Co-optimization of CO2-EOR and Storage Processes under Geological Uncertainty

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Abstract

This paper presents an integrated numerical framework to co-optimize EOR and CO_2 storage performance in the Farnsworth field unit (FWU), Ochiltree County, Texas. The framework includes a field-scale compositional reservoir flow model, an uncertainty quantification model and a neural network optimization process. The reservoir flow model has been constructed based on the field geophysical, geological, and engineering data. A laboratory fluid analysis was tuned to an equation of state and subsequently used to predict the thermodynamic minimum miscible pressure (MMP).
A history match of primary and secondary recovery processes was conducted to estimate the reservoir and multiphase flow parameters as the baseline case for analyzing the effect of recycling produced gas, infill drilling and water alternating gas (WAG) cycles on oil recovery and CO_2 storage. A multi-objective optimization model was defined for maximizing both oil recovery and CO_2 storage. The uncertainty quantification model comprising the Latin Hypercube sampling, Monte Carlo simulation, and sensitivity analysis, was used to study the effects of uncertain variables on the defined objective functions. Uncertain variables such as bottom hole injection pressure, WAG cycle, injection and production group rates, and gas-oil ratio among others were selected. The most significant variables were selected as control variables to be used for the optimization process. A neural network optimization algorithm was utilized to optimize the objective function both with and without geological uncertainty. The vertical permeability anisotropy (Kv/Kh) was selected as one of the uncertain parameters in the optimization process.
The simulation results were compared to a scenario baseline case that predicted CO_2 storage of 74%. The results showed an improved approach for optimizing oil recovery and CO_2 storage in the FWU. The optimization process predicted more than 94% of CO_2 storage and most importantly about 28% of incremental oil recovery. The sensitivity analysis reduced the number of control variables to decrease computational time. A risk aversion factor was used to represent results at various confidence levels to assist management in the decision-making process. The defined objective functions were proved to be a robust approach to co-optimize oil recovery and CO_2 storage. The Farnsworth CO_2 project will serve as a benchmark for future CO_2–EOR or CCUS projects in the Anadarko basin or geologically similar basins throughout the world.

Motivation for this Work

- Ampomah et al 2016 (SPE-179528) presented a scenario based model to study different injection strategies effects on oil recovery and CO_2 storage
- Their work resulted in about 75% of CO_2 storage which is used as the baseline case for this study
- **This work** seeks to use advanced optimization with uncertainty procedure with multi-objective function to improve prediction of CO_2 storage and/or oil recovery

Conclusions

- A real time reservoir performance has been developed by using fast proxy methodology which can reduce computational cost without compromising on accuracy
- The use of a complex multi-objective function resulted in optimum operational variables that yielded 94% of CO_2 storage and more than 25% incremental of OOIP oil recovery beyond waterflood at FWU
- This work, and ongoing efforts, will serve as a blueprint for future CCUS project with Anadarko basin and similar geological basins around the world

FWU Reservoir Production History

- First discovery well drilled by Unocal in October 1955
- Initial reservoir pressure at datum of 4900 ft was 2203 psig
- Original bubble pointpressure was 2059 psig
- OOIP ~120 MMSTB
- Secondary recovery started 1964
- Tertiary recovery started 2010

Development Strategy (Baseline & Optimized Case)

- Convert all injectors to WAG wells (25 wells) using both purchased and recycled CO_2
- Purchase a constant 10,000 Mscf of anthropogenic CO_2 per month until 2024
- Systematically decrease volume of purchased CO_2 from 2024 to 2030
- Inject only recycled gas after 2030.

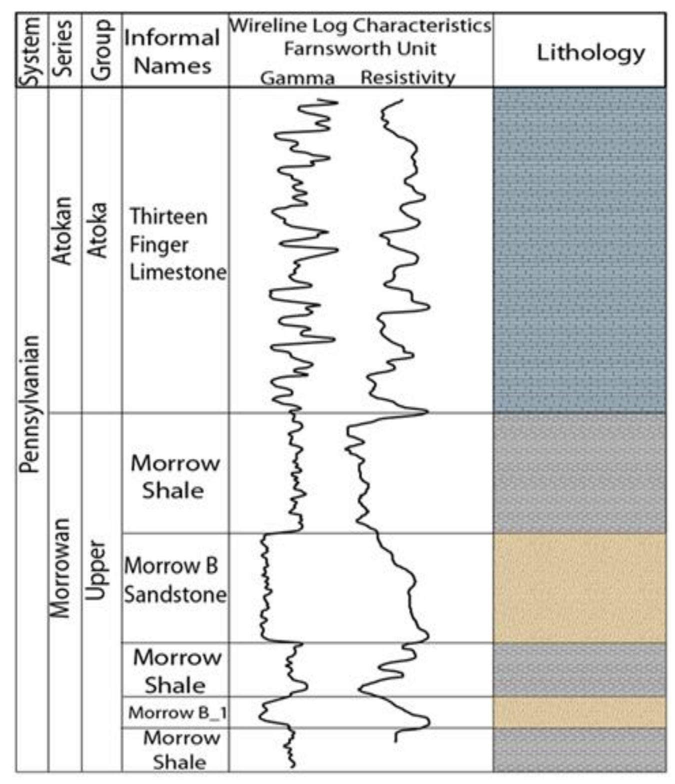
Additional constraints include:

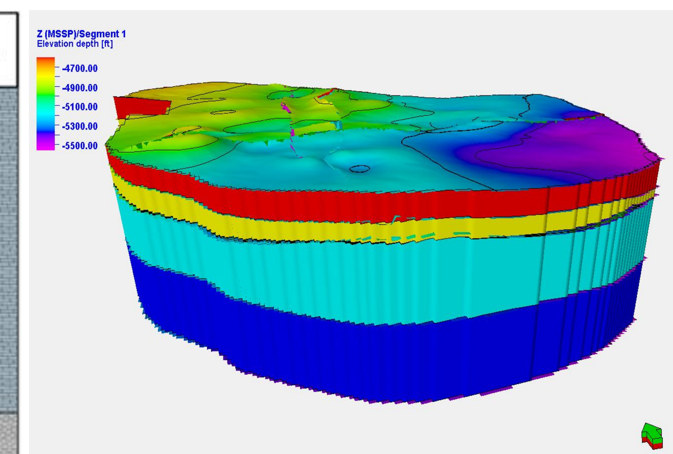
- Compressor capacity ~ 20,000 Mscf/d
- Production well tubing pressure = 900 psi
- Injection well tubing pressure = 2500 psi
- Maximum Production target = 3500 stb/d
- Injection target = CO_2 purchased volume + recycled volume

P_{init}, psig @ Datum Depth	**2203**
P_{bubble}, psig @ Datum Depth	**2059**
Datum Depth(subsea), ft	**4900**
GOR, Mscf/stb	**0.345**
Temperature, °F	**168**
Initial Water saturation	**0.31**

The table shows important information used to initialize simulation modeling at FWU. The immediate figure shows oil-water and gas-oil binary pair relative permeability curves.

Geological Model



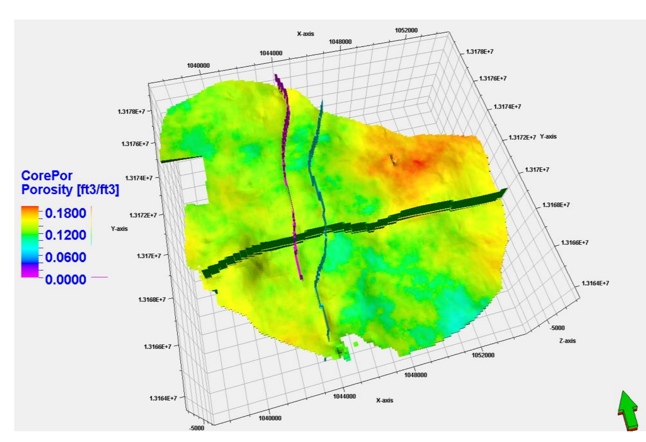


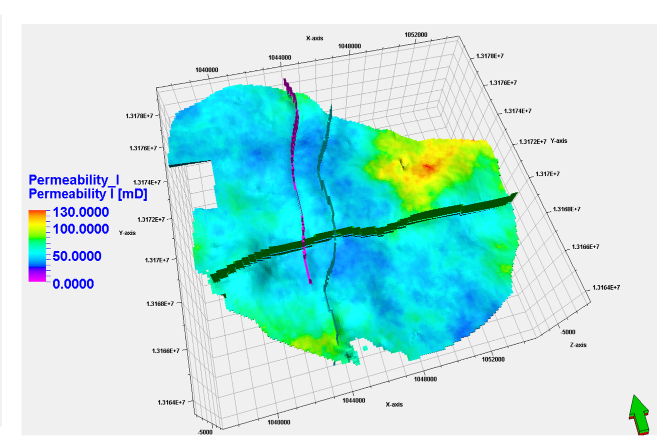
Model Statistics

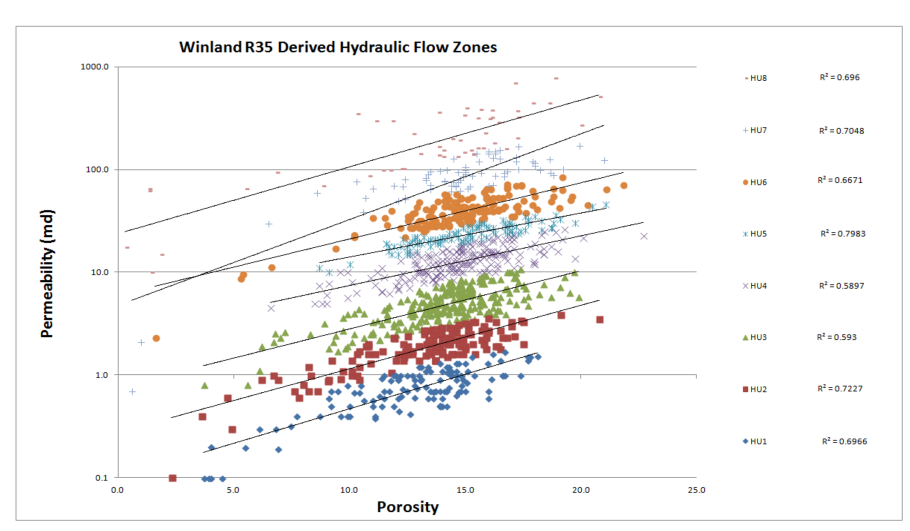
- Grid Cells 176*163*8
- Grid Dimensions 100ft*100ft
- Total # cells 229,504

The stratigraphic column shows a type log at FWU with formations included in the static model . The structural model is shown at the right.

Property Modeling



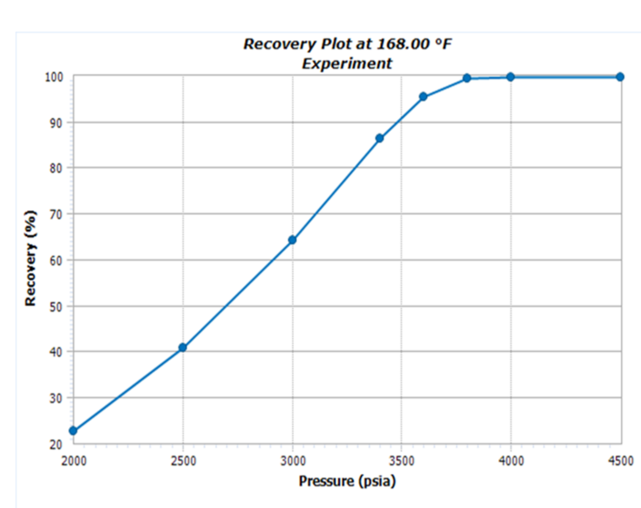




Porosity versus permeability for 51 cored wells separated by pore throat size into Hydraulic Flow Units.

FWU Reservoir Fluid Analysis

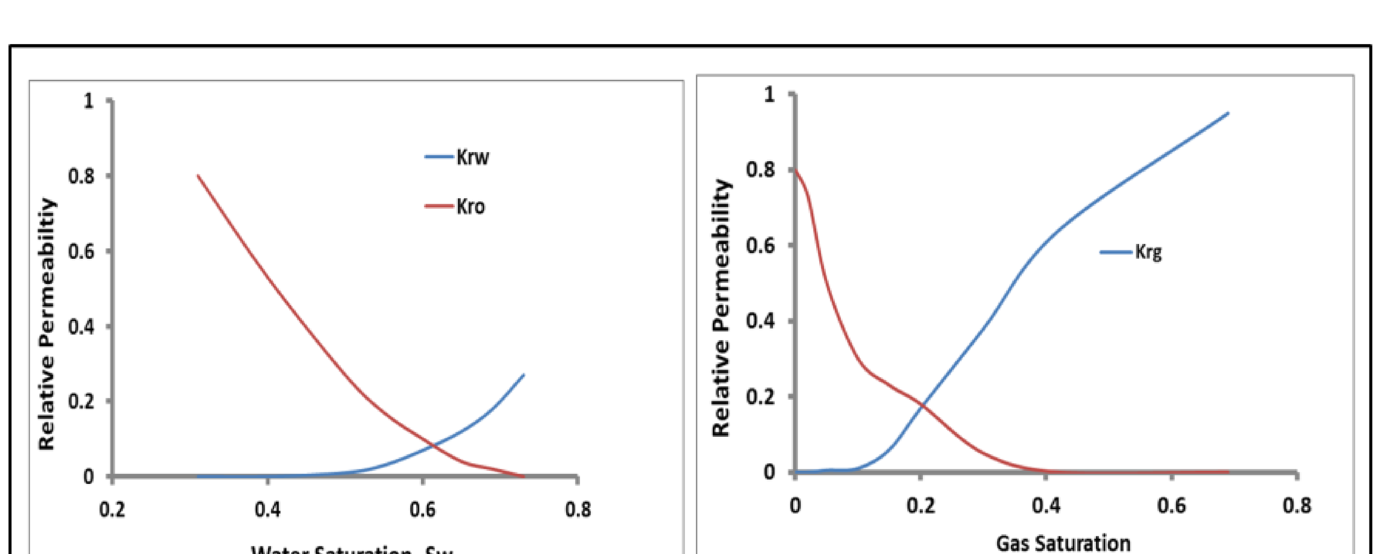
Properties	Units	% Error
Saturation Pressure	psia	2.84
Oil Density	g/cc	1.3
Vapor Z-factor		0.22
GOR	Mscf/stb	1.58
Gas Gravity		2.39
Liquid Viscosity	cp	9.7



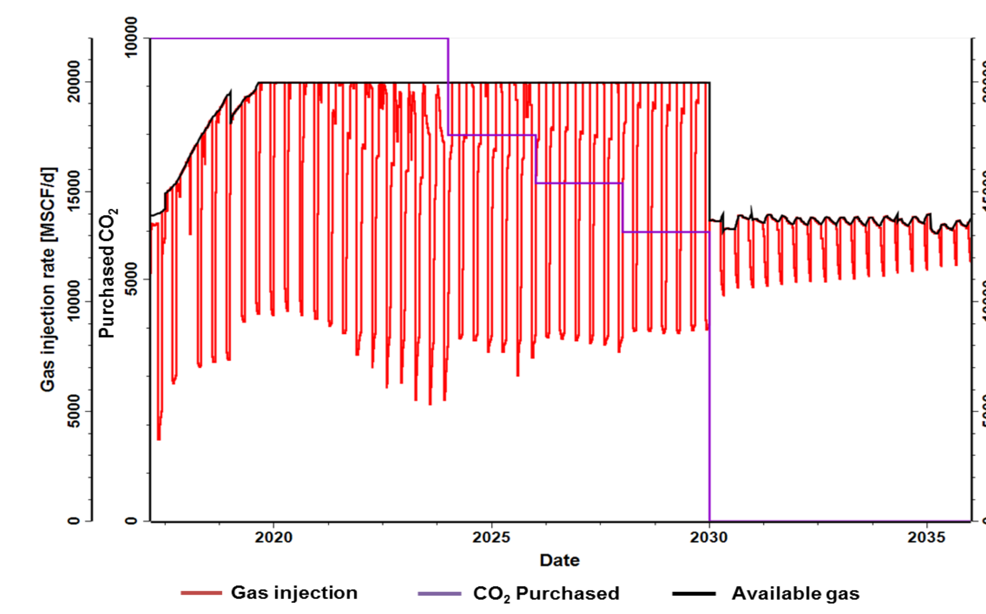
Properties	Units	Observed	Before Regression	After Regression	%Error
MMP	psia	4200	3038.4	4008.8	4.5

A fluid sampled from the FWU was analyzed and calibrated to the equation of state to assist in compositional modeling. A slim tube simulation experiment was used to compute the MMP and compared to lab estimation.

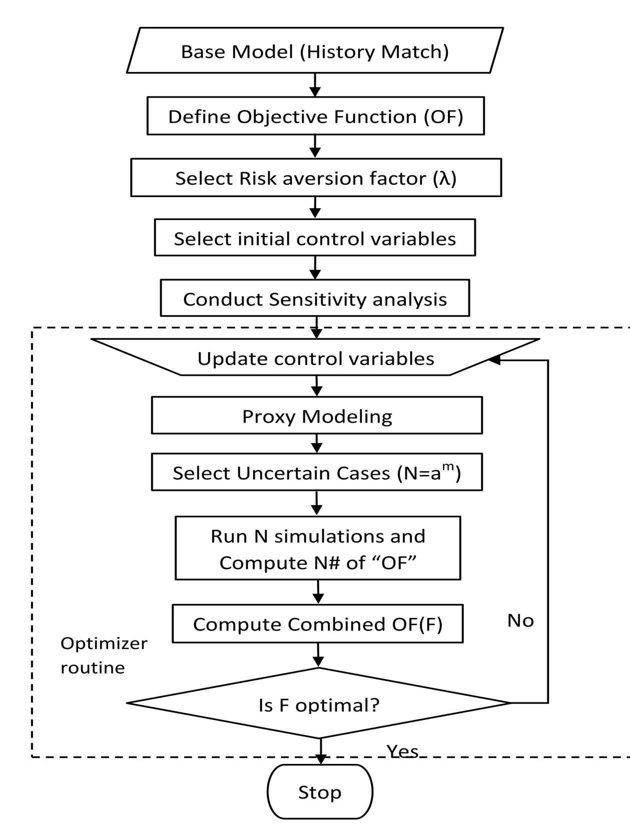
Simulation & Optimization Models



Simulation & Optimization Models



CO_2 volume profile for the baseline case. It is evident that not all available CO_2 was injected. This could be because control variables are not fully optimized.



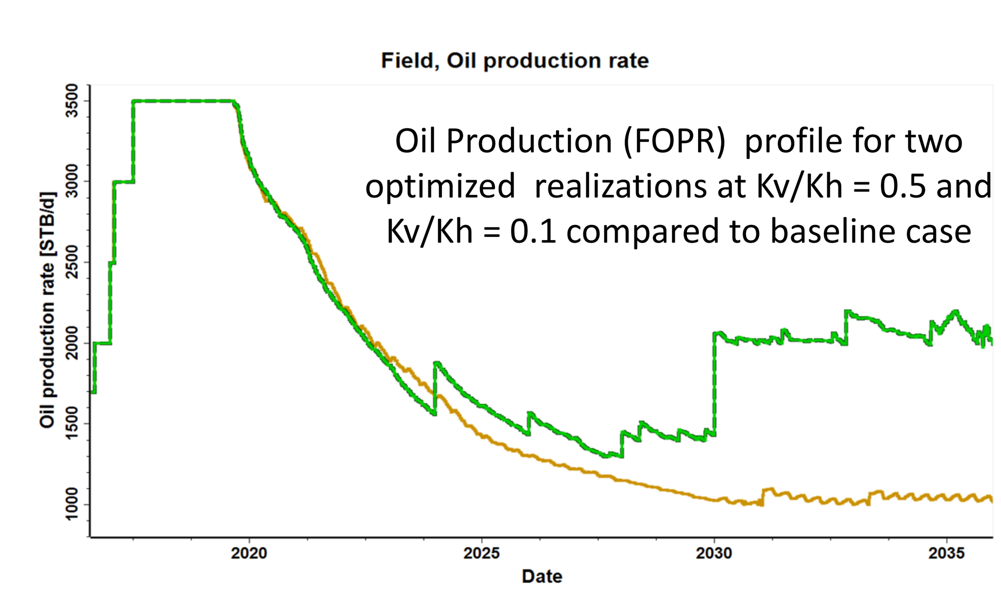
Flow chart showing detail procedure for performing optimization under uncertainty with proxy

σ = standard deviation μ = mean

λ = risk aversion factor

Sensitive control variables used in the proxy and optimization processes

Control Variables	Units	Minimum	Maximum
Gas cycle Well Group 1 (2020-2036)	months	2	10
Gas cycle Well Group 2 (2020-2036)	months	2	10
Gas cycle Well Group 3 (2020-2036)	months	2	10
Gas cycle Well Group 4 (2020-2036)	months	2	10
Water Cycle Well Group 1 (2020-2036)	months	0	3
Water Cycle Well Group 2 (2020-2036)	months	0	3
Water Cycle Well Group 3 (2020-2036)	months	0	3
Water Cycle Well Group 4 (2020-2036)	months	0	3
Production Group Rate Target (2020-2036)	stb	500	3500
Well Bottomhole Injection Pressure	psia	4700	5000
Well Bottomhole Production Pressure (2020-2036)	psia	1500	2500
Well Bottomhole Production Pressure (2016-2020)	psia	1500	2500



Oil Production (FOPR) profile for two optimized realizations at Kv/Kh = 0.5 and Kv/Kh = 0.1 compared to baseline case

Summary of uncertainty associated with CO_2 storage at different confidence levels

λ	Confidence level	Combined Vector, BScf	Stored %	Gains over Base Case
0	50	57.63	93.76	19.45
1	84	54.50	88.65	14.34
2	98	49.84	81.09	6.78

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