Research Group in Reservoir Simulation and Management

Case Study for Field Development and Management - Selection of Production Strategy based on UNISIM-II

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Summary

1. Introduction

The aim of this document is to present a reservoir case study to be submitted to decision analysis to define an oil exploitation strategy for field development, entitled **UNISIM-II-D**.

The simulation model (Figure 1) was built based on the reference model **UNISIM-II-R,** developed by Correia et al. (2015). It is a black-oil simulation model with a grid cell size of 100 x 100 x 8m where the grid type is corner point defined by 65 mil active blocks.

The required data for reservoir simulation using IMEX (version 2017.10) and the case study description are available for download via a web page by interested third parties, such as universities and research centers *(*http://www.unisim.cepetro.unicamp.br/benchmarks/unisim-ii/*)*.

The case study has 516 days (t_d) of initial production data of 1 vertical well (Wildcat). The exploitation strategy, considering water injection as a secondary recovery technique, is to be set between t_d and the maximum final date (t_{final}).

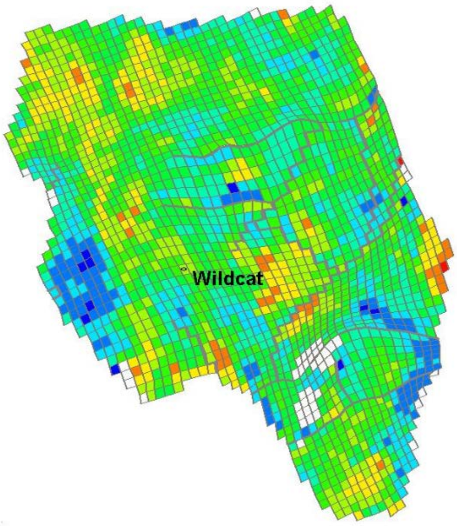

Figure 1: Porosity map (layer 11) for the base model with the location of the Wildcat well.

The objective of the study is to propose a production strategy (reservoir development and management) considering two approaches:

1) Deterministic, without uncertainties;
2) Probabilistic, with reservoir, economic and operational uncertainties.

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2. Problem Description - Field Development and Management

2.1 Decision variables

The decision variables for exploitation strategy selection are:

- Number of wells;
- Well type (producer or injector);
- Well technology (conventional or intelligent);
- Well direction (vertical or horizontal);
- Wells placement (I, J, K);
- Wells schedule (opening sequence of each well);
- Well management variables: pressure, rates, water cut, shut-in date etc.;
- Platform system capacities, namely flow-rate constraints for:
  - liquid processing (Cp_L);
  - oil processing (Cp_O);
  - gas processing (Cp_G);
  - water processing (Cp_W);
  - water injection (Ci_W).
- Platform location (L_P);
- Well and gathering systems:
  - Riser diameter (d_R);
  - Production/injection line diameter (d_L);
  - Production/injection column diameter (d_C);
  - Gas lift rate (q_{GI});
  - Gas lift valve position (h_{GL}).

Wells operating conditions must consider production system configurations. If operation incurs costs (e.g. inflow control valves (ICV)) these must be considered in the cash flow. Information about production system configurations are described in appendix I.

For a similar execution of this project between participants, any additional costs should be communicated by email (unisim-benchmark@cepetro.unicamp.br). The values and information will be available at benchmark's webpage to all groups working on this project.

2.2 Important Events

This section lists the main events of the proposal, including field production and cash flow events.

Time (day)	Date (MMM/DD/YYYY)	Event – Field Timeline Description
0	SEP/30/2016	1. Simulation initial date
0	SEP/30/2016	2. Production starting time
516	FEB/28/2018	3. End of production history (t_d)
517	MAR/01/2018	4. Starting date of production forecast
517	MAR/01/2018	5. Beginning of well drilling operation
547	APR/01/2018	6. Beginning of well completion operation
1247	FEB/29/2020	7. Beginning of production system installation
1247	FEB/29/2020	8. 1st well connection (well-platform)
10957	SEP/30/2046	9. Simulation final time (simulation may end earlier but not later)
10957	SEP/30/2046	10. Maximum date for field abandonment

Table 1 : UNISIM-II-D timeline events – field production.

Time (day)	Date (MMM/DD/YYYY)	Event – Cash Flow Timeline Description
516	FEB/28/2018	1. Reference date for analysis (for updating cash flow) REFERENCE (Present Date)
547	MAR/31/2018	2. Investments on 1st well drilling
577	APR/30/2018	3. Investments on 1st well completion
1247	FEB/29/2020	4. Investments on platform and facilities
1247	FEB/29/2020	5. Investments on 1st well connection (well-platform)
10957	SEP/30/2046	6. Maximum Incidence date - field abandonment cost

Table 2 : UNISIM-II-D timeline events – cash flow.

2.3 Premises

The decision analysis process is based on the premises:

- Liquid and gas production rates and BHP of the Wildcat well (history data):
    - "UNISIM-II-D_HistoryData_td.zip" file
    - Production data history generated on UNISIM-II-R containing noise
- If the Wildcat is used in the exploitation strategy, only the well-platform connection cost must be considered; this is, because drilling and completion costs have already been accounted for before the date of analysis (i.e., in the history period)
- Characteristics of producers and injectors:
    - Vertical or horizontal wells, regarding grid orientation (I, J, K)
    - Conventional or intelligent completion
- Minimum time interval between each well drilling: 30 days
- Minimum time interval between each well completion: 30 days
- One dedicated vessel will work on drilling and completion
- Well connection schedule: minimum of 30 days
- One dedicated vessel will work on connection
- Minimum time interval between each well conversion: 30 days
- Minimum time interval between each well recompletion: 30 days
- Minimum distance between wells: 1 block (around 100 m)
- Minimum distance between wellheads: 500m
- Maximum horizontal well length: 1000 m
- Vertical well length: free
- Maximum capacity for well-platform connection: 32 wells
    - For strategies with more wells, additional platforms should be considered
- Field abandonment event has to be carried out on the shut-in date of the last well in operation

Table 3 present well operational conditions using standalone reservoir simulations, when adopted simplified production system configurations. Table 4 and Table 5 present the equipment data and operating conditions for production forecasts.

Type	Well Producer	Well Injector	Unit
Water rate	--	Max 5000	m^3/day
Liquid rate	Max 3000	--	m^3/day
Gas lift rate	Max 240000	--	m^3/day
BHP	Min 275	Max 480	Kgf/cm^2

Table 3: Well operational conditions(1).

Type	Well	Unit
Radius	0.108	m
Geofac(2)	0.37	--
Wfrac(3)	1	--
Skin(4)	0	--

Table 4: Well data.

Type	Platform Production	Platform Injection	Unit(1) x10^3
Max Water rate	120	240	bbl/day(1)
Max Liquid rate	180	--	bbl/day(1)
Max Oil rate	180	--	bbl/day(1)
Max Gas rate	8000	8000	m^3/day

Table 5: Platform data and operational conditions. (1)

(1) Modified SI system. (2) Geometric factor. (3) Angular well fraction. (4) Well skin factor.

2.4 Deterministic approach

2.4.1 Objective Functions

We recommend the following objective functions for the deterministic approach, but others may be considered:

- Net present value (NPV);
- Cumulative oil production (Np);
- Cumulative gas production (Gp);
- Cumulative water production (Wp);
- Cumulative water injection (Wi);
- Recovery factor (Rf).

We categorize the objective functions as follows:

1. Field
    a. Main: NPV, measures of risk, Np, Rf;
    b. Secondary: Gp, Wp, Wi, Pavg (reservoir average pressure);
2. Well
    a. Producers: oil rate, gas rate, water rate, bottom-hole pressure, and economic index;
    b. Injector: injected water rate, bottom-hole pressure, and economic index.

2.4.2 Economic Scenario

Equation 1 shows how to calculate investments on platforms. This equation is based on data presented by Hayashi (2006) with some changes to incorporate additional parameters.

$$Inv_{plat} = 417 + 3.15 \times Cp_l + 12.2 \times Cp_o + 3.15 \times Cp_w + 3.15 \times Ci_w + 9.61 \times Cp_g + 0.1 \times Cn_w \qquad \text{Equation 1}$$

given that:

Inv_{plat}	:	investment on platform	($\times 10^6$ USD)
Cp_L	:	liquid processing capacity	($\times 10^3$ m^3/day)
Cp_o	:	oil processing capacity	($\times 10^3$ m^3/day)
Cp_w	:	water processing capacity	($\times 10^3$ m^3/day)
Ci_w	:	water injection capacity	($\times 10^3$ m^3/day)
Cp_g	:	gas processing capacity	($\times 10^6$ m^3/day)
Cn_w	:	number of wells capacity	

The 1st term of Equation 1 (417) is a constant representing a fixed cost.

The objective function given by Equation 2 is the Net Present Value (NPV) indicator, defined as the sum of the inflows and outflows of the cash flows, discounted at a given date.

$$NPV = \sum_{j=1}^{N_t} \frac{NCF_j}{(1+i)^{t_j}} \qquad \text{Equation 2}$$

given that:

NCF_j	:	Net cash flow at period j
j	:	time period
N_t	:	total number of time periods
i	:	discount rate
t_j	:	time period j (average time of the period) related to the date of analysis

In this project, the net cash flow for each period is calculated using the following simplified equation based on the Brazilian R&T fiscal regime (Equation 3):

$$\mathrm{NCF} = \left[(\mathrm{R} - \mathrm{Roy} - \mathrm{ST} - \mathrm{OC}) * (1 - \mathrm{T})\right] - \mathrm{Inv} - \mathrm{AC} \qquad \text{Equation 3}$$

given that:

NCF	:	Net cash flow
R	:	Gross revenues from oil and gas selling
Roy	:	Total amount paid in royalties (charged over gross revenue)
ST	:	Total amount paid in Social Taxes (special taxes on gross revenues)
CO	:	Operational production costs (associated with the oil and water production and water injection)
T	:	Corporate tax rate
Inv	:	Investments on equipment and facilities (platform, production and injection wells, network systems, pipelines etc.)
AC	:	Abandonment cost

Table 6 presents fiscal assumptions and Table 7 the deterministic most-likely economic scenario when adopted simplified production system configurations.

Variable	Value
Corporate tax rate	34%
Social tax rate - charged over gross revenue	9.25%
Royalties rate - charged over gross revenue	10%

Table 6: Fiscal assumptions.

Variable/Parameter	Value	Unit
Oil price	257.9	USD/m^3
Gas price	0.026	USD/m^3
Oil production cost	48.57	USD/m^3
Gas production cost	0.013	USD/m^3
Water production cost	4.86	USD/m^3
Water injection cost	4.86	USD/m^3
Drilling and completion of horizontal well (fixed cost)	73.75	10^6 USD
Drilling and completion of horizontal well (variable cost)	0.032	10^6 USD/m
Connection of horizontal well (well-platform)	13.30	10^6 USD
Drilling of vertical well	23.40	10^6 USD
Completion of vertical well	26.94	10^6 USD
Connection of vertical well (well-platform)	13.30	10^6 USD
Recompletion of horizontal well	11.02	10^6 USD
Recompletion of vertical well	10.97	10^6 USD
Well conversion	11.02	10^6 USD
1st Inflow Control Valve (ICV) (for each well)	1.00	10^6 USD
2nd or more ICV (for each well)	0.30	10^6 USD/ICV
Platform	(Equation 1)	10^6 USD
Abandonment cost(1)	8.2%	--
Annual discount rate	9%	--

Table 7: Deterministic economic scenario (most likely).

(1) The Abandonment cost is a percentage of investment in drilling and completion.

2.5 Probabilistic Approach

2.5.1 Objective Functions

In the probabilistic approach, the expected value of the deterministic objective functions is used. The expected value of a discrete random variable X, E[X], is given by the sum of the value X of each scenario weighted by its respective probability. Equation 4 determines the expected value of NPV, commonly referred to as expected monetary value (EMV).

$$EMV = \sum_{i=1}^{n} p_i \cdot NPV_i \qquad \text{Equation 4}$$

given that:

EMV : expected monetary value
p_i : probability of occurrence of scenario i
NPV_i : Net Present Value of scenario i
n : total number of scenarios

The expected value alone may be insufficient because it does not capture the magnitude of potential losses and gains. Thus, it can be combined with indicators of downside risk and upside potential.

In a similar approach to that of the deterministic analysis, we categorize the probabilistic objective functions as follows:

1. Field
    a. Main: EMV, measures of risk, E[Np], E[Rf];
    b. Secondary: E[Gp], E[Wp], E[Wi], Pavg;
2. Well
    a. Producers: oil rate, gas rate, water rate and economic index;
    b. Injector: injected water rate and economic index.

2.5.2 Uncertainties

The probability levels for the discrete attributes of the reservoir, economic and operational uncertainties are provided in the next topics.

2.5.3 Reservoir Attributes

An uncertainty modeling was conducted to generate equiprobable geostatistical realizations (images) to be integrated into this decision analysis project. In addition, other uncertainties are considered.

The set of reservoir attributes include:

- A set of images of petrophysical characteristics (matrix and fracture porosities, matrix and fracture permeabilities, fracture spacing, net-to-gross thickness ratio, and rock type); other realizations can be generated for future application
- Kr: water relative permeability
- Cpor: rock compressibility
- PVT: pressure-volume-temperature table
- PB: bubble point pressure
- dWi: well index multiplier

Table 8 summarizes the input uncertain properties (images) for reservoir simulation, considering the geological uncertain attributes described in Correia et al. (2015). The dynamic uncertainties considered are the relative permeability and PVT data. For reservoir simulation purposes, the static properties have to be tied together in each realization as they are dependent attributes. The relative permeability is independent of static behavior, and, consequently, could be randomly combined with static properties.

Uncertainty Reservoir Property for Simulation (input data)	UNISIM-II (nomenclature for include files)
Matrix Porosity	POR
Fracture Porosity	PFR
Matrix Permeability	KX; KY; KZ
Fracture Permeability	KFX; KFY; KF
Fracture Spacing	SGX; SGY; SGZ
Net to Gross	NG
Rock Type	rtype
Relative Permeability	Kr
PVT	PVT
Well Index	dWi

Table 8. Input uncertainty data for reservoir simulation.

Table 9 and Table 10 show the uncertain levels and probabilities of static and dynamic attributes. Static properties are equiprobable, meaning that each image has equal probability of occurrence. Relative permeability, PVT and Well Index are defined by three probability levels. Defining the probability of each level is a difficult task and can be subjective, but in this project, we take Level 0 as the most likely to occur. PB level is directly linked to PVT level, i.e., PB0 is tied to PVT0 and so on.

Attribute	Levels (Probability)		
	-1	0	+1
Img	500 petrophysical images (equiprobable)		
Kr	KR-1 (0.3)	KR0 (0.4)	KR1 (0.3)
PVT	PVT-1 (0.3)	PVT0 (0.4)	PVT1 (0.3)
PB	PB-1 (0.3)	PB0 (0.4)	PB1 (0.3)
dWi	0.7 (0.33)	1.0 (0.34)	1.4 (0.33)

Table 9. Uncertainty levels and probabilities of static and dynamic attributes.

Attribute	Unit	PDF*
Cpor / (10^6)	cm^2/kgf	$\begin{cases} 0, & x \leq 10 \\ \frac{x-10}{1849}, & 10 < x \leq 53 \\ \frac{96-x}{1849}, & 53 < x \leq 96 \\ 0, & x > 96 \end{cases}$

Table 10: Uncertainty levels of the continuous geological attributes.

* Probability Density Function

2.5.4 Economic Scenario

Uncertainty in oil price takes the Probability Density Function showed in Table 11 and is modeled by a triangular distribution.

Attribute	Unit	PDF*
Oil price	USD/m³	$f(x)=\begin{cases} 0, & x \le 10 \\ \frac{x-10}{800}, & 10 < x \le 30 \\ \frac{90-x}{2400}, & 30 < x \le 90 \\ 0, & x > 90 \end{cases}$

Table 11: Uncertainty levels for oil price in the economic scenarios.

* Probability Density Function

In addition to the most-likely scenario, the optimistic and pessimistic economic scenarios are defined shown in Table 12 when adopted simplified production system configurations. Probabilities of occurrence considered for the pessimistic, the most-likely and the optimistic scenarios are 25%, 50% and 25%, respectively.

Variable/Parameter	Optimistic	Pessimistic	Unit
Oil price	412.0	151.8	USD/m³
Gas price	0.041	0.016	USD/m³
Oil production cost	82.41	30.37	USD/m³
Gas production cost	0.16	0.06	USD/m³
Water production cost	7.76	2.86	USD/m³
Drilling and completion of horizontal well (fixed cost)	117.84	43.42	10^6 USD
Drilling and completion of horizontal well (variable cost)	0.05	0.02	10^6 USD/m
Connection of horizontal well (well-platform)	21.25	7.83	10^6 USD
Drilling and completion of vertical well	80.43	29.64	10^6 USD
Drilling of vertical well	37.39	13.78	10^6 USD
Connection of vertical well (well-platform)	21.25	7.83	10^6 USD
Recompletion of horizontal well	17.61	6.49	10^6 USD
Recompletion of vertical well	17.53	6.46	10^6 USD
Well conversion	17.61	6.49	10^6 USD
1st Inflow Control Valve (ICV) (for each well)	1.60	0.59	10^6 USD
2nd or more ICV (for each well)	0.48	0.18	10^6 USD/ICV
Platform	1.25 x (Equation 1)	0.8 x (Equation 1)	10^6 USD
Abandonment cost(1)	8.2%	8.2%	--
Annual discount rate	9%	9%	--

Table 12: Optimistic and Pessimistic Economic Scenario.

(1) The Abandonment cost is a percentage of investment in drilling and completion.

2.5.5 Other Uncertainties

Uncertainties for operational attributes are also considered as shown in Table 13.

- SA: System availability, applied to platform, groups, producers, and injectors (Note that the IMEX keyword ON-TIME can be used).

Attribute	Type	Levels (Probabilities)		
		0 (0.34)	**1** (0.33)	**-1** (0.33)
SA	Platform	0.95	1.00	0.90
	Group	0.96	1.00	0.91
	Producer	0.96	1.00	0.91
	Injector	0.98	1.00	0.92

Table 13: Uncertainty levels and probabilities for technical attributes.

2.5.6 Managing Uncertainty

Participants are encouraged to assess the effects of uncertainty and to find actions to manage it, either to mitigate risks or exploit upsides. Actions to manage uncertainty include (1) acquiring additional information to reduce reservoir uncertainty, (2) defining a flexible production system that allows system modifications as uncertainties unfold over time, and (3) defining a robust production strategy able to cope with uncertainty without requiring system modifications after production has started. Because these actions incur additional investments and costs, and potentially delay production, their values must be quantified using the Expected Value of Information (EVoI), Flexibility (EVoF), and Robustness (EVoR) analyses. These actions should be recommended only in cases of positive EVoI, EVoF, and EVoR.

In the first action, decision makers defer the development decision while new information is acquired. They aim to change the current knowledge of uncertain reservoir attributes so that decisions can be improved. The term “information” is typically used in a broad sense and commonly refers to acquiring data, namely seismic surveys, well testing, and drilling appraisal wells. The term also covers performing technical studies, hiring consultants, and performing diagnostic tests.

The attractiveness of flexibility arises from the options available, allowing active reactions based on the knowledge gained over time. Examples of flexible production systems include platform capacity expansion, modularity, intelligent wells, flexible subsea layouts, and the ability to redistribute injection quotas or switch the injected fluid.

A robust production strategy can be obtained through “robust optimization”, an optimization problem formulated under uncertainty to maximize a probabilistic objective function. Alternatively, the robustness of a specialized optimized production strategy (based on deterministic approach of the reservoir properties) can be increased using performance indicators over multiple scenarios. A textbook example of robustness is the placement of producers and injectors in relation to a fault to cope with uncertainty in fault transmissibility.

3. Expected Results

After the decision regarding the strategy selection, a report should be generated including:

1. Selected strategy configuration (IJK coordinates and operational conditions of each well, production system variables, and groups constraints).
2. Efficiency indicators of the optimization process: chosen methods, number of simulation runs, computational cost, and objective function evolution.
3. Performance indicators of the selected exploitation strategy:
    a. Main indicators: NPV, EMV, measures of risk, Np, Rf etc.;
    b. Secondary indicators: Gp, Wp, Wi, Pavg;
    c. Producers indicators: oil rate, gas rate, water rate, water cut and economic index;
    d. Injector indicators: injected water rate and costs.

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5. Provided files

The necessary files for reservoir simulation data are available for download at http://www.unisim.cepetro.unicamp.br/benchmarks/unisim-ii/