficient oilfield operation (Aziz, 1979).

The MINLP formulation for oilfield production optimization of Kosmidis (2004) uses detailed well models and serves as a starting point in the case examined in this study. Therein, the nonlinear reservoir behavior, the multiphase flow in pipelines, and surface capacity constraints are *all* considered (multiphase flow is handled by DAE systems, which in turn comprise ODEs for flow equations and algebraics for phys. properties). The model uses a degrees-of-freedom analysis and well bounding, but most importantly approximates each well model with piecewise linear functions (via data preprocessing).

Here, explicit reservoir flow simulation via a dynamic reservoir simulator (ECLIPSE®) is combined with an equation-oriented process optimizer (gPROMS®), towards integrated modeling and optimization of a literature problem (Kosmidis, 2005 – Ex. 2a). An asynchronous fashion is employed: the first step is the calculation of state variable profiles from a detailed description of the production system (reservoir) via ECLIPSE®. This is possible by rigorously simulating the multiphase flow within the reservoir, with real-world physical properties (whose extraction is laborious: Economides et al., 1994). These dynamic state variable profiles (pressure, oil, gas and water saturation, flows) are a lot more accurate than piecewise linear approximations (Kosmidis, 2003), serving as initial conditions for the higher-level dynamic optimization model (within gPROMS®). Crucially, these profiles constitute major sources of uncertainty in simplified models. Considering the oil and gas pressure drop evolution within the reservoir and along the wells, one can solve single-period or multi-period dynamic optimization problems that yield superior optima, because piecewise linear pressure underestimation is avoided. While integrating different levels (sub-surface elements and surface facilities – Fig. 1) is vital, interfacing CFD simulation with MINLP optimization is here pursued in an asynchronous fashion (given the computational burden for CFD nested within MINLP). The concept of integrated modeling and optimization is illustrated in detail in Figure 2:

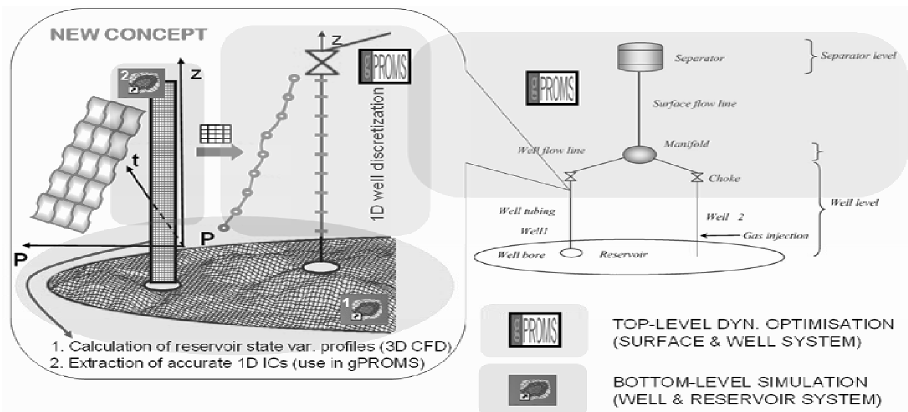

Figure 2: Integrated modeling and optimization of oil and gas production systems: illustration of the explicit consideration of multiphase flow within reservoirs and wells.

3. Problem Definition and Model Formulation

Dynamic CFD modeling for explicit multiphase flow simulation in reservoirs and wells comprises a large number of conservation laws and constitutive equations for closure: Table 1 presents only the most important ones, which are implemented in ECLIPSE®. The *black-oil model* (Peaceman, 1977) is adopted in this study, to manage complexity. More complicated, *compositional models* are widely applied in literature (Aziz, 1979), accounting explicitly for different hydrocarbon real- or pseudo-species concentrations. A black-oil model allows for multiphase simulation via only 3 phases (oil, water, gas).

Table 1: Multiphase flow CFD model equations (Nomenclature as in: Kosmidis, 2004).

Oil	$\nabla[\frac{k\,k_{ro}}{\mu_o B_o}\nabla(P_o+\rho g h)]+q_o=\frac{\partial}{\partial t}(\phi\frac{S_o}{B_o})$	(1)
Water	$\nabla[\frac{k\,k_{rw}}{\mu_w B_w}\nabla(P_w+\rho g h)]+q_w=\frac{\partial}{\partial t}(\phi\frac{S_w}{B_w})$	(2)
Gas	$\nabla[\frac{k\,k_{rg}}{\mu_g B_g}\nabla(P_g+\rho g h)]+\nabla[R_s\frac{k\,k_{ro}}{\mu_o B_o}\nabla(P_o+\rho g h)]+q_g=\frac{\partial}{\partial t}(\phi\frac{S_g}{B_g}+R_s\frac{\phi S_o}{B_o})$	(3)
Total pressure gradient	$\frac{dP}{dx}=-g\rho_m(x)\sin(\theta)-\frac{\tau_w(x)S}{A}$	(4)
Capillary pressure (oil/gas)	$P_{cog}(S_o,S_g)=P_o-P_g$	(5)
Capillary pressure (oil/water)	$P_{cow}(S_o,S_w)=P_o-P_w$	(6)
Multiphase mixture saturation	$S_o+S_w+S_g=1$	(7)
Multiphase mixture density	$\rho_m(x)=\rho_l(x)E_l(x)+\rho_g(x)E_g(x)$	(8)
Multiphase mixture viscosity	$\mu_m(x)=\mu_l(x)E_l(x)+\mu_g(x)E_g(x)$	(9)
Multiphase mixture sup. velocity	$U_m(x)=\frac{\rho_l(x)}{\rho_m(x)}U_{sl}(x)+\frac{\rho_g(x)}{\rho_m(x)}U_{sg}(x)$	(10)
Multiphase mixture holdup closure	$E_g(x)+E_l(x)=1$	(11)
Drift flux model (gas holdup)	$E_g=f_d(U_{sl},U_{sg},\textit{mixture properties})$	(12)
Choke model (for well & valve i)	$q_{L,i}=f_c(d_i,P_i(x_{ch}^-),P_i(x_{ch}^+),c_i,q_{g,i},q_{w,i})$	(13)
Choke setting (for well & valve i)	$c_i=\max(c_c,P_i(x_{ch}^-),P_i(x_{ch}^+))$	(14)
Performance (flow vs. pressure)	$q_{j,i}=f_j(P_{wf,j,i}),\forall i\in I,\forall j\in\{o,w,g\}$	(15)

Reduced (1D) multiphase flow balances are solved using a fully implicit formulation and Newton's method (Kosmidis, 2003), but only for the wells and not for the reservoir. The present paper uses: (a) explicit reservoir and well 3D multiphase flow simulation, (b) elimination of Eq. (15) (performance relations/preprocessing obsolete due to CFD), (c) CFD profiles as initial conditions (asynchronous fashion) for dynamic optimization. The MINLP optimization objective (maximize oil production) and model structure is adopted from the literature (Kosmidis, 2005) via a gPROMS® – SLP implementation. Adopting an SQP strategy can increase robustness as well as computational complexity.

Reservoir Multiphase Flow Simulation Results

Dynamic multiphase flow simulation results (from ECLIPSE®) are presented in Figure 3

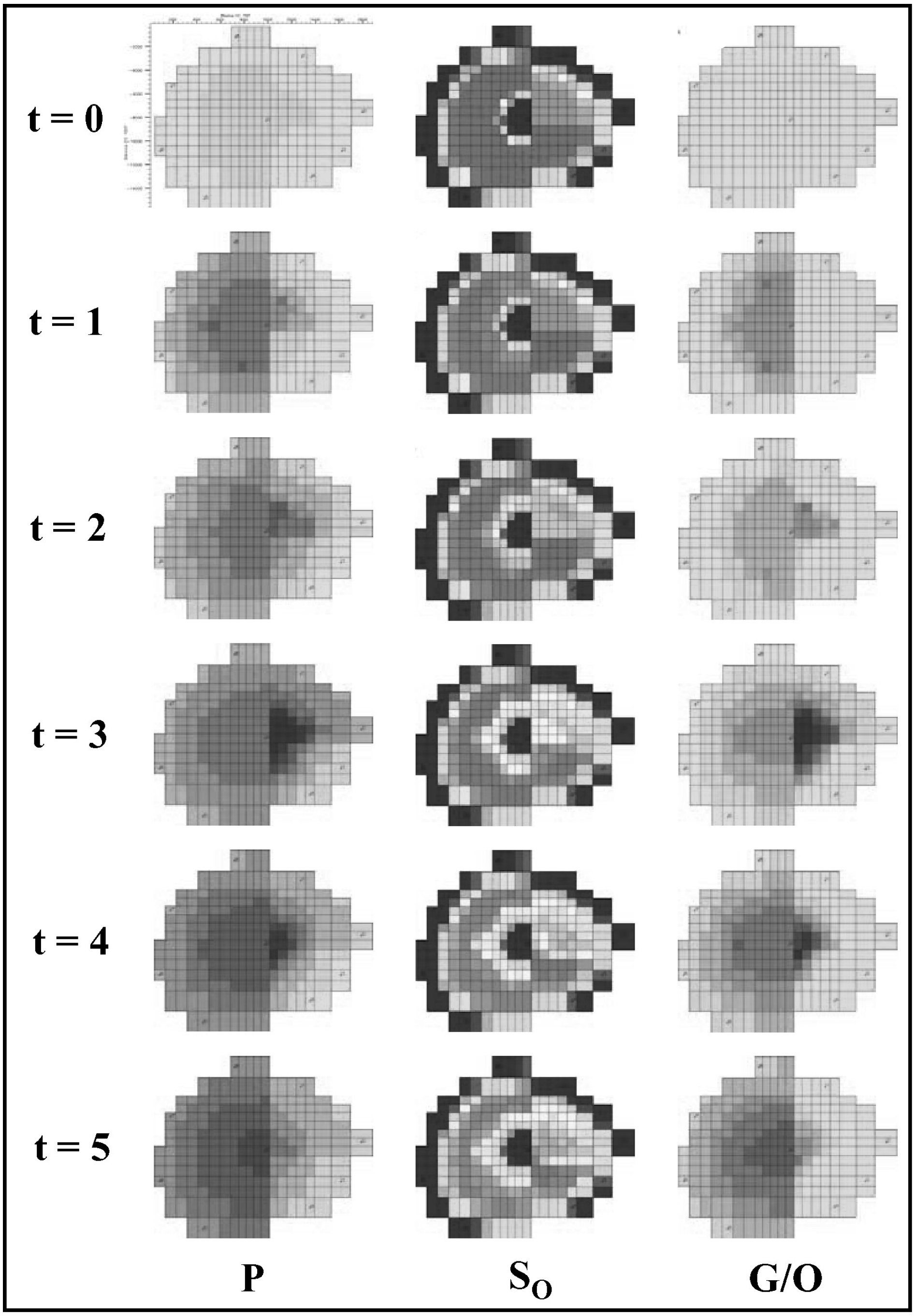

Figure 3: Temporal evolution of pressure, oil saturation and gas/oil ratio in an oilfield: the gradual depletion of oil in reservoirs is explicitly considered for optimization (t: yr).

4. Oil Production Optimization Results

Table 1: Oil production optimization using reservoir simulation boundary conditions.

Example 2a, Kosmidis et al (2005)	Total capacity	Kosmidis et al (2005)	This work (%)
Oil production (STB/day)	35000	29317.2	30193.7 (+2.9%)
Gas production (MSCF/day)	60000	60000	60000
Water production (STB/day)	14000	11294.3	11720.1 (+3.8%)

5. Conclusions and Future Goals

The combination of dynamic multiphase CFD simulation and MINLP optimization has the potential to yield improved solutions towards efficiently maximizing oil production. The present paper addresses integrated oilfield modeling and optimization, treating the oil reservoirs, wells and surface facilities as a combined system: most importantly, it stresses the benefit of computing accurate state variable profiles for reservoirs via CFD. Explicit CFD simulations via a dynamic reservoir simulator (ECLIPSE®, Schlumberger) are combined with equation-oriented process optimization software (gPROMS®, PSE): the key idea is to use reduced-order copies of CFD profiles for dynamic optimization. The literature problem solved shows that explicit use of CFD results in optimization yields improved optima at additional cost (CPU cost *and* cost for efficient separation of the additional water; the percentage difference is due to accurate reservoir simulation). These must be evaluated systematically for larger case studies under various conditions.

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