Determination of Cost-Effectiveness of CO_2-EOR and CO_2 Utilization Factor as Feasibility Indicators for Permanent CO_2 Storage

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Submitted to

University of Rome

Sapienza Università di Roma

University of Zagreb

Sveučilište u Zagrebu

in partial fulfillment of the requirements
for the second level international Master study

"CO_2 Geological Storage"

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November 2020

Acknowledgments

I would like to thank the University of Rome and the University of Zagreb for being hosts on this second level international masters' study. Special thanks to all the professors from different institutions who gave all their efforts during these difficult times and made it possible to successfully continue and finish this master. I must thank specially to Professor Sabina Bigi for her help previous and during this study, who along with Professor Bruno Saftić were coordinating and made everything possible.

I would like to express my gratitude to my supervisor Professor Domagoj Vulin for being such a great guide for this investigation and not only an excellent teacher but an extraordinary human being. Thank you for always answering my questions with the best attitude and for explaining with patience and clarity.

Thanks to my family Helga, José, Arantxa, and Fernando who have been great support for me during this period even when we are more than 10000 km apart, also to Berta and Fernando that in a special way have been always cheering me up. I am deeply thankful for all the help and support, not only for this investigation but for everything that Maja and Lucija have given me.

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Abstract

Carbon Capture Utilization and Storage (CCUS) is an effective technology for achieving climate change goals. As part of CCUS, CO_2 - enhanced oil recovery results with permanent storage of significant amounts of CO_2 and is an attractive technique for oil companies, with the main goal to maximize oil production, and minimize the injected CO_2. For this investigation, oil production and retention were observed and compared in 72 reservoir simulation cases with an economic evaluation considering Utilization Factor (UF) and Net Present Value (NPV) which was assessed with different scenarios of CO_2 and oil prices (32 scenarios, which, with observed simulation results totals in 1728 cases for economical evaluation). The cases were generated with three different WAG ratios, three permeabilities, two well distances and three depths, each with its specific pressure and temperature conditions. This was set to see the impact of the miscibility on oil production and CO_2 sequestration and therefore finding the most optimal case. It was observed that well distances have a significant impact on retention and NPV, being the smaller distance arrange the most favourable for retention in observed period (15 years of CO_2-EOR) and considering all aspects, the greatest benefit comes from cases that are at 1545 m with WAG ratio of 1:2 and permeability of 50 mD. Optimum (cost-effective) CO_2 EOR cases all result with higher amount of CO_2 stored, with 1.8 to 6.7 times CO_2 storage capacity increase, compared to the respective cases without CO_2-EOR.

Key words: CO_2 EOR, CCUS, CO_2 Retention, Utilization Factor, WAG, EU-ETS

Thesis contains 20 pages, 3 tables and 16 figures.

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List of abbreviations and symbols

$M_{CO_2}^S$ - *Mass of CO_2 stored (kg)*
$M_{CO_2}^T$ - *Total storage capacity of the reservoir (kg)*
S_o – *Saturation of oil*
B_{oi} - *Initial formation volume factor (rm^3/sm^3)*
CAPEX – Capital expenses
CCUS- Carbon Capture and Utilization
DLE – Differential liberation
E_A - *areal sweep efficiency*
E_D - *microscopic efficiency*
EOR- Enhanced oil recovery
ETS- European Trading System
EU- European Union
EUA – European Union allowances
E_V -*vertical sweep efficiency*
FGIR – Field gas injection rate
FGIT- Field gas injection total
FOPT- Field oil production total (sm^3)
FWIT – Field water injection rate
FYMF - Vapor mole fraction

i - Discount rate or return and
IFT – Interfacial tension
k_{rg} *- Relative permeability of the gas phase*
k_{ro} *- Relative permeability of the liquid phase*
MMP – Minimum miscibility pressure
N_P *- Cumulative oil recovery* (m^3)
NPV- Net present value
OIP - Oil in place (m^3)
OOIP- Original oil in place
OPEX – Operating expenses
PV - Pore volume (m^3)
q_{CO2inj} *and* $q_{CO2prod}$ *- Injected and produced volumes of* CO_2 *respectively (Mscf)*
q_{oprod} *- Produced oil volume (bbl)*
RF- Recovery factor
R_t *- Net cash flow*
S_g *– Saturation of gas*
S_{wi} *- Initial water saturation*
t- Number of time periods
UF- Utilization factor
v -Mean velocity (m/s)
w_1 *and* w_2 *- Weights for oil recovery and* CO_2 *storage*
WAG- Water alternated gas
μ *- Viscosity (Pa·s)*
σ *- Surface tension (N/m)*

1. Introduction

Anthropogenic emissions of CO_2 recorded their highest numbers in 2018 (IEA, 2020). Carbon dioxide is a greenhouse gas, which means that it avoids the escaping from the Earth of the heat generated by the Sun. The highly excessive sum of CO_2 in the atmosphere has contributed to global warming, causing Earth's temperature to rise, oceans change composition and several other consequences. Therefore, it is essential to discover ways of stopping emissions from going higher and reducing the quantity of CO_2 that is currently in the atmosphere.

According to the International Energy Agency [1] oil industry emitted 11415 Mt CO_2 in 2018 worldwide, which represents around 34% of the total emanations from energy sources. Even though oil industry is a major contributor, some practices can mitigate the impact. Enhanced oil recovery (EOR) with CO_2 injection might be an attractive alternative because of the possible carbon dioxide retention in the reservoir [2], which provides a positive effect on emission reduction. This reduction of emissions is one of the obligations within European Union international agreements within the climate change domain such as the Paris agreement from the year 2015 (United Nations [3]), where one of the central goals is to avoid global temperature to rise 1,5° C higher than pre-industrial levels.

Sustainable development is based on finding the balance between industry growth and the environment, this means generating the lowest amount of damage while operating industrial activities. According to the United Nations, there are 17 goals for achieving sustainable development, three of them are relevant in this context: Economic growth and decent work, industry innovation and infrastructure, and climate action.

Climate action is referred to combat climate change and its impacts, it is known that climate change is a consequence mostly of high amounts of CO_2 in the atmosphere.

Enhanced oil recovery with the injection and storage of CO_2 seems to represent an effective way to support sustainable development because CO_2 will be trapped underground hence out of the atmosphere, also economic growth and industry innovation are going to be achieved for the oil industry.

To make clear that CO_2-EOR represents feasible, mature and clean carbon capture utilization and storage (CCUS) option, it is crucial to demonstrate the best and most economically favorable option that can be applied depending on the parameters that can be set for developing a CO_2 EOR operation.

CO_2 flooding has been considered in the oil industry since the '30s and huge development was achieved in the '70s. Previous studies affirm that it can prolong the production life of reservoirs with light or medium oil which are near depletion, with waterflood by 12 to 20 years more and it could recover from 15% to 25% of the original oil in place [4].

Because of the costs and investment required for implementing a CO_2 EOR operation, the benefits of producing extra oil must be as high as possible in the economic aspect. That is why companies need to find the best option for operating. This option can be determined through multiple simulations from several hypothetical scenarios that represent different reservoirs with a variety of properties such as permeability, depth, wells distribution, temperature, pressure and injection patterns.

CO_2 EOR is usually implemented as a tertiary process of oil recovery (after primary production and after waterflood). The mechanism of CO_2-EOR is changing the physical properties of the oil, primarily its density and viscosity. After mixing with CO_2, the oil density and oil viscosity decrease, resulting in oil *swelling effect* (an increase of oil saturation in pores) and higher oil mobility.

When considering the CO_2-EOR method in the context of carbon utilization and storage, the two most important parameters are the quantities of oil produced, and the required injected amounts of CO_2. To estimate the feasibility of a CO_2-EOR project, CO_2 utilization factor can be an useful parameter. It is defined as the amount of CO_2 that is needed for generating each incremental barrel of oil that is produced [5].

Oil recovery factor (RF) is dependent on areal sweep efficiency E_A, vertical sweep efficiency E_V and microscopic efficiency E_D.

$$RF = E_A.E_V.E_D$$

Macroscopic efficiency is a measure of how effectively the displacing fluid interacts with the reservoir in a volumetric sense, it includes areal and vertical sweep efficiencies.

Microscopic displacement efficiency is linked to the fluid-fluid interfacial (surface) tension and fluid-rock interactions at pore scale. While macroscopic efficiency comprises, bulk volume swept by injection fluid and is described by the movement front of displacing fluid, microscopic efficiency is related to saturation changes. The link between complex pore-scale fluid physics and reservoir scale assessment can be established through the evaluation of viscous and capillary forces. Capillary number is the ratio of viscous to capillary forces:

$$N_c = v \cdot \frac{\mu}{\sigma} = \frac{\frac{m}{s} \cdot \frac{N \cdot s}{m^2}}{\frac{N}{m}}$$

Where v is the mean velocity of the fluid in observed volume (m/s), μ is the viscosity of the fluid (Pa·s) and σ is the surface tension (N/m). Capillary number changes with CO_2 mixing in oil and with the disappearance of two-phase (CO_2, oil) surface, which generally means residual saturation decrease with increasing capillary number (Figure 1).

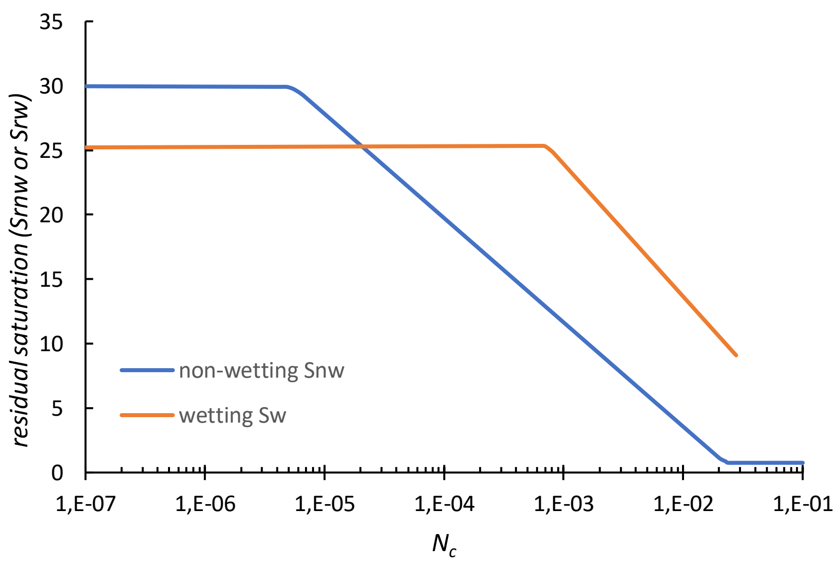


Figure 1. Capillary number curves.

During near miscible and miscible process Nc is reduced, and microscopic efficiency is increased.

There are several options for the injection of CO_2 in a reservoir. Water alternating gas (WAG) is one of them and it consists of injecting alternating slugs or volumes of water and gas (CO_2) alternatively, it is proved to have both macroscopic and microscopic displacement efficiencies which leads to higher oil recovery [6].

This investigation is a parameter-sensitivity study with certain characteristics that represent the best relation cost-effectiveness of a CO_2-EOR development by generating numerous cases from simulations with different input data and analyzing distinct conceptual models.

The thesis consists of a simulation analysis (using the Schlumberger Eclipse reservoir simulator E300) of a conceptual model, i.e. a base case that corresponds in terms of dynamic properties to the oil reservoir properties in Sava Depression.

Based on general (base) case, analysis of primary production, secondary production and different settings of CO_2 injection (WAG ratios 0, 1:1 and 1:2) and conditions of injection pressure (to simulate near- miscible and miscible conditions) has been conducted.

Among other analyses and considerations results are compared for different observed resulting parameters:

(1) Storage without CO_2-EOR.

(2) Storage after CO_2-EOR with maximum CO_2 retention.

(3) Storage with maximum oil recovery.

(4) Optimal CO_2 EOR case (employing maximum discounted value, with considered CO_2 EU ETS price and scenarios of oil price).

Hypothesis: optimal CO_2 EOR case (ad 4) results with a higher amount of CO_2 stored, compared to storage without CO_2 EOR. (ad 1).

2. Background and Literature Review

2.1 Oil recovery Techniques

Through the life of a reservoir, oil production is usually developed in two or three phases.

Primary recovery methods are based on using the pressure differences in the reservoir and production wells bottom hole pressure. This can be called “reservoir natural drive” and it forces the oil to from the well to the surface. During this phase, recovery can be in the range of 5-25% of OOIP (original oil in place) [7].

Secondary recovery comes when primary recovery is no longer effective, it consists of injecting fluids (usually water but other liquids and gases can be used) into the reservoir through injection wells aiming to maintain/increase pressure acting as “artificial drive” and replacing the natural drive. Recovery from this phase is in the range of 6 – 30% of OOIP[7].

Tertiary recovery, known as EOR (enhanced oil recovery) or improved oil recovery (IOR), are applied near the ending of a reservoirs lifetime and produce additional oil in the range of 5-15% of OOIP. [7]

In any EOR process, the main objective is to inject a driving fluid/gas (immiscible gas, CO_2, hydrocarbon solvent, polymer, etc.) that will add energy to the almost depleted reservoir and push the remaining oil to the production wells. [6]

2.1.1 CO_2 flooding processes

It is known that EOR injecting CO_2 is a commonly used technique. CO_2 is typically 95-99% pure and must be compressed, dried and cooled before going into the reservoir. [7]

Several processes exist for CO_2 EOR:

1. Continuous CO_2 gas injection.
2. Injection of water-CO_2 mixture
3. Injection of CO_2 slugs, gas or liquid, followed by continuous water injection.
4. Injection of CO_2 slugs, gas or liquid, followed by alternating CO2 gas injection (WAG).
5. Huff and puff processes.

It can also be classified depending on the characteristics of the fluids at reservoir conditions and the displacement of oil by the gas injection of $CO_{2:}$

Miscible: it refers to the injection of CO_2 above miscibility pressure (or minimum miscibility pressure, MMP), which leads to microscopic displacement efficiency is improved due to viscosity reduction, oil swelling, lower interfacial tension and change of density of oil and brine [4].

Immiscible: this process occurs when the injection of CO_2 is below the MMP. This leads to less interchange of components or mixture between the CO_2 and the fluids in the reservoir [4].

The ideal process should be a miscible one, in this way CO_2 flooding improves oil recovery trough gas drive, swelling of oil consequently reducing its viscosity. The mixture between CO_2 and oil occurs trough three mass transfer processes: solubility, diffusion and dispersion. Injected CO_2 becomes miscible with oil by the reduction of the interfacial tension (IFT) between them to zero. For immiscible processes, this IFT is not zero and it can generate lower oil recoveries and residual oil saturation.

Minimum miscibility pressure (MMP) is usually defined as the pressure at which oil recovery goes up to 80% at a given CO_2 breakthrough time, or the pressure where the final oil recovery achieves 90-95% with 1,2 PV CO_2 injection, oil recovery rises with the flooding pressure [4]. There are four principal methods for determine MMP: slim-tube experiments, compositional simulation, mixing cell models and analytical methods [8]. The value of the minimum miscibility pressure depends mostly on oil composition and the reservoir temperature, and for the exact determination of the minimum miscibility pressure, a detailed PVT characterization of oil and mixture of oil and CO_2 is necessary.

Even though injecting CO_2 has many advantages, there could be disadvantages related to the high mobility ratio, meaning that CO_2 will channel trough the oil and leaving it behind. To avoid this, it is recommended to inject CO_2 in combination with water by alternating (WAG). This should generate the mobilization of oil with the gas and with the water that sweeps oil to the production wells.

Wang [9] designed special equipment for visual detection of miscibility of a process and he showed that miscible, semi-miscible and immiscible displacement can occur at the same time during the CO_2 injection. Among others, he also states that oil recovery cannot be the only criterion for MMP determination, and he proposed the determination of the optimal portion of CO_2 in WAG process.

Sigmund, Kerr, and MacPherson [10] gave a simple correlation for relative permeability determination in a slim-tube simulation model:

$$k_{ro} = \left(\frac{S_o - 0.15}{1 - 0.15}\right)^2 \quad (1)$$

$$k_{rg} = \left(\frac{S_g - 0.04}{1 - 0.19}\right)^2 \tag{2}$$

Where k_{ro} is relative permeability of the liquid phase, and k_{rg} is the relative permeability of the gas phase.

Li and Luo [11] used displacement on core samples and slim-tube experiments to determine a correlation for relative permeabilities determination which represents input data needed for simulation. They tried to correlate Corey's exponents and displacement pressure, but they concluded that relative permeability curves need to be adjusted by matching the simulation model with experimental data.

2.2 WAG Injection

WAG technique is the most usually employed process for CO_2 EOR [7]. Water and CO_2 are alternated in slugs with different ratios and injected into the formation, see Figure 2.

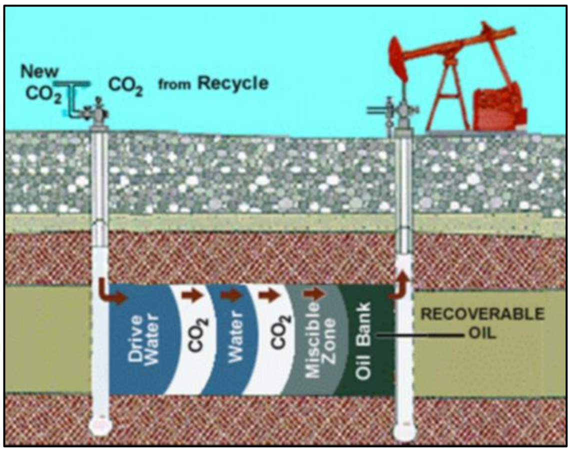


Figure 2 CO_2-EOR scheme [7]

Water alternating gas can be beneficial because of many reasons. Some of them cost-effective (miscible) pressure maintenance, limited CO_2 availability, etc. There are no guidelines for the analysis or selection of WAG ratios, well distance, permeability and time of primary production parameter based on multi-case simulation study as an input. The main reason for the absence of such guidelines and in general the reason such analysis is not performed is long run-time of compositional reservoir model.

WAG injection can increase oil mobility, increase displacement efficiency and oil recovery, but the usual problem of a WAG process is reduced displacement efficiency due to water blockage of CO_2-oil contact [12] and that is the main reason why it is crucial to correctly design the injection process.

Christensen, Stenby, and Skauge [12] gave an overview of 59 WAG projects. The expected recovery increase in some fields is up to 20 %. Most of WAG projects started in the tertiary phase of the exploitation. In other words, only recent WAG projects in the North Sea started in earlier exploitation phase. 80 percent of projects are done in miscible conditions, and the ratio of water and gas injection is mostly 1:1.

Usual problems of the field under WAG process are described, such as injectivity reduction, early water and gas breakthrough, corrosion, different temperatures of injected phased, hydrates formation, etc.

During WAG injection in water-wet rock, relative permeabilities depend on fluid saturation, saturation history, and mobility will also depend on the interaction of viscosity, gravity and capillary pressure [13]. Measurement of relative permeabilities during the three-phase displacement is usually not performed in a lab, therefore, it is common to measure relative permeabilities of a two-phase system, which is an acceptable input format for most of the commercial reservoir simulators.

2.3 Efficiency of CO_2-EOR

Jahangiri and Zhang [14] introduced mass of the stored CO_2, in relation to the overall CO_2 mass storage capacity of the reservoir:

$$f = w_1 \frac{N_p}{OIP} + w_2 \frac{M^S_{CO_2}}{M^T_{CO_2}} \tag{3}$$

Where w_1 and w_2 are weights for oil recovery and CO_2 storage in objective function (dimensionless), N_P is cumulative oil recovery (m^3), OIP is oil in place (m^3), $M^S_{CO_2}$ is the mass of CO_2 stored (kg) and $M^T_{CO_2}$ is the total storage capacity of the reservoir (kg).

However, the overall CO_2 storage capacity of the reservoir is an uncertain parameter [15] and there is still no adequate optimization function of oil recovery and CO_2 sequestration.

2.3.1 CO_2 Utilization factor

Optimization of CO_2 injection in CO_2-EOR projects can be evaluated through CO_2 utilization factors (UF). CO_2 utilization factor is defined by some authors ([16]–[18]) as:

$$UF = \frac{\left(q_{CO2_{inj}} - q_{CO2_{prod}}\right)[Mscf]}{q_{o_{prod}}[stb]} \tag{7}$$

Where q_{CO2inj} and $q_{CO2prod}$ are injected and produced volumes of CO_2 respectively (10^6 cubic feet at standard conditions) and q_{oprod} is produced oil volume (barrels at standard conditions).

This value will determine the efficiency of the flood and it must be calculated to avoid losses from poorer production performance. It is expected to achieve values of UF between 5 to 10 Mscf/b (ZHOU). Many authors express and compare the CO_2-EOR results with UF in field units, i.e. Mscf/stb. E.g. some researchers [5], [19], [20]define UF as the volume of CO_2 required for the production of one incremental barrel of oil, neglecting produced CO_2, and calculating only with additional oil recovery. Tanakov and Yafei [19] state that it can be estimated by using simulation models and analogy, and that is UF = 6 to 10 Mscf/stb for very efficient CO_2-EOR displacement. Merchant [21] states that the industry standard for UF in a successful CO_2-EOR project is UF= 5 to 10 Mscf/stb.

2.3.2 CO_2 Retention

Since the final goal for the CO_2-EOR project is to store CO_2 underground, it is necessary to determine the amount of carbon dioxide that will remain underground after the operation.

CO_2 retention is expressed as the part of total injected CO_2:

$$retention = \frac{CO_{2_{injected}} - CO_{2_{produced}}}{CO_{2_{injected}}} \tag{4}$$

Following the statements expressed in the EU directive for geological storage of CO_2, a project should not intend to store below 100 kilotons of carbon dioxide. Even though enhanced oil recovery is not included in the directive, where EOR is combined with geological storage, the provisions of such document would apply [22].

CO_2 will be trapped in the reservoir trough different stages, firstly most of the volume is trapped in the pore space after displacing the fluids present in the reservoir. Then, CO_2 will also dissolve in the formation water. It can also be retained in some adjacent aquifer if it is injected at the bottom of the oil column, transition zone, or flanks. CO_2 solubility has a great dependency on pressure, temperature and water salinity, so the retention depends on reservoir fluid and rock properties, and reservoir conditions. The volume of water in the reservoir will change over time and CO_2 dissolved in water is proportional to this amount. The final stage of trapping can come from geochemical reactions of carbon dioxide with reservoir rocks, but these reactions are long term happening after EOR development [19].

2.3.3 Oil Recovery

Another relevant parameter to determine is the recovery of oil, which refers to the amount of oil that is extracted from the reservoir during the operation.

Recovery is total recovery (before EOR and during the EOR) fraction of total reservoir volume saturated with oil

$$recovery = \frac{FOPT \cdot B_{oi}}{PV - PV \cdot S_{wi}} \tag{5}$$

where FOPT is total oil produced (standard m^3, sm^3), B_{oi} (rm^3/sm^3) is initial formation volume factor (ratio of oil volume at reservoir conditions and the volume of oil of the same composition and amount in moles at standard conditions), PV is total pore volume (m^3) and S_{wi} is initial water saturation, i.e. the fraction of PV initially saturated with water.

a) Recovery during EOR is calculated as a fraction of total reservoir volume saturated with oil:

$$EOR_{UR} = \frac{EOR_{recovery}}{PV - PV \cdot S_{wi}} \tag{6}$$

2.4 Economic Aspects

In any CO_2 injection project, one of the most important aspects is the source of carbon dioxide. This can be taken from natural sources or anthropogenic which can come from separation during the manufacture of nitrogen or ammonia and from combustion processes.

From the economical point of view, it is crucial to have the source of CO_2 as close as possible to the injection point. This will reduce the costs of transportation and infrastructure such as pipelines.

CO_2 can also be recycled from the EOR process itself.

During the planning of any EOR project, it is crucial to develop an economic screen. There are numerous methods for comparing investment possibilities in the oil and gas industry, these are Cash Flow, Payback Period, Net Present Value (NPV) and CO_2 UF [5].

Going into more detail for the net present value or net present worth (NPV) of a series of incoming and outgoing cash flows; it is defined as the sum of all the present values (PVs) of each cash flow. NPV is a crucial tool for discounted cash flow (DCF) analysis and it's used as a standard methodology for utilizing the time value of money to evaluate long-term developments [5].

The formula for NPV appears as:

$$NPV = \sum_{t=0}^{n} \frac{Rt}{(1+i)^t}$$

Where:

R_t= net cash flow (inflow – outflow) during period t, i= discount rate or return and t= number of time periods.

NPV can show how much value a project with investment will add to a certain company. It is expected that companies will invest in projects that represent a positive net present value.

2.4.1 European Emissions Trading System (ETS)

EU ETS consists of a policy that aims to fight climate change and reduce greenhouse gases emissions involving all EU countries as well as: Iceland, Lichtenstein and Norway. Each member can produce only some specific volume of greenhouse gases, the limit is defined by a cap.

When a possible CO_2 EOR project is being evaluated all economic aspects must be considered, a relevant one is the EU emissions trading system, it imposes a cost on CO_2 emissions, which is set by the market price of tradeable CO_2 certificates [23]. The costs of CCUS depend heavily on two factors: the price of oil and gas and the European Emissions Allowance Price (CO_2 EUA price), emitters can receive and buy their allowances, which they can trade as needed. Transfer of allowances takes place between EU ETS registry accounts , if their emissions are high, they must buy additional allowances, otherwise, heavy fines are imposed, there is a penalty of 100 euros per tCO_2 [24].

Every emission allowance provides each holder the right to emit: one ton of CO_2 or the equal volume of two other more powerful greenhouse gases.

The European Trading System Directive has set guidelines for monitoring and reporting for greenhouse gases emissions from the capture and geological storage of CO_2. These guidelines specify how the CO_2 emissions from storage activities must be accounted and reported for purposes of the EU ETS.

3 Methods and input datasets

Reservoir simulations are performed with Schlumberger's numerical reservoir simulator E300 (Eclipse compositional), which uses the finite volume method to calculate fluid flow.

3.1 Simulation cases

The selected grid for all models has 29 cells in the x-direction (NX=29), 29 cells in the y-direction (NY=29) and 9 cells in the z-direction (NZ=9) wherein the dimensions of the cells in the x and y directions are 50 m both, while the dimension of the cells in the z-direction is 10 m.

The simulations for this study were divided into three different models discriminated by depth, which are 715, 1545 and 1845 m then each of these 3 listed models is broken down for cases of the greater and smaller distance between production and injection wells and for three different permeabilities (5 mD, 50 mD and 250 mD).

The start of production is January 1967 until January 2024, Secondary production phase for all reservoir simulation cases starts after 10 years of primary production and lasts 48 years. then CO_2 EOR phase lasts fifteen years until December 2039.For all models, an initial stage of only oil production without any WAG process (primary production and waterflood) is the same, then three WAG ratios are simulated: WAG1:1, WAG1:2, WAG2:1.

In order to simulate CO_2 storage without EOR, input files should consider only gas injection, all production wells must be shut down as well as injection of water.

Each model has a base case and its own initial datum pressure, for 715 m it is 78 bar, for 1545 m we have 164 bar and for 1845 m the pressure is 195 bar and initial reservoirs temperatures of 60 °C, 96 °C and 110 °C respectively (Table 1), these cases generate a total of 72 simulations.

Table 1. Parameter matrix for numerical simulation case-sensitivity analysis

	Model 1	Model 2	Model 3
Depth	715 m	1545 m	1845 m
WAG Ratios	1:1, 1:2, 2:1	1:1, 1:2, 2:1.	1:1, 1:2, 2:1
Initial Datum Pressure	78 bar	164 bar.	195 bar
Reservoir Temperature	60° C	96.6° C	110° C
Permeabilities	5, 50, 250 mD	5, 50, 250 mD	5, 50, 250 mD
Well Distances	Smaller and Greater	Smaller and Greater	Smaller and Greater

Difference between distances is set by alternating (shut and open) wells as shown in Figure 3 and Figure 4. Injection wells are named after *W* and production wells after *P*, there are 13 production wells and 8 injection wells.

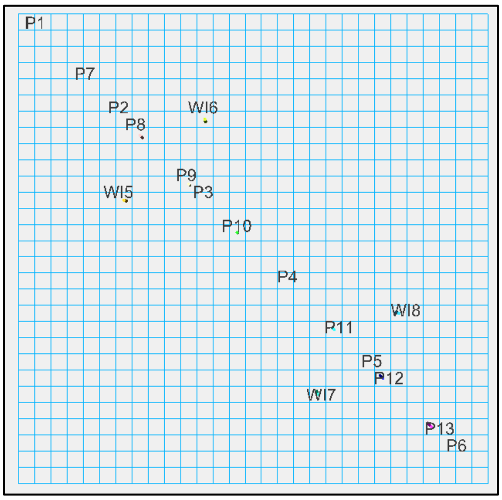


Figure 3. Model grid scheme for smaller distance

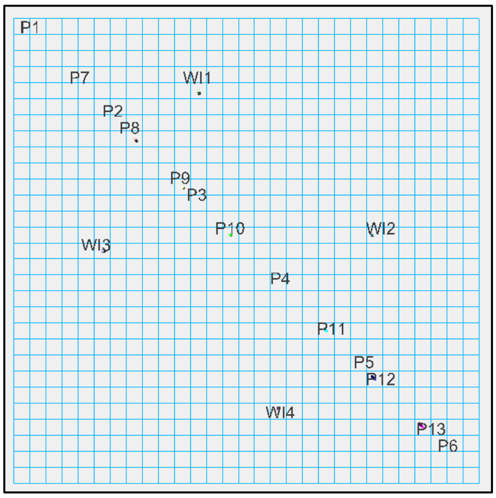


Figure 4. Model grid scheme for greater distance

3.2 PVT properties

The rock system is assumed to be practically incompressible (compressibility of the formation $c_f = 10^{-8} bar^{-1}$), and water saturation of low compressibility ($c_w = 3 \cdot 10^{-7} bar^{-1}$) is irreducible (no active aquifer).

The fluid composition and characterization (phase, and volume changes at different pressures and temperatures = PVT properties) of the fluid was taken from Vulin et al. [25] and entered in PVTp (Petroleum Experts software for PVT analysis) after which the composition from the DLE (Differential Liberation) test at the pressure that corresponds to the initial pressure of each model was taken as the input composition of each model.

There were several parameters of interest and their influence on CO_2-EOR associated with CO_2 storage performance was examined, with the objective defined by maximum oil recovery and maximum CO_2 retention:

- the influence of WAG ratio
- the distance between wells
- permeability of the reservoir
- the impact of the PVT was used. The motivation for such analysis is that PVT CO_2-EOR studies are often conducted more than a decade before commercial EOR starts. This analysis includes several moments of EOR start, also, after several test simulation cases, it was shown that the analysis can be performed in two ways: (1) with constant production limit, which is appropriate for CO_2 retention analysis and (2) with constant bottom hole pressure limit at the producer, which is more appropriate for additional recovery analysis

As the base fluid model, the same model is used as already published in 14. In that work, detailed data on the PVT study including a slim-tube test was elaborated and the resulting matched CO_2 injection EOS was based on PVT laboratory data as well. The injection pressure in this work is set according to the determined MMP in the above-mentioned work (Figure 5).

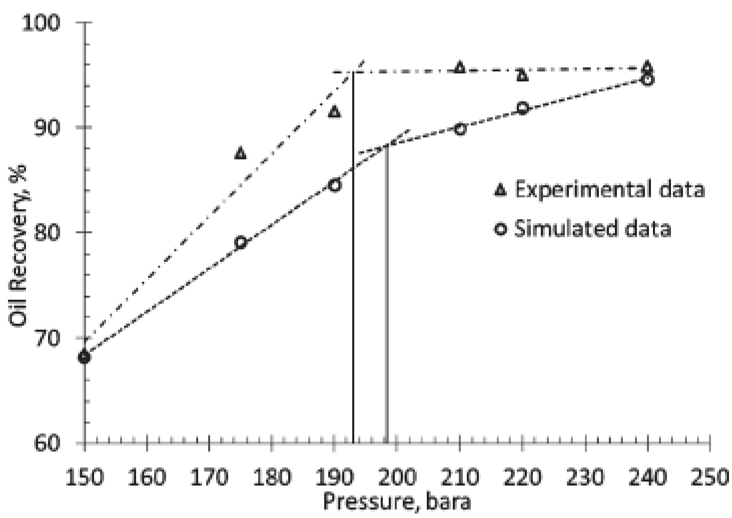


Figure 5. Oil recovery at different slim-tube pressures (Vulin et al. [25]*)*

Initial oil composition for Model 3 is based on composition from [25] and for Model 1 and Model 2 is set based on the reservoir pressure/depth and is determined from DLE test (i.e. the differential liberation composition is used at steps corresponding with the assumed initial reservoir pressure (7). Since the saturation pressure is 192 bar the initial oil composition for Model 2 and Model 3 are the same.

3.3 Economic evaluation

3.3.1 Input data from simulations

One of the main parameters to evaluate is oil production of the reservoir, additionally, the amount of water and gas injected must be considered, and to assess the feasibility of storing CO_2 in the reservoir, it is necessary to determine the retention and volume of CO_2 that can be recycled. These parameters can be obtained from outcomes given by simulations from Eclipse300.

A Python code is used to extract, from RSM files, the relevant parameters used for calculations, these are FOPT (field oil cumulative production total), FGIT (field gas injection cumulative total), FGPT (field gas production cumulative total), FYMF_2 (vapor mole fraction for component 2, which is CO_2), FGIR (field gas injection rate), field water injection rate and FWIT (field water injection cumulative total).

Injected CO_2 (FGIT) includes recycled CO_2, which is the amount of CO_2 that comes out from production wells and can be re-injected into the reservoir, plus new CO2 that should be brought to complete the total required injected volume (Figure 6).

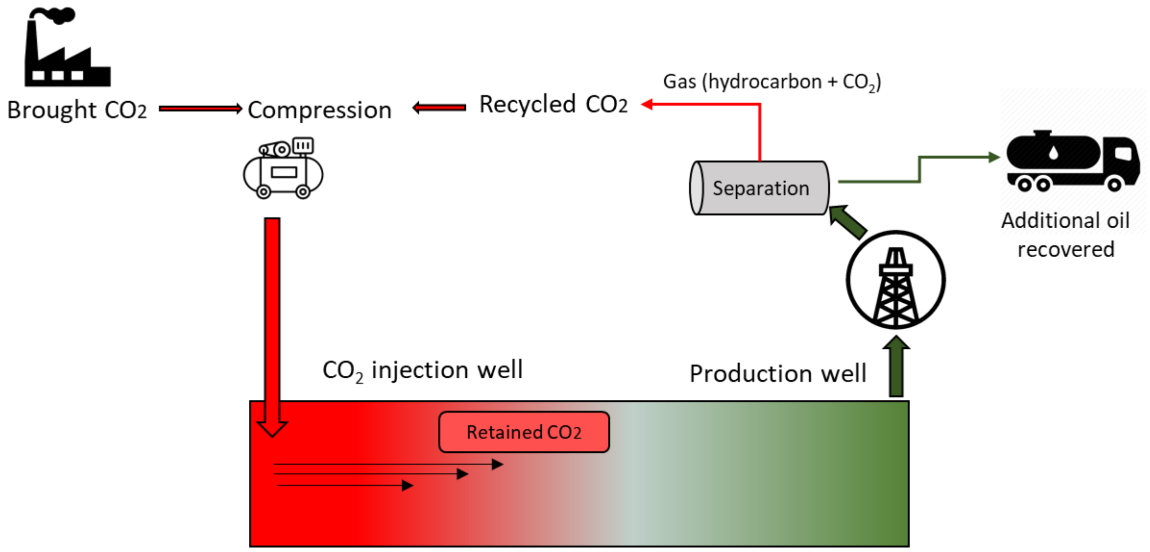


Figure 6 Conceptual cycle of CO_2 during EOR

3.3.2 Base assumptions

For calculating net present value, earnings and expenses must be considered. Earnings of a CO_2 EOR storage project comes from production (FOPT) multiplied by the price of the oil barrel and avoided CO_2 multiplied by the price of CO_2 ton in the EU ETS.

Avoided CO_2 refers to the amount of gas that is not being released in the atmosphere and this volume of gas can be considered as allowances and therefore used for trading in the ETS.

Expenses involve the operating cost OPEX and the price of new CO_2 that is acquired. Operational costs are considered annually and include compression and injection of CO_2, monitoring activities and general processes for an oil field.

Since oil and carbon prices are constantly changing, different input values for each will be considered (Table 2). Discount rate (r) is the interest percentage that will define future cash flows, which can be a crucial factor for shareholders regarding investment risk. That is why different values are evaluated in order to cover various cash flows and costs possibilities from more optimistic to pessimistic scenarios.

The price of oil now (October 2020) is 40,31$ per barrel and EU ETS carbon price for February 2020 is 25,15 € per allowance.

Table 2. Input values for oil, carbon prices and discount rate

Parameter	Price	Price	Price	Price
Oil		25$/bbl	40$/bbl	50$/bbl
CO_2	10€/t	25€/t	40€/t	55€/t
r		8%	10%	12%

Royalty will be constant for evaluation and is defined as the tax that a company must pay as a percentage of produced oil and the.

Capital Cost (CAPEX) is considered most of the time when calculating evaluating economic aspects, it is defined as the funds that a company invests to purchase, renovate and maintain physical assets. For this investigation, it was not possible to determine a value for CAPEX because in references [26]–[31] costs of CAPEX vary too significantly, ranges go from tens to thousands of M€, therefore, CPAEX is a parameter highly site specific

From reviewed literature [32], [33] the selected input values for injection and royalty are presented in Table 3.

Table 3. Economic base assumptions

Parameter	Value
OPEX, percentage of produced oil value	5%
Injection of CO_2	3 €/t
Injection of water	1 €/t
Royalty, percentage of produced oil value	12%

4 Results

The main objective was to show how CO_2-EOR affects CO_2 storage capacity. It is obvious, for cases of CO_2 injection and oil production, that additional space will be freed for storage. However, pure CO_2 injection is usually not feasible in CO_2-EOR processes. The more interesting observations are then those related to WAG CO_2 injection, where injected water also occupies part of the reservoir. In the most WAG cases, storage has been improved (Figure 7).

It can be seen that the best cases will be those at some mediocre permeability around 50 mD, at lower depth and with WAG ratio 1:2. Also, at greater depths more CO_2 should be added to the system from the outside (new CO_2) – for greater well distances, depths (1845 m), permeabilities (250 mD), and WAG ratio, minimum value of *storage improved* after 15 years is 0,5. Then the depth affects the storage, as the second smallest value is for 1545 m depth (*storage improved* = 0,63), and the latest is the WAG ratio 2:1 which gave for 1845 m and other values the same value of 0,78 etc.

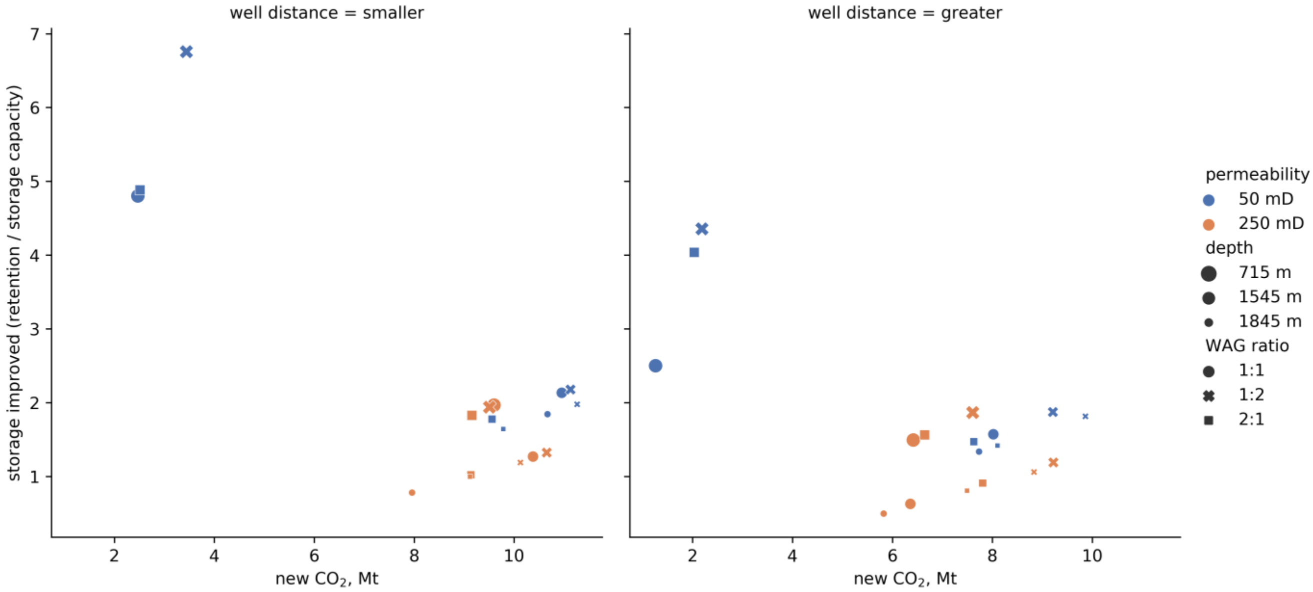


Figure 7. Improvement of storage capacity, after 15 years of CO_2-EOR.

Simulations for only storage were possible only for permeabilities of 50 and 250 mD. For the other cases (5 mD), due to low permeability, (too) high pressure is quickly reached in the near-wellbore zone when CO_2 is injected for storage (there is no oil production and pressure release at production wells), and storage capacities in such cases are not significant and do not account as physically (or economically) feasible.

If retention is observed by itself, then absolute stored values show that the highest amounts of CO_2 can be stored at greatest depths (Figure 8).

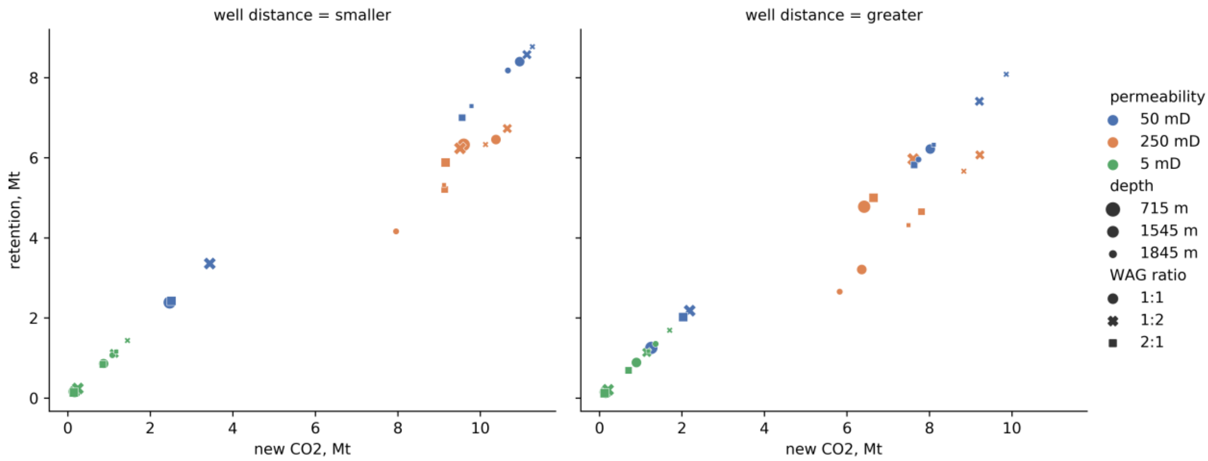


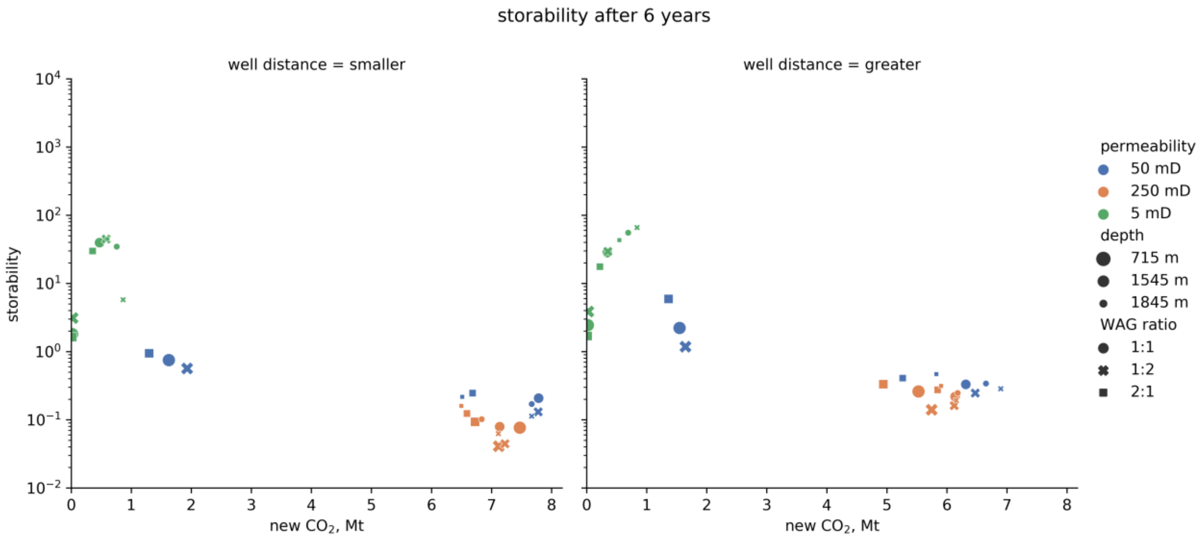
Figure 8. Retention after 15 years of CO_2-EOR

As the results are sensitive to multiple parameters, storage improved, retention and new CO_2 are not showing all the details of the injection process. We defined storability as: $storability = \frac{retention}{CO_2\ recycled}$. That number shows how much CO_2 produced with oil at production well should be separated and injected again (circulated through the system) for a given retention (Figure 8), and the results also reveal the retention for those cases where CO_2 storage (without EOR) is not possible. In Figure 9different stages of CO_2-EOR WAG injection can be discussed. After six years, all the process went through at least two full WAG cycles (two for WAG = 1:2 and WAG = 2:1, and three cycles for WAG = 1:1), the effect of permeability is visible – low permeability (5 mD) means later CO_2 breakthrough to the production wells. At permeability of 50 mD, less CO_2 is needed to add to the system (*new* CO_2), but several times more CO_2 is recycled than it was retained. The figures might be confusing, because there is a long period of CO_2 recycling, without significant new retention. That can be considered as time needed for adding value to the project, in terms of additional oil recovery. In other words, first few years relate to the most of CO_2 retention, covering only part of the investment and operating costs, and the remaining of injection will increase net present value with additional recovery.

The increase of additional recovery (AR) shows the monotonic trend of increase for all cases, which goes into favor of assumption that it will bring value needed for CO_2 storage to become feasible (Figure 10). Even though significant amounts of CO_2 will be recycled, the recovery increases even after fifteen years.

AR is the highest at greatest depths, highest permeabilities and for WAG ratio 1:2. Medium permeability cases end with higher amount of CO_2 that needs to be added to the system, but with lower recovery.

After plotting additional recovery versus retention, it becomes obvious that those two parameters are slightly opposed (Figure 11). It also becomes clearer that smaller well-distance (surprisingly) generally results with higher retention. This can be explained by the lower pressure between injection and production wells in cases with greater well distance, which results with worse mixing conditions and thus viscous fingering of CO_2.



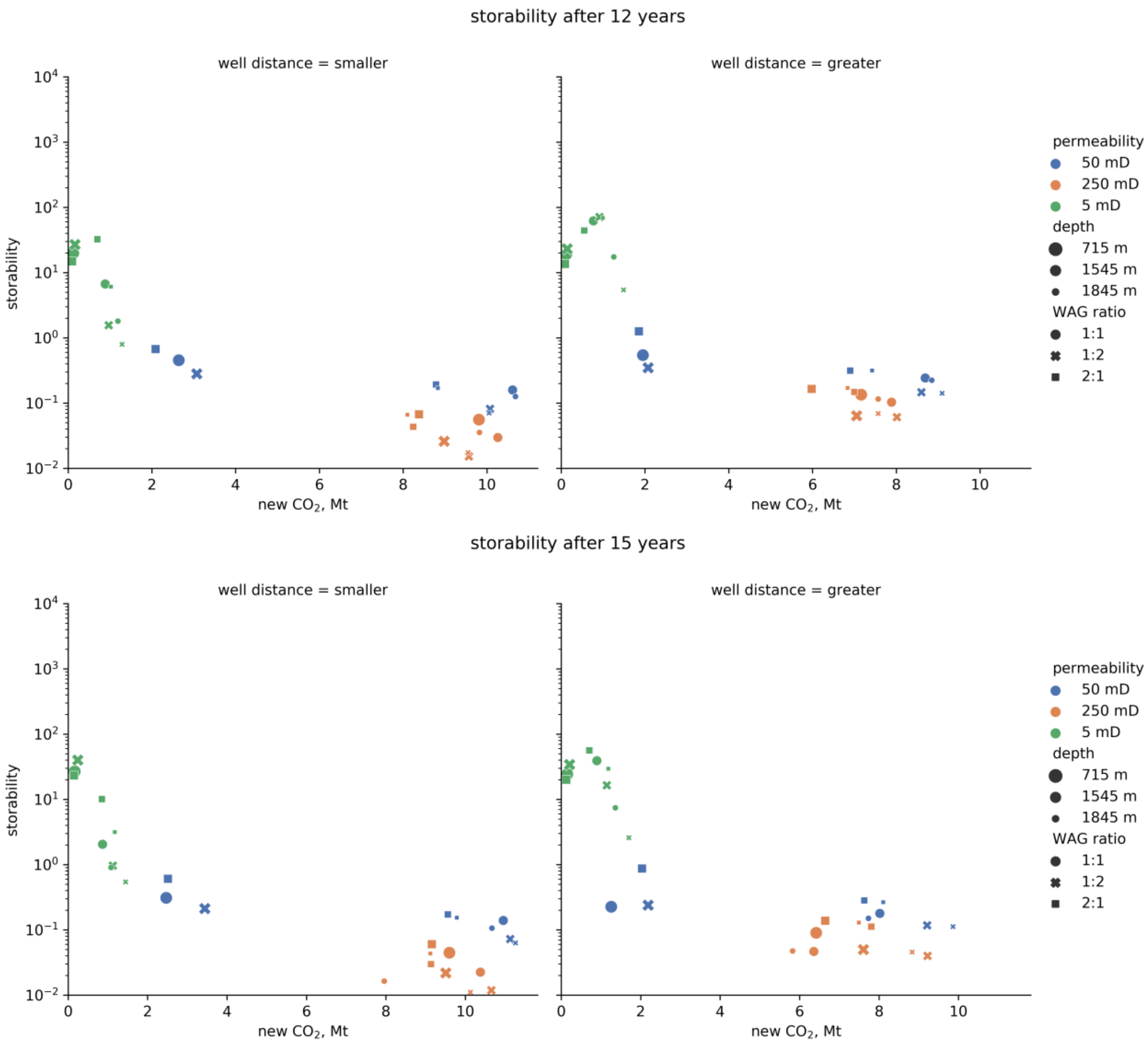


Figure 9. Storability after different times of CO_2-EOR injection.

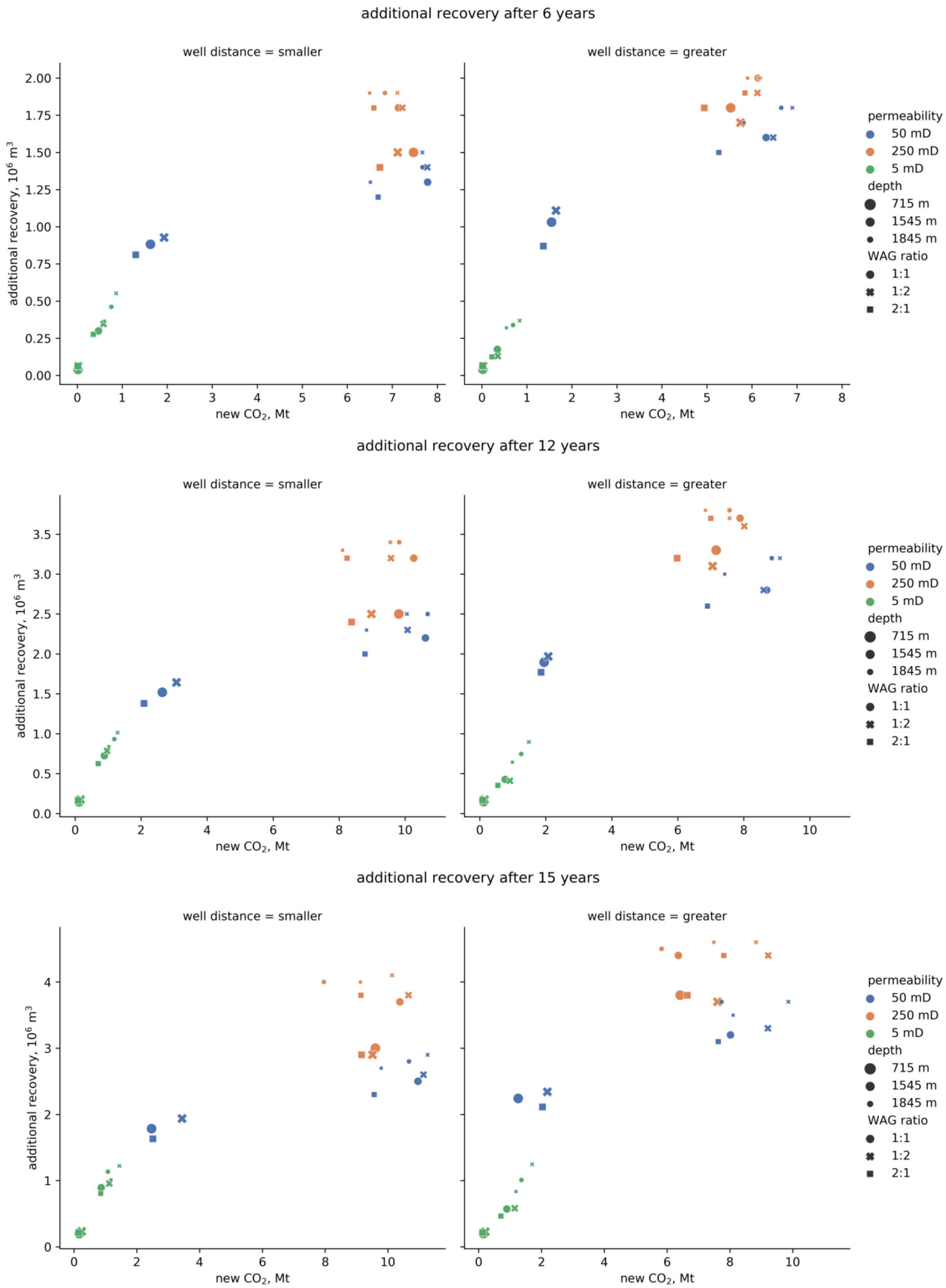


Figure 10. Additional oil recovery

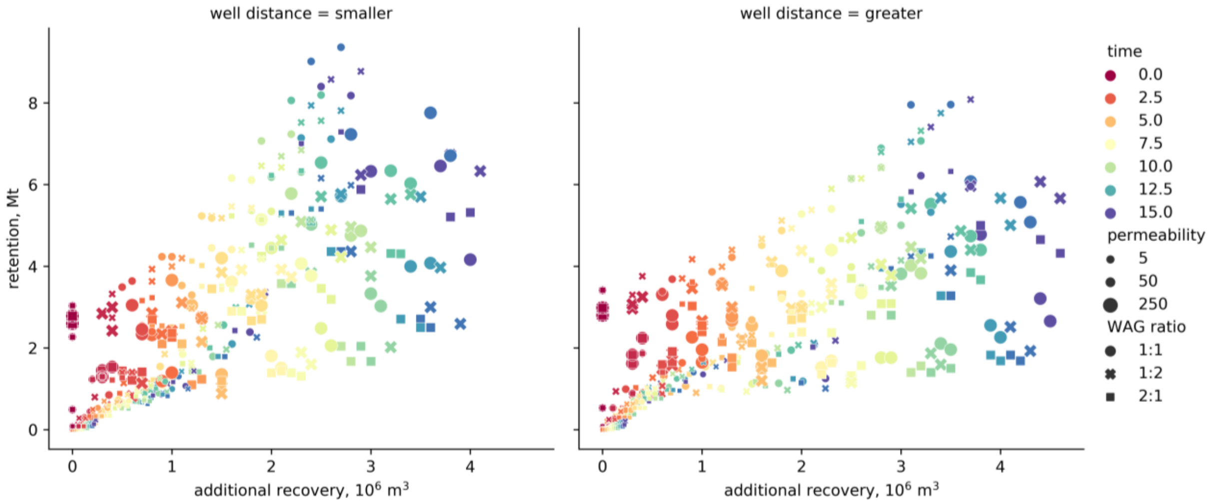


Figure 11. Retention versus additional recovery.

At the end of EOR, well distance has no considerable influence on recovery (Figure 12), but greater retention comes from cases with smaller distances. Specifically, cases with larger permeabilities (50 and 250 mD) and WAG ratios of 1:1 and 1:2 have the overall biggest amount of recovery and retention.

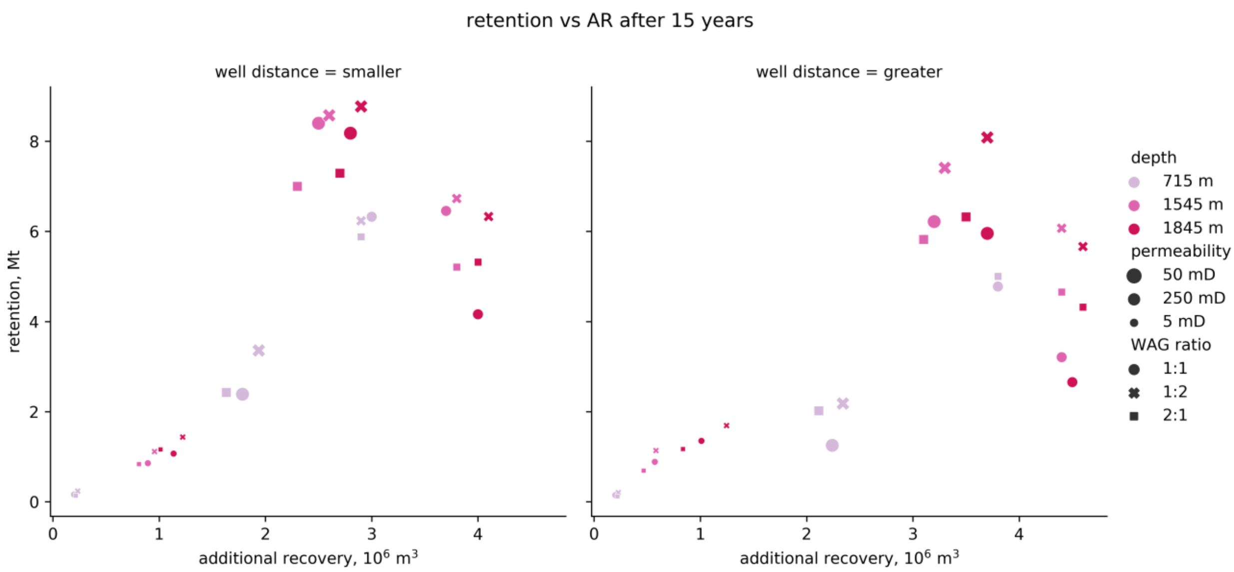


Figure 12. Oil recovery vs retention at the end of EOR

When the EOR operation is halfway complete (after 8 years), around 80% of the volume of retained CO_2 is reached (for smaller distance, WAG 1:1, 50 mD at 1545 m it's 6,16 Mt and for greater distance, WAG 1:1, 50 mD at 1545 m it's 5,4 Mt, (Figure 13). Oil recovery for respective smaller distance case is at 93 %, and retention is at 73 % compared to the end of the operation. For higher respective greater distance case, oil recovery is at 91 %, and the retention is at 91 % as well. However, additional recovery is at 64 % and 62 % for respective good retention cases.

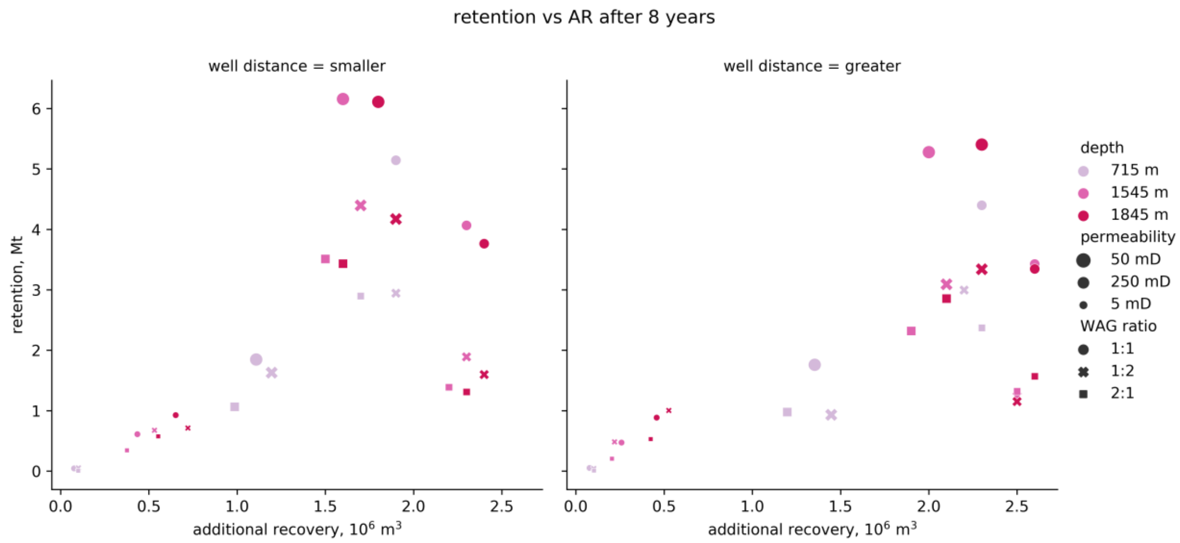


Figure 13. Oil recovery vs retention after eight years of EOR.

Simulation results were used for economical evaluation with different scenarios for oil and carbon (EUA) prices, and different discount rates. It should be noted that capital investments (CAPEX, for CO_2 compression system, special anticorrosive well completion, special separation and dehydration of produced gas) are out of the scope of this research, but NPV value can simply be decreased for CAPEX (for any observed time-step of simulated EOR).

There's a realistic scenario that represents the closest to current values of oil and carbon (Figure 14), the graphics show that well distance impacts significantly on values of NPV. The most cost-effective are those cases with highest utilization factors (UF), permeability of 50 mD, WAG = 1:2 and at 1545 m. More feasible are cases with smaller well distance as well.

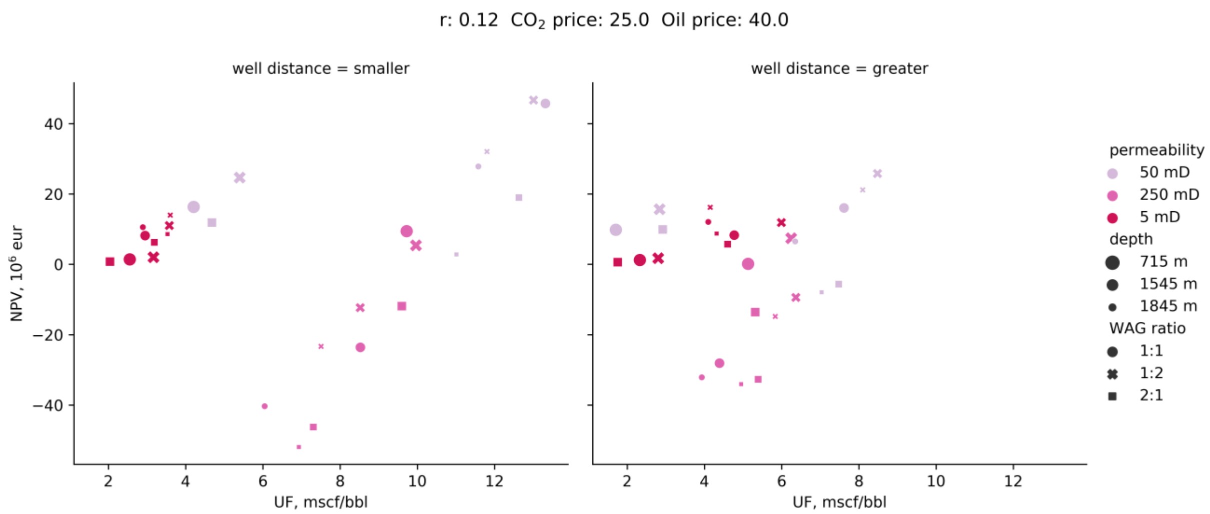


Figure 14. NPV vs UF for the realistic scenario (recent CO_2 and oil price) at the end of EOR

The most optimistic case represents the highest prices of oil and carbon, and lowest discount rate (Figure 15) in the other hand, the most pessimistic scenario has the lowest prices for carbon and oil and the highest discount rate (Figure 16).

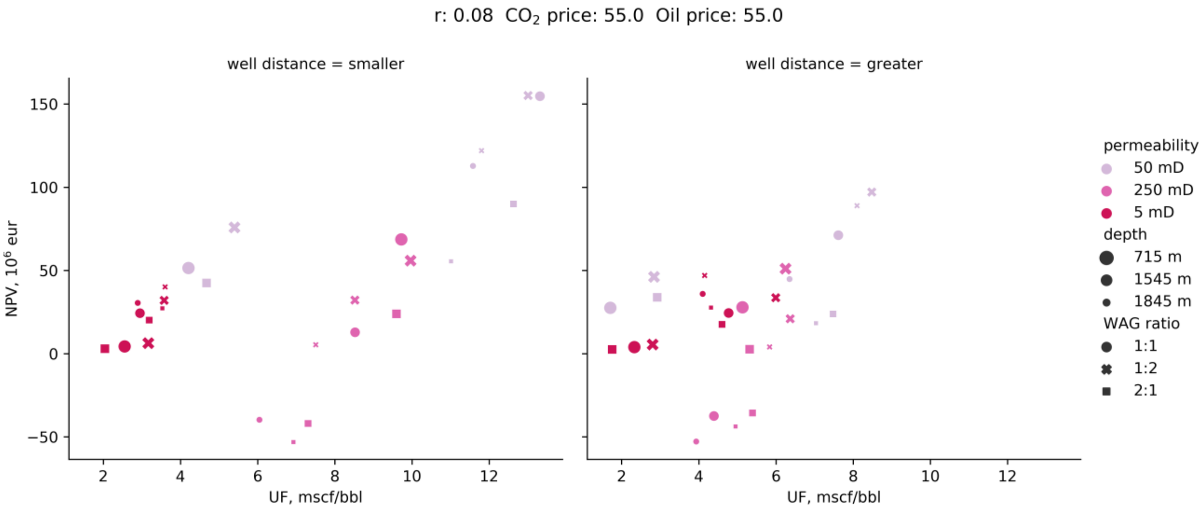


Figure 15. NPV vs UF for the optimistic scenario at the end of EOR

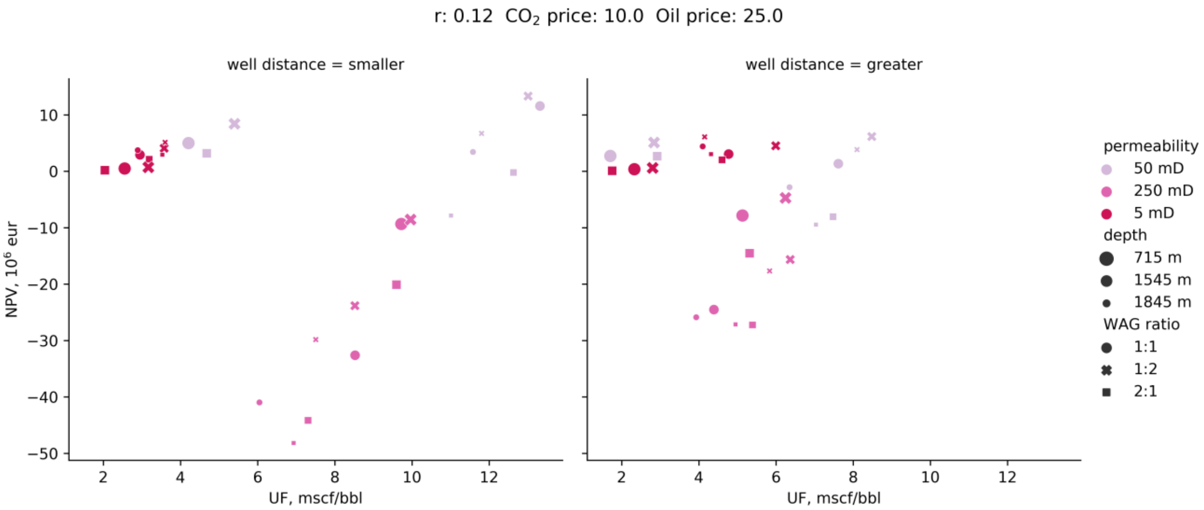


Figure 16. NPV vs UF for the pessimistic scenario at the end of EOR

For the optimistic scenario, NPV goes as high as 150 M€, and for the pessimistic scenario, it only reaches a value slightly larger than 10M€. Considering that the NPV should be decreased by CAPEX, which is not in the scope of analysis, high price of CO_2 and oil is needed to make such projects economically feasible. Smaller distance is more profitable for both cases in conjunction with a permeability of 50 mD.

Although only three graphics are shown in this section, resulting plots for all scenarios are available in 7. For all scenarios, the value of UF is the same and in accordance with reviewed literature ([19], [21]).

5 Conclusions

The numerical simulation analysis, which consists of 54 different CO_2-EOR injection cases (all combinations of three permeabilities, three depths, two well distances and three WAG ratios) was taken as a basis for economic assessment (which consisted of three assumptions of interest rate, four CO_2 prices, and three oil prices), with final number of cases for economic feasibility analysis $= 54 \cdot 32 = 1728$.

Considering such a large number of cases was a challenge in which it was necessary to create a database (SQLite) of results and inputs and a system (Python code) for data processing and charting.

Simulated base models were restarted to simulate waterflood period, and after that, the simulation has been restarted to test different WAG scenarios.

Following conclusions may be drawn:

1. CO_2 storage capacity is higher if there was an EOR operation in the reservoir because displacement of oil leaves available space where CO_2 can be retained. In evaluated cases the differences on stored volume are up to 4,64 Mt. Lower quartile (Q1) of respective differences is 0.41 Mt, however, some cases are not available for CO_2 storage so the results are in fact more "positive".

2. Retention of CO_2 is affected by the distance between injection and production wells; smaller distances between them means a higher volume of retained CO_2 related with higher permeabilities and depth. WAG ratio also has an impact on retention: ratios of 1:1 and 1:2 show bigger retention caused by slug size of gas injection which means more volume of CO_2 injected.

3. When considering economic factors, well distance has an important effect on values of NPV. Higher values of NPV are attached to smaller distances and cases with a permeability of 50 mD. For greater distances, the value of NPV is lower. UF will not be affected by oil and carbon prices, discount rates and royalty. So, despite markets situation, having a lower UF with positive NPV is an indicator of perspective EOR strategy, because of less expenses for CO_2 recycling.

4. The most optimal case should fulfill highest NPV and retention and lowest UF. From results of this investigation, an optimal case has permeability of 50 mD, depth should be between 1545 and 1845 m, the WAG ratio 1:2 as best followed by 1:1. Regarding well distances, choice should be based on benefit from a higher NPV (risked to changing oil and carbon prices) with a higher UF, or a moderately smaller NPV with slightly lower UF. In absence of more simulation results, it can be concluded that there is some optimum (not maximum or minimum) depth and permeability which will give the highest retention, additional recovery and thus NPV.

The injection of CO_2 into a reservoir for EOR is economically feasible for companies, and it has been applied for decades. Specifically, for the simulated conceptual models with some previously analyzed properties of oil fields in "Sava depression", for the actual prices of carbon and oil it is economically advantageous to develop new CO_2-EOR projects and it is clear that including EU ETS and CO_2-EOR as utilization and storage of CO_2 would make a big difference in terms of CO_2 storage, providing more assets for application of advanced methods of monitoring and tracking the CO_2 in the entire process.

Finally, the hypothesis of this work is confirmed - optimum CO_2 EOR cases (employing maximum discounted value, with considered CO_2 EU ETS price and scenarios of oil price) all result with higher amount of CO_2 stored – for example at lowest or highest prices of CO_2 (10 or 40 €/t) and oil (25 or 55

$/bbl), and highest or lowest value of discount rate (12 or 8 %), the optimal CO_2 EOR cases are at 1545 m (appendix B and C, some at 1845 m are also near the same values for greater well distance), WAG = 1:2 and k = 50 mD – minimum storage difference (retention from CO_2-EOR minus CO_2 storage capacity without EOR) is 1,68 Mt (or 1.82 times more), mean is 3,43 Mt (or 3.15 times more), and maximum difference is 4.64 Mt (or 6.76 times more).

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7 Appendixes

7.1 Appendix A: Oil composition tables

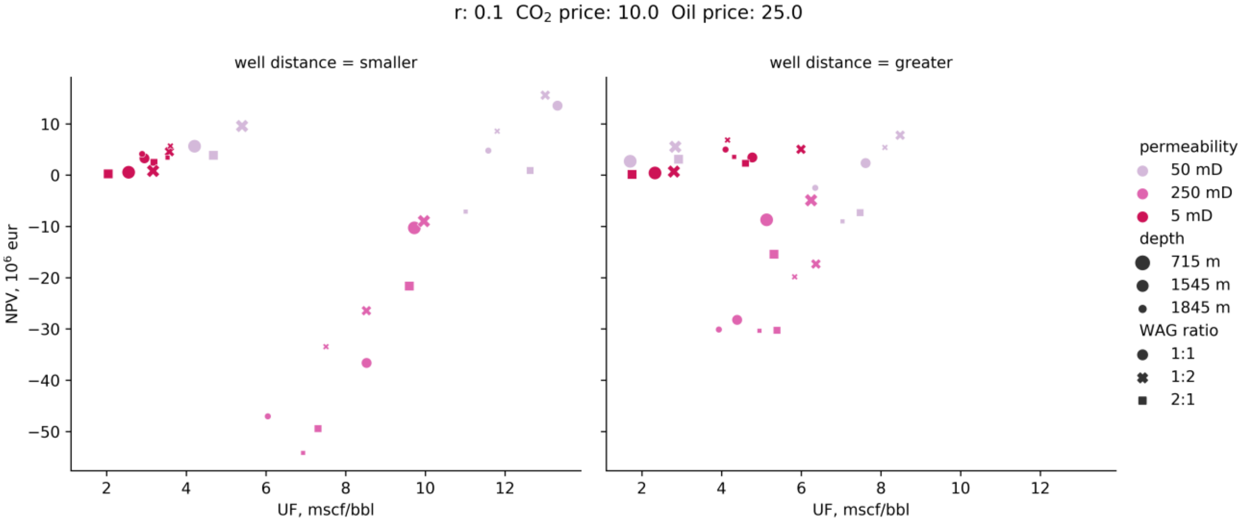
Table i. Oil composition for Model 3 and Model 2

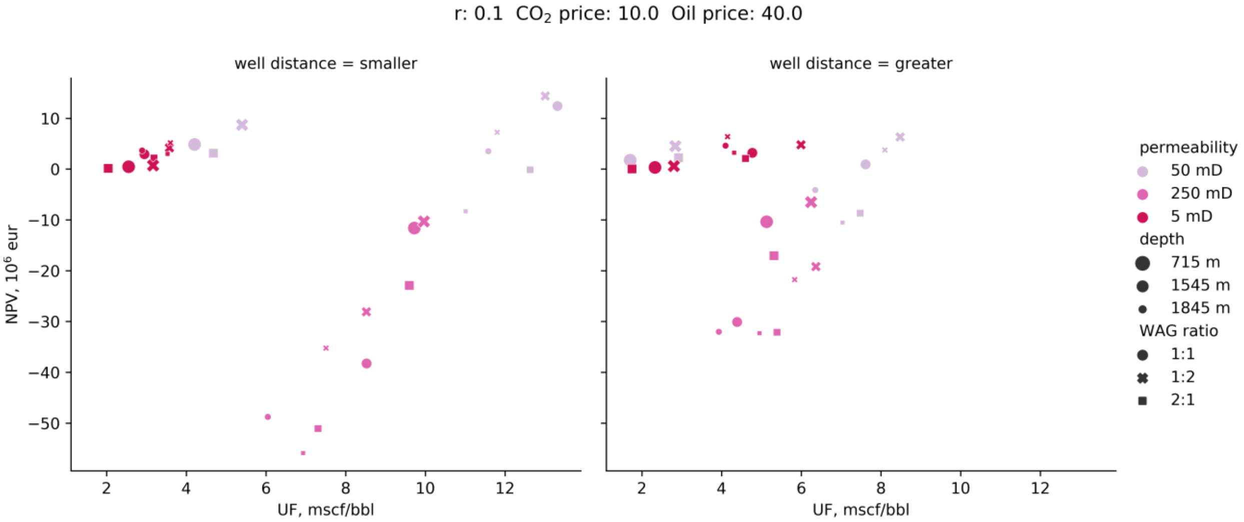
Component	mol%
N2	0.094
CO_2	0.462
C1	33.246
C2	3.921
C3	3.110
NC4	2.833
NC5	2.808
C6	2.783
C7::13	7.242
C14::19	13.601
C20::25	14.290
C26::32	10.414
C33::C46	5.196

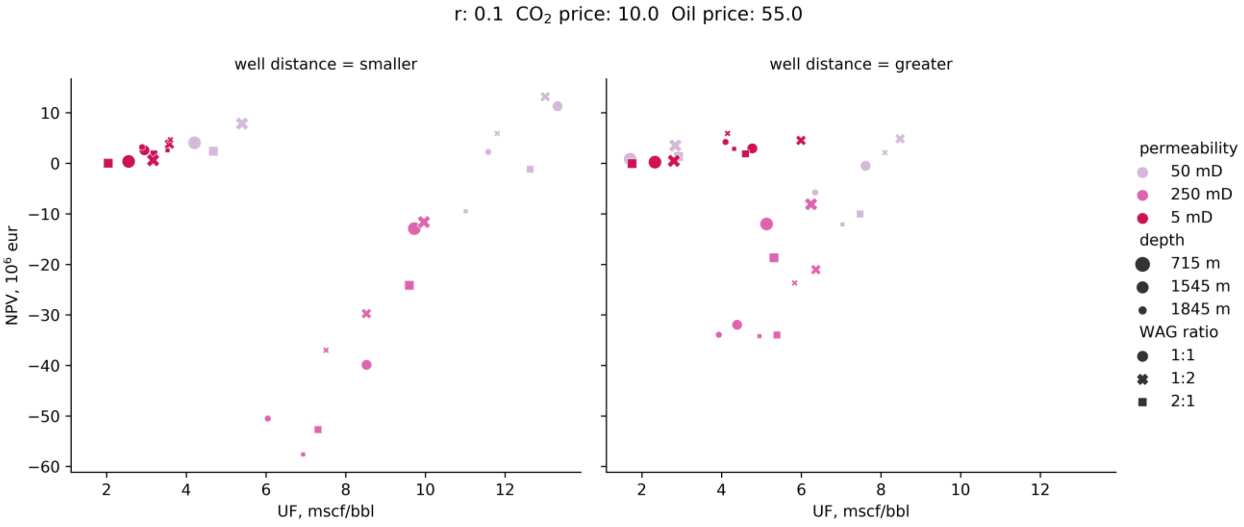
Table ii. Oil composition in Model 1

Component	mol%
N2	0.043
CO_2	0.3558
C1	20.2983
C2	3.6608
C3	3.3053
NC4	3.2333
NC5	3.3241
C6	3.3584
C7::13	8.7953
C14::19	16.7204
C20::25	17.6351
C26::32	12.8559
C33::C46	6.4144

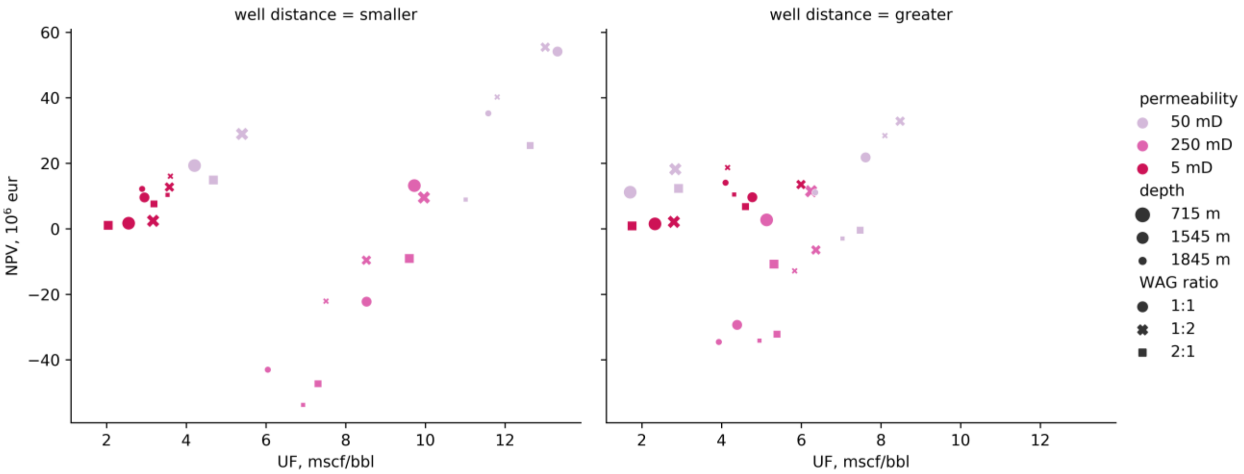
7.2 Appendix B: Diagrams for different scenarios of prices and discount rates – NPV vs UF



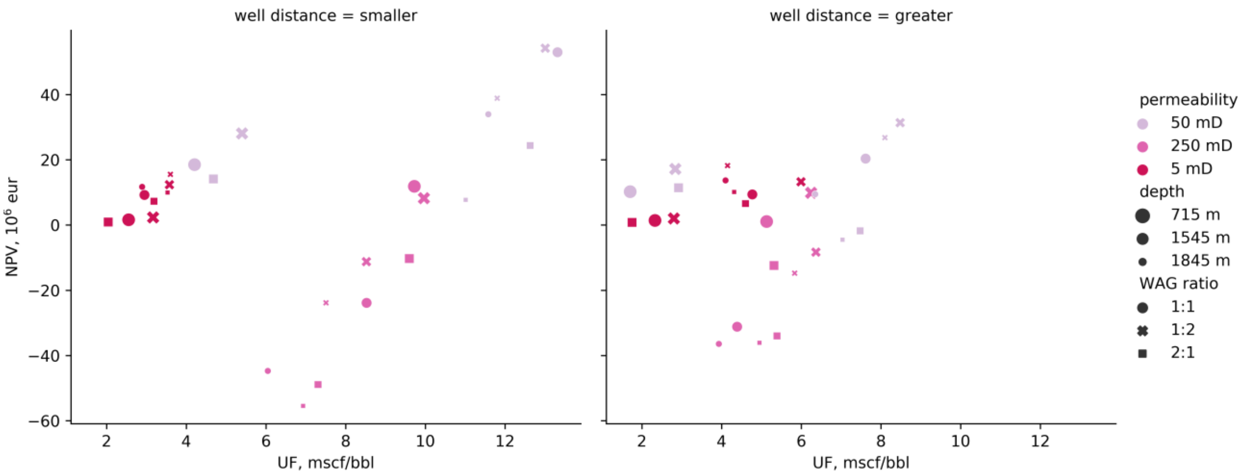




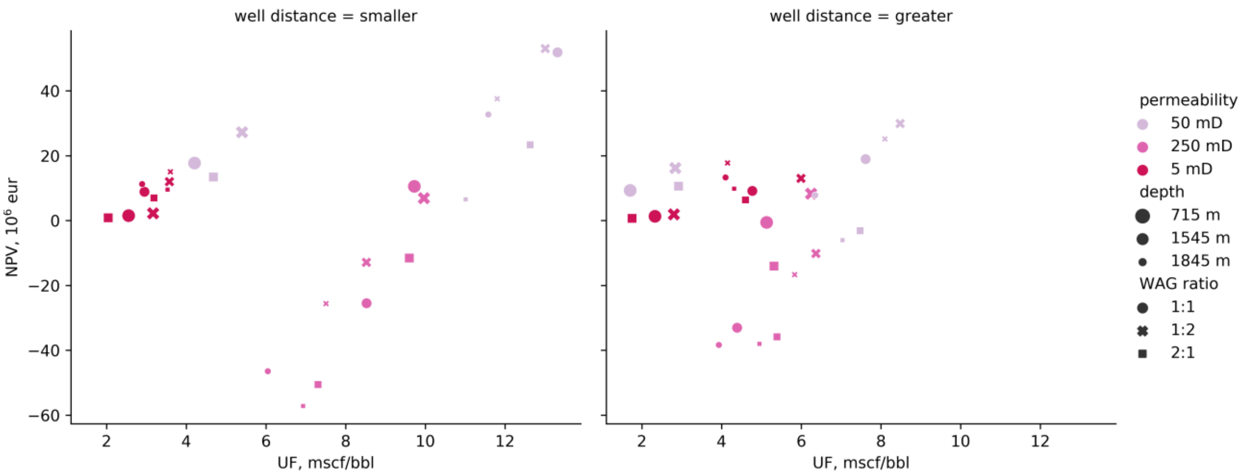
r: 0.1 CO_2 price: 25.0 Oil price: 25.0

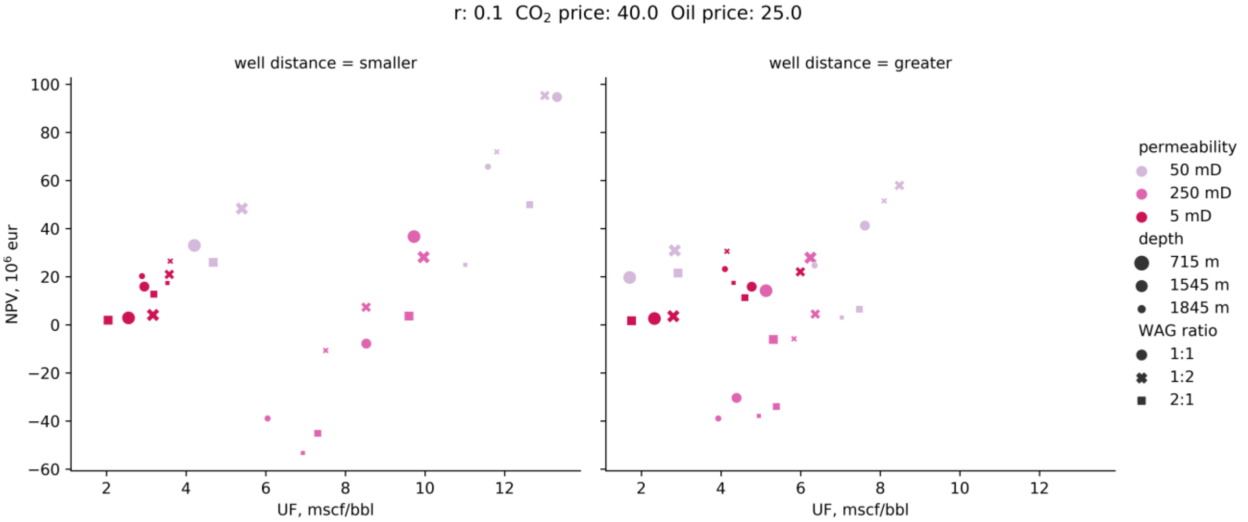


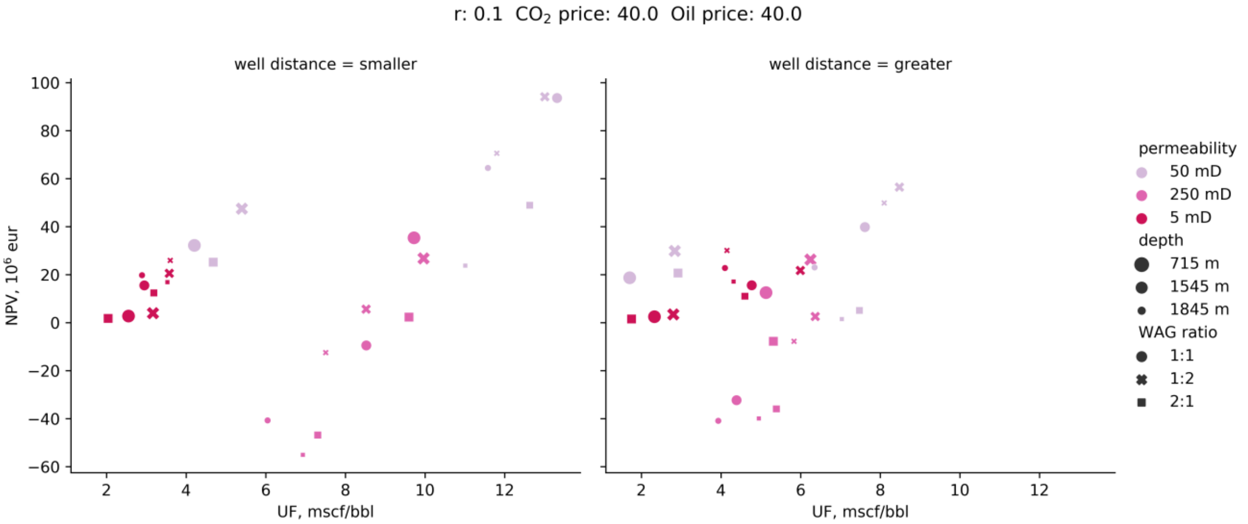
r: 0.1 CO_2 price: 25.0 Oil price: 40.0

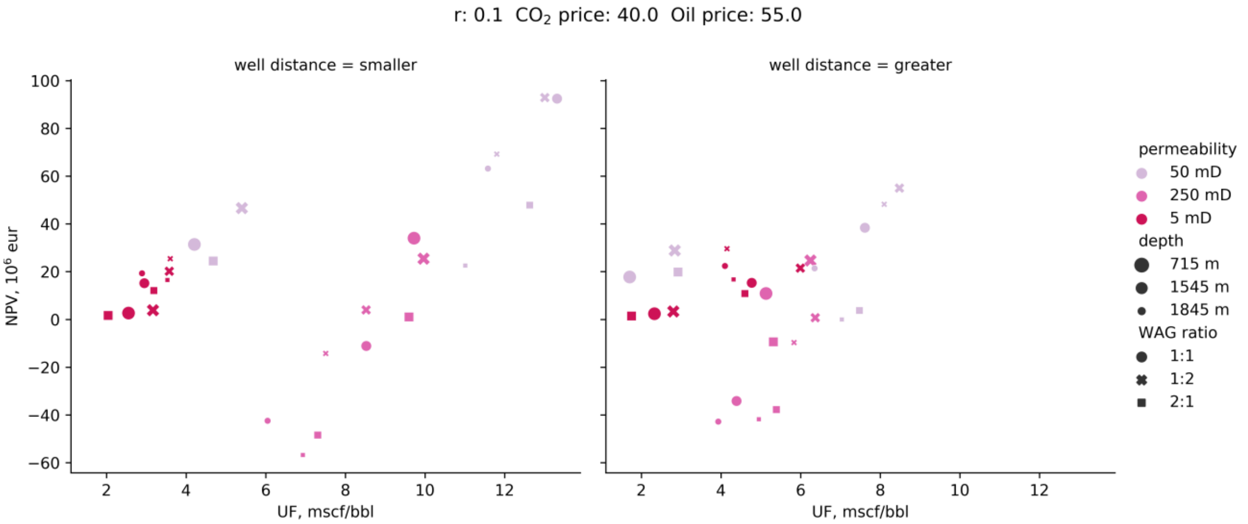


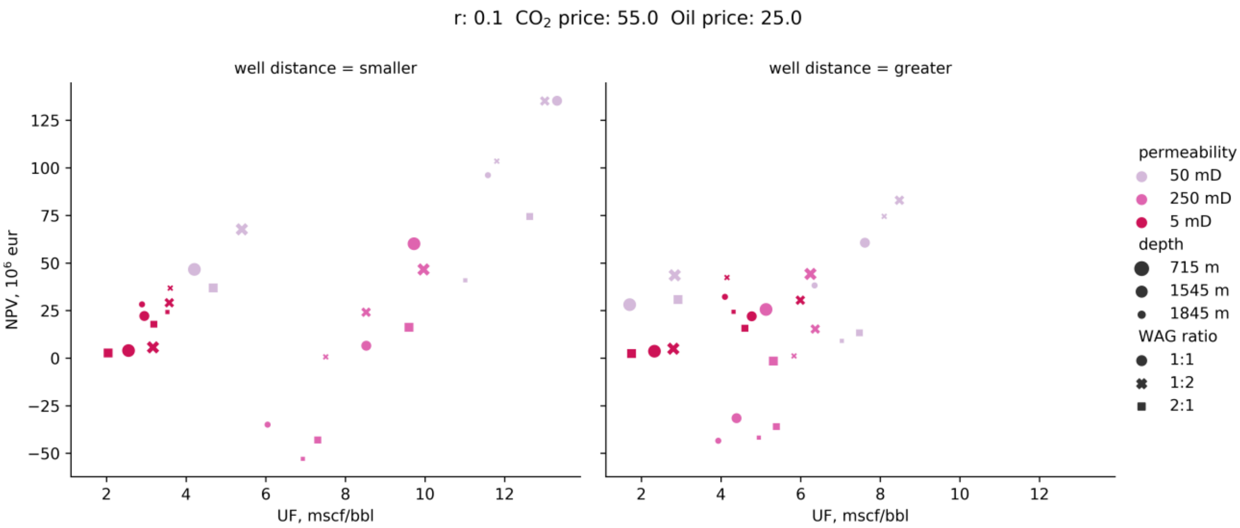
r: 0.1 CO_2 price: 25.0 Oil price: 55.0

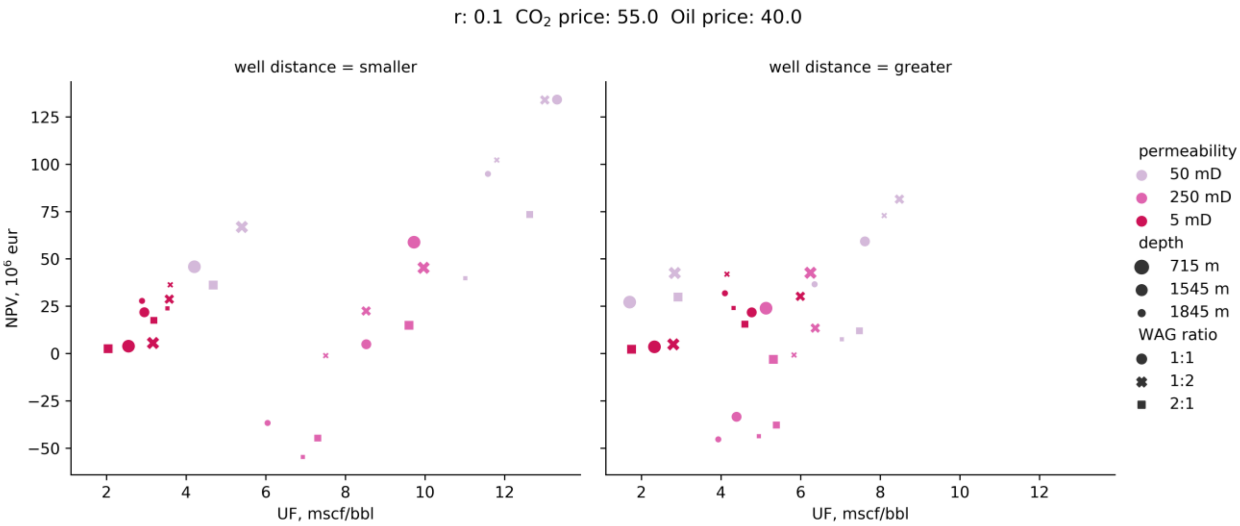


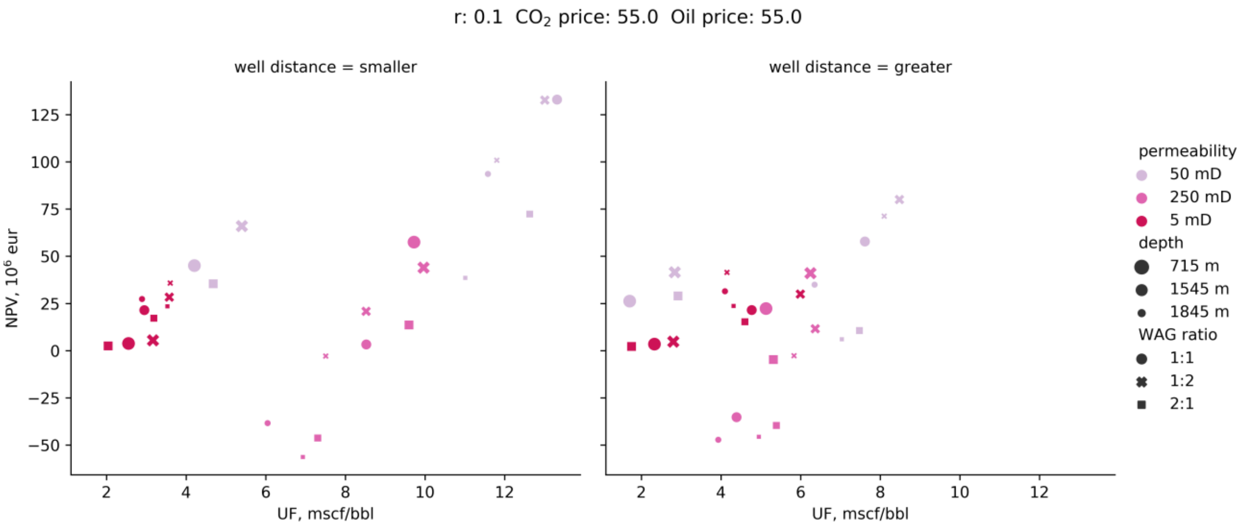

r: 0.1 CO₂ price: 40.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10⁶ eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1

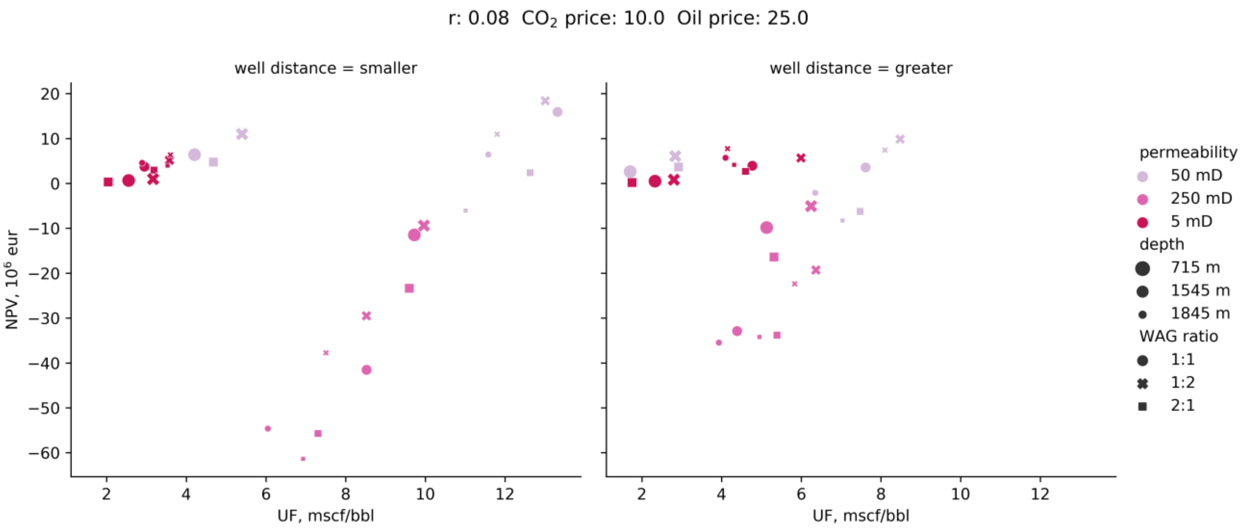

r: 0.1 CO₂ price: 40.0 Oil price: 40.0
well distance = smaller
well distance = greater
NPV, 10⁶ eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.1 CO₂ price: 40.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10⁶ eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.1 CO2 price: 55.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
125
100
75
50
25
0
−25
−50
2
4
6
8
10
12
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.1 CO2 price: 55.0 Oil price: 40.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
125
100
75
50
25
0
−25
−50
2
4
6
8
10
12
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.1 CO2 price: 55.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
125
100
75
50
25
0
−25
−50
2
4
6
8
10
12
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.08 CO_2 price: 10.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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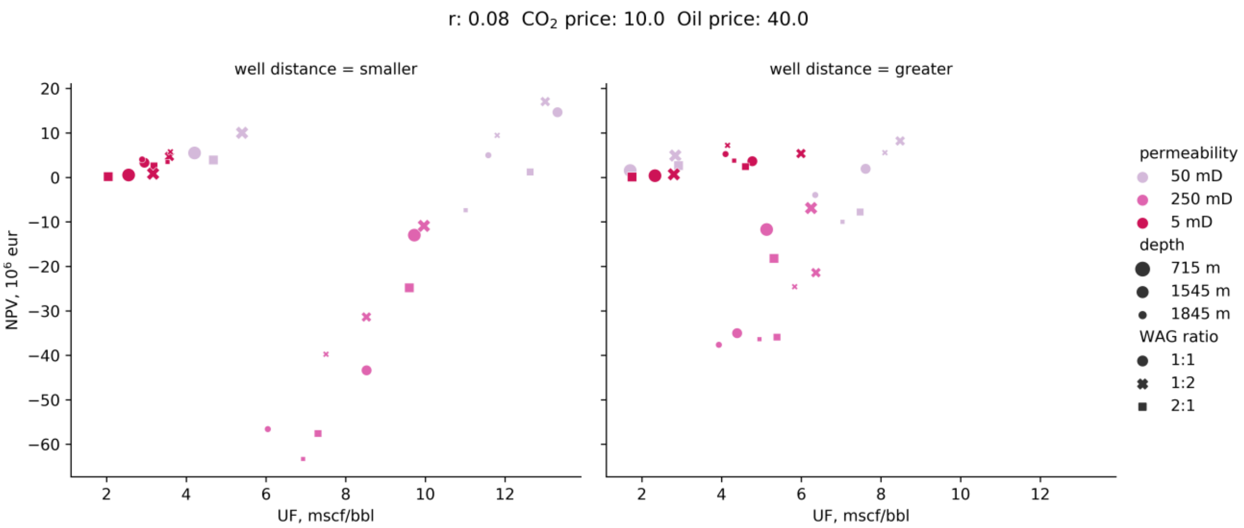
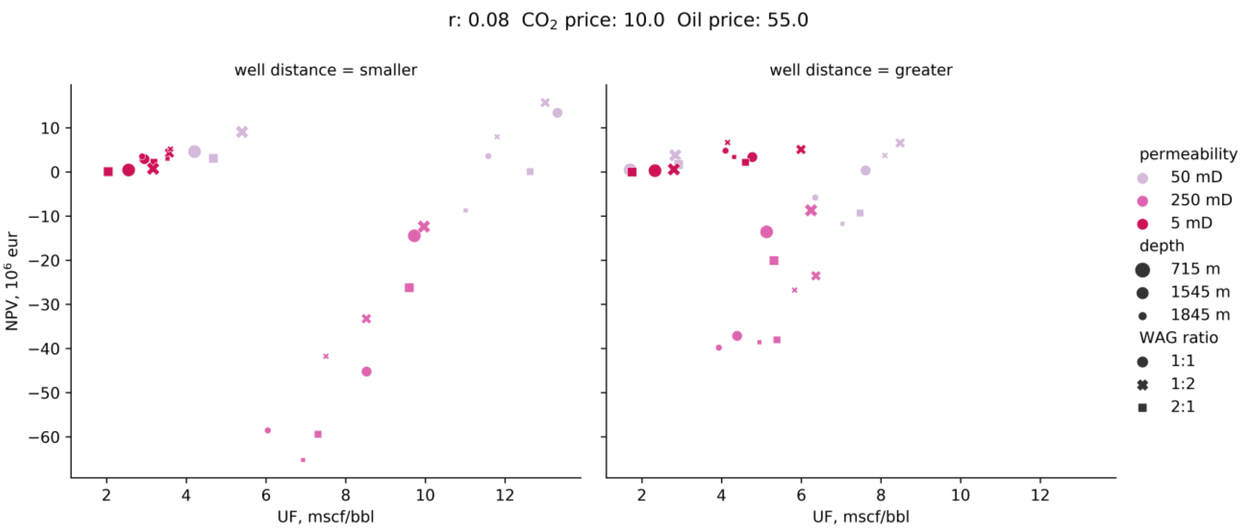
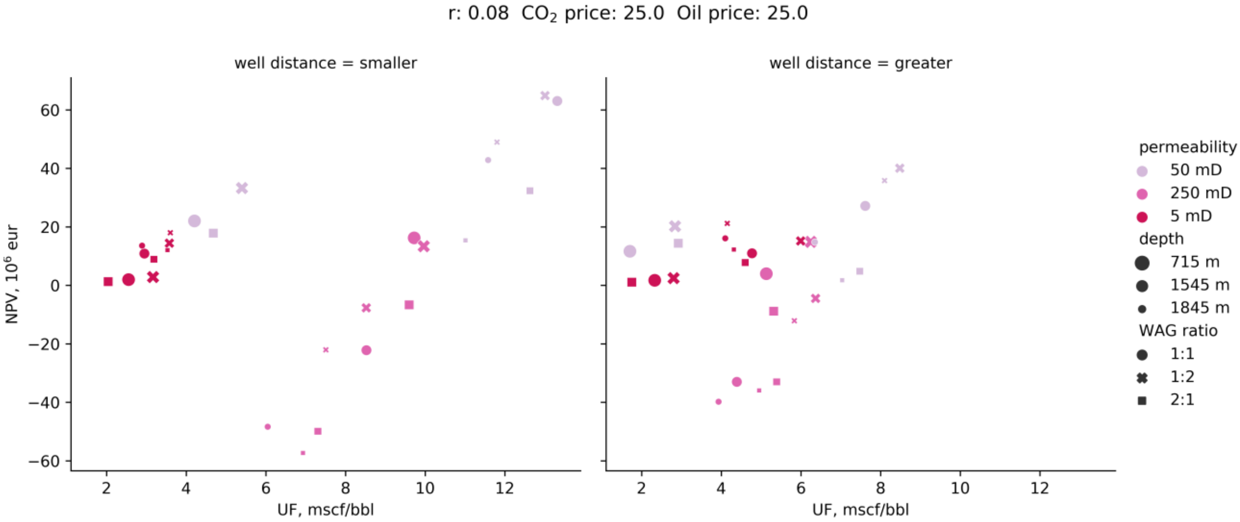
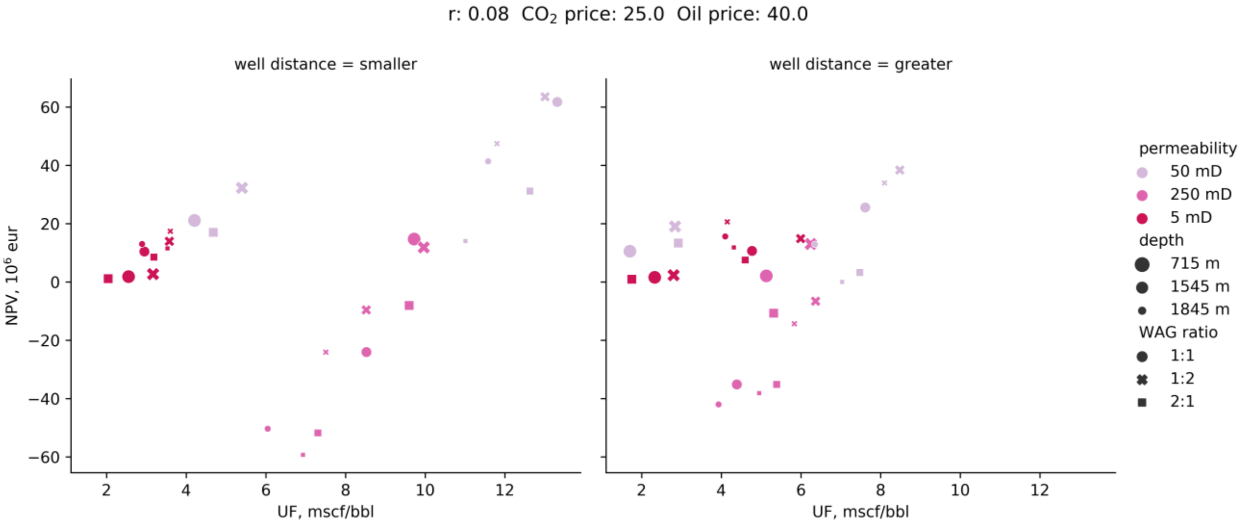
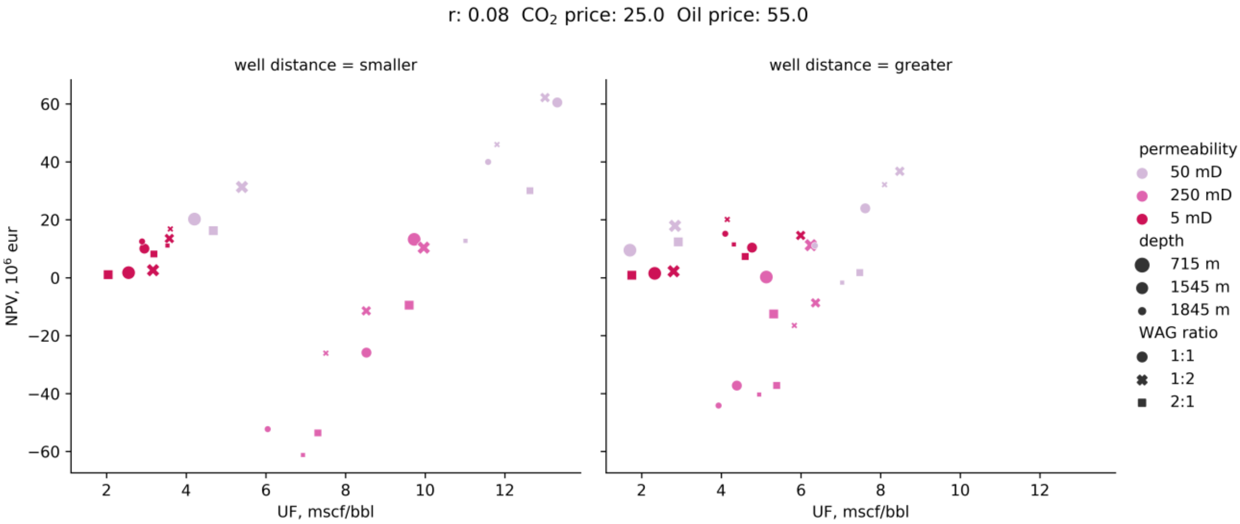
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.08 CO_2 price: 10.0 Oil price: 40.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.08 CO_2 price: 10.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.08 CO2 price: 25.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.08 CO2 price: 25.0 Oil price: 40.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.08 CO2 price: 25.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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5 mD
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1545 m
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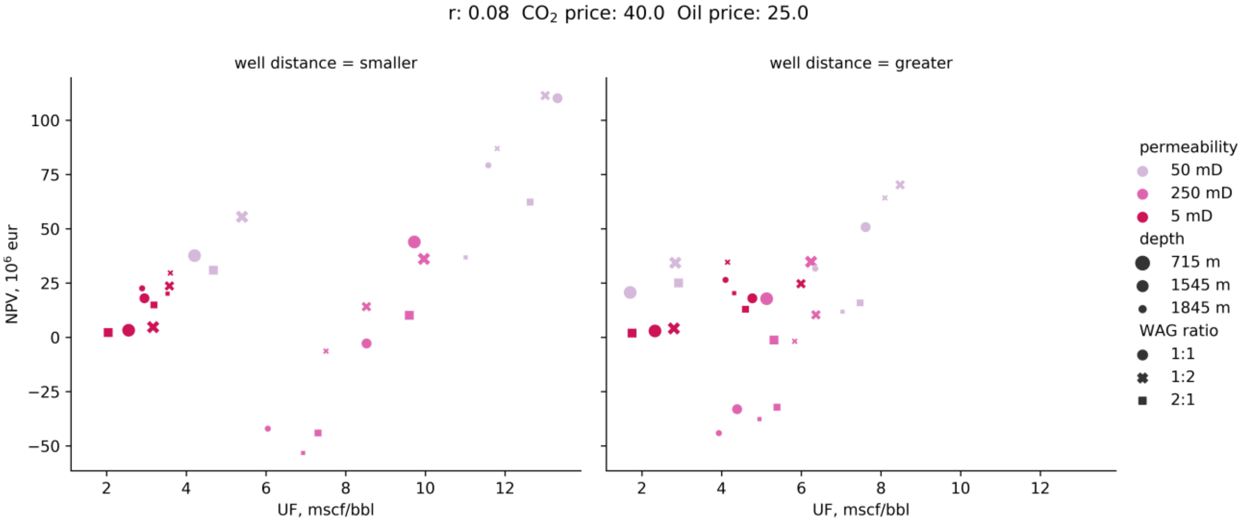
WAG ratio
1:1
1:2
2:1



r: 0.08 CO2 price: 40.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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250 mD
5 mD
depth
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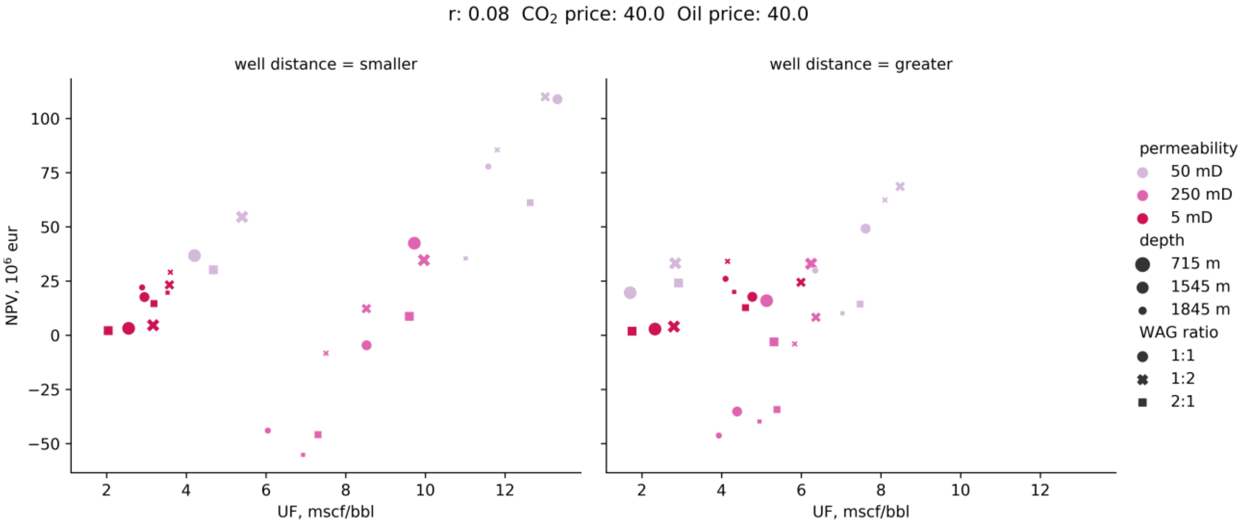
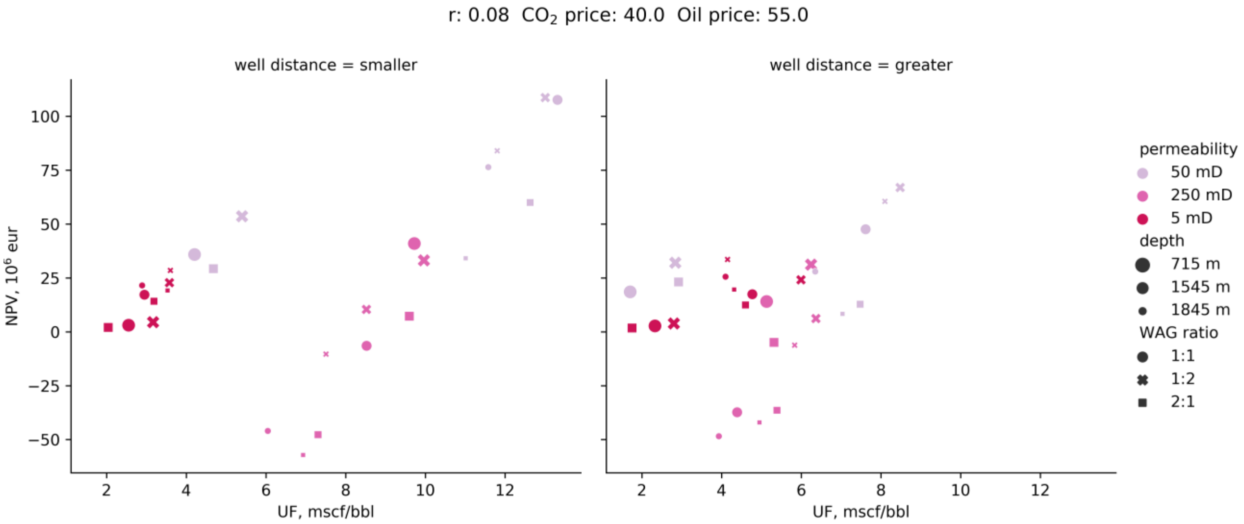
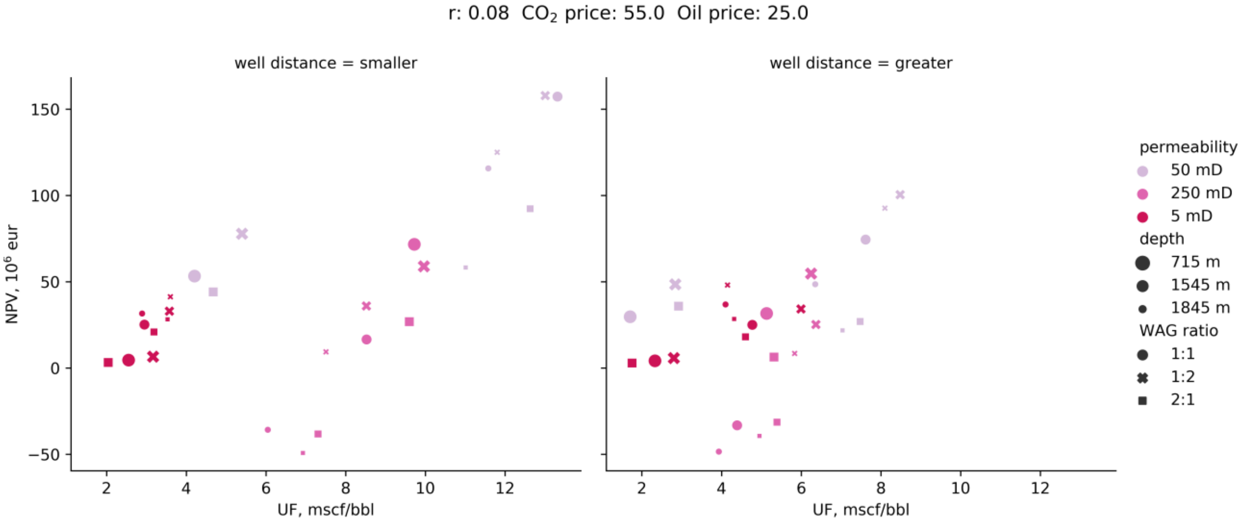
WAG ratio
1:1
1:2
2:1

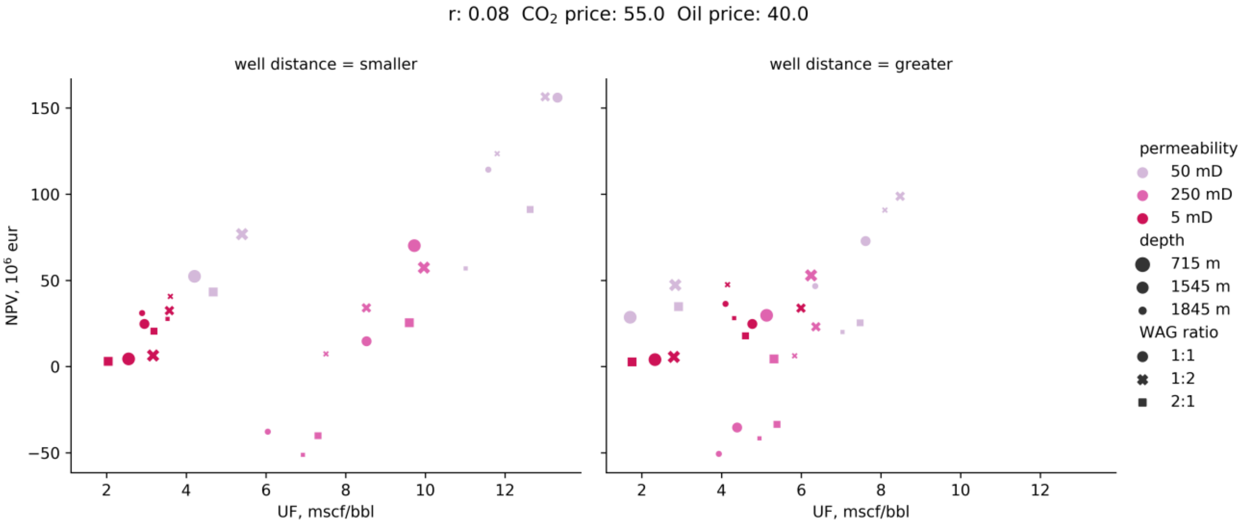


r: 0.08 CO2 price: 40.0 Oil price: 40.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1



r: 0.08 CO2 price: 40.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.08 CO_2 price: 55.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1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well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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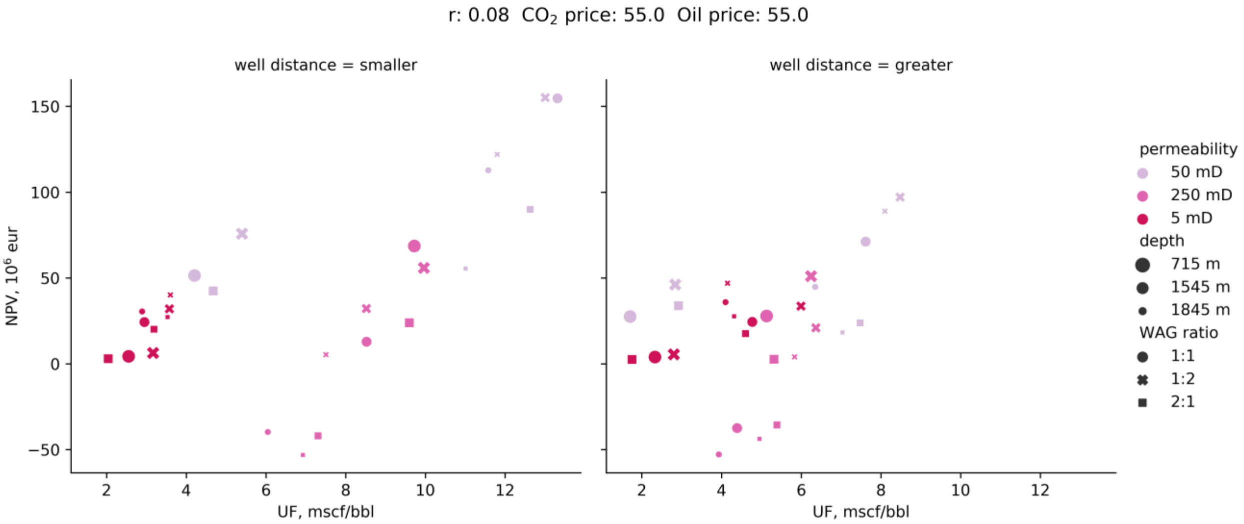
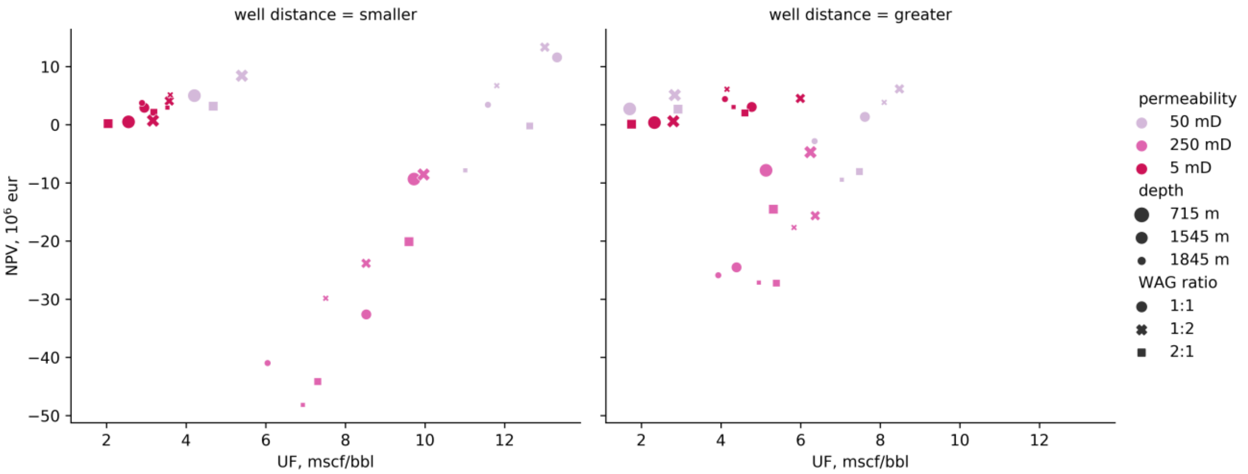
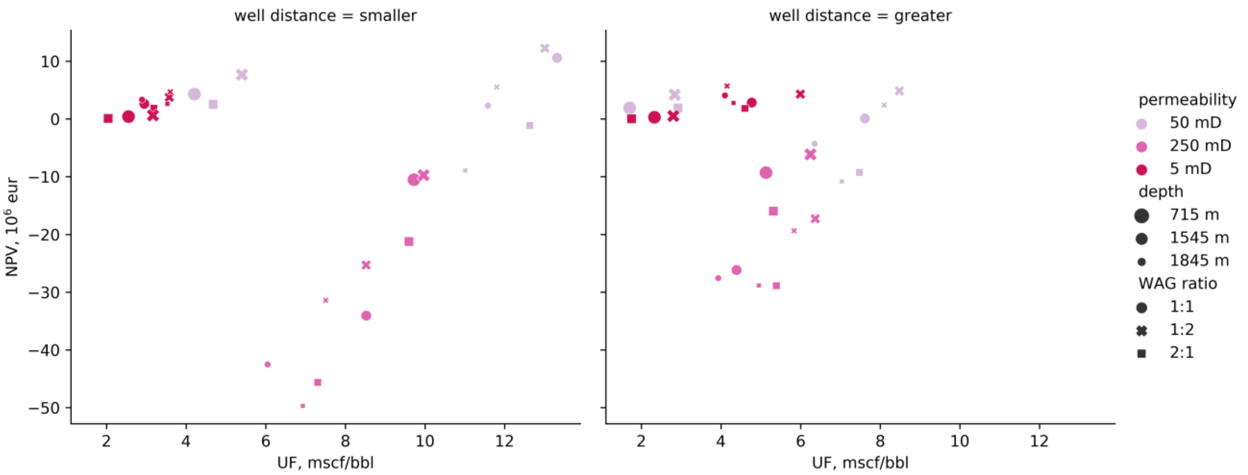
WAG ratio
1:1
1:2
2:1


r: 0.08 CO_2 price: 55.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1

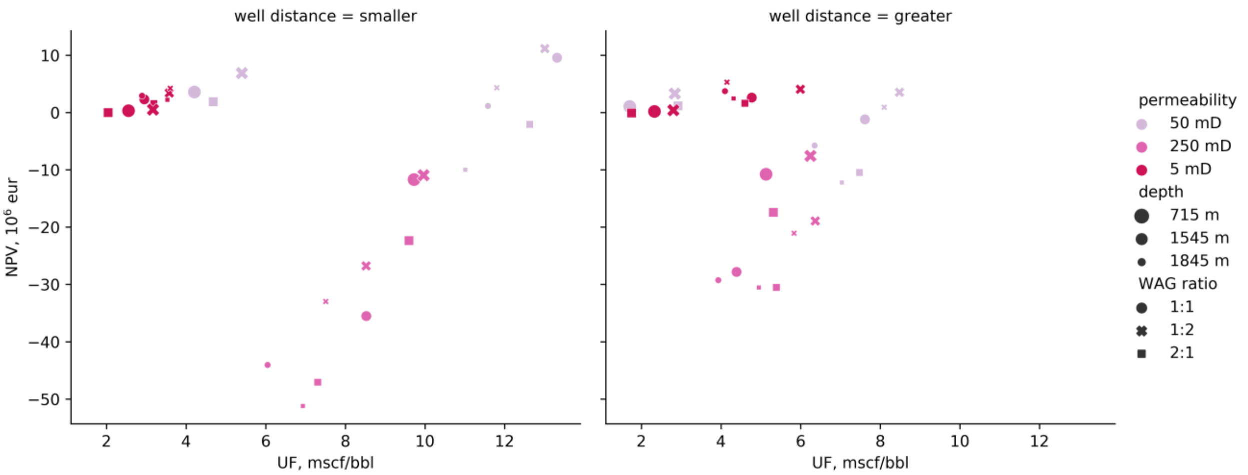
r: 0.12 CO_2 price: 10.0 Oil price: 25.0

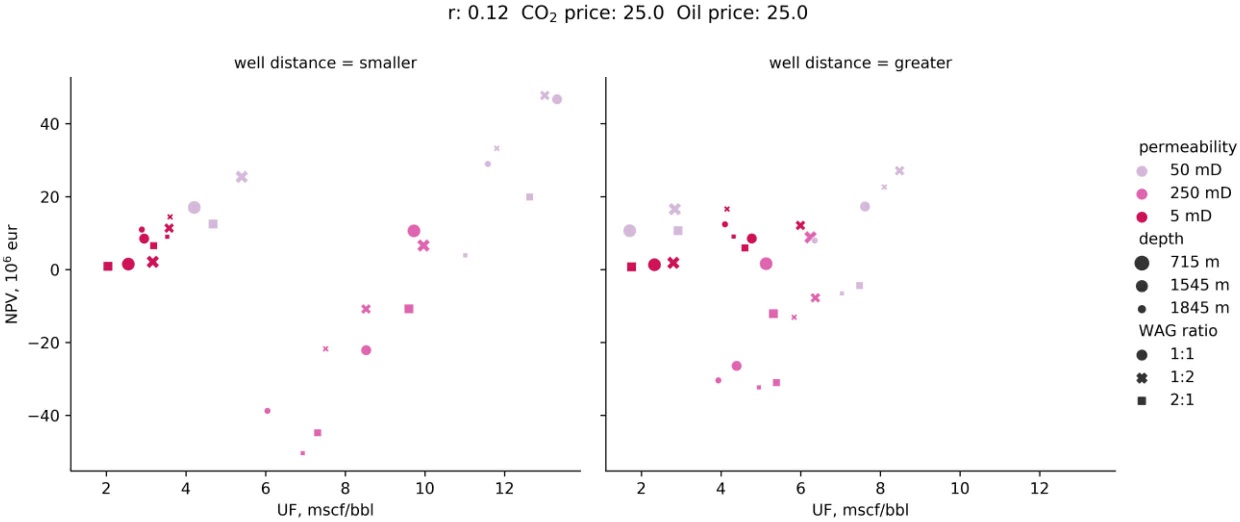


r: 0.12 CO_2 price: 10.0 Oil price: 40.0



r: 0.12 CO_2 price: 10.0 Oil price: 55.0




r: 0.12 CO_2 price: 25.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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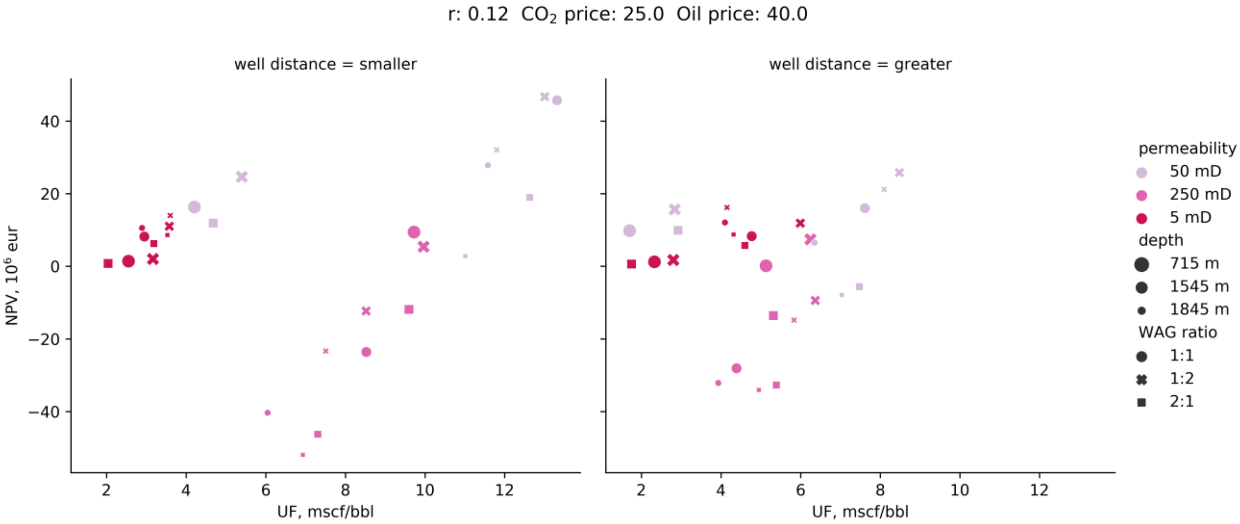
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1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well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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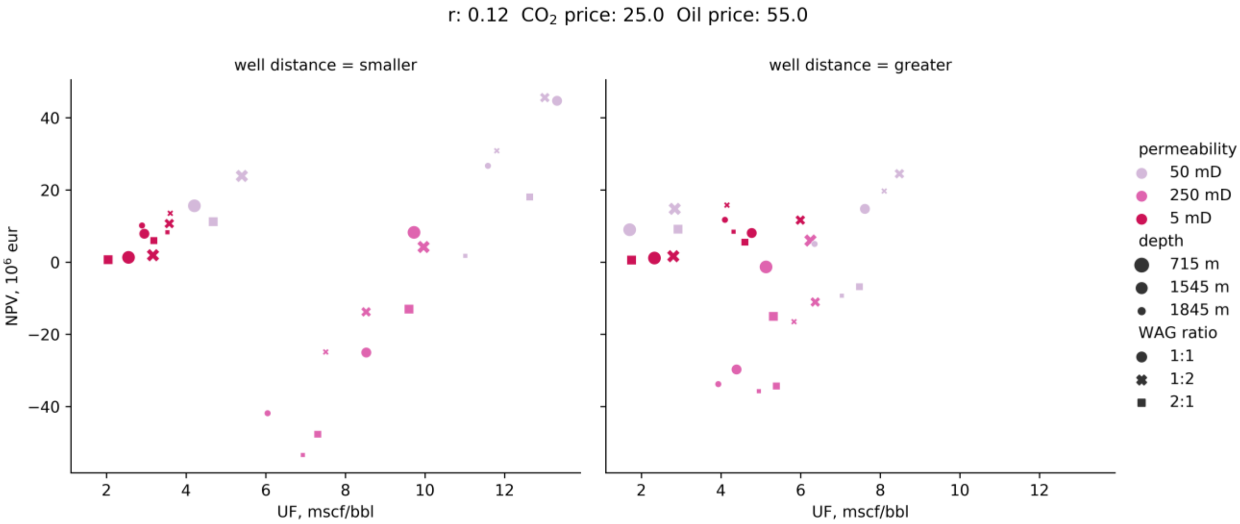
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.12 CO_2 price: 25.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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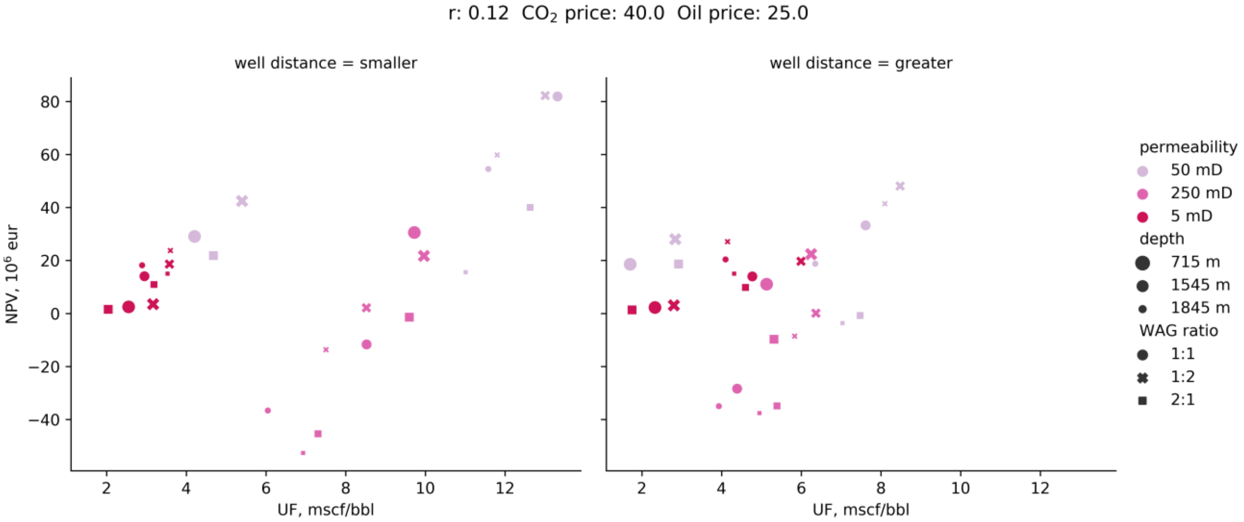
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1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well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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250 mD
5 mD
depth
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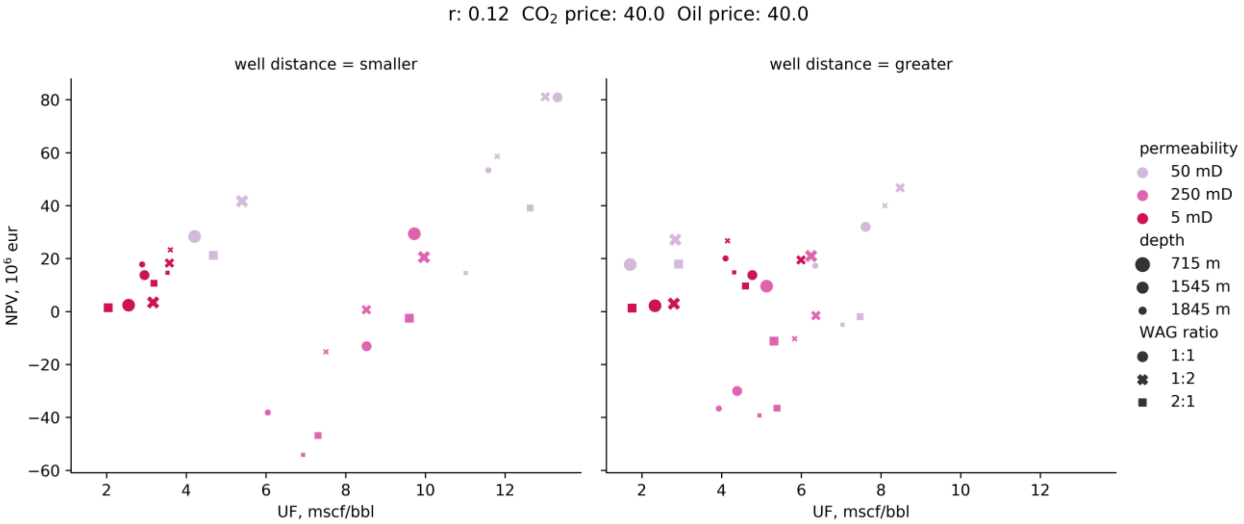
1545 m
1845 m
WAG ratio
1:1
1:2
2:1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well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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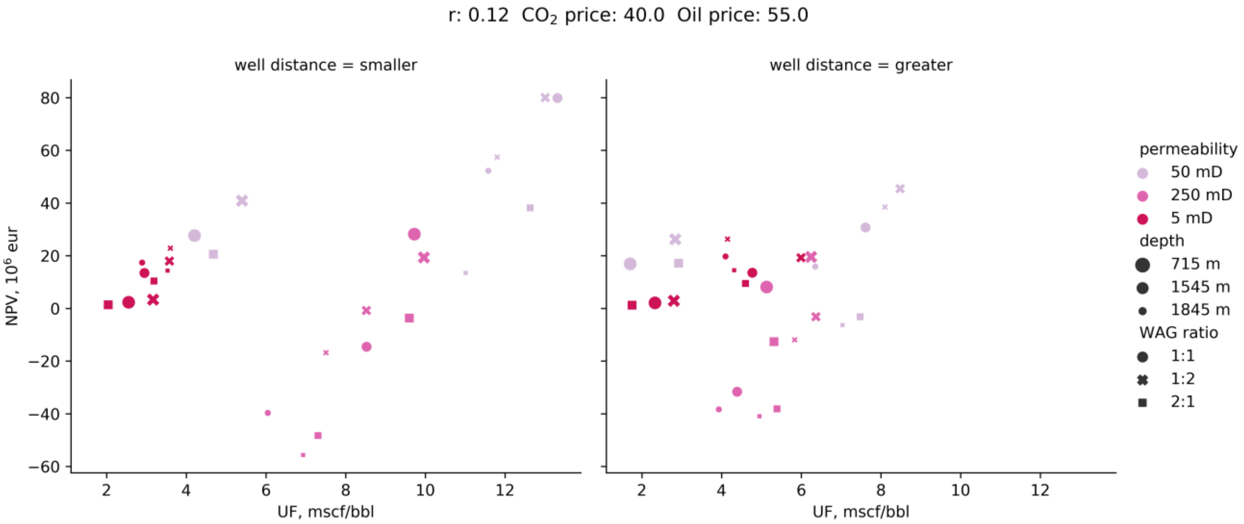
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.12 CO_2 price: 40.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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250 mD
5 mD
depth
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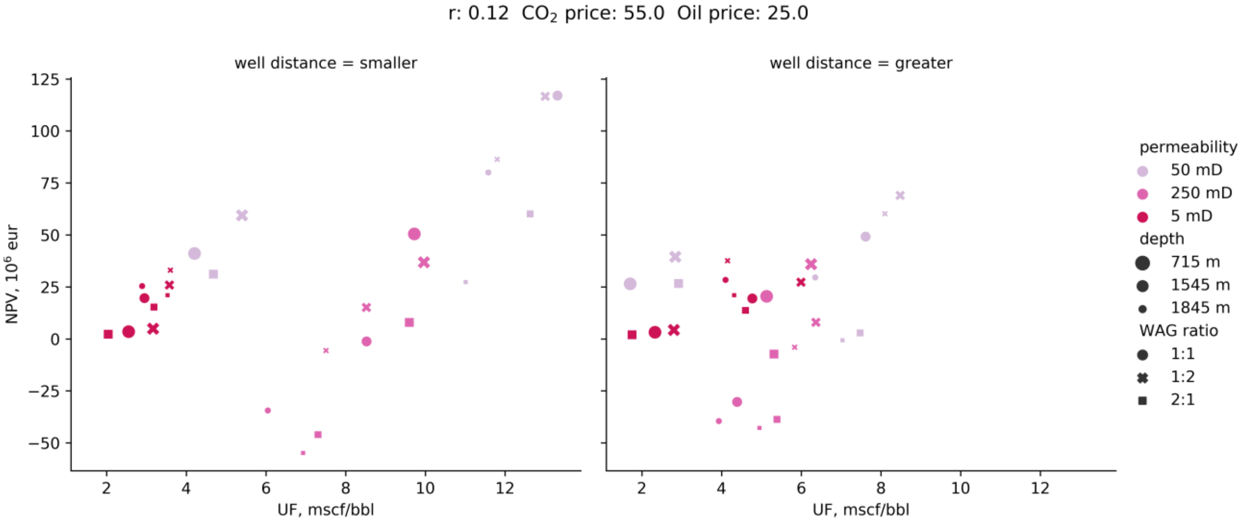
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.12 CO_2 price: 55.0 Oil price: 25.0
well distance = smaller
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NPV, 10^6 eur
UF, mscf/bbl
permeability
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5 mD
depth
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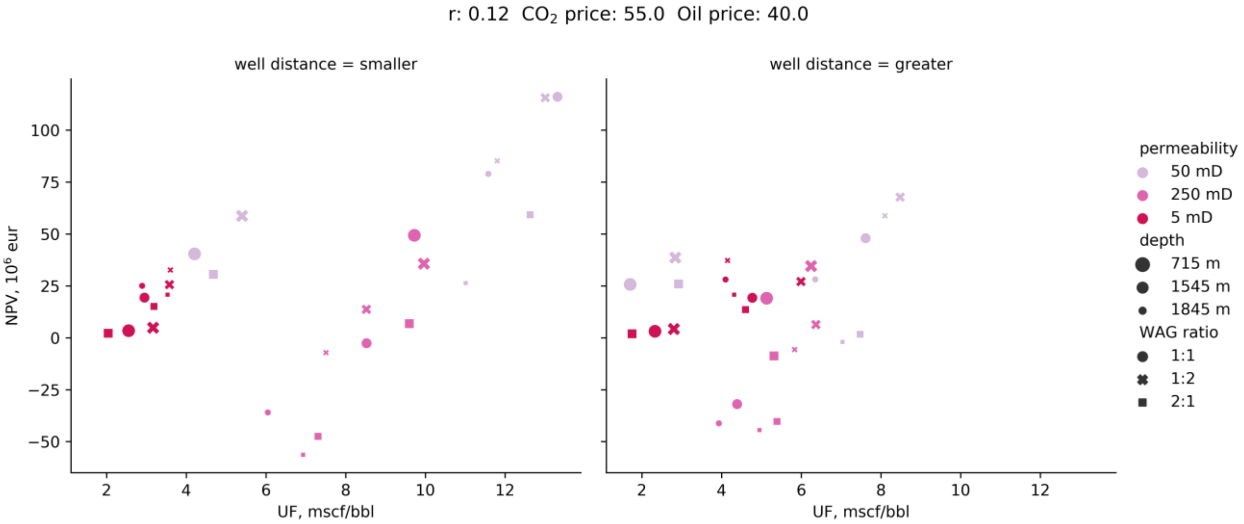
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.12 CO_2 price: 55.0 Oil price: 40.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
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250 mD
5 mD
depth
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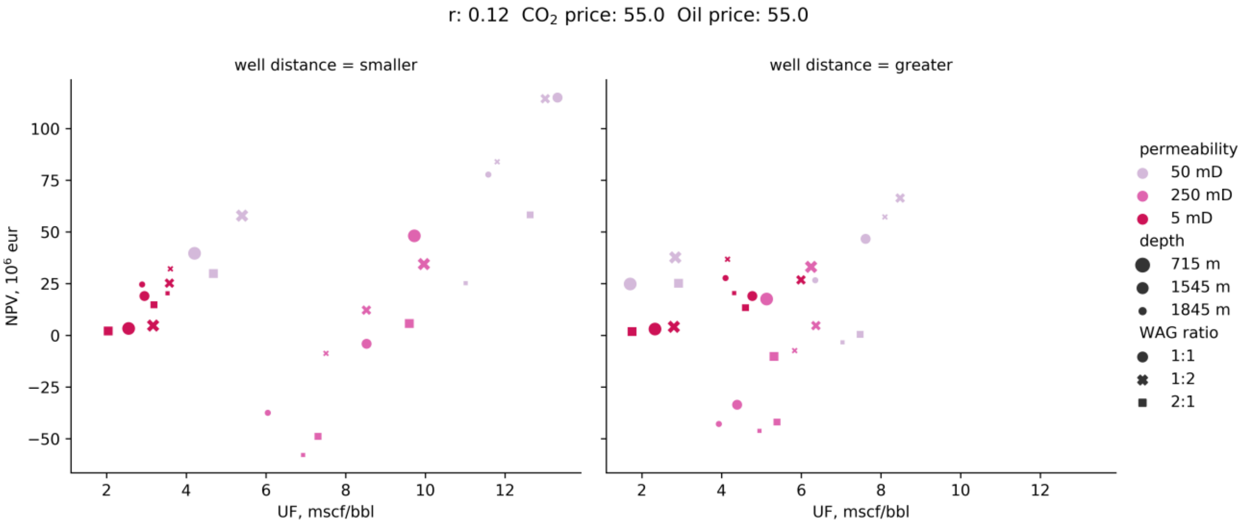
1545 m
1845 m
WAG ratio
1:1
1:2
2:1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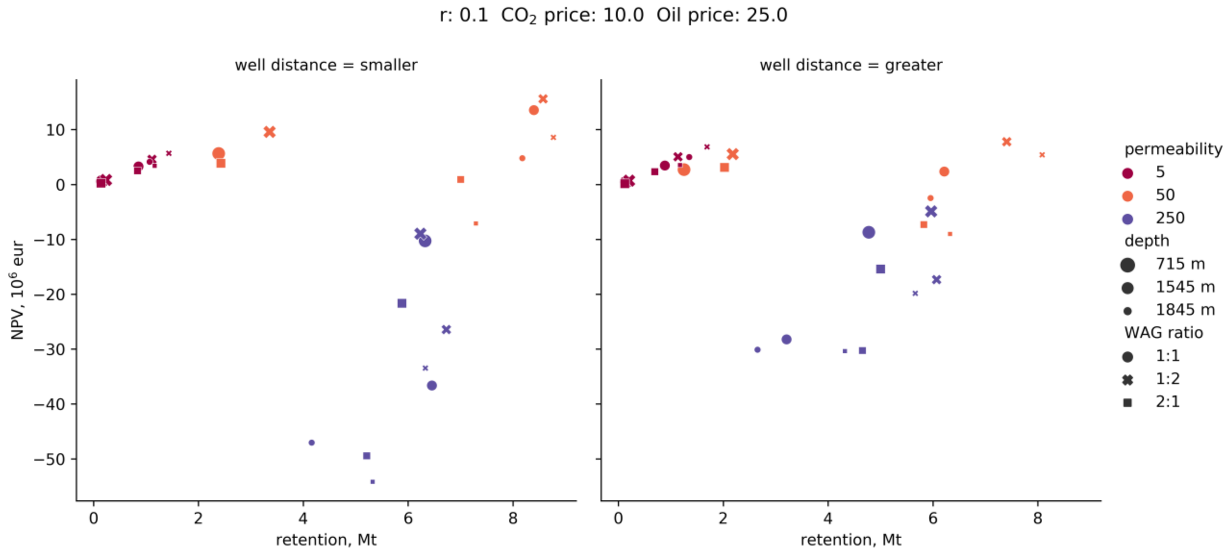
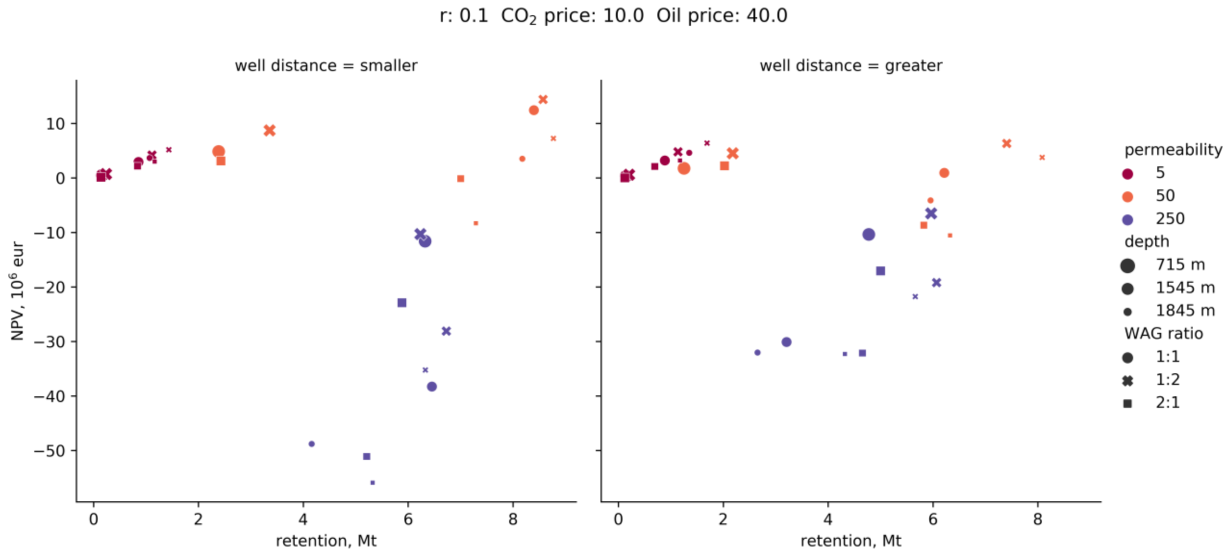
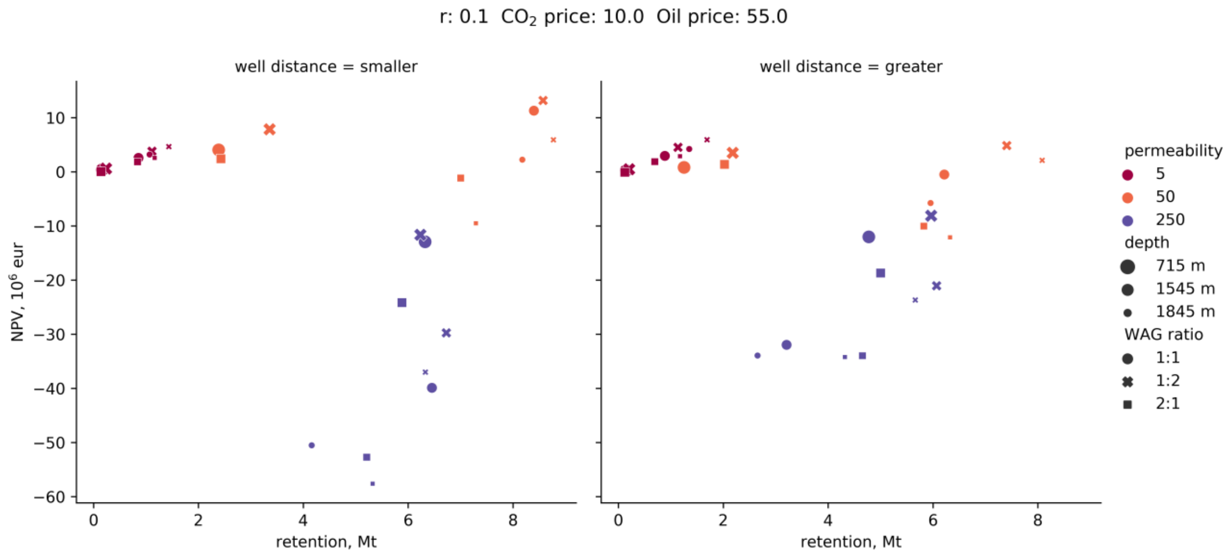
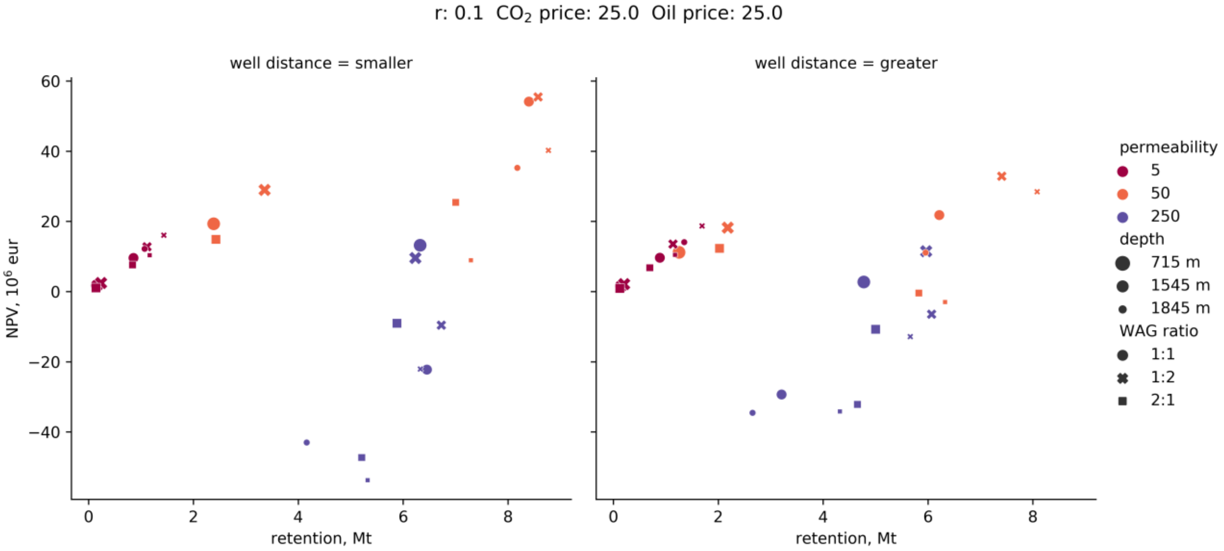
well distance = smaller
well distance = greater
NPV, 10^6 eur
UF, mscf/bbl
permeability
50 mD
250 mD
5 mD
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1

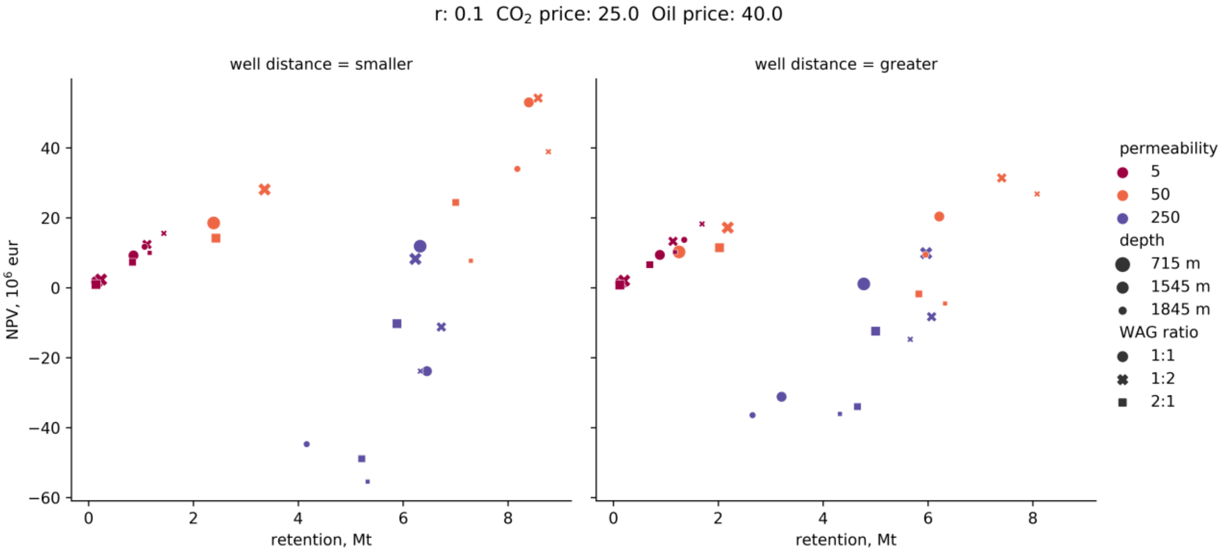
7.3 Appendix C: Diagrams for different scenarios of prices and discount rates - NPV vs retention

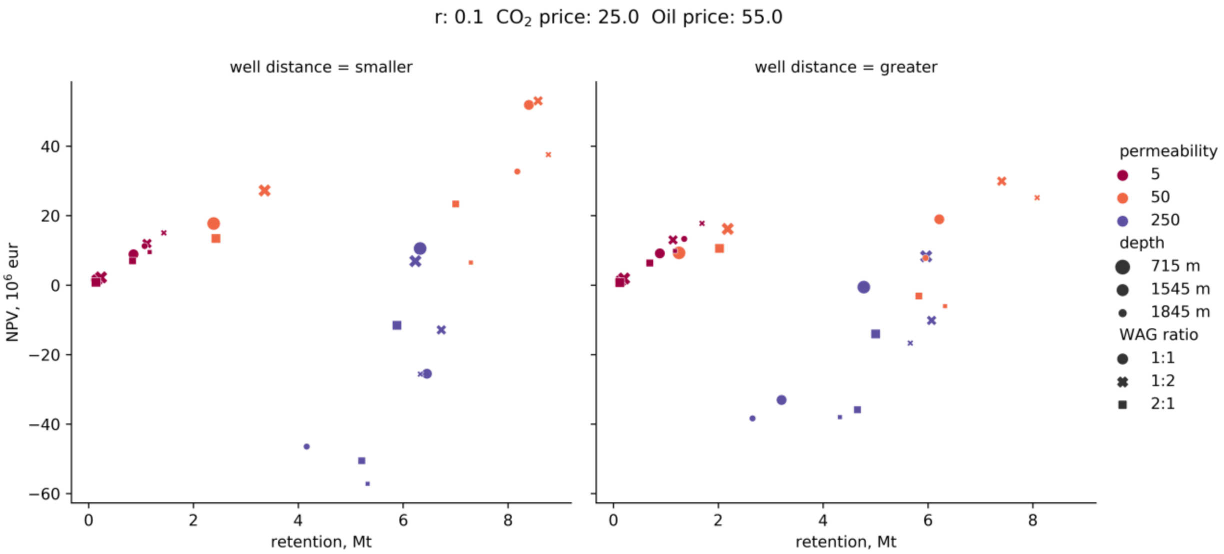


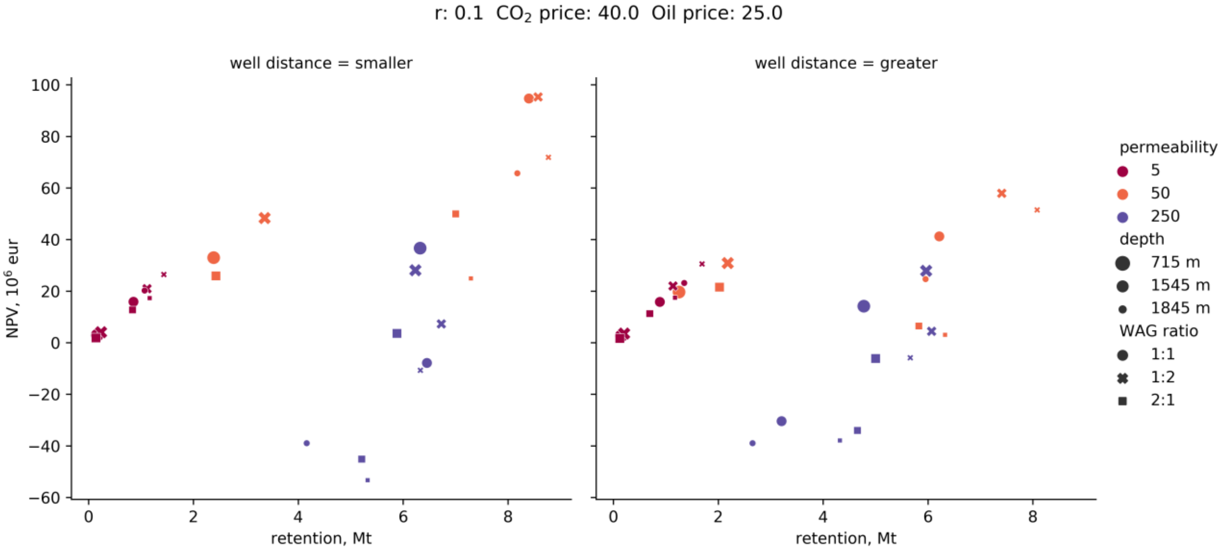





r: 0.1 CO_2 price: 25.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
retention, Mt
permeability
5
50
250
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.1 CO_2 price: 25.0 Oil price: 40.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
retention, Mt
permeability
5
50
250
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.1 CO_2 price: 25.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
retention, Mt
permeability
5
50
250
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1



r: 0.1 CO_2 price: 40.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
retention, Mt
permeability
5
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depth
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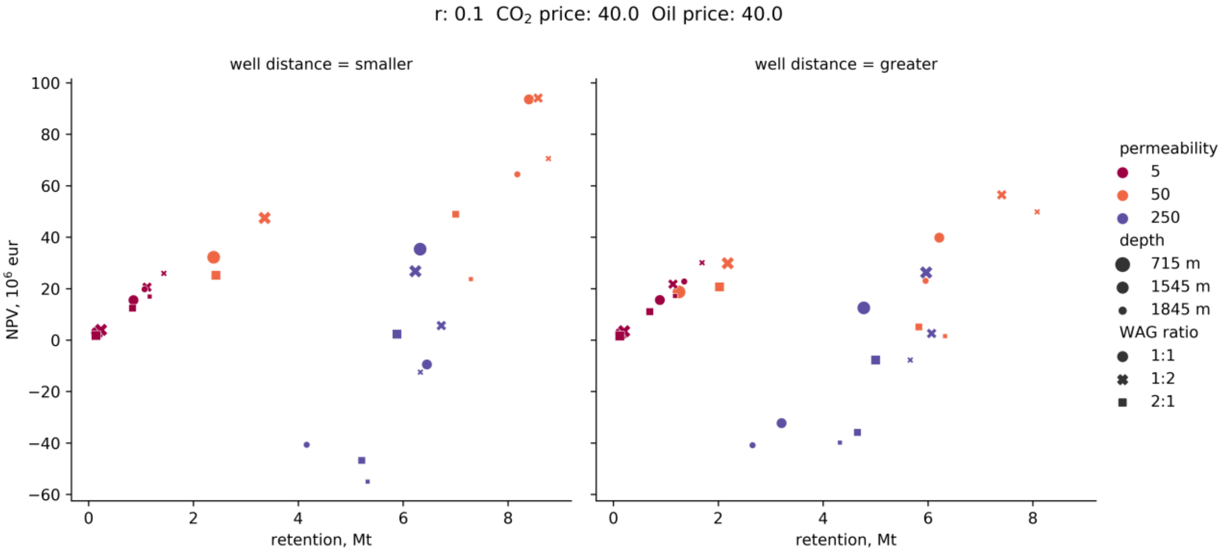
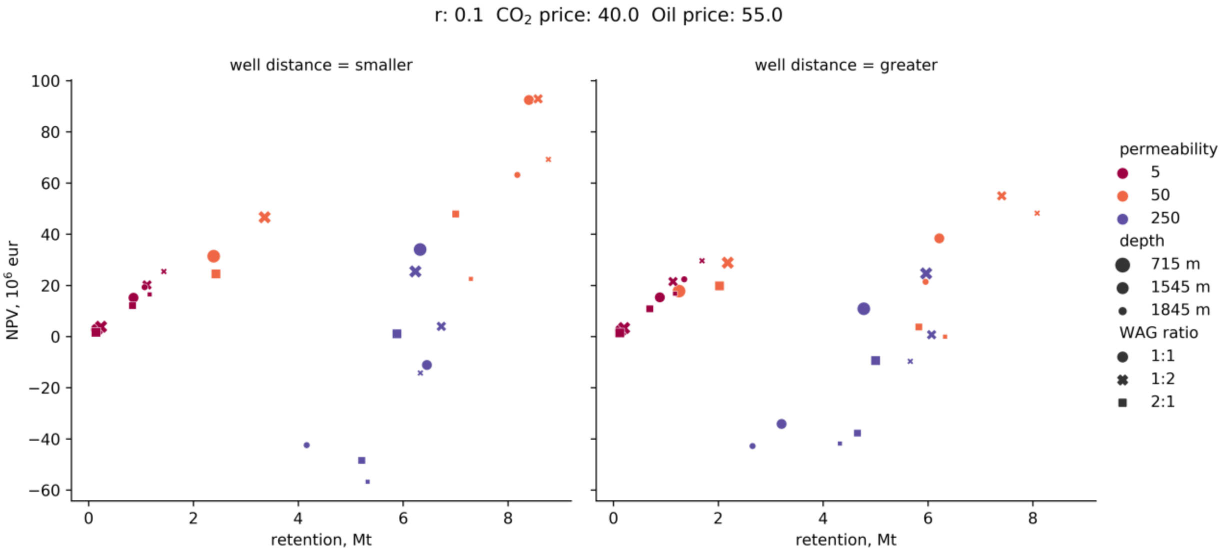
1845 m
WAG ratio
1:1
1:2
2:1



r: 0.1 CO_2 price: 40.0 Oil price: 40.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
retention, Mt
permeability
5
50
250
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1



r: 0.1 CO_2 price: 40.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
retention, Mt
permeability
5
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depth
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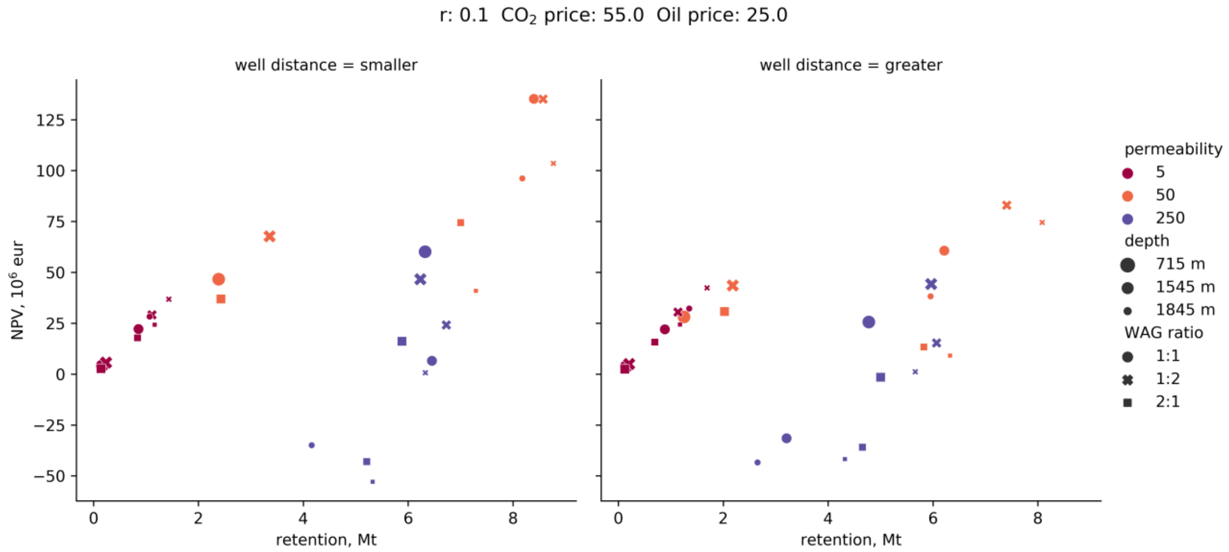
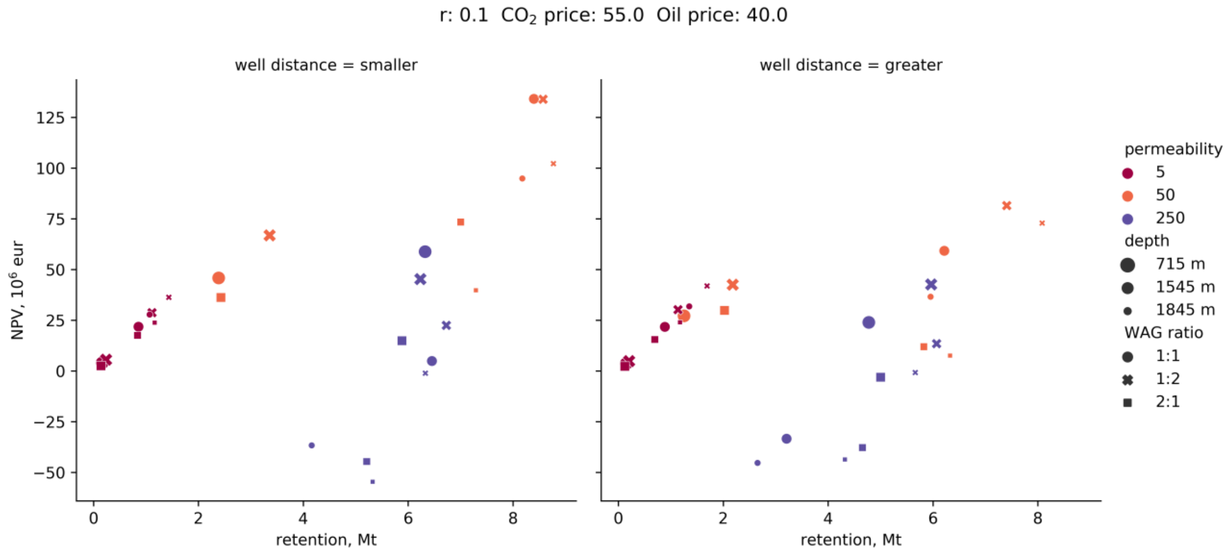
WAG ratio
1:1
1:2
2:1


r: 0.1 CO_2 price: 55.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
retention, Mt
permeability
5
50
250
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.1 CO_2 price: 55.0 Oil price: 40.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
retention, Mt
permeability
5
50
250
depth
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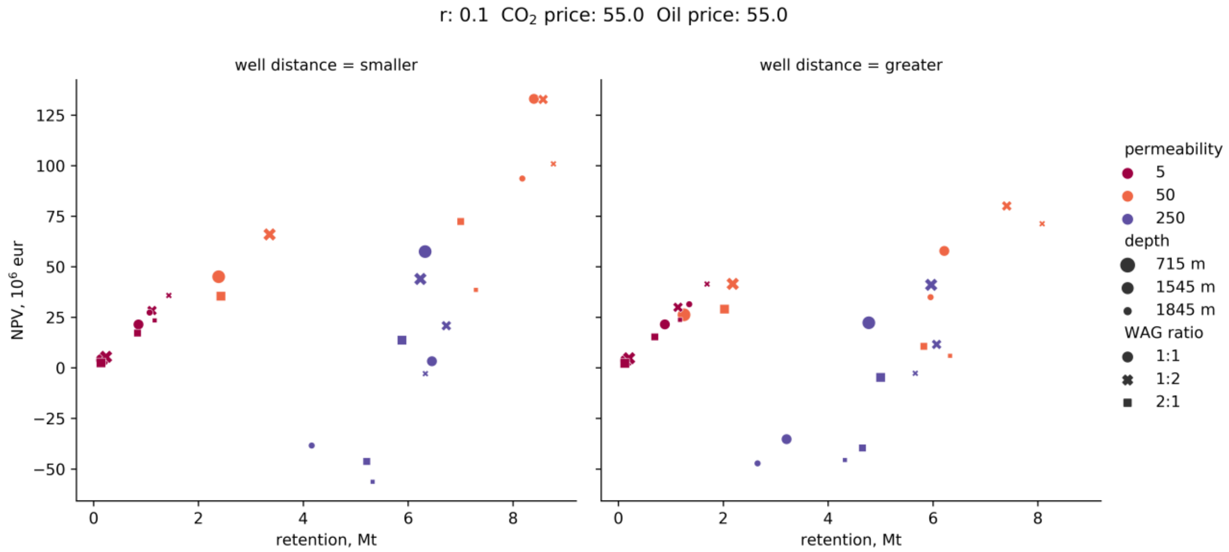
1545 m
1845 m
WAG ratio
1:1
1:2
2:1


r: 0.1 CO_2 price: 55.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
retention, Mt
permeability
5
50
250
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715 m
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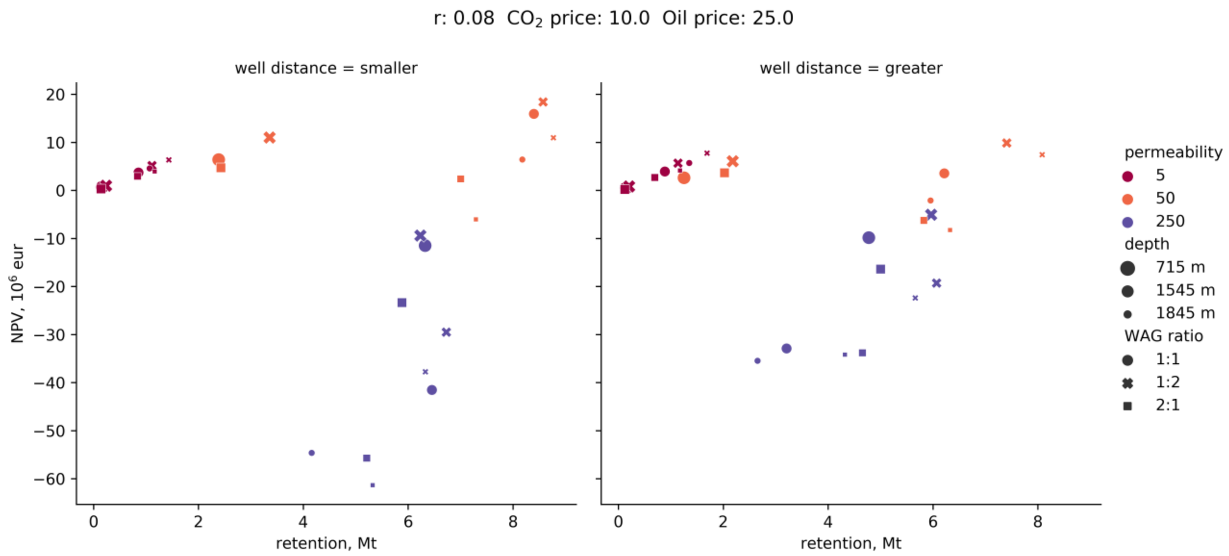
1845 m
WAG ratio
1:1
1:2
2:1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well distance = smaller
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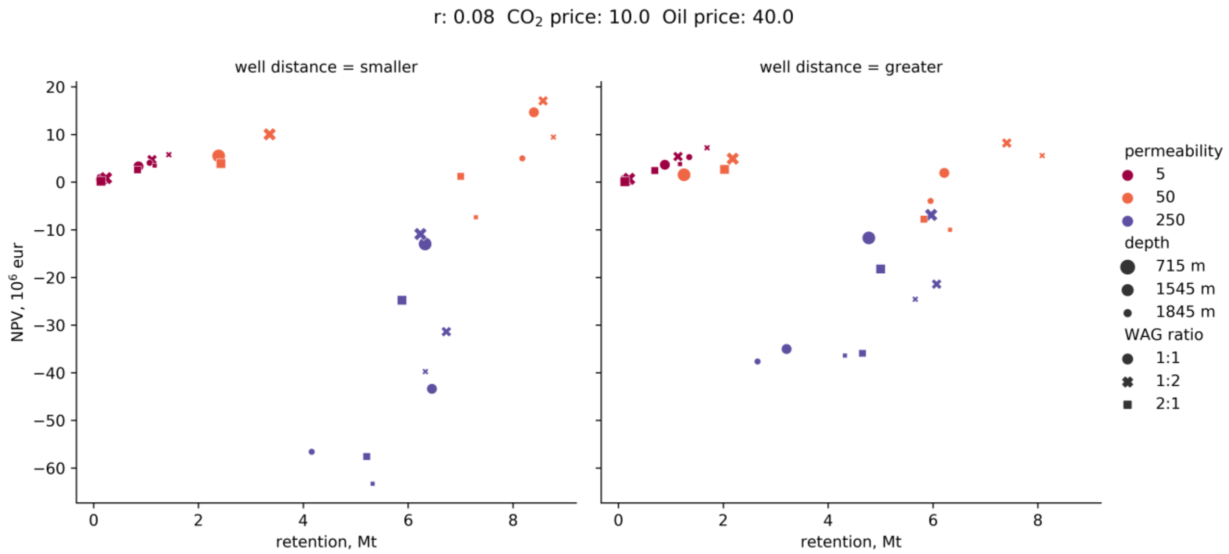
NPV, 10^6 eur
retention, Mt
permeability
5
50
250
depth
715 m
1545 m
1845 m
WAG ratio
1:1
1:2
2:1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retention, Mt
permeability
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depth
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WAG ratio
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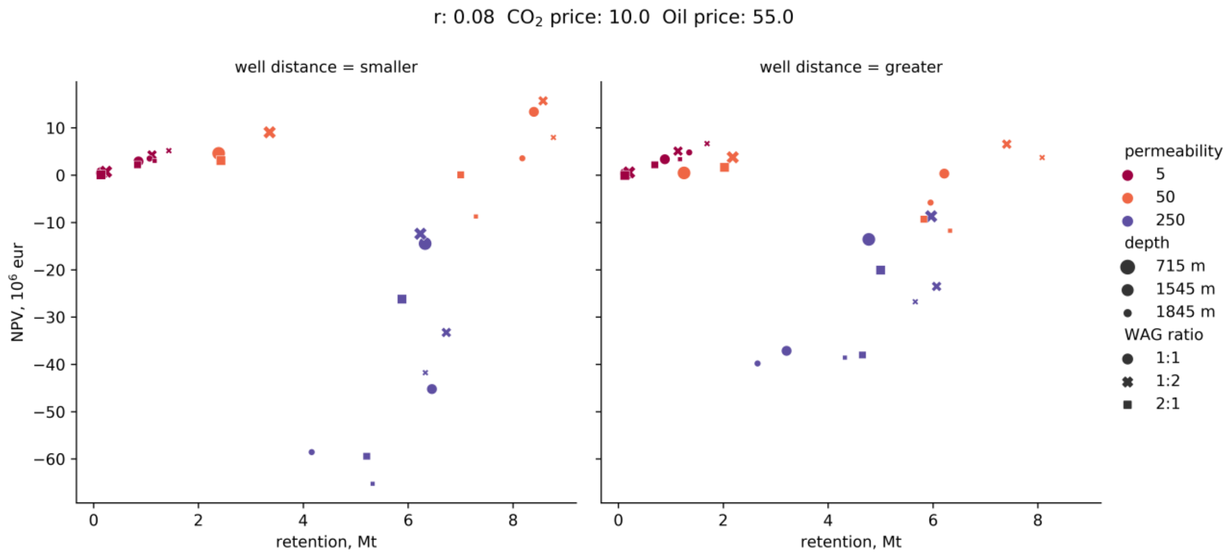
1:2
2:1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NPV, 10^6 eur
retention, Mt
permeability
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depth
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1545 m
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WAG ratio
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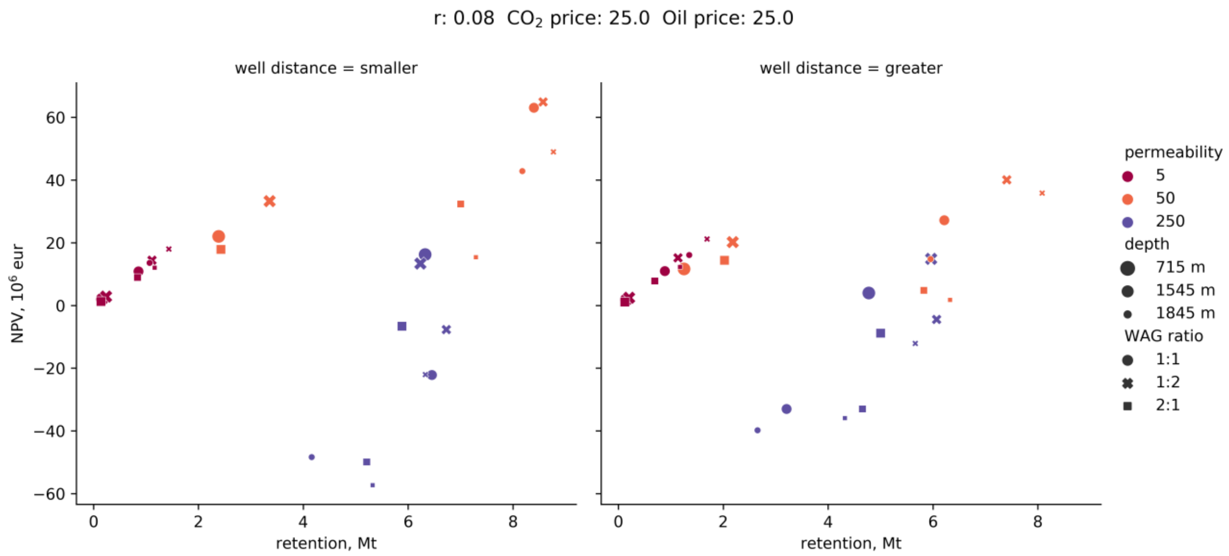
2:1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retention, Mt
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depth
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1545 m
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WAG ratio
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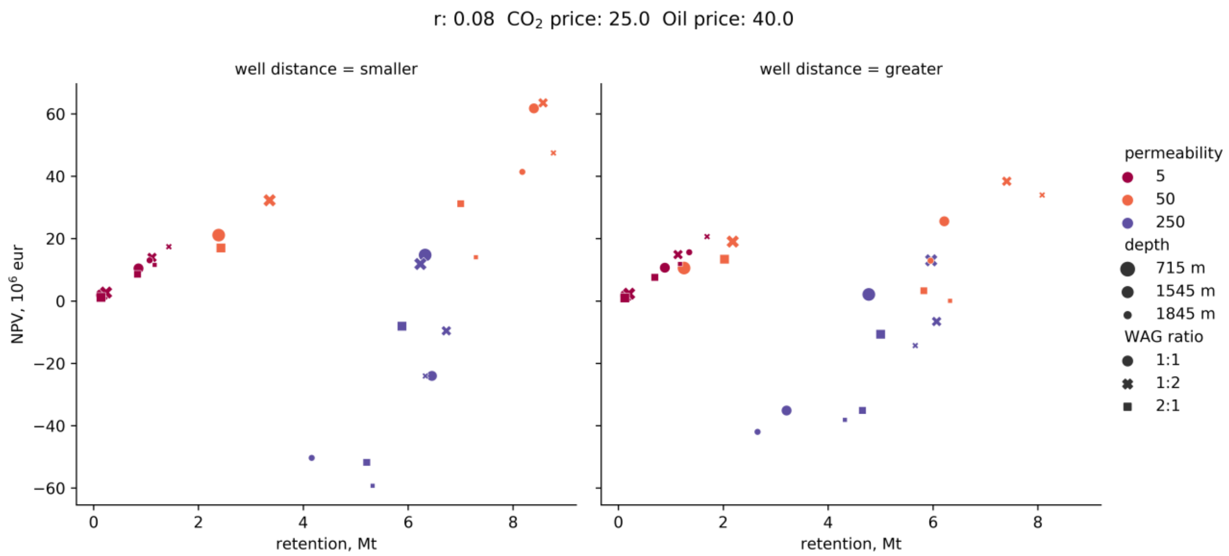
2:1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depth
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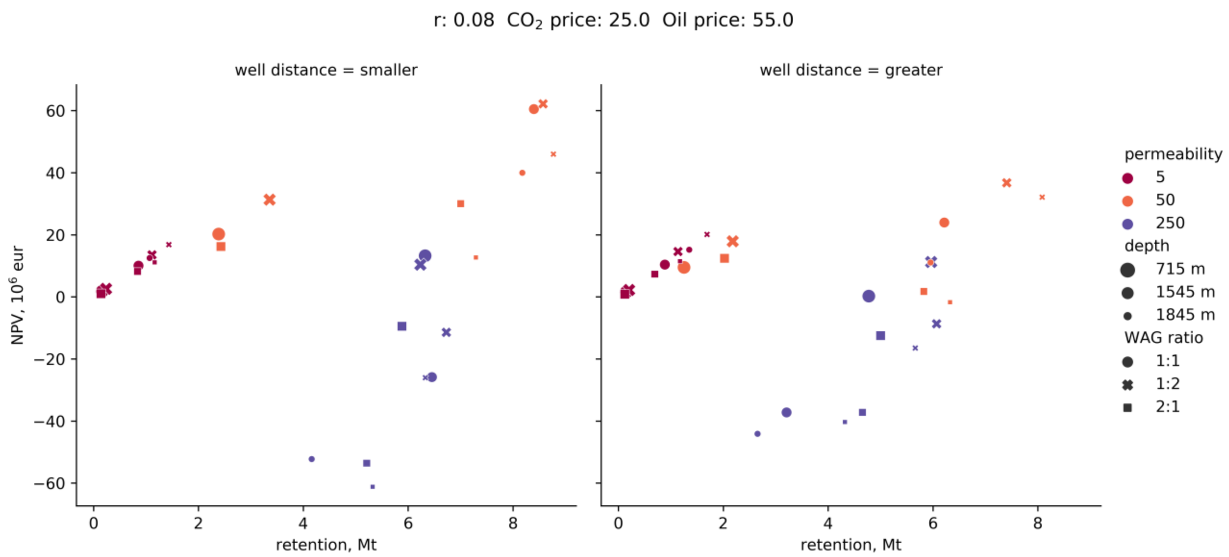
1545 m
1845 m
WAG ratio
1:1
1:2
2:1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retention, Mt
permeability
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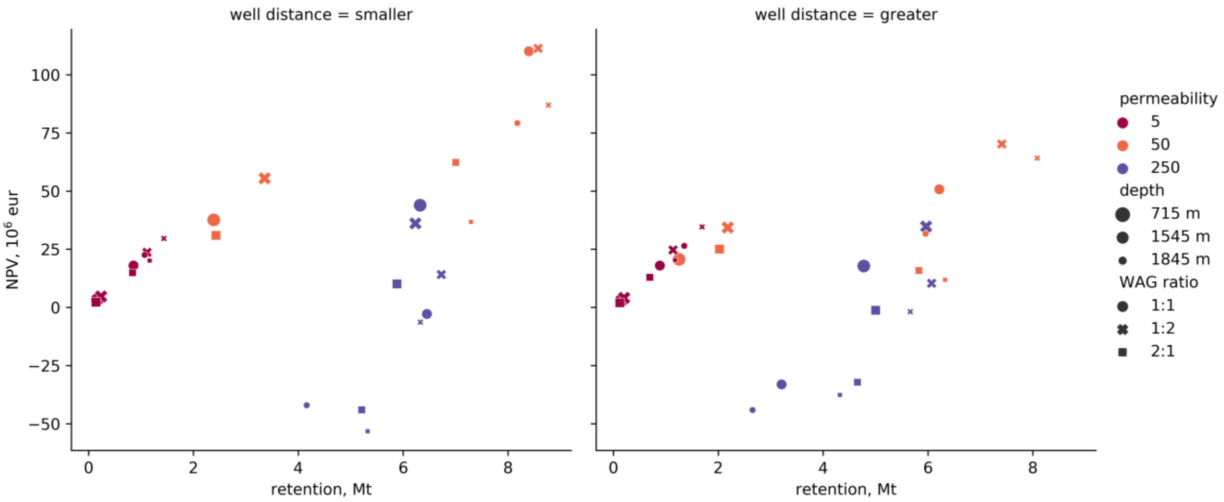
WAG ratio
1:1
1:2
2:1

r: 0.08 CO_2 price: 40.0 Oil price: 25.0



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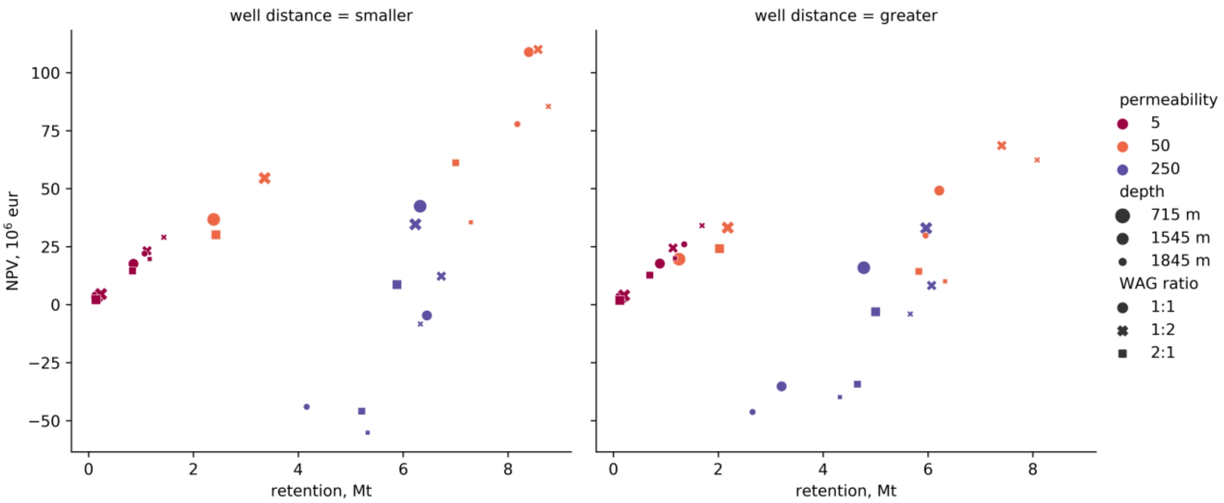

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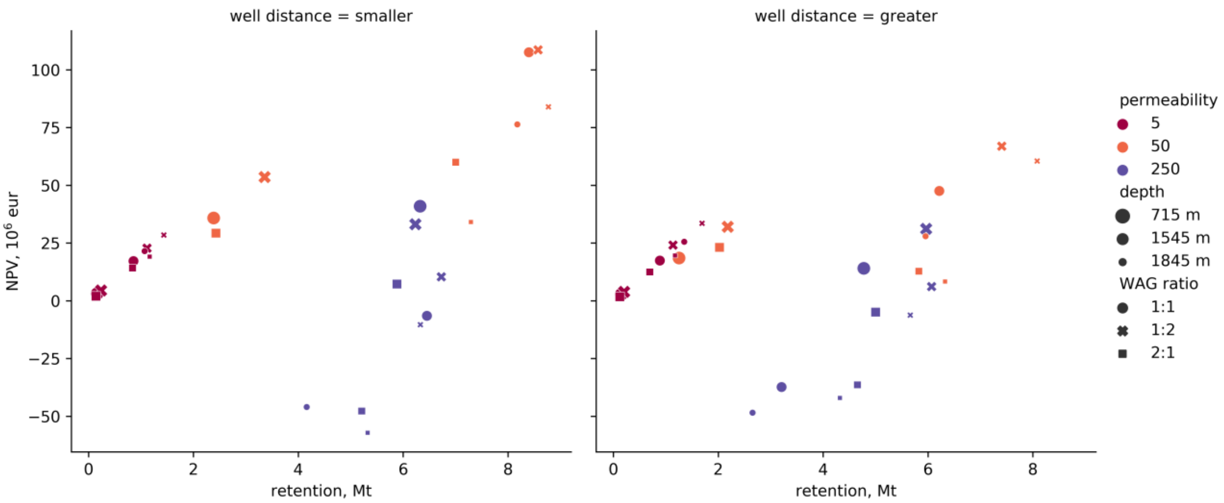

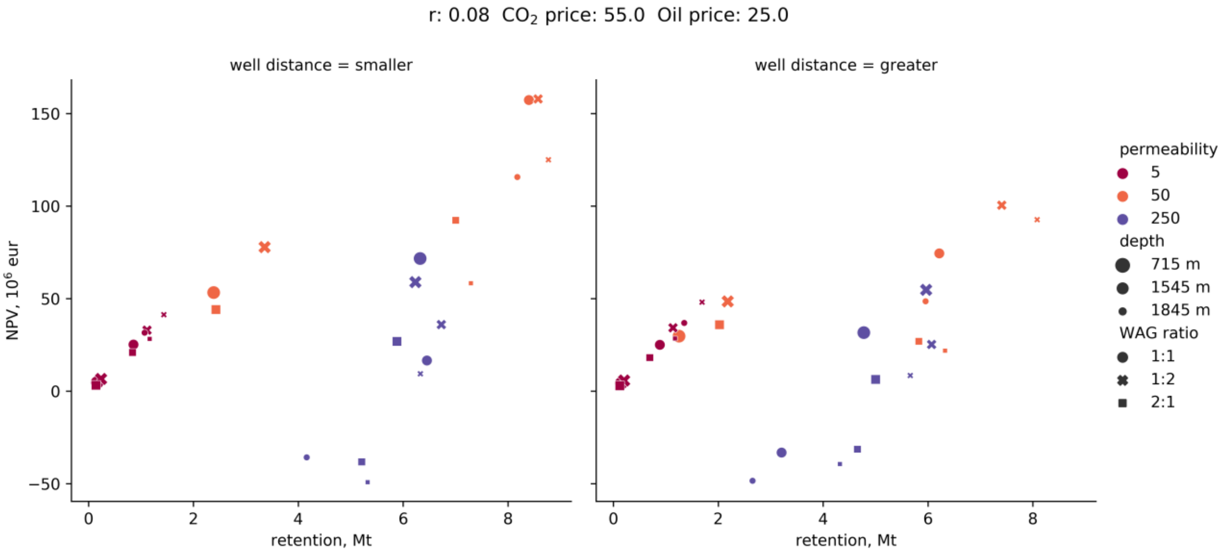
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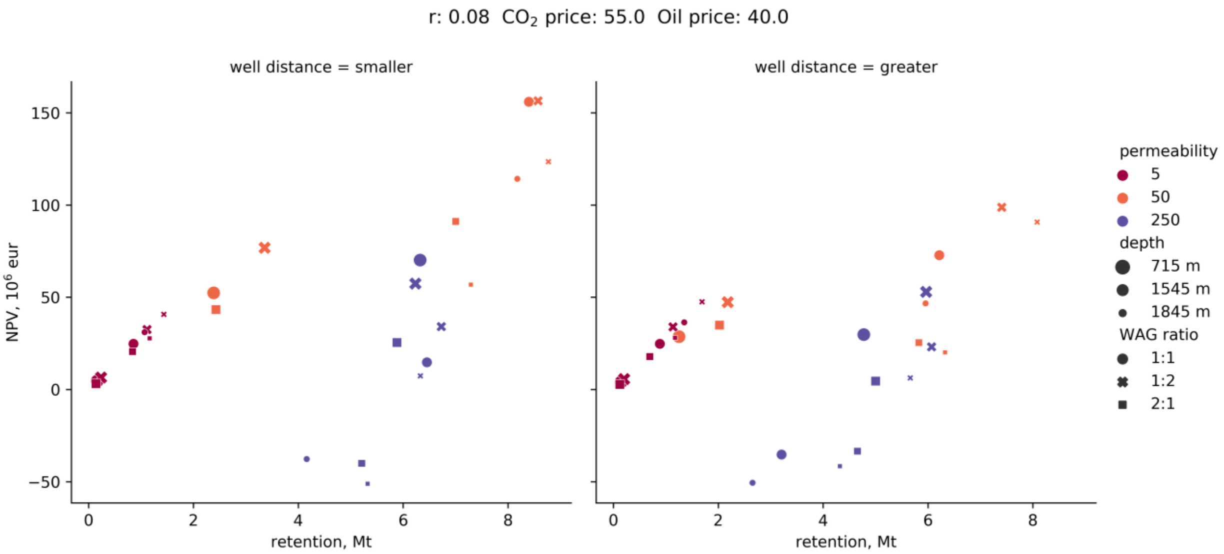
1:2
2:1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depth
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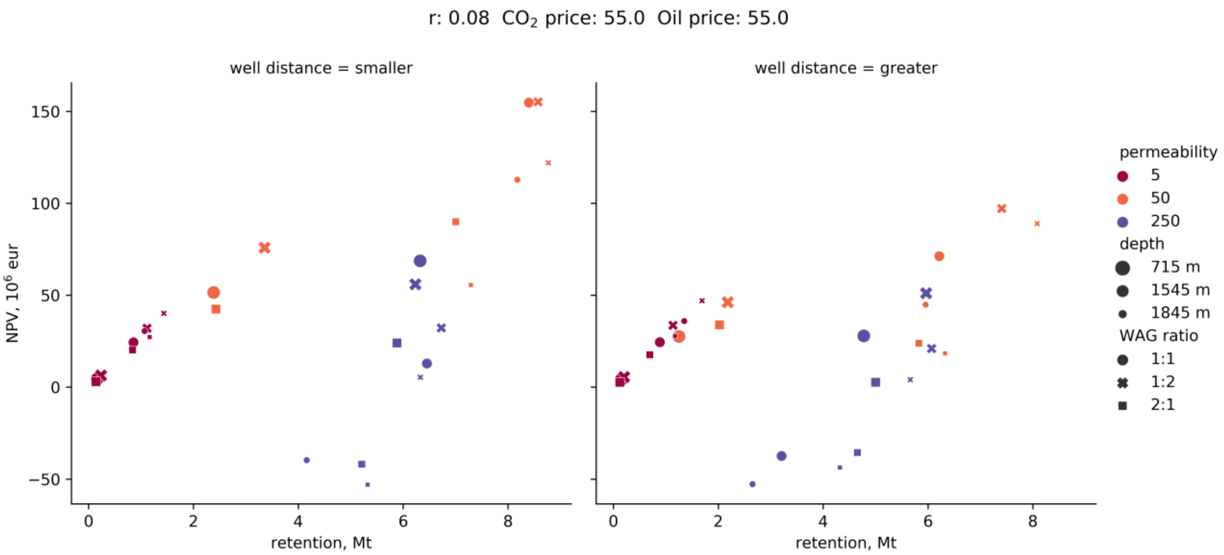
1845 m
WAG ratio
1:1
1:2
2:1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retention, Mt
permeability
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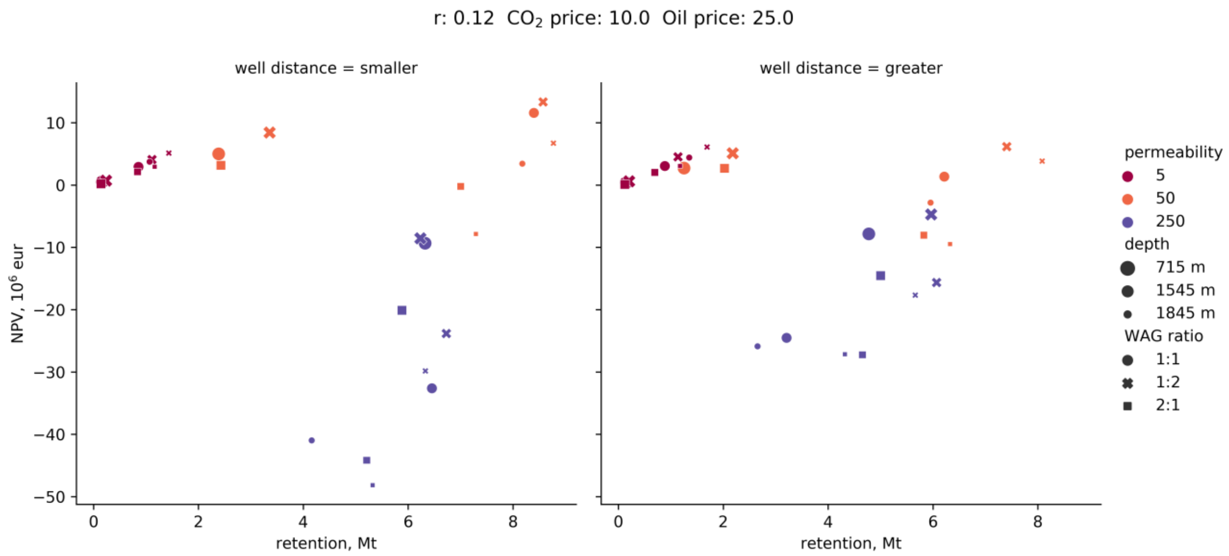
1:2
2:1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1:2
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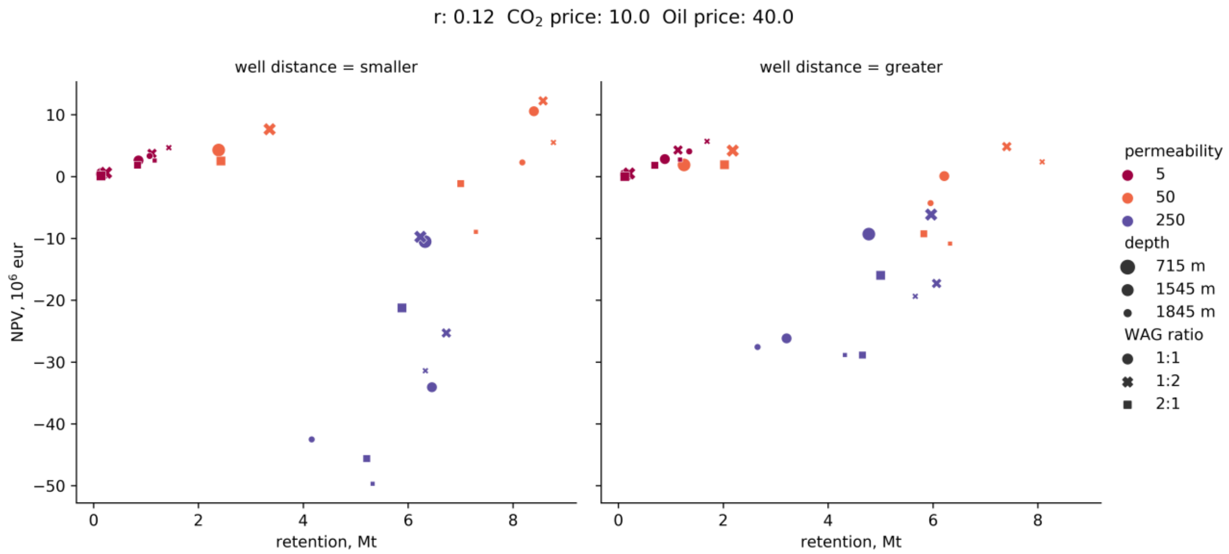
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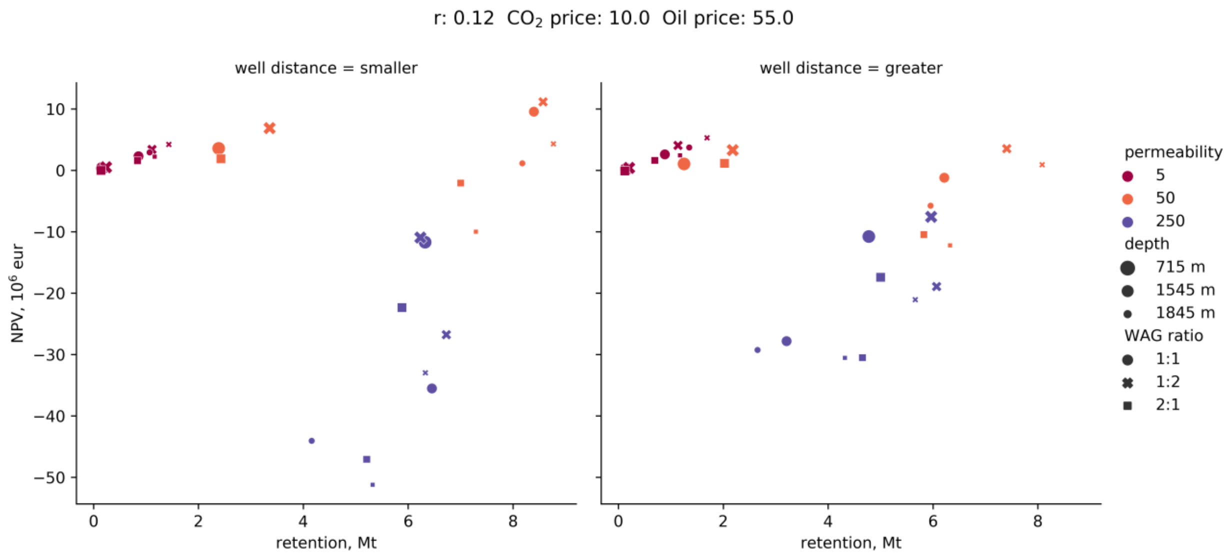
2:1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WAG ratio
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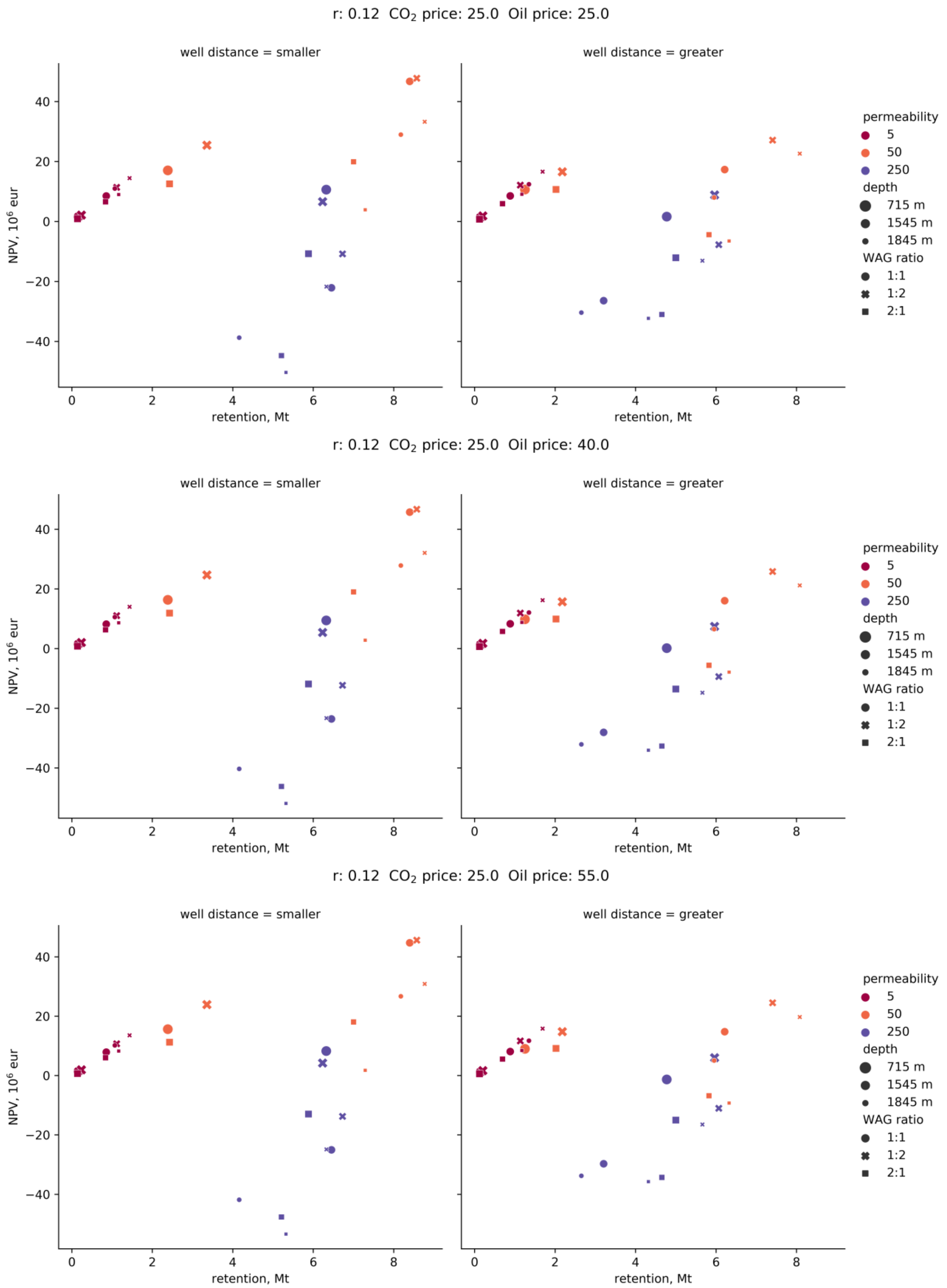
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permeability
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depth
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2:1
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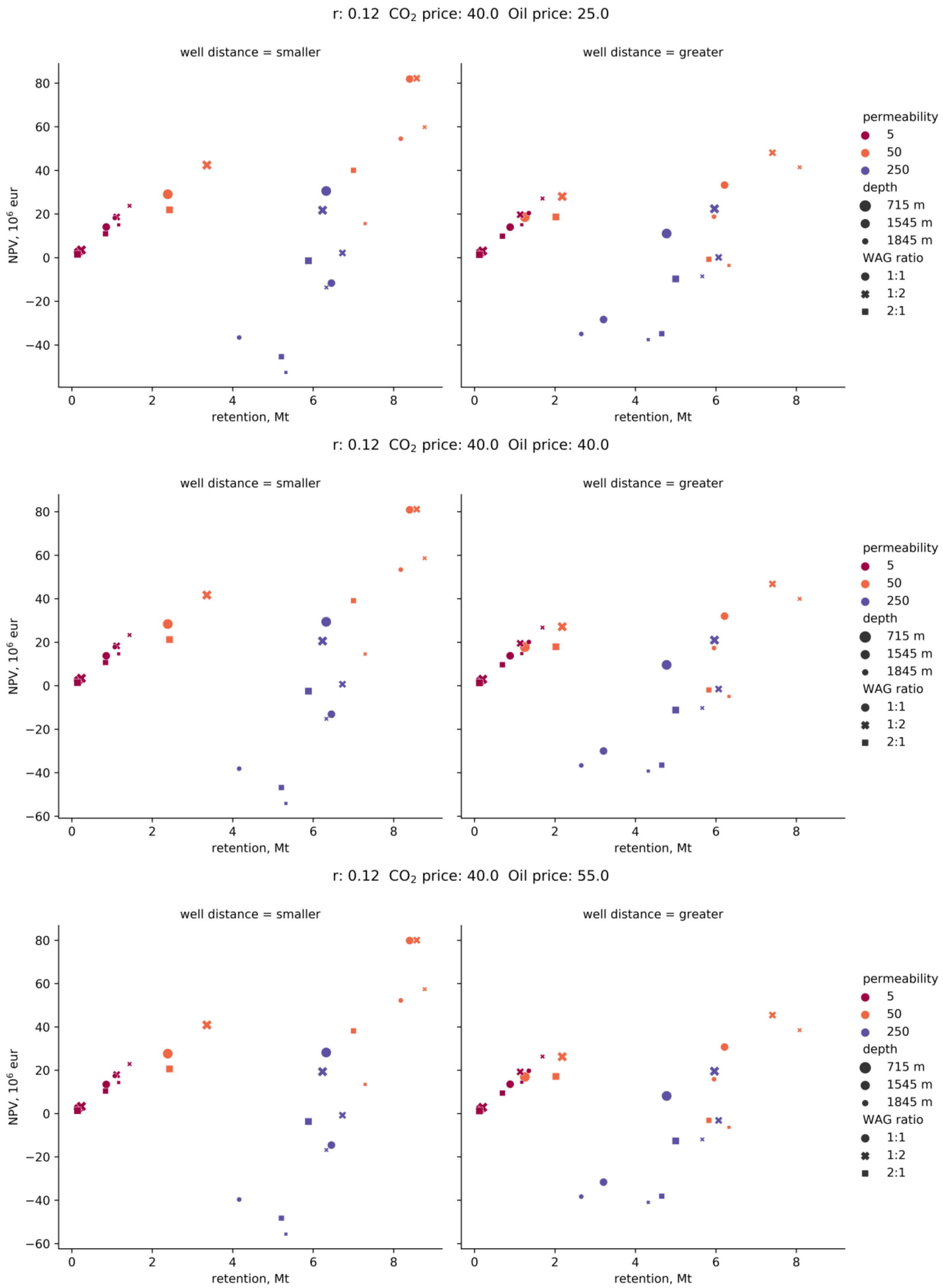
r: 0.12 CO2 price: 25.0 Oil price: 55.0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r: 0.12 CO2 price: 40.0 Oil price: 40.0
r: 0.12 CO2 price: 40.0 Oil price: 55.0
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well distance = greater
NPV, 10^6 eur
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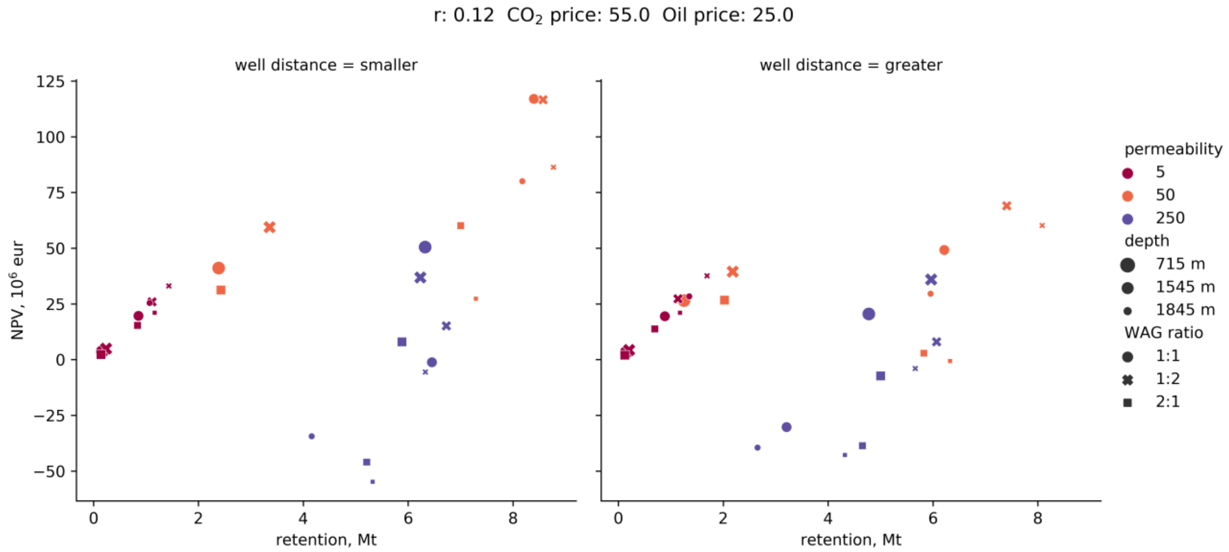
1:2
2:1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1:2
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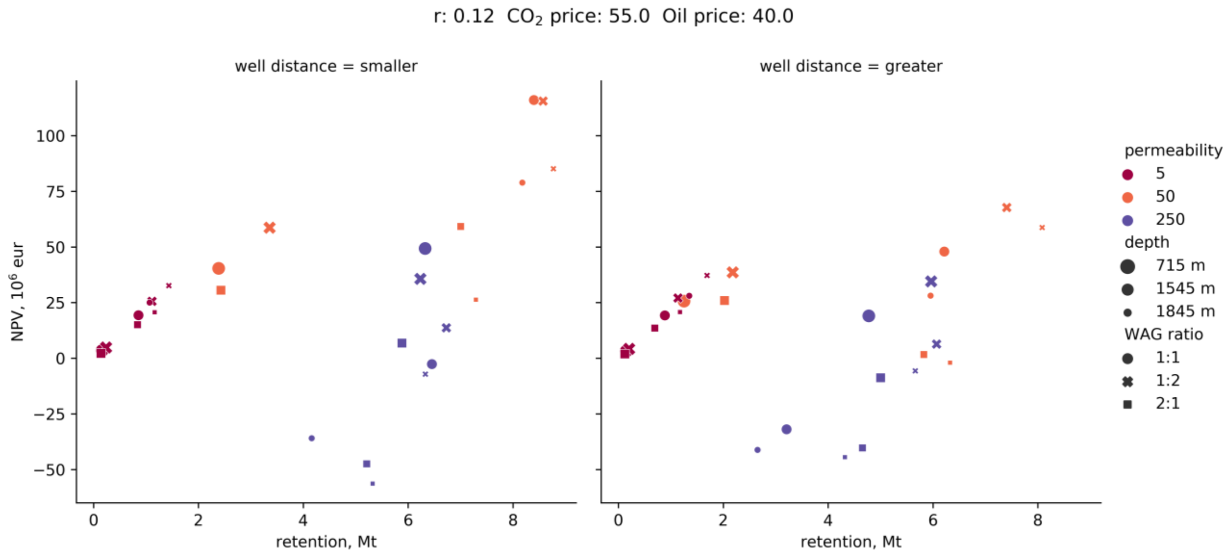
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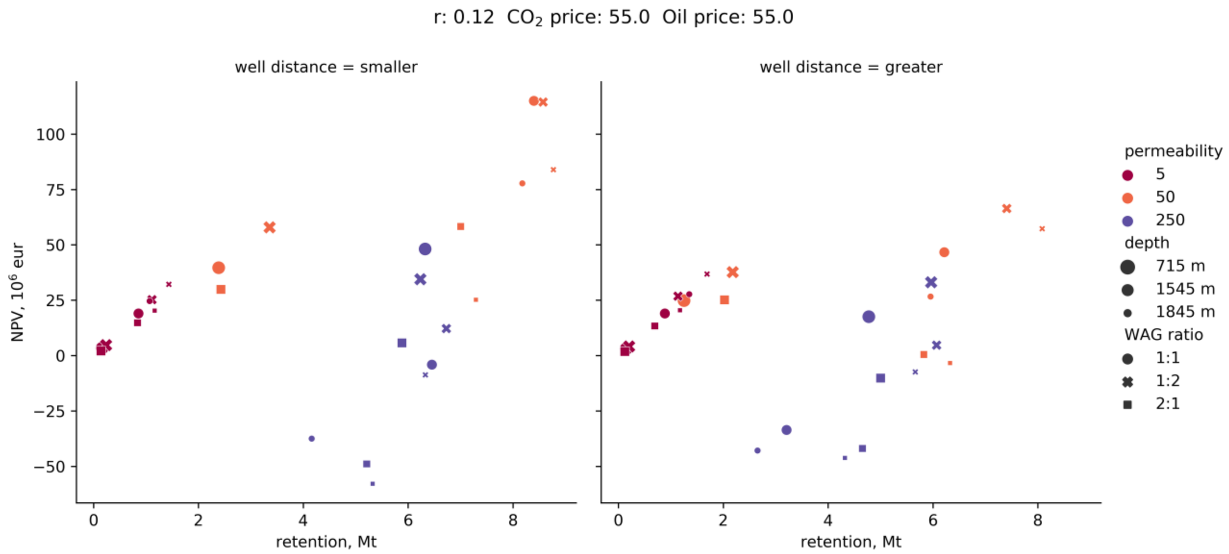
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retention, Mt
permeability
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depth
715 m
1545 m
1845 m
WAG ratio
1:1
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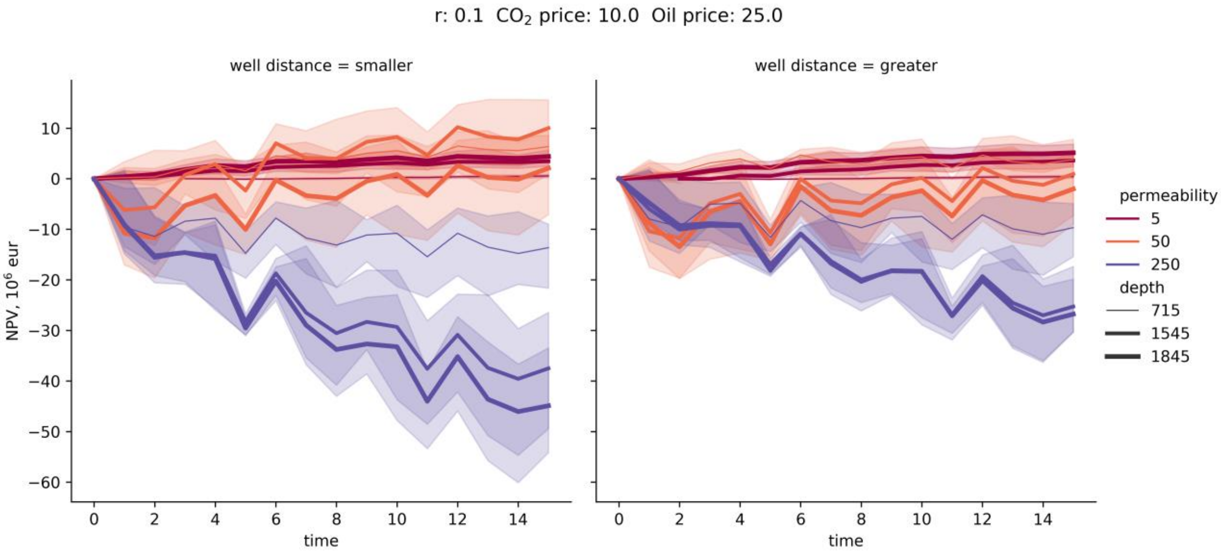
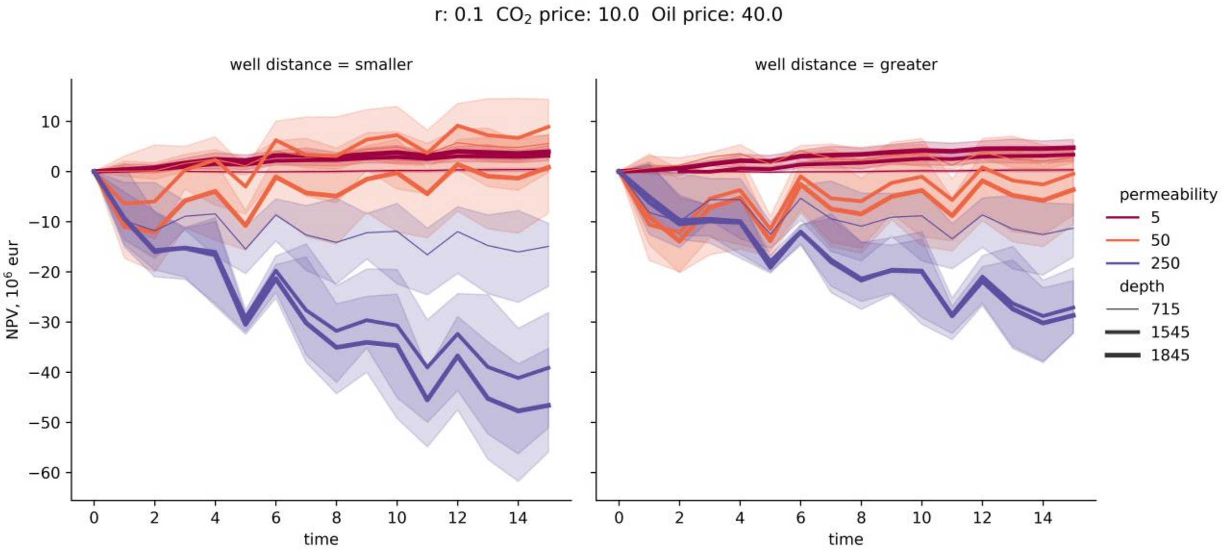
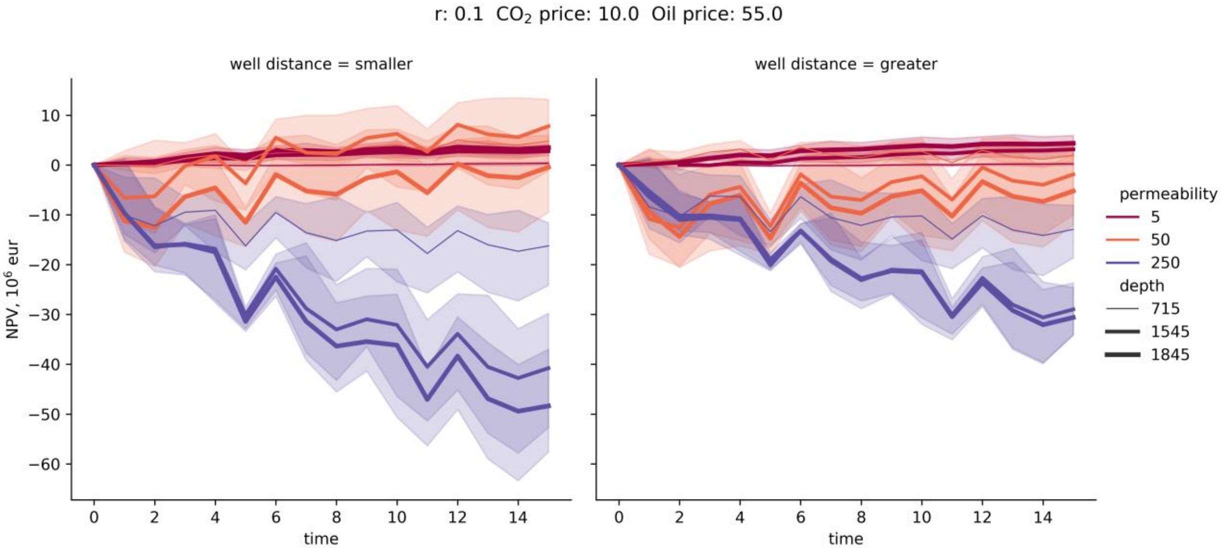
2:1

7.4 Appendix D: Diagrams for different scenarios of prices and discount rates - NPV vs time

Note: mean values are lines, and the shaded part is the confidence interval.







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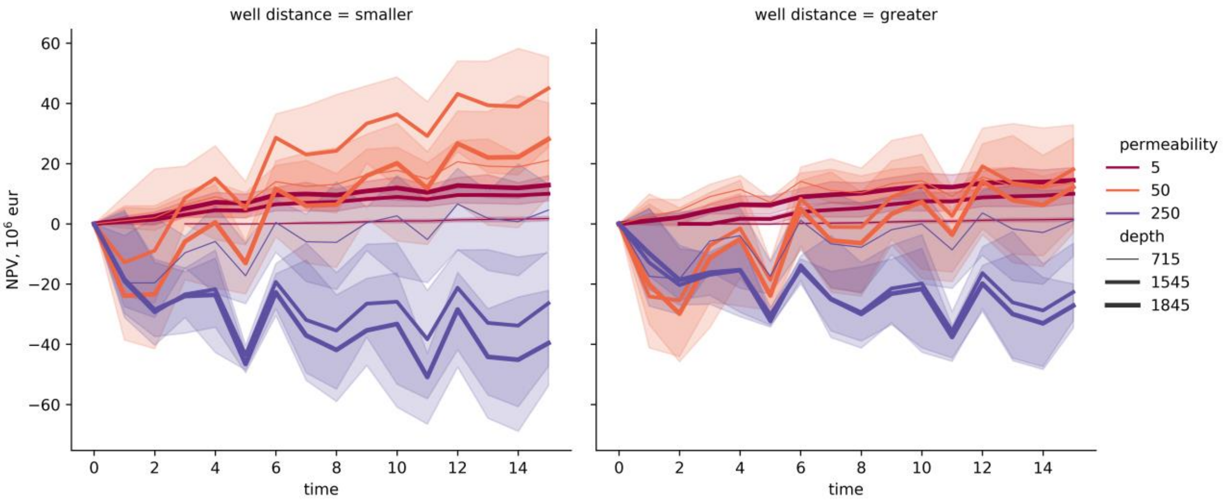

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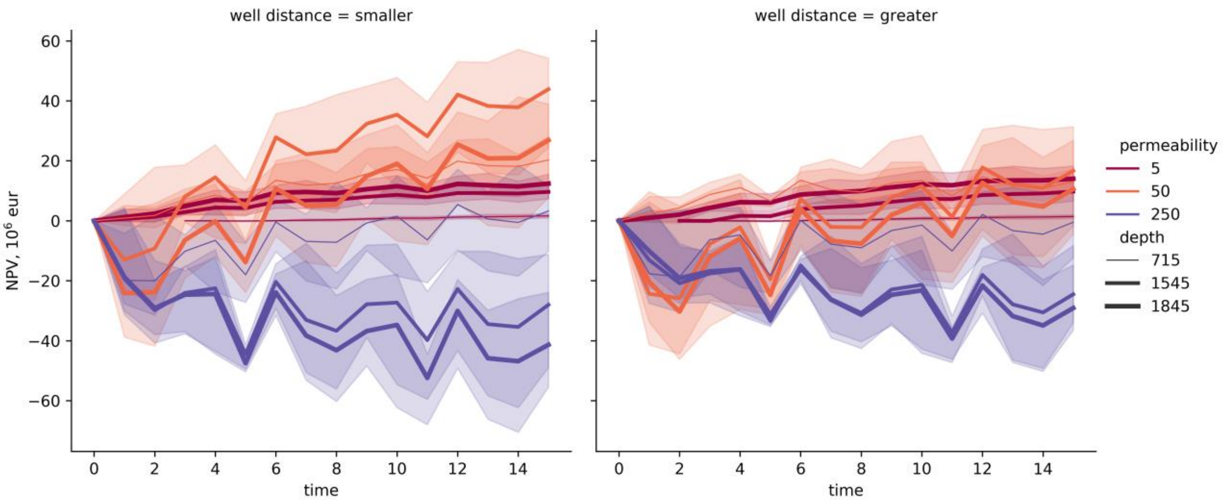

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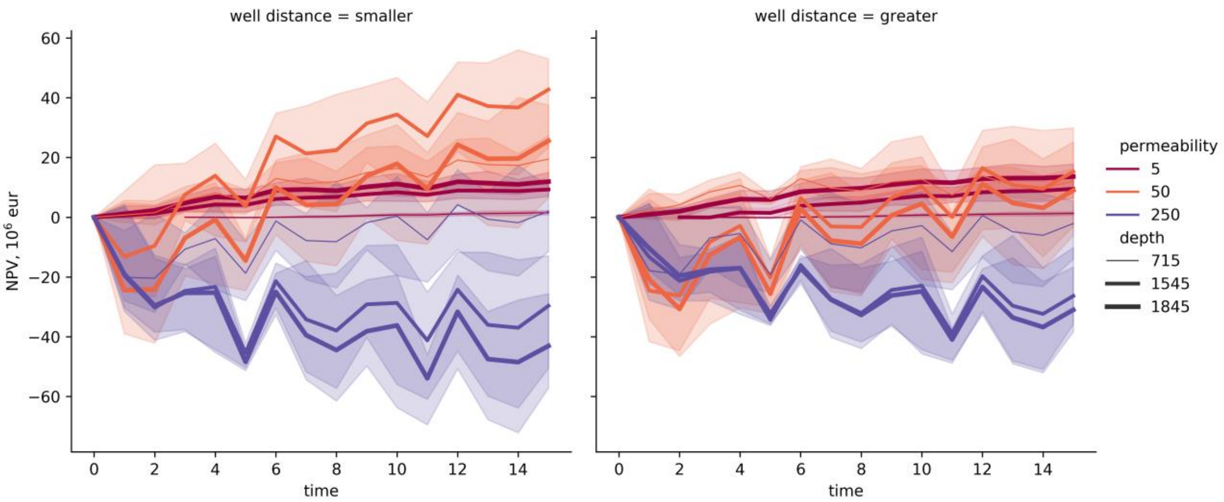

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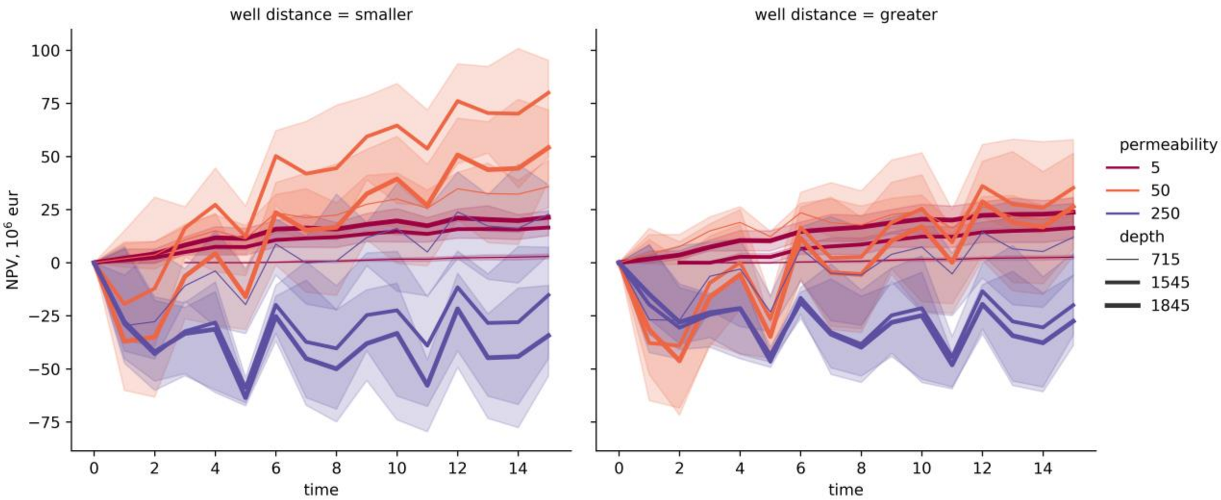

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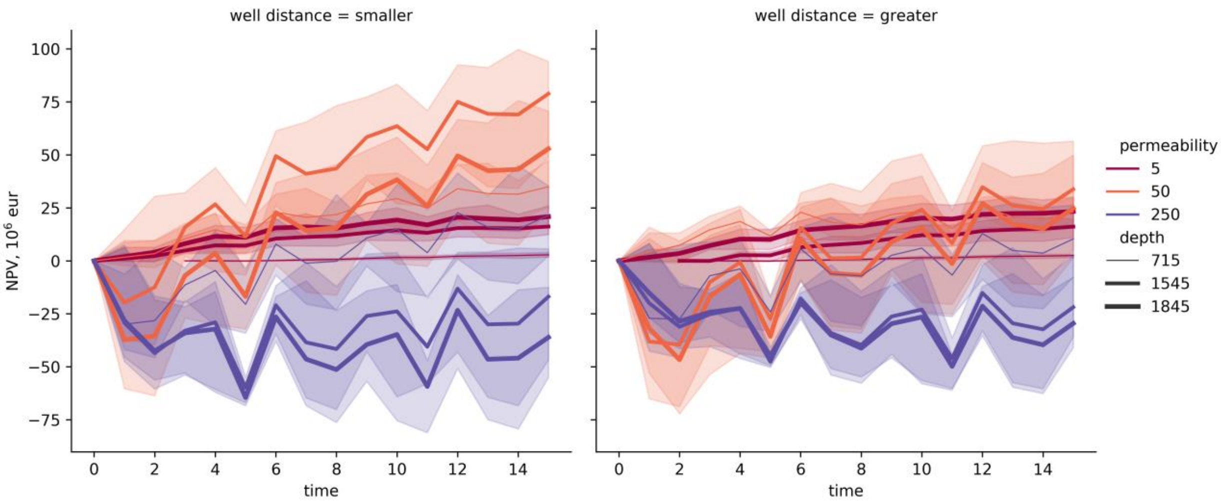

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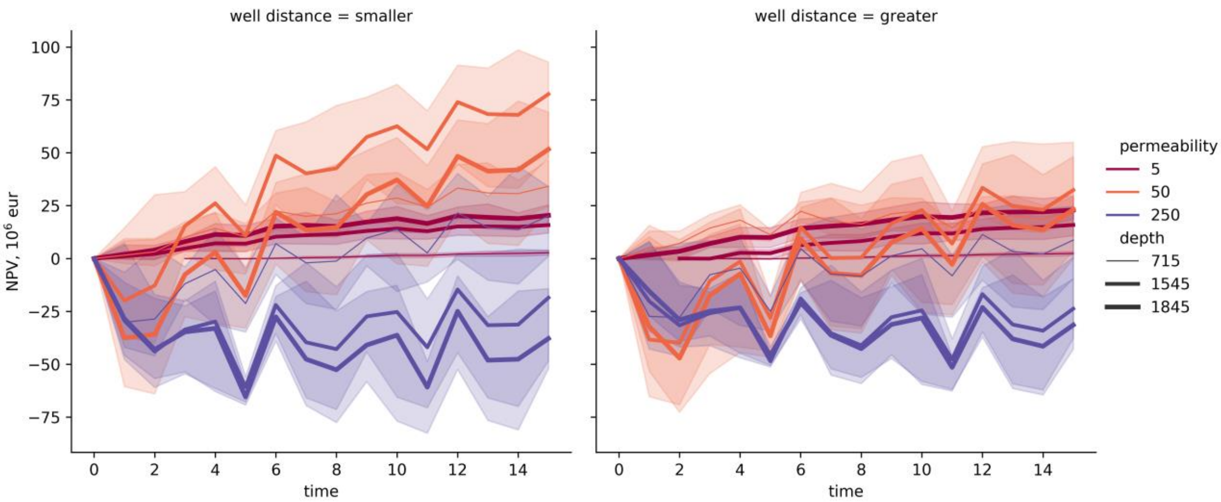

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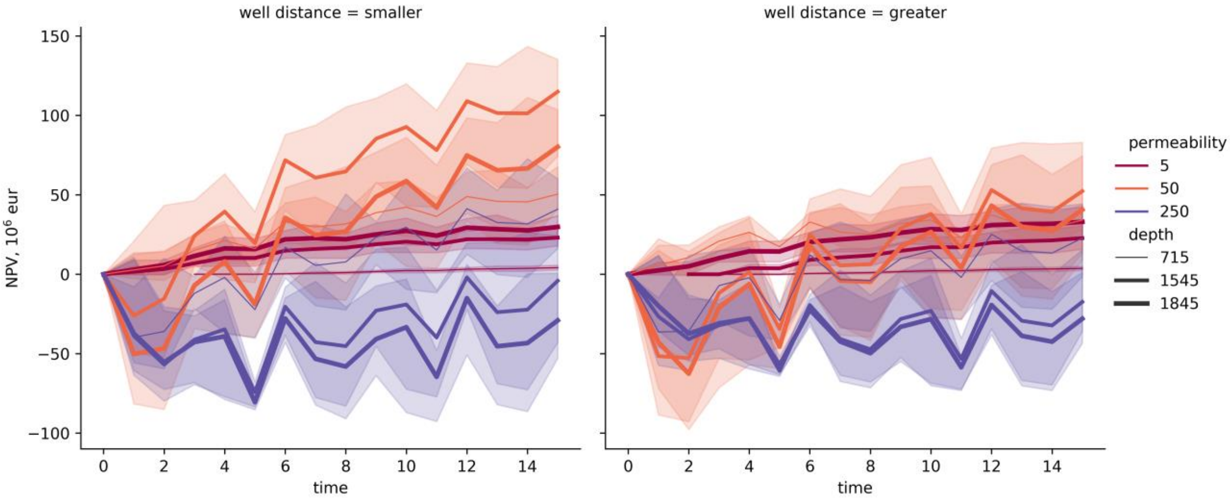

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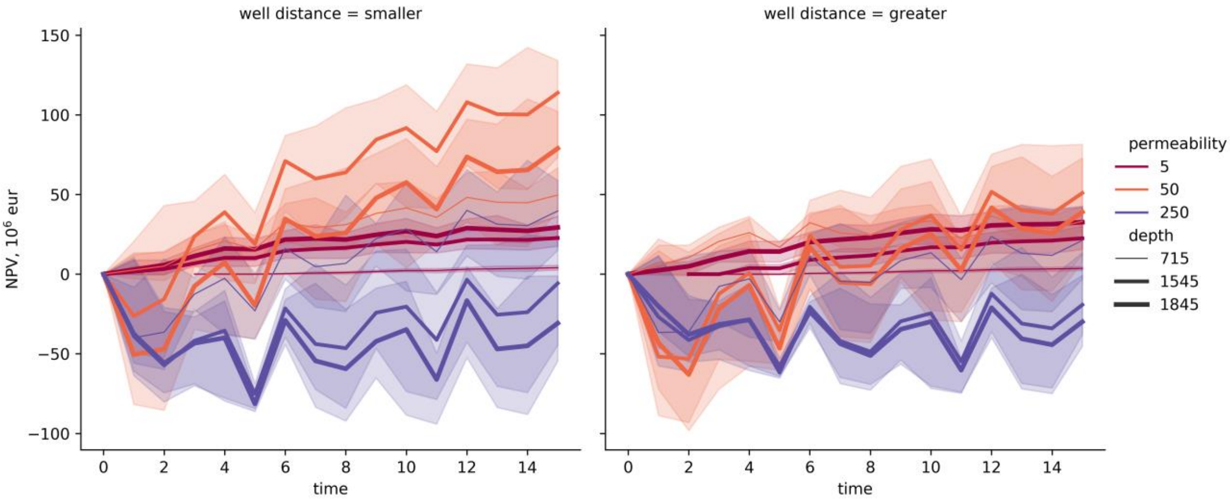

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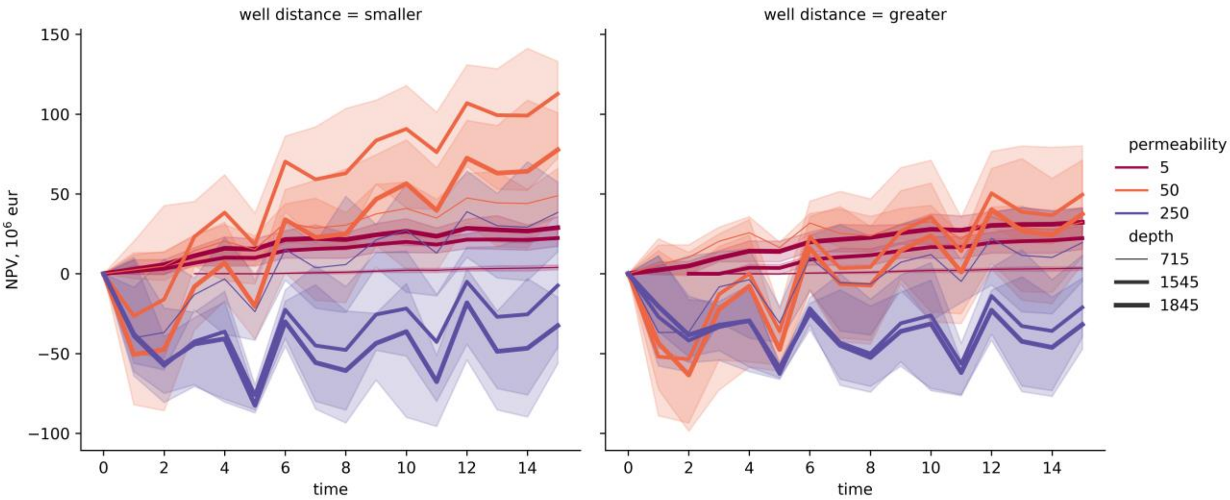

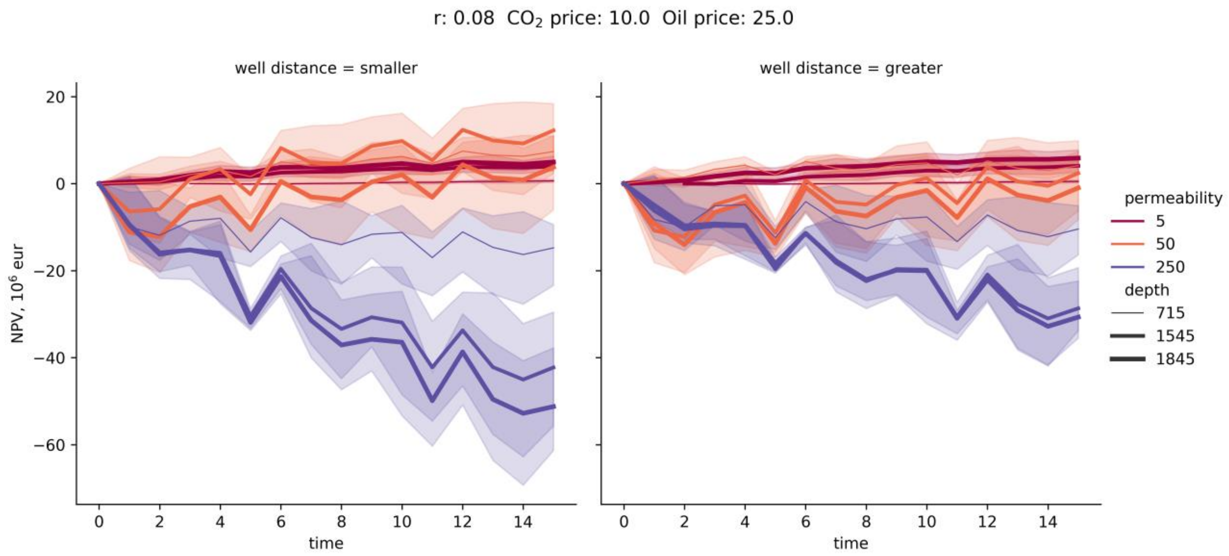
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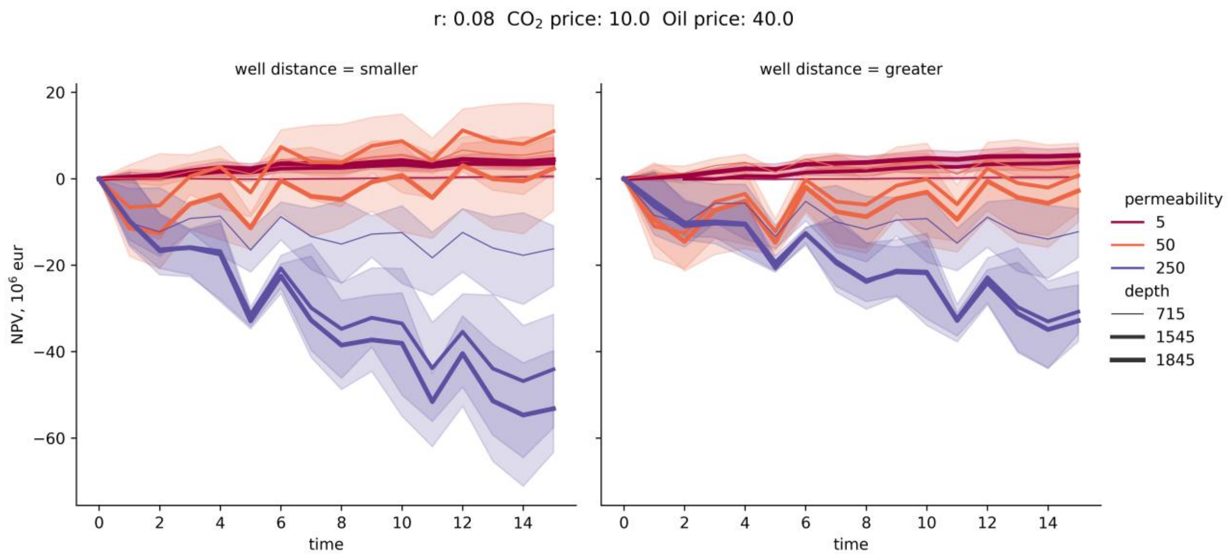
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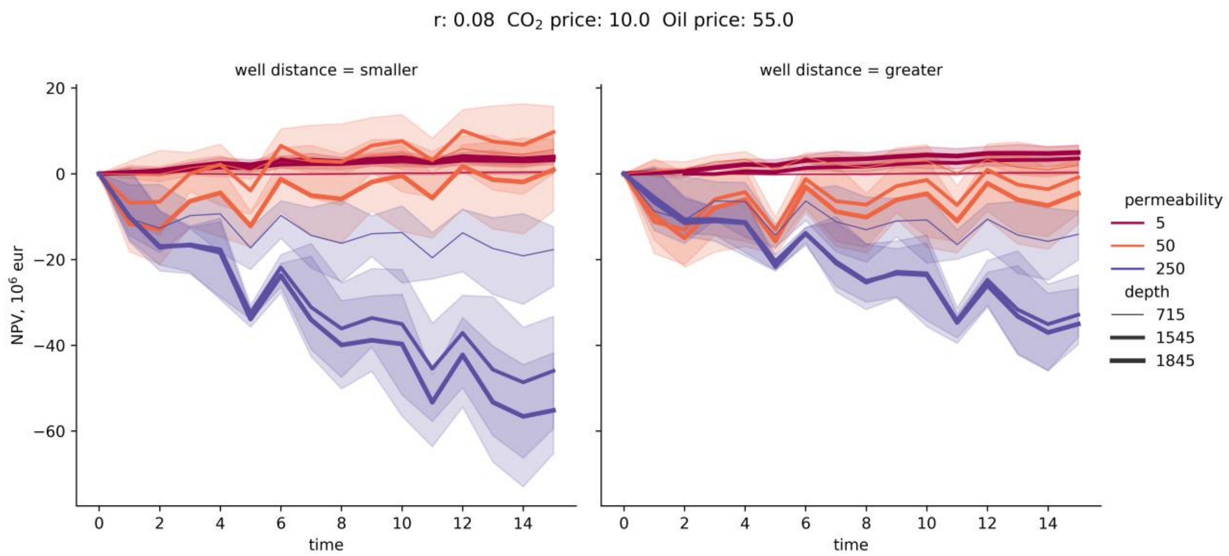
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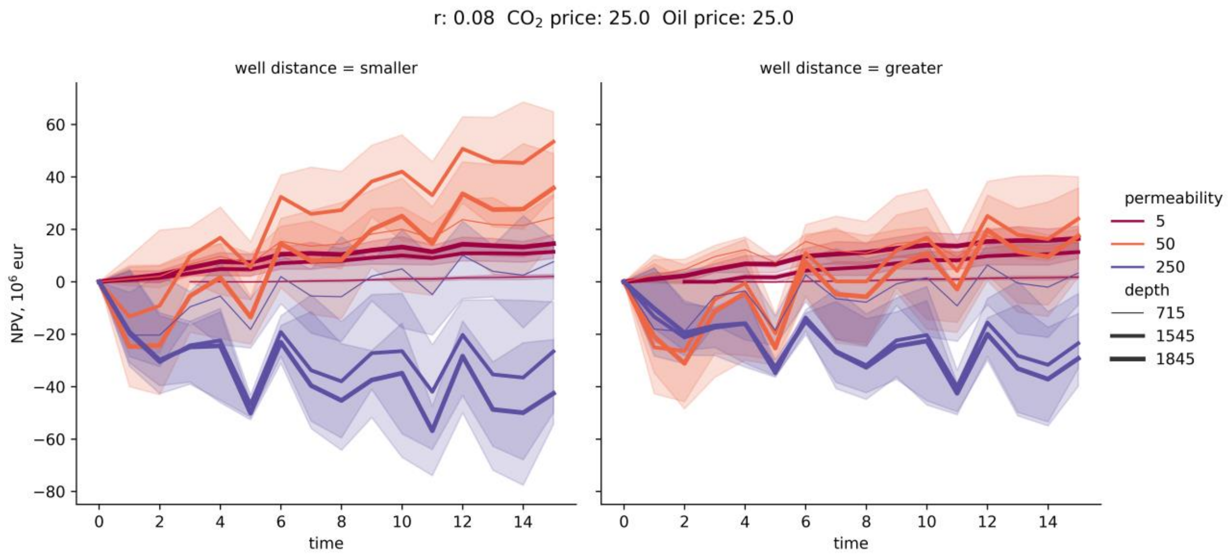
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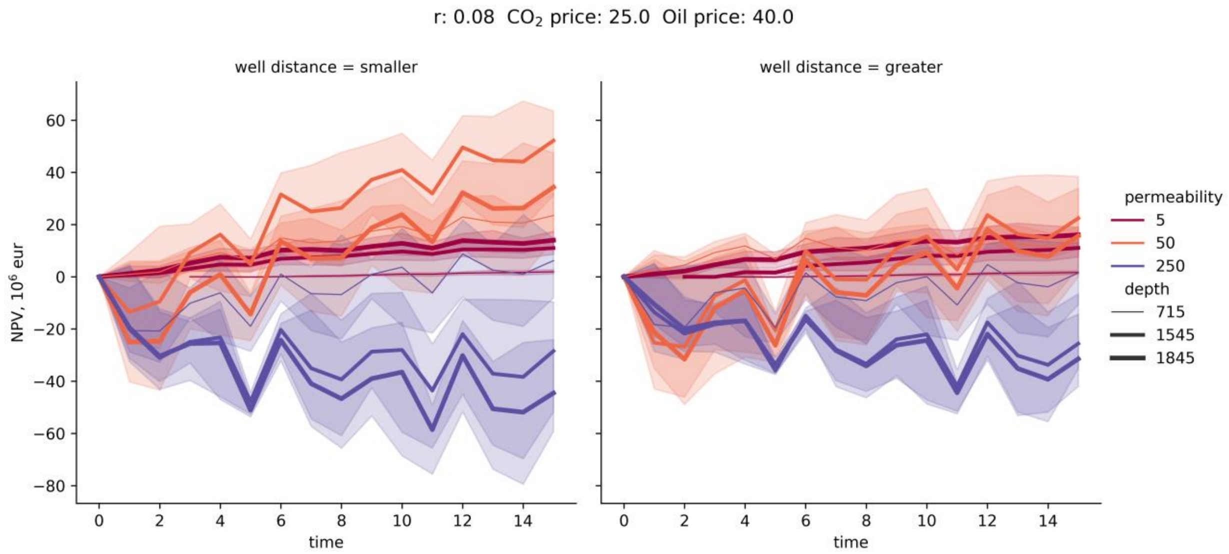
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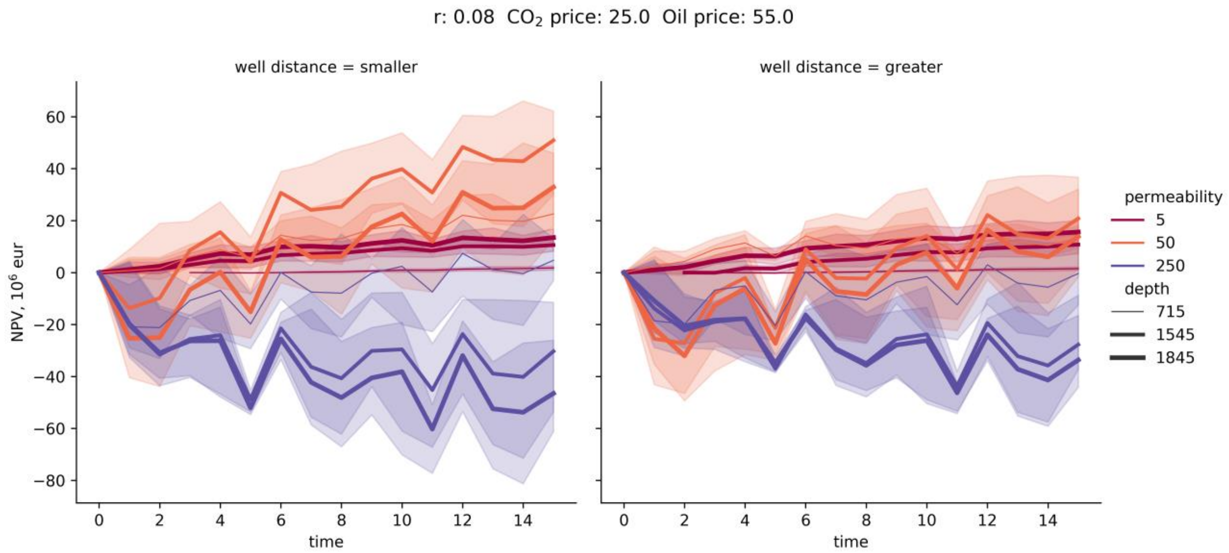
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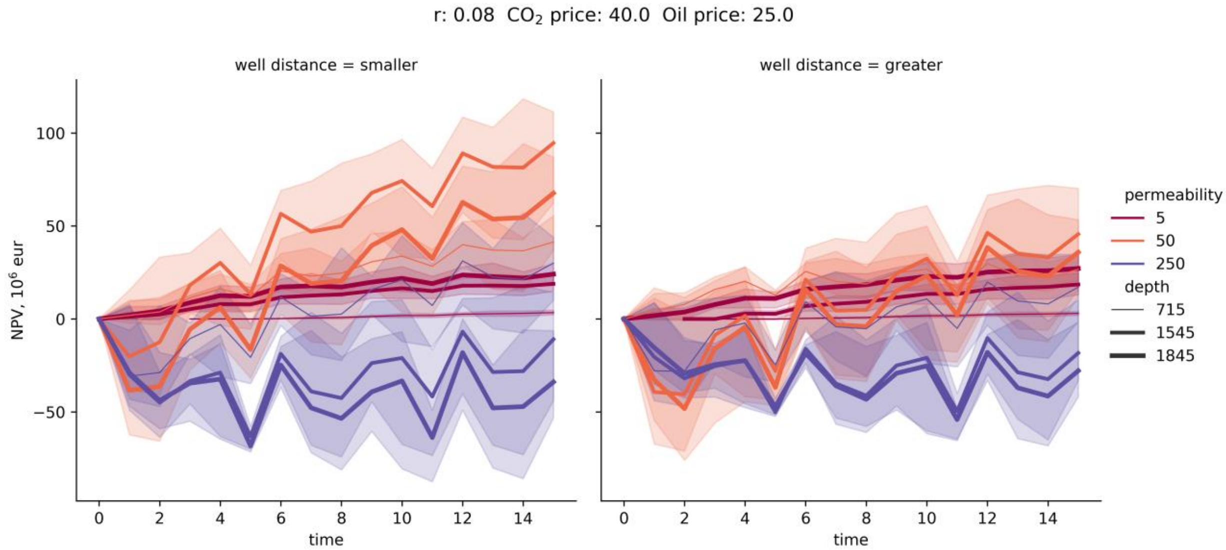
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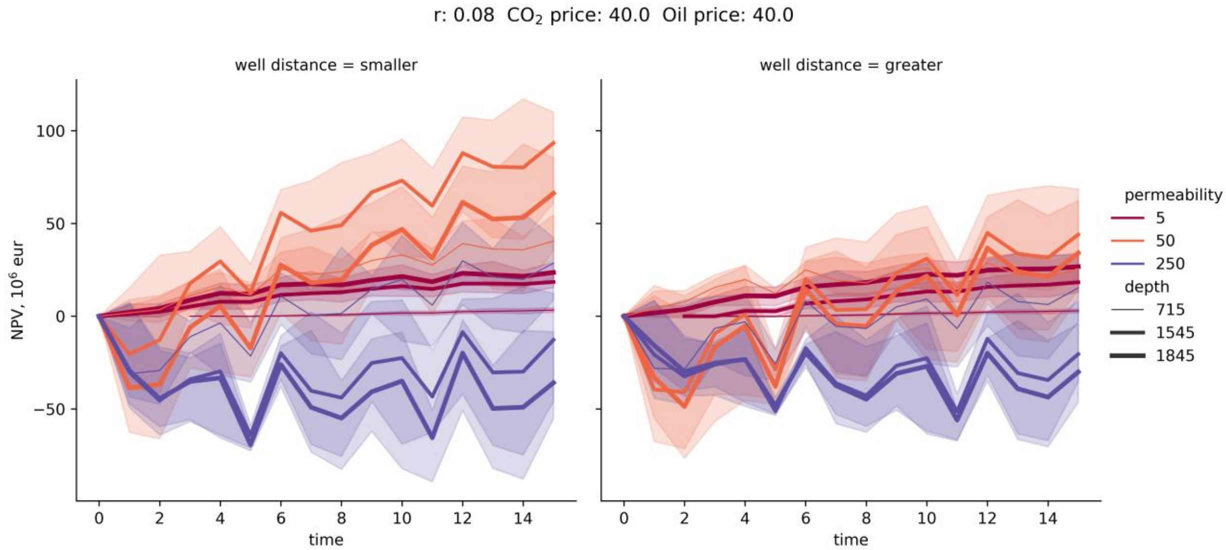
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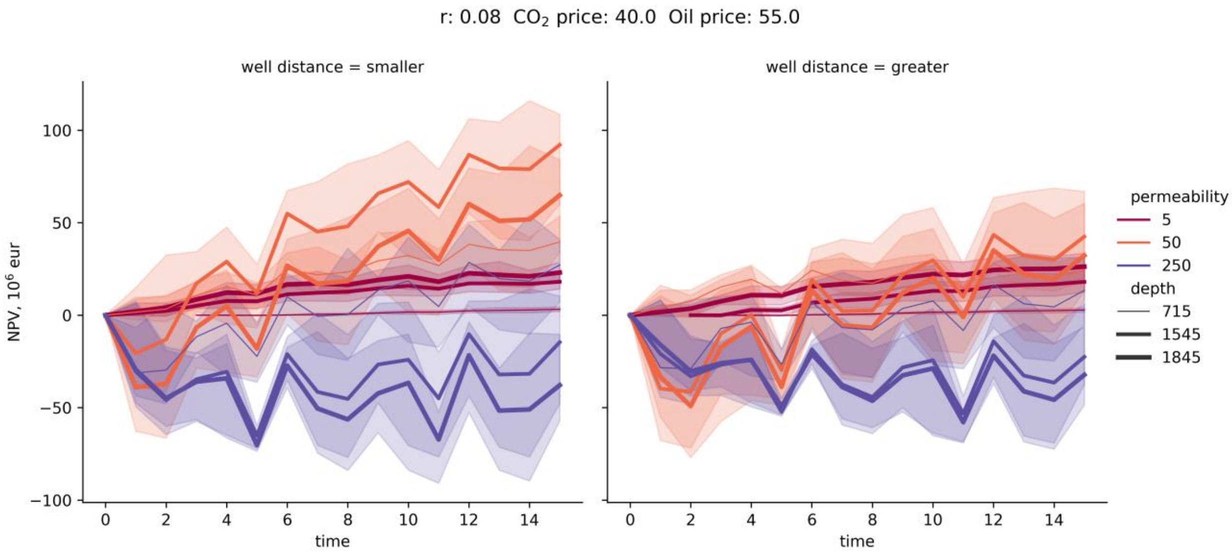
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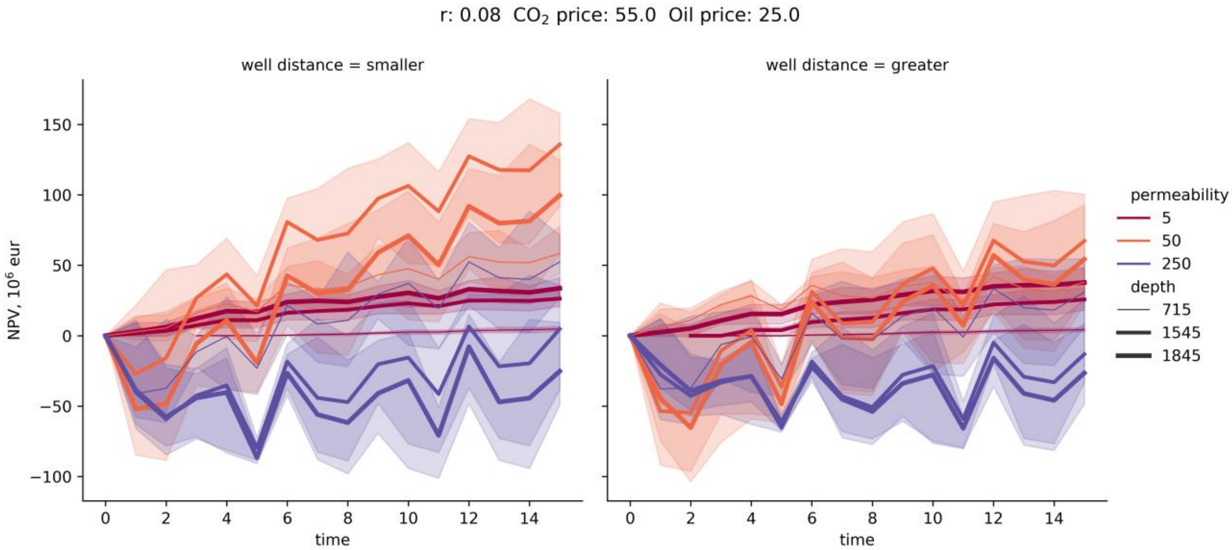
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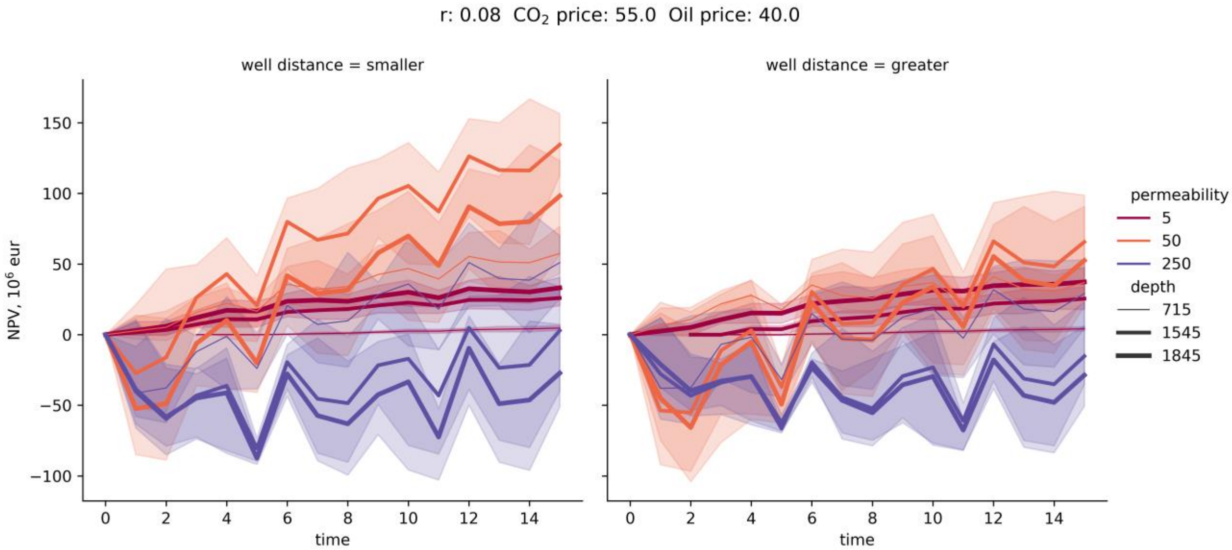
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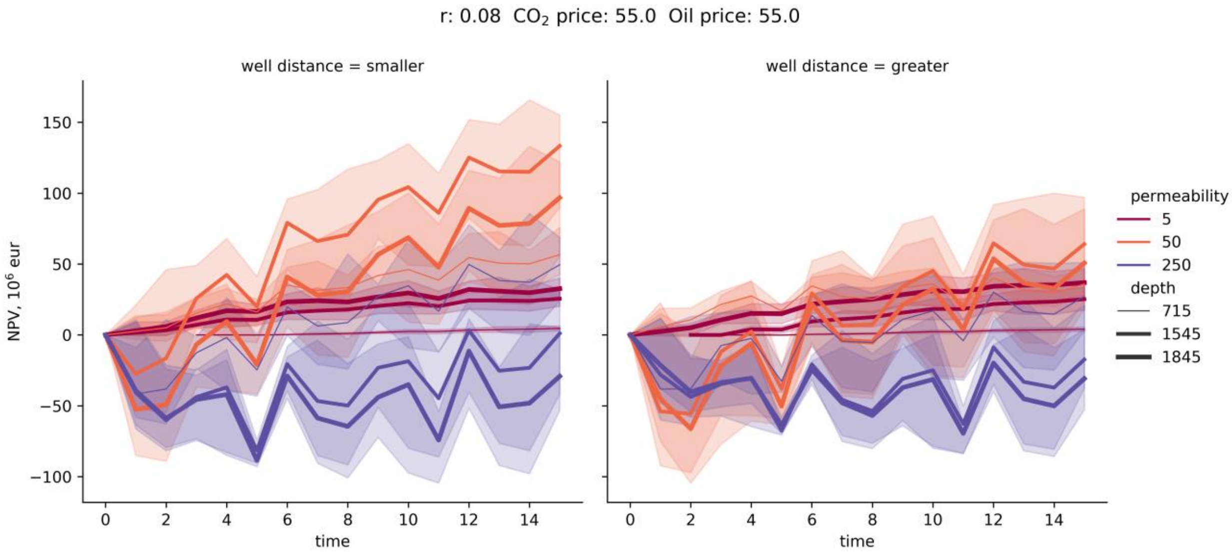
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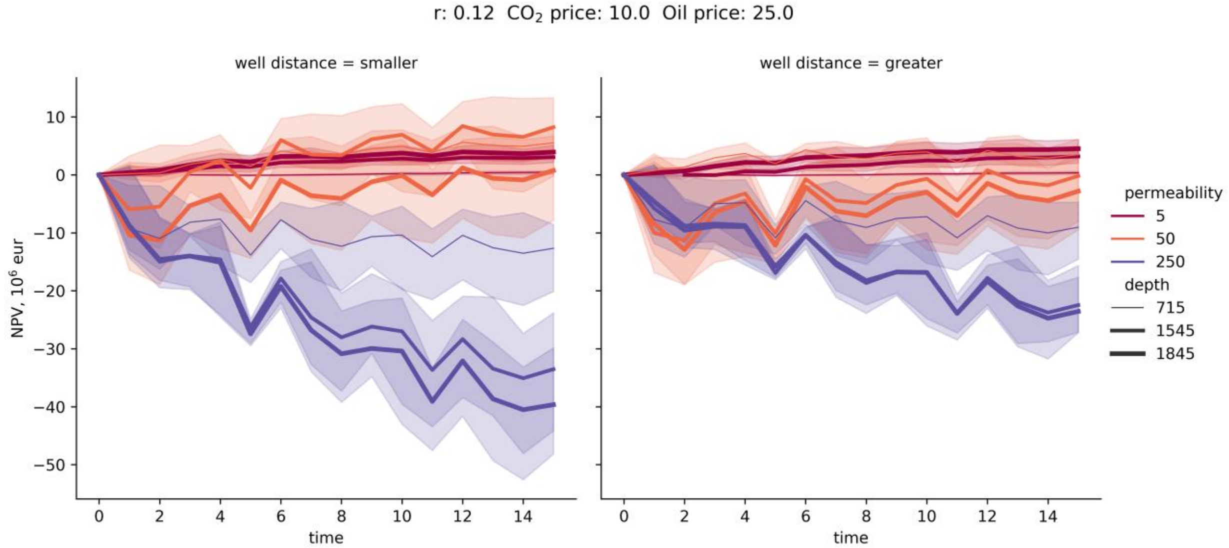
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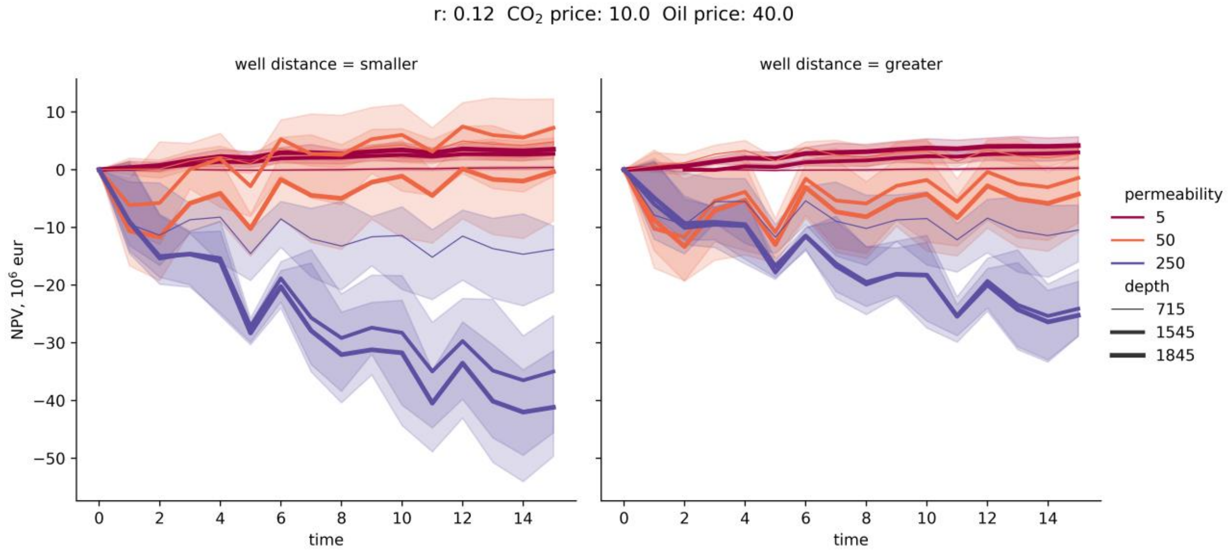
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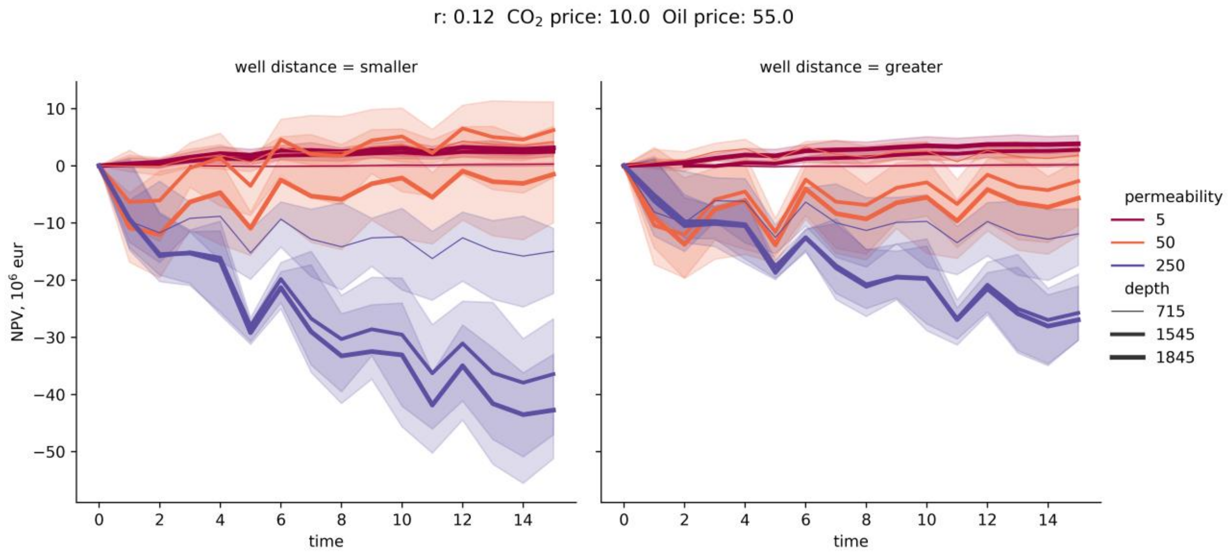
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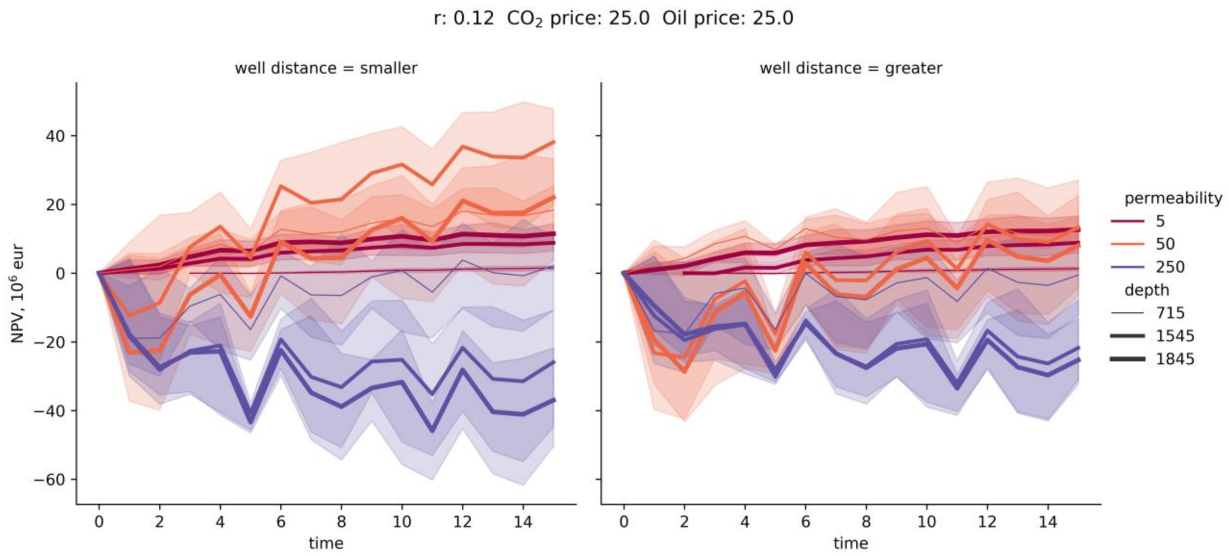
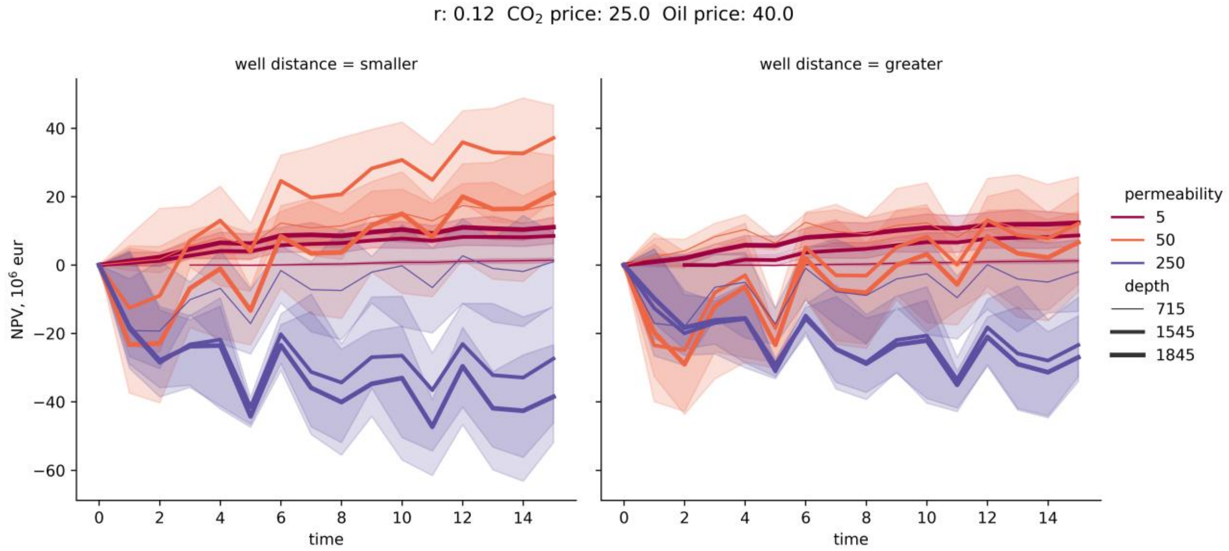

r: 0.12 CO_2 price: 25.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
time
permeability
5
50
250
depth
715
1545
1845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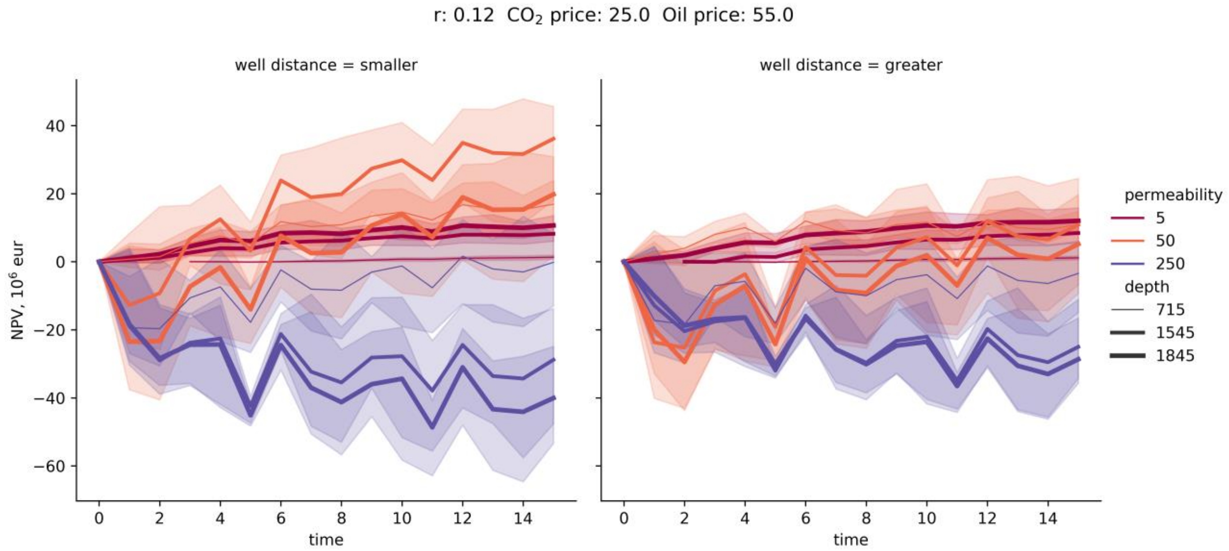
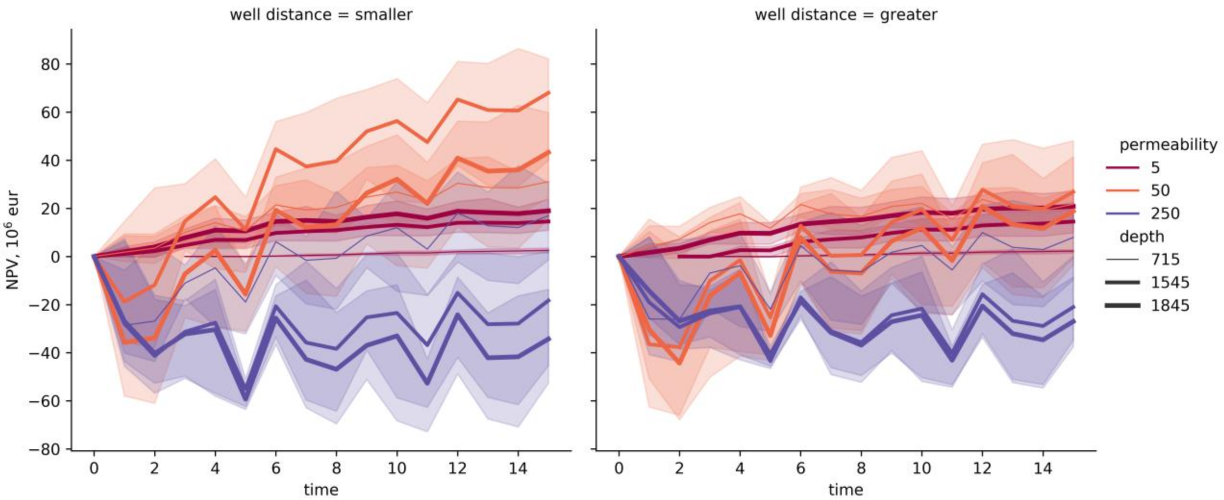
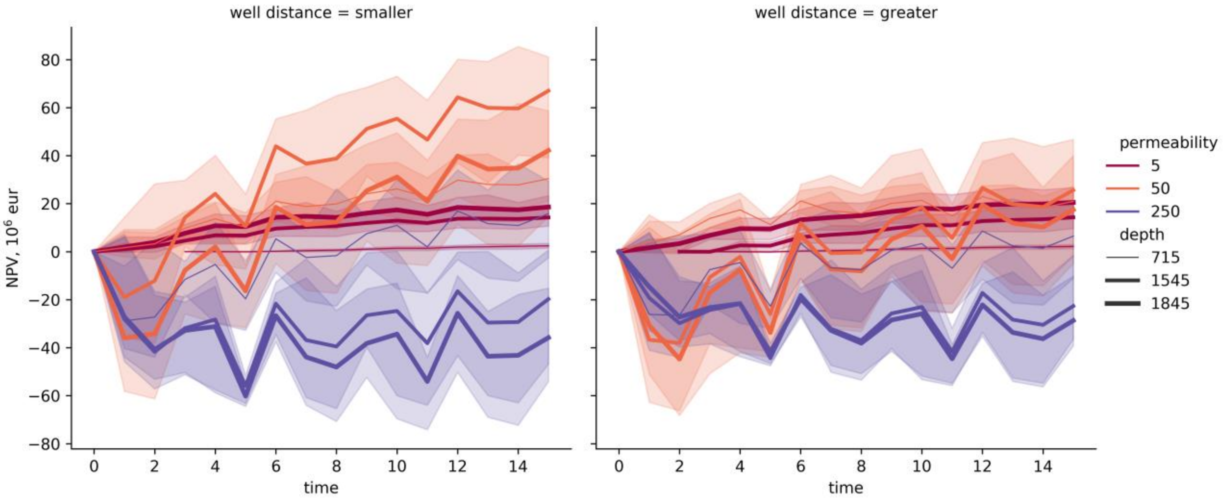
well distance = greater
NPV, 10^6 eur
time
permeability
5
50
250
depth
715
1545
1845


r: 0.12 CO_2 price: 25.0 Oil price: 55.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
time
permeability
5
50
250
depth
715
1545
1845

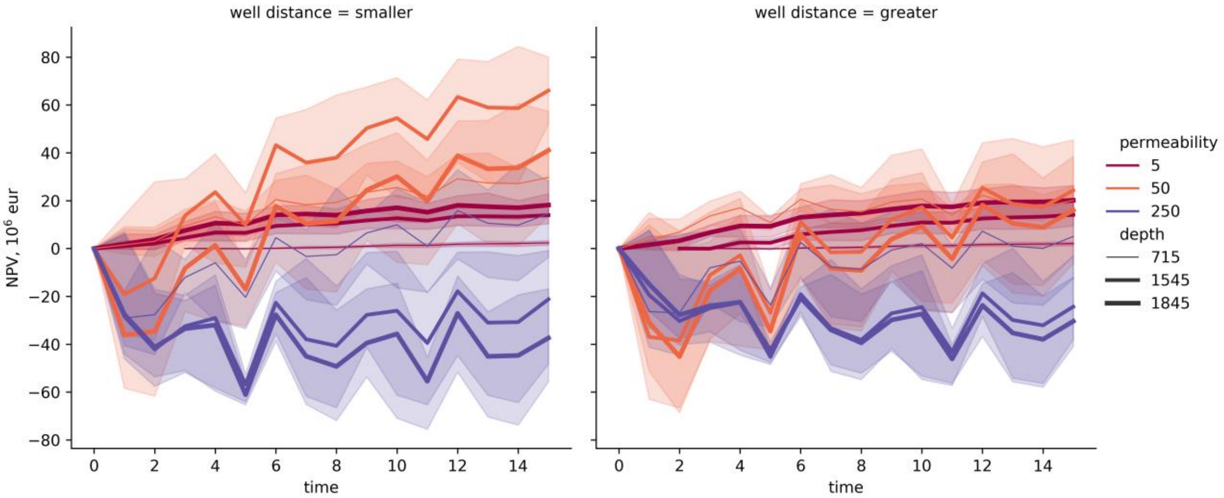
r: 0.12 CO_2 price: 40.0 Oil price: 25.0

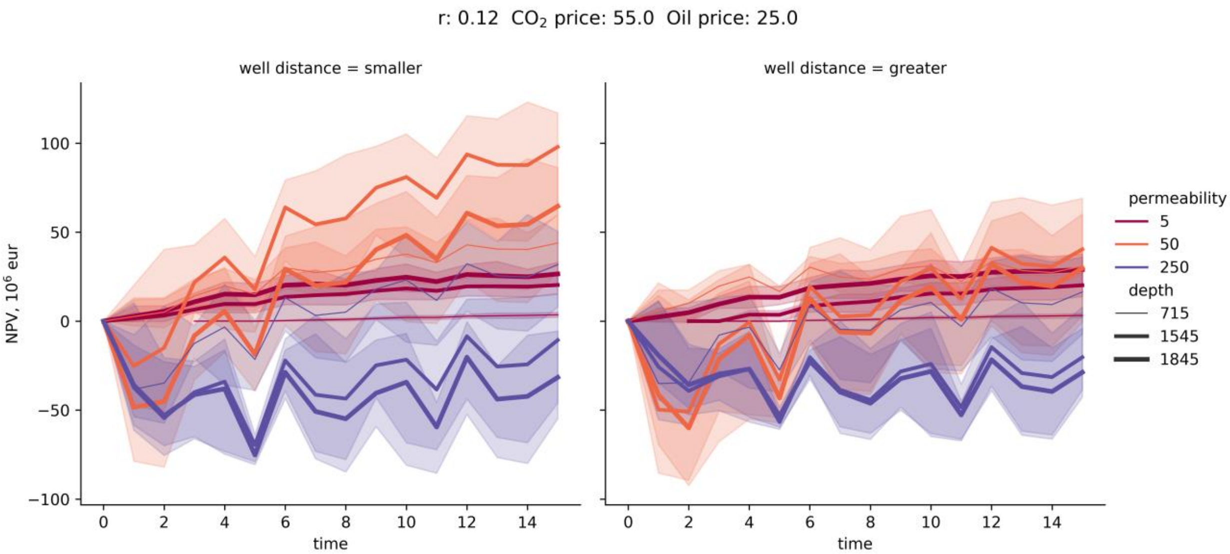


r: 0.12 CO_2 price: 40.0 Oil price: 40.0



r: 0.12 CO_2 price: 40.0 Oil price: 55.0




r: 0.12 CO2 price: 55.0 Oil price: 25.0
well distance = smaller
well distance = greater
NPV, 10^6 eur
time
permeability
5
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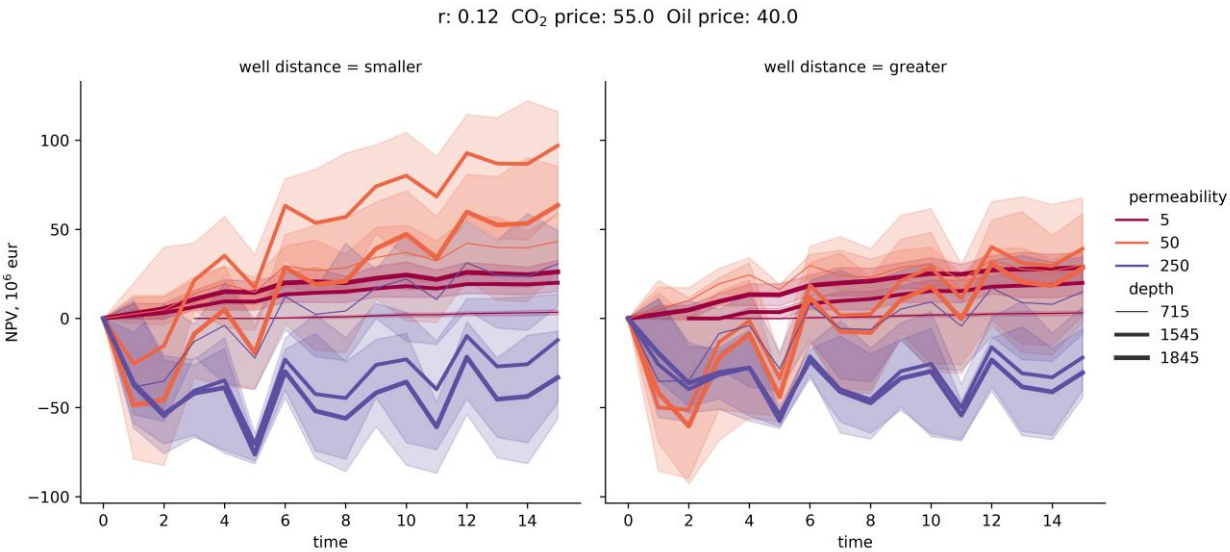
depth
715
1545
1845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well distance = smaller
well distance = greater
NPV, 10^6 eur
time
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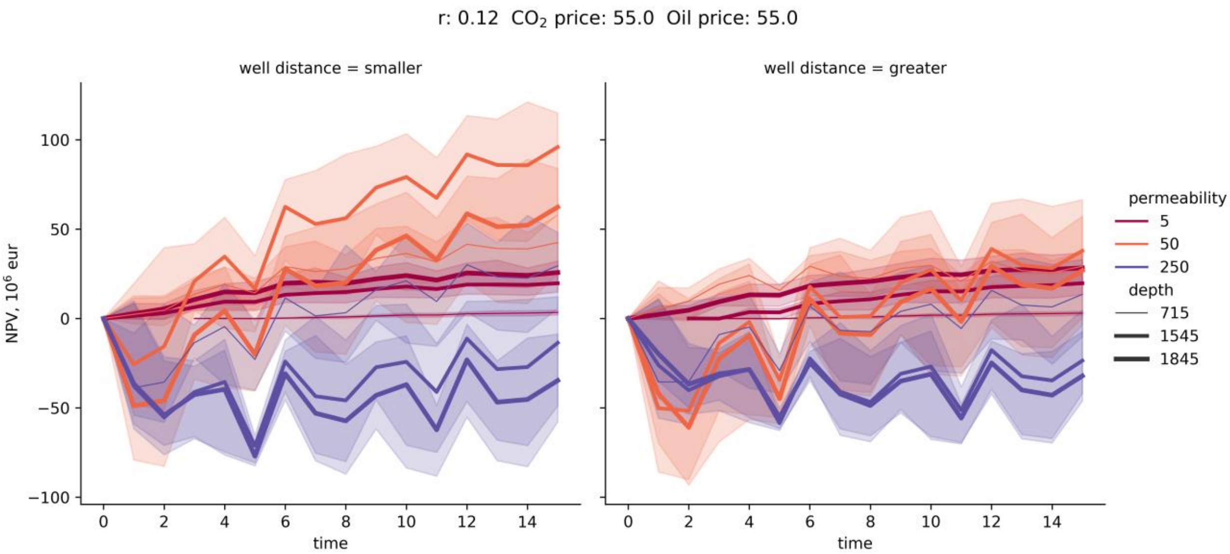
1545
1845


r: 0.12 CO2 price: 55.0 Oil price: 55.0
well distance = smaller
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NPV, 10^6 eur
time
permeability
5
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depth
715
1545
1845