Integration of Reservoir Modelling with Oil Field Planning and Infrastructure Optimization

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Motivation for Integration

- **Goal:** To optimize the investment and operations decisions for oil and gas field development problem with computational ease and sufficient accuracy.

- Recent simultaneous models assume fixed linear reservoir production profiles or piecewise linear approximations that led to suboptimal solutions.

- **Objective:** Develop models to incorporate detailed reservoir profile for accurate planning.
Operations Problem: Multiperiod NLP for Production Planning

- **Given information:**
  - Number and location of wells.
  - Productivity indices and Pressure Profiles.
  - Variation of GOR and WOR.
  - Maximum Separator Capacity of 8000 bbl./year.
  - Selling prices and Costs.

- **Objective** is to maximize the NPV in the long term horizon.
- Initial investment of 150 MUSD is not included in the objective function since it is constant and is paid up-front.

- **Assumptions:**
  - Natural Depletion of the reserves.
  - Pipeline network is already established.
  - Planning horizon is discretized into a number of time periods ‘t’, typically 1 year.
  - Water is re-injected into the well after separation and gas is sold.
Multi-period NLP model

• Objective function: Maximize NPV, \( \text{NPV} = \sum_{\text{time}} [\text{REV}(t) - \text{COST}(t)] \ast \text{disc}(t) \)

• Total Revenue: \( \text{REV}(t) = \text{del}(t) \ast (\text{oil price}(t) \ast \text{oil produced}(t)) + (\text{gas price}(t) + \text{gas produced}(t)) \)

• Total costs:
  \( \text{COST}(t) = \text{del}(t) \ast (\text{gas compression cost} \ast \text{gas produced}(t)) + (\text{water treatment} \ast \text{water produced}(t)) \)

• Total Liquid Produced:
  \( \text{Liquid produced (well, time)} = \text{Productivity index (well)} \ast \text{Pressure variation (well, time)} \)

• Oil produced (well, time) = \( \text{Liquid produced} \ast (1 - \text{wct}\%(\text{well, time})) \)

• Gas produced (well, time) = \( \text{Oil produced(\text{well, time})} \ast \text{GOR(\text{well, time})} \)

• Total liquid produced(time) = \( \sum_{\text{well}} \text{Liquid produced(\text{well, time})} \)

• Upper bound for liquid produced: \( \text{Total liquid produced}(t) \leq \text{Maximum separation capacity}(t) \)

• Upper bound for Oil production: \( \sum_{\text{well}} \text{Oil recovered(\text{well, time})} \leq \text{Cumulative Oil produced (well)} \)
Results & Statistics of the Multi-period NLP model

- **Model Statistics (BARON 14.4):**
  - Number of wells: 5
  - Number of time periods: 20 time periods of 1 year each.
  - Number of Variables: 1303
  - Number of single equations: 1408
  - Solver CPU time: 67.54 seconds (1% relative optimality gap)

- NPV = 1119 MUSD
Design problem: Optimal placement of wells

- **Allowing:**
  - Reservoir may have arbitrary and irregular shapes.
  - Existing manifolds and centers can make/receive new connections.
  - Processing centers can receive fluids from wells directly or through manifolds.

- **Following:**
  - Each well must be beyond some minimum distance from all other wells.
  - A well that hits its water-cut limit is shut in.

- **Assumptions:**
  - Reservoirs are horizontal and planar. Field surface elevation may vary from point to point.
  - Wells are vertical, can pass through multiple reservoirs, but can be perforated to access only one reservoir.
  - A wellhead may be connected to one or more manifolds/centers.
  - Each well (existing or potential) is preallocated to some manifolds/centers (existing or potential) based on distance, from which best allocations will be selected.
  - Each reservoir may have different pressure and saturation distribution.
Schematic of a hydrocarbon field, with three different reservoirs in the same field. *Blue lines* are injector wells and *black lines* are producer wells.
Well placement model

- **Given:**
  - Geological information such as dimensions, porosity, permeability.
  - PVT information such as formation volume factor and fluid properties.
  - Existing wells and their types.
  - Minimum allowable well to well distance.
  - Operational data such as water cut limits, max injection pressure, capacity expansion plans for surface facilities.
  - Production horizons for ‘H’ years.
  - Demand curve, drilling budget and costs.

- **Obtain:**
  - **Number and location of new producer wells and their production profiles.**
  - Number and location of manifolds and processing centers and incremental capacity expansion plan for surface processing centers.
  - Potential well-to-manifold, well-to-surface, and manifold-to-surface-center allocations.
  - Dynamic pressure profiles along the network at processing centers, manifolds, wellheads, well bore holes.
  - Dynamic pressure and saturation profiles for each reservoir.

Model:
- **Maximize NPV**
  - Reservoir Dynamics and spatial discretization
  - Drilling and infrastructure Design Decisions
  - Well and surface Network flow management
- **Solution Strategy:** Using the Modified Outer Approximation Algorithm
Dynamic multiphase flow in a reservoir

The Mass Balances Equation

\[
\frac{\partial}{\partial t}\left[ S_f \right] + q_f - \nabla \left[ \frac{kr_f}{\mu_f B_f} \left( \nabla P_f - \rho_f \frac{g}{g_c} \nabla z \right) \right] = 0
\]

2-D discretization of reservoir

- Binary variable: \( y(n) \rightarrow 1 \) if a well should exist in cell 'n'
- Empirical equations for estimating BHP.
- Allow upstream mobility values for convective flows to be chosen dynamically based on pressure time map at time (t-1).

Backward finite difference approximation

\[
\begin{align*}
&\left( \frac{d}{dt} \right) \left[ d_{o,1,n}^t \left( p_n^t - p_{n-1}^{t-1} \right) + d_{o,2,n}^t \left( S_n^t - S_{n-1}^{t-1} \right) \right] + q_{0,n\notin IW}^t \\
&\quad + \left( \left[ M_{o,x}^t \cdot T_{n-1}^x \cdot \left( p_n^t - p_{n-1}^{t-1} \right) \right]_{n \in IX} + \left( M_{o,x+}^t \cdot T_n^x \cdot \left( p_{n+1}^t - p_n^{t-1} \right) \right)_{n \in IX} \\
&\quad + \left( M_{o,y-}^t \cdot T_{n-1}^y \cdot \left( p_n^t - p_{n-1}^{t-1} \right) \right)_{n \in IV} + \left( M_{o,y+}^t \cdot T_{n+1}^y \cdot \left( p_{n+1}^t - p_n^{t-1} \right) \right)_{n \in IV} \right)_{n \in IX} = 0
\end{align*}
\]
STRATEGY: Bi-Level Decomposition

**DP**: Vijay Gupta and Grossmann (2012)

**PP**: Tavallali, Karimi et al. (2012)

**UPPER LEVEL DESIGN PROBLEM (DP)**
Max NPV

- Feasible?
  - yes: Upper bound $UB = Z^{dp}$
  - no: Add design cuts

- Add integer cuts

**LOWER LEVEL PLANNING PROBLEM (PP)**

- Feasible?
  - yes: Lower bound $LB = Z^{pp}$
  - no: STOP

- $UB - LB < \text{Tolerance}$?
  - yes: STOP, Solution is $Z^{pp}$
  - no: Add integer cuts

Assignment of platforms to wells and their installation

Selection of wells and production planning

GRID BASED
Incorporating field data

- **Two-level Optimization approach**

  - Upper level minimization of error (with data)
    \[
    \min \phi(u,v,\Theta) \\
    \text{s.t.} \quad \max \text{NPV}(u,v,\Theta) \\
    \text{s.t.} \quad g(u,v,\Theta) \leq 0
    \]
    Fitting error \( \phi(\Theta) = \frac{1}{2}(u-u^\alpha)^2 \)
    select \( \Theta \) to minimize the error function.

  - Lower level optimization of model (as shown in previous slide)

This approach ensures that we are not compromising on the number of degrees of freedom.
Conclusion and Future work

- Model development for Production planning:
  - Add Gas lift operations to the model.

- Well placement model:
  - Implementation of an improved optimization approach in the well placement model.
  - Validation of the results from historical production data and ECLIPSE simulation.
  - Integration of PETEX suite for well simulations.