ISAPP (Integrated Systems Approach to Petroleum Production) is a joint project of TNO, Delft University of Technology, ENI, Statoil and Petrobras.

Document title: Well Control Optimization Exercise

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Author: O. Leeuwenburgh and R.M. Fonseca, TNO

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Well Control Optimization

In this task participants are expected to optimize well targets for the 18 wells provided in the input files. The location and trajectory of the wells cannot be altered for this exercise.

This section aims to give a sufficient description of this exercise. In case of questions you are directed to the support pages on www.isapp2.com on the ISAPP Field Development optimization benchmark challenge to find an answer and/or to find the way to get them answered.

Controls

The well targets can be adjusted every 3 calendar months (i.e. at the first day of every third month) Participants are free to choose control time intervals as any multiple of a 3-month period. For the 18 wells in the deck and a life cycle period of 20 years this would result, in case of 3-month control intervals in a total of 1440 controls as all the wells are assumed to be drilled and completed at the starting time. Participants are though free to decide the total number of controls which is a function of the number of control time intervals. Furthermore, participants are also free to decide the controls (rates, pressures, single well PI multiplier etc.) they aim to optimize, but where multiple ICV controls along the wells are not allowed. All optimal strategies must adhere to the bounds on well flow rates and bottom hole pressures specified in Table 1 as well as the maximum liquid production rate specified.

Table 1: Operational Constraints to be used to define optimization problem

Type	*Value*	*Unit*	*Value*	*SI Unit*
Maximum platform liquid production rate	88000	bbl/day	14000	m^3/day
Maximum well oil production rate	5700	bbl/day	900	m^3/day
Maximum well water injection rate	10000	bbl/day	1600	m^3/day
Maximum Injector BHP	235	bar		
Minimum Producer BHP	150	bar		

Objective Function

The performance of the optimal field operating strategy is measured by expected Net Present Value (NPV) as evaluated over the full provided set of 50 model realizations (i.e. mean NPV). Contributions to the NPV are listed in Table 2 in units of $.

Table 2 : Information to be used to calculate objective function value for the optimization.

Contribution	*Value*	*Units*
Oil price	45	$ per bbl
Cost produced water	6	$ per bbl
Cost injected water	2	$ per bbl
Annual discount factor	0.08	
End of the life cycle period	20 years	

The following formula should be used to compute NPV for a single realization in US $:

$$NPV = \sum_{i=1}^{N_t} \frac{R(t_i)}{(1+d)^{t_i/\tau}}$$

Where index i refers to the time interval with length $\Delta t_i = t_i - t_{i-1}$ and starting at t_{i-1} and ending at time t_i, all in days, N_t is the total number of time intervals over the life cycle period, d is the discount factor, τ is the time interval for discounting (365 days), and $R(t_i)$ is the sum of all expenses and incomes incurred during the time interval Δt_i. The time intervals are fixed to calendar months to ensure consistency in the NPV calculation for all participants. All cash flows and discounting are assumed to take place on the time t_i. The term $R(t_i)$ in $ is defined as

$$R(t_i) = Q_{op}(t_i) \cdot r_{op} - Q_{wp}(t_i) \cdot r_{wp} - Q_{wi}(t_i) \cdot r_{wi}$$

where $Q_{op}(t_i)$, $Q_{wp}(t_i)$ and $Q_{wi}(t_i)$ are the total oil production, water production and water injection volumes over the time interval Δt_i, respectively. For example: $Q_{op}(t_i) = FOPT(t_i) - FOPT(t_{i-1})$. where r_{op}, r_{wp} and r_{wi} are the corresponding oil revenue (price) and water production and injection costs in $ per unit volume.

Reactive Control

Any optimized strategy should be compared with a reactive control strategy which consists of maximum injection and production and shut-in of all producer well connections when the water-cut for that well becomes uneconomic. The economic water cut based on the prices give above has been calculated to be 88% i.e. for water cuts higher than 88% the wells are uneconomic.

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<u>Document title</u>: Field Development Optimization Exercise

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<u>Author</u>: O. Leeuwenburgh and R.M. Fonseca, TNO

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FIELD DEVELOPMENT OPTIMIZATION

In this task field development plans are the focus of the exercise. The number, type, order and trajectories of the wells to be used is the focus of the optimization. The well placement strategy provided in the previous exercise does not need to be used. Infact, participants are encouraged not to use that well placement strategy.

This section aims to give a sufficient description of this exercise. In case of questions you are directed to the support pages on www.isapp2.com on the ISAPP Field Development optimization benchmark challenge to find an answer and/or to find the way to get them answered.

Controls

For this task participants are expected to deliver a development plan that consists of:

- the coordinates $(X_p, Y_p, 0)$ of one or more platforms,
- a well drilling sequence (which also determines the number of wells N_w to be drilled),
- the full trajectories (as survey files) of all drilled wells starting from a platform location with coordinates $\left(X_p, Y_p, Z_{k,i}\right)$ where $i = 1, \dots, N_w$ to the end point of each well with coordinates $\left(X_p + \Delta X, Y_p + \Delta Y, Z_{e,i}\right)$,
- assignment of the type of each well (producer or injector).

The field development options are constrained by a number of factors:

- The wells must adhere to a constraint on dogleg severity as applied to a smooth well-path.
- Each well i, with $i = 1, \dots, N_w$, can have a different kick-off depth $Z_{k,i}$.
- Only single-bore wells are allowed (i.e. no side tracks).
- Wells cannot be converted (e.g. from producer to injector or vice versa) at later time.
- A platform has space for 20 well slots only.
- The liquid processing capacity of the platform facilities limits the field production rate.
- Drilling of each next well is started immediately after finishing the previous one, i.e. without idle time between completing one well and starting the drilling of the next well.
- There are operational well rate capacity and pressure limits.
- The recovery strategy is water flooding so only water can be injected.
- The diameter for all wells is assumed to be 0.1905 m (and which may differ from the default values for the specific reservoir simulators).

These and other constraints are listed and quantified in Table 3.

Table 3: Operational Constraints to be used to define optimization problem

Type	*Value*	*Unit*	*Value*	*SI Unit*
Maximum number of wells on the platform	20			
Maximum platform liquid production rate	88000	bbl/day	14000	m^3/day
Maximum well oil production rate	5700	bbl/day	900	m^3/day
Maximum well water injection rate	10000	bbl/day	1600	m^3/day
Injector BHP	235	bar		
Producer BHP	150	bar		
Maximum dogleg severity	10/30.48	°/m		

For this exercise participants must operate their wells on based on BHP values provided in Table 3 and using the reactive control limits specified in the well control challenge. Each well is assumed to come on stream immediately after drilling and completion of the well is completed.

Objective Function

The performance of the field development plan is measured by expected Net Present Value (NPV) as evaluated over the full provided set of 50 model realizations (i.e. mean NPV) and based on a reactive operational strategy for a fixed time horizon of 20 years. Contributions to the NPV are listed in Table 4 in units of $.

Table 4 : Information to be used to calculate objective function value for the optimization.

Contribution	*Value*	*Units*
Platform investment	500	Million $
Drilling and completion	$5000 \cdot \Delta Z + 10000 \cdot \lvert\Delta XY\rvert$	$, ΔZ and ΔXY in m
Oil price	45	$ per bbl
Cost produced water	6	$ per bbl
Cost injected water	2	$ per bbl
Annual discount factor	0.08	
End of the life cycle period	20 years	

The following formula should be used to compute NPV for a single realization in US $:

$$NPV = \sum_{i=1}^{N_t} \frac{R(t_i)}{(1+d)^{t_i/\tau}}$$

Where index i refers to the time interval with length $\Delta t_i = t_i - t_{i-1}$ and starting at t_{i-1} and ending at time t_i, all in days, N_t is the total number of time intervals over the life cycle period, d is the discount factor, τ is the time interval for discounting (365 days), and $R(t_i)$ is the sum of all expenses and incomes incurred during the time interval Δt_i. The time intervals are fixed to calendar months to ensure consistency in the NPV calculation for all participants. All cash flows and discounting are assumed to take place on time t_i. Well drilling and completion costs associated with finished drilling and completion of a well in the time interval Δt_i are also assumed to be incurred at the time t_i. The platform investment cost must be introduced in the time interval in which drilling of its first well starts (which is the very first month for the first platform). The cost term $R(t_i)$ in $ is defined as

$$R(t_i) = Q_{op}(t_i) \cdot r_{op} - Q_{wp}(t_i) \cdot r_{wp} - Q_{wi}(t_i) \cdot r_{wi} - P(t_i) - D(t_i)$$

where $Q_{op}(t_i)$, $Q_{wp}(t_i)$ and $Q_{wi}(t_i)$ are the total oil production, water production and water injection volumes over the time interval Δt_i, respectively. For example: $Q_{op}(t_i) = FOPT(t_i) - FOPT(t_{i-1})$. Furthermore, r_{op}, r_{wp} and r_{wi} are the corresponding oil revenue (price) and water production and injection costs in $ per unit volume, whereas $P(t_i)$ is the platform investment costs, $D(t_i)$ is the total well drilling and completion costs incurred during the time interval Δt_i specified in Table 4.

Production platform investments cost are assumed to be related to the installed capacity and are therefore not included in the cost per drilled well. Note that since there is no time period between drilling of two wells, the drill rig is never idle and the rig rate is assumed to be incorporated in the costs per well. Moreover, royalties and social and corporate taxes are not considered explicitly. The simulation start time corresponds to the start of the drilling of the first well.

Drilling Time Calculation

The following formula should be used for the time (in days) to drill and complete a well:

$$\Delta t_D = 0.015 \cdot \Delta Z + 0.02 \cdot |\Delta XY|$$

where $\Delta Z = Z_{e,i}$ and $|\Delta XY| = \sqrt{\Delta X^2 + \Delta Y^2}$ is the horizontal offset (step-out) of the well end point from the platform location. Note that this assumes that the well end point is both laterally and in depth the furthest point from the platform location. With the above formula, and using the values in Table 4, we obtain a drilling and completion time of 30 days for a vertical well to 2000 m depth and a cost of 10 million \$. For a well with end point at 2000 m depth and 2000 m offset from the platform, drilling cost and time works out to 30 million \$ and 70 days respectively.

Miscellaneous

It is assumed that all produced associated gas is consumed or exported. We do not include a price of gas in the economic model and assume that all oil and gas processing and exporting costs are incorporated in the oil price listed in Table 4.

It is recommended that each participant, before performing any optimization, attempts first of all to come up with a development plan based on common practice and engineering principles. If multiple plans from different groups are eventually available, we will be better able to evaluate if optimization tends to provide any additional value. This is intended to be an equivalent to the use of a reactive strategy as a reference for well control optimization problems.

ISAPP (Integrated Systems Approach to Petroleum Production) is a joint project of TNO, Delft University of Technology, ENI, Statoil and Petrobras.

Document title: Joint Well Placement and Well Control Optimization Exercise

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Author: O. Leeuwenburgh and R.M. Fonseca, TNO

Prepared for: ISAPP field development optimization challenge

Joint Field Development and Well Control Optimization

In this task participants are encouraged to come up with optimal field development strategies as well as well control (operational strategies). All the inputs needed for this exercise are exactly the same as the inputs used for the field development optimization task.

In case of questions you are directed to the support pages on www.isapp2.com on the ISAPP Field Development optimization benchmark challenge to find an answer and/or to find the way to get them answered.