Application of Integrated Production System Modelling (IPSM) for long-term Production Forecasting and Optimization, a Case Study in Deepwater Assets, Malaysia

Presenter and Author:

Shodiq Khoirur Rofieq

Computer Modelling Group Ltd. (CMG)

Co-Authors:

Kok Kin Chun (PETRONAS)
Nicholas Aloysius Surin (PETRONAS)
Nurhidayah Hutamin (PETRONAS)

Sayed Mousa MousaviMirkalaei (CMG)
Gerry Adam Alwyn Syah (CMG)
Mark Edmondson (CMG)

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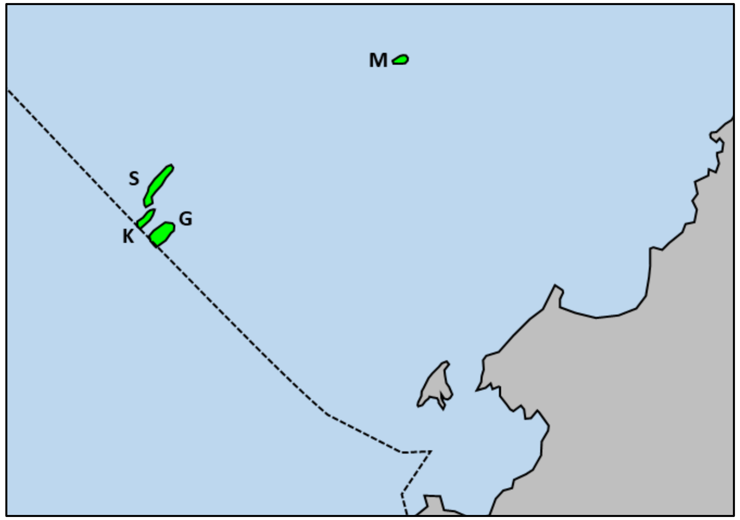
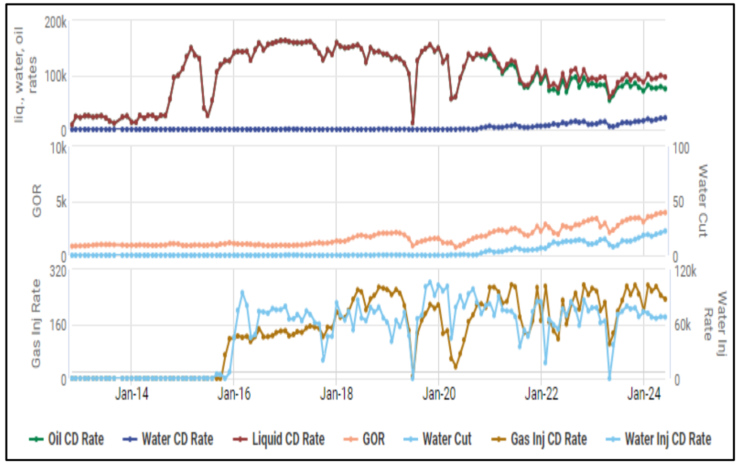
Objectives

This study aims to evaluate the advantages of utilizing an **Integrated Production System Modelling** (IPSM) approach using CoFlow software to optimize production and injection strategy while under a range of facility constraints. This includes:

1. Building an IPSM model for Field G to capture the complex interactions between facilities and reservoir performance through multi-disciplinary collaboration.
2. Performing long-term (10 years plus) forecasting, production optimization and sensitivity analysis using Field G IPSM model.

Field Background and Development History





The G field is a deepwater oil field:

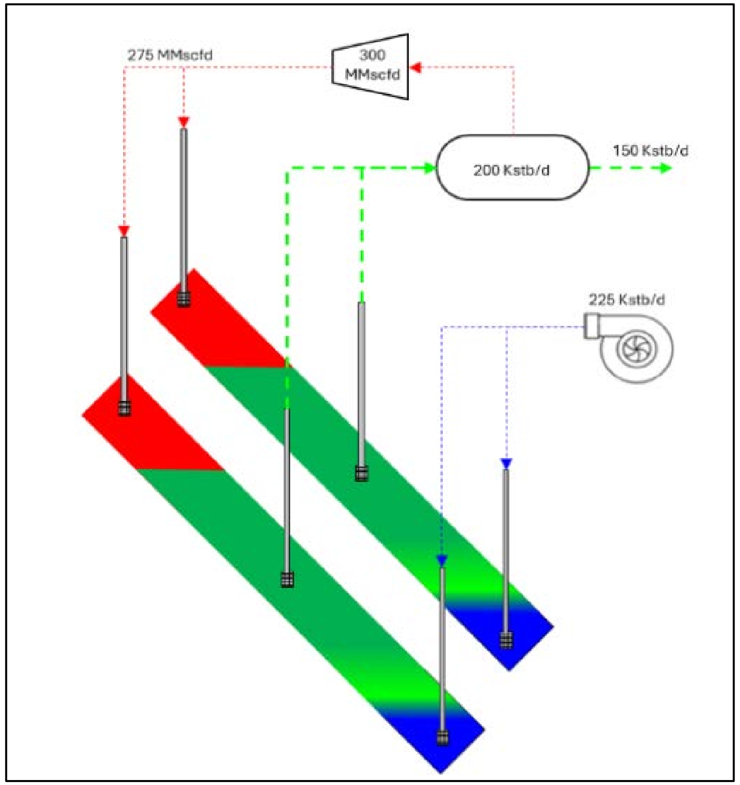
- Located 120 km offshore from Sabah, Malaysia, in water depths ranging from 2,800 to 4,000 ft.
- Discovered in 2003, FOD in 2012 via the K field Tie Back Interim Crude Evacuation System as early monetization approach.

Phase Development:

- Phase 1 development began in 2014, involved drilling of producers, water injectors, and gas injectors, along with commission of a semi-floating production system.
- 1st water injection and gas reinjection was achieved in 2015, marking the start of oil rim management to maintain reservoir pressures and enhance sweeping as secondary recovery.
- Phase 2 development began in 2019 targeting P and U reservoirs followed by Phase 3 development of same reservoirs.
- Phase 4 development has recently commenced, and subsequent studies for the next phase still ongoing.

As of 2024, cumulative oil production exceeded 400 MMstb.

Reservoir Management Plan (RMP) & Current Facilities Operating Philosophy & Constraints



The RMP strategy aims to safeguard ultimate recovery via:

- Prioritize offtake from low GOR wells to optimize production.
- Minimize reservoir pressure depletion via 2 critical control parameters which are Gas Injection to Gas Production (Gi/Gp) ratio & Voidage Replacement Ratios (VRR).

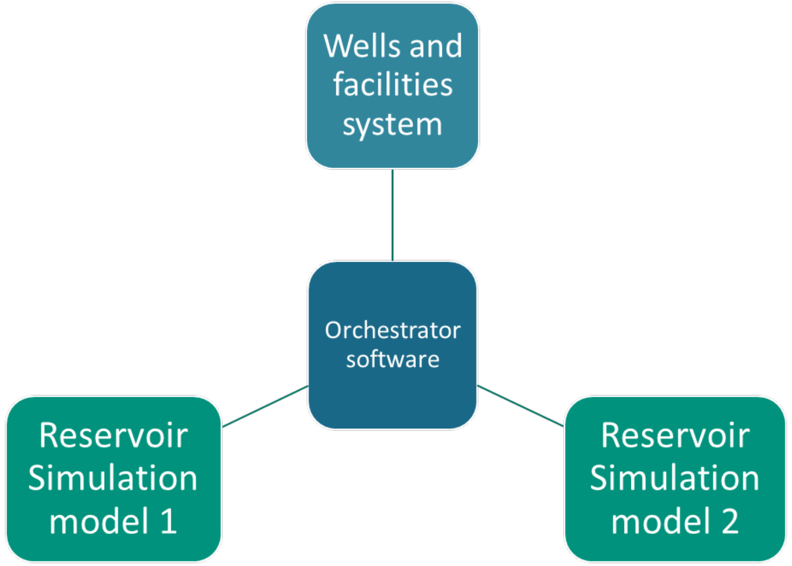
Injection Philosophy & Constraints

- The gas injection philosophy is designed to reinject all produced gas into the gas cap to preserve the gas for future gascap blowdown. As a result, the gascap is expected to expand with continued reinjection and may eventually transition to a gas recycling process
- Although water injection is sourced from seawater, its effectiveness in building up reservoir pressure is limited by the number of injectors and deteriorating injectivity.

Facilities Operating Philosophy & Constraints:

- Gas compression capacity is expected to become the limiting factor in production once the producers experience gas breakthrough
- Flexibility in managing offtake and prioritizing lower GOR wells is essential to ensure consistent production delivery

Current Optimization Study Approach and Case for Change



During early field life, when facilities are constrained by oil throughput rate:

- The optimization focus on balancing production and injection between wells to optimize recovery and maintain correct voidage replacement.

Later in field life, when gas and water handling become dominant constraints:

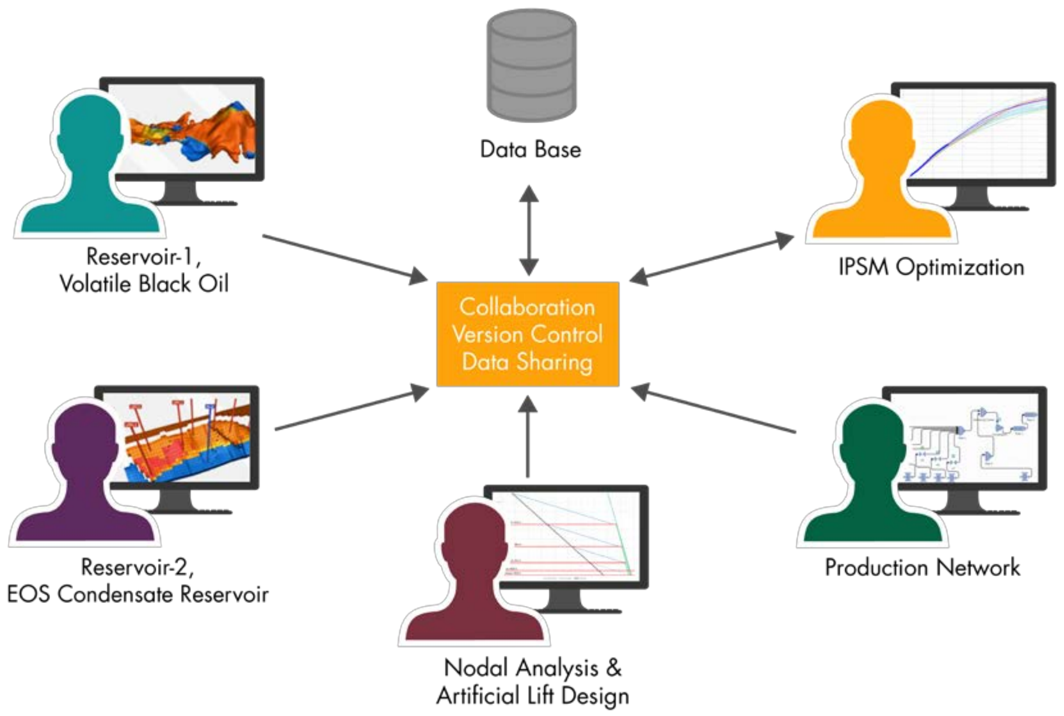
- Focus on optimizing production between wells to maximize oil production within given constraints.
- Focus on optimizing water and gas injection between zones with evidence of gas or water breakthrough.

Production & injection Optimization Study Approach In the past :

- Commercial surface network software and subsurface 3D modeling software were used and integrated via third-party platforms, but they lack flexibility in data transfer, speed, and system stability when predicting well performance and optimizing under various constraints.
- May lead to suboptimal production planning, potentially exacerbating reserves and recovery issues due to subsurface uncertainties.

Therefore, an integrated approach is proposed for production and injection optimization studies, to serve as the operating strategy.

Integrated Production System Modelling (IPSM) Approach



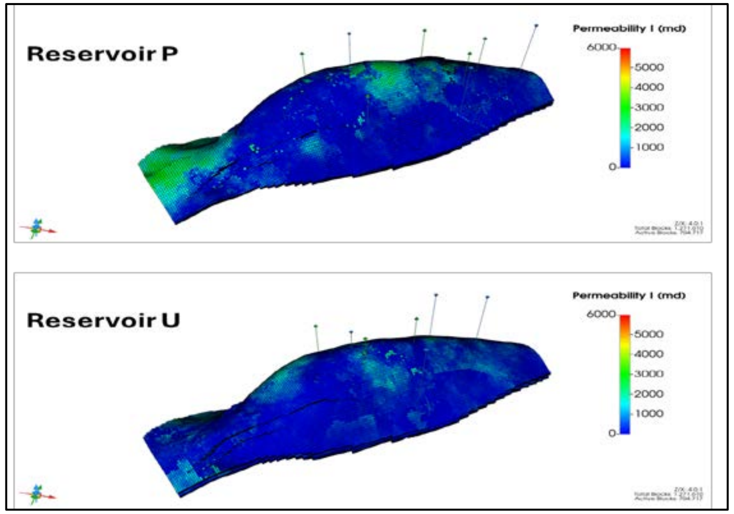
The IPSM approach (utilizing CoFlow software) has been adopted to pursue production and injection optimization studies and address current issues through several multi-faceted aspects, including:

- Multi-User
- Multi-Disciplinary
- Multi-Fidelity
- Multi-Reservoir
- Integrated Uncertainty & Optimization

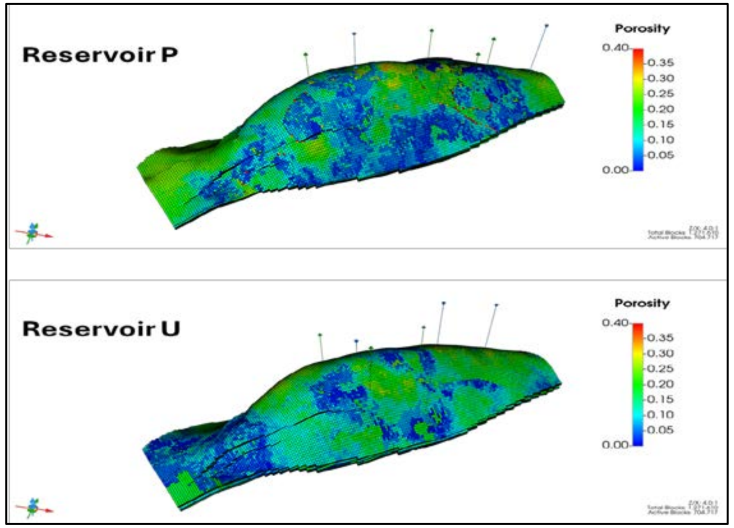
Other benefits from the IPSM approach are:

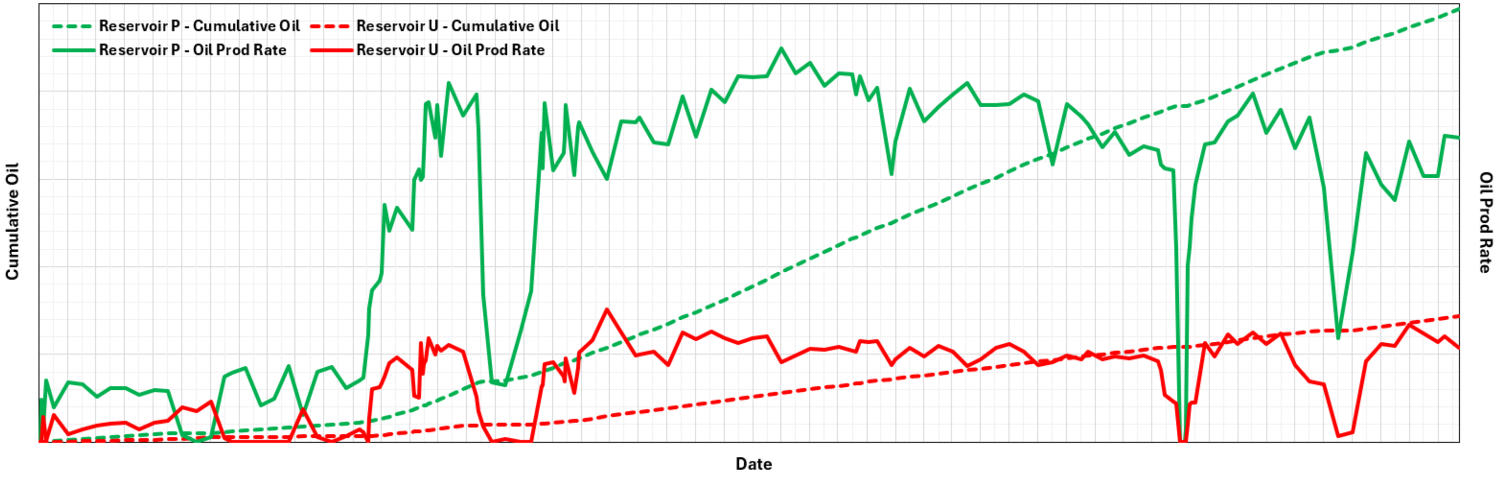
- Consistent fluid model for reservoir, wells and facility.
- Consistent injection compositions.
- Consistent calculation of pressure and temperature drops / changes from reservoirs, wells and facilities.
- Ability to handle various constraint at production and injection system without compromising run time.

Model Description – Reservoir Model

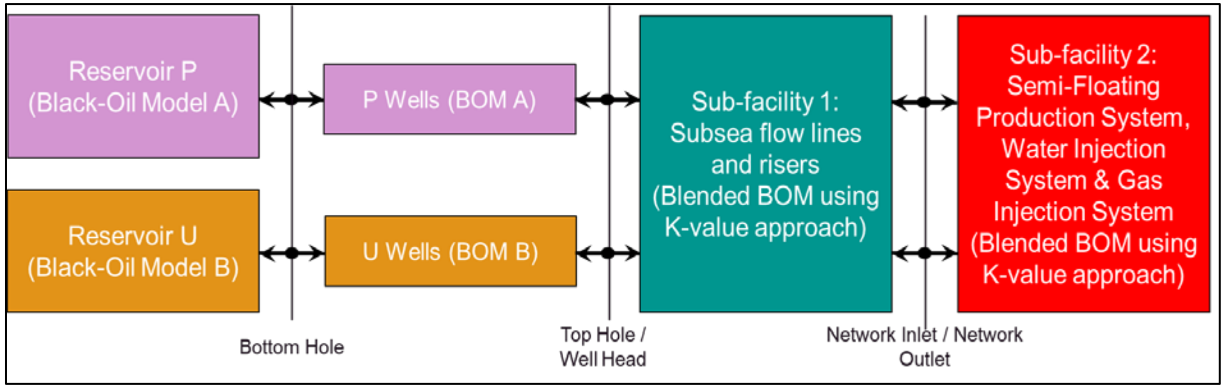


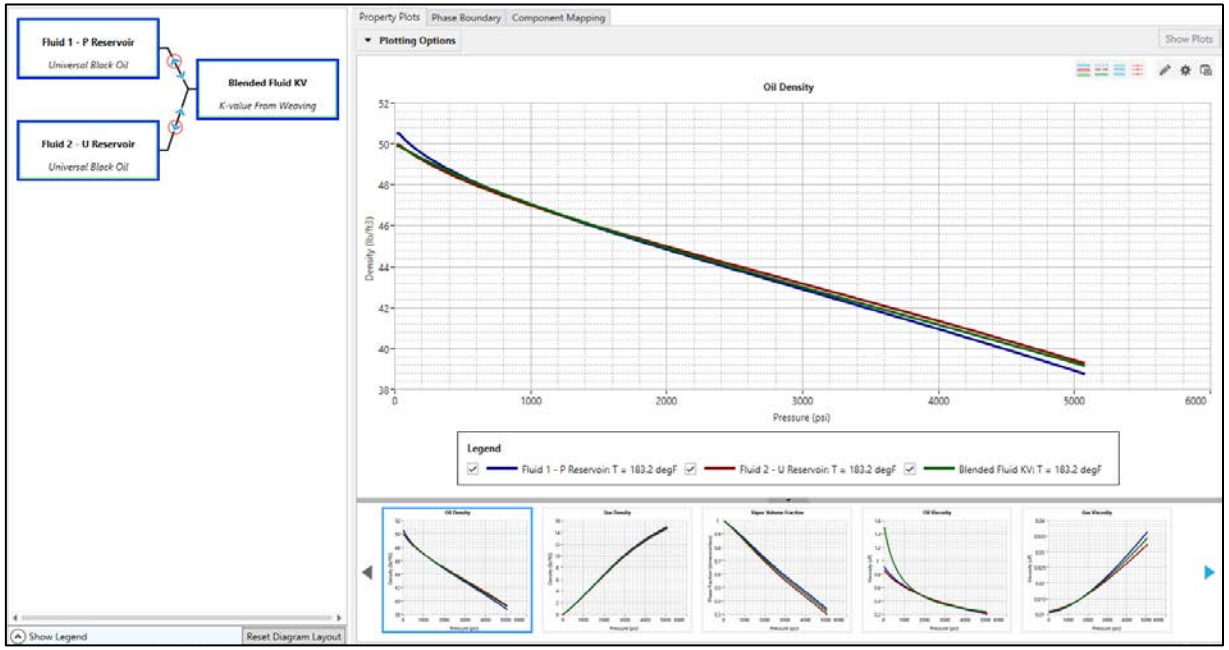
- Field G were simplified into two main reservoirs referred to as reservoir P and reservoir U. There were no comingled producer or injector wells.
- Reservoir P is on top of Reservoir U, since Reservoir U is found deeper with its top reservoir located at a depth of around 7300 ft. Reservoir U has a smaller volume of oil in-place compared to Reservoir P due to its proximity to water-oil contact that varies in depth from 7800 to 8400 ft.
- Each reservoir has its own PVT model and was defined as separate sectors (models). The picture shows the distribution of permeability (in horizontal direction) and porosity.





Model Description – Fluid Model





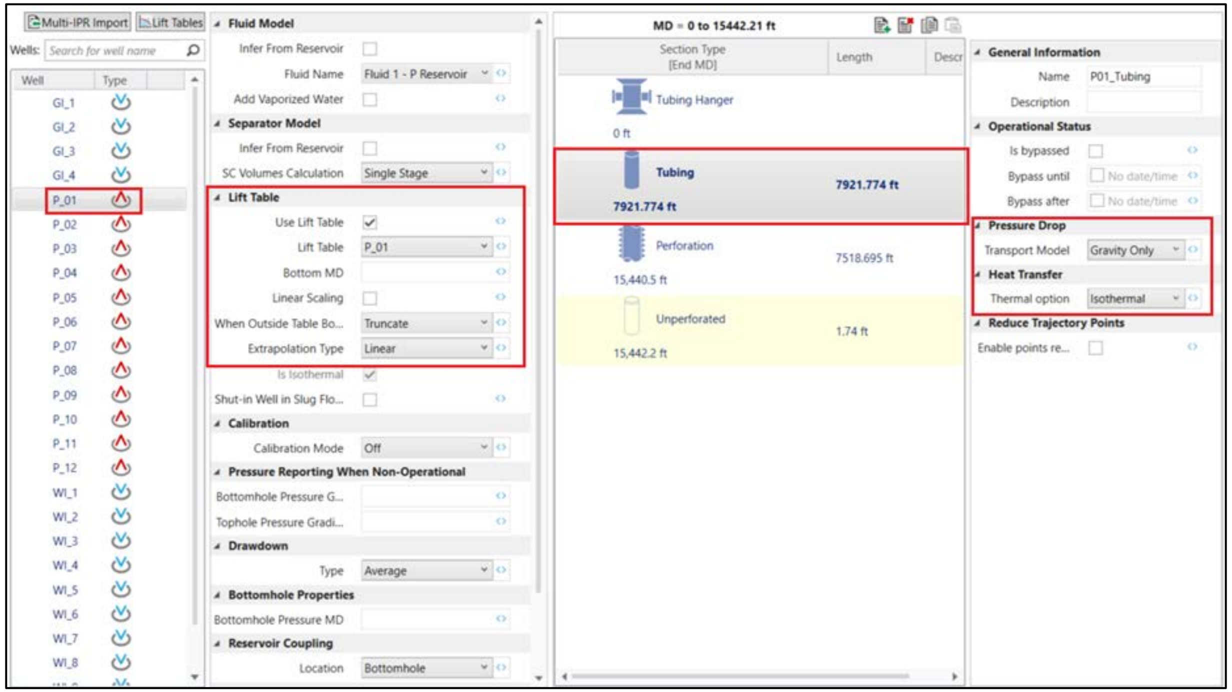
The importance of using a blended fluid for the facilities cannot be understated. The blended fluid must be optimized for performance and accuracy (fit for purpose) as shown in the figure beside.

Fluid Model - Blending

- Allows the rigor of fluid calculations to be applied where it is needed.
- “K-value From Weaving” blending option was used.
- Capable of multiple black oil models to be weaved together (blended) by converting the black oil data to a K-value equivalent.
- “Fluids Analysis” feature in as shown in the figure beside allow users to further check the model consistency.

Model Description – Well Data

Well Type	Max Production / Injection Rate (STB/day / MMscfd)	Min THP (psi)	Min BHP (psi)
Oil Producer	9,000~30,000	1500	500
Water Injector	3,000~23,000	-	4300~4900
Gas Injector	200	-	3900-5000

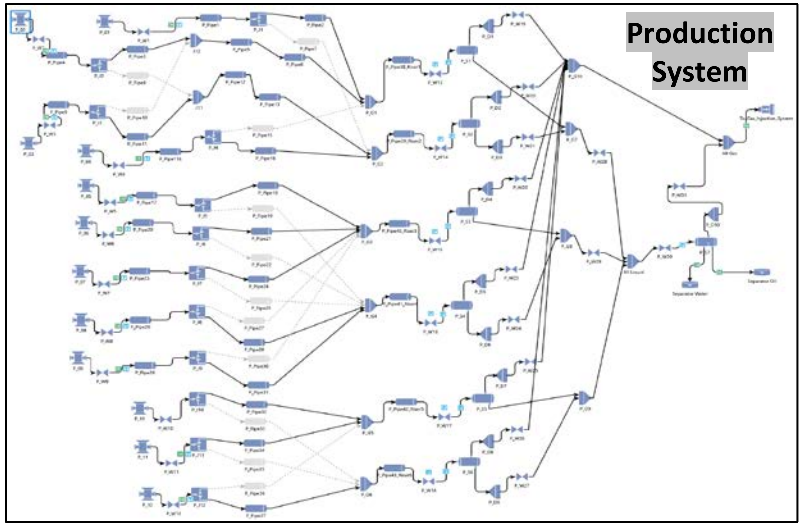


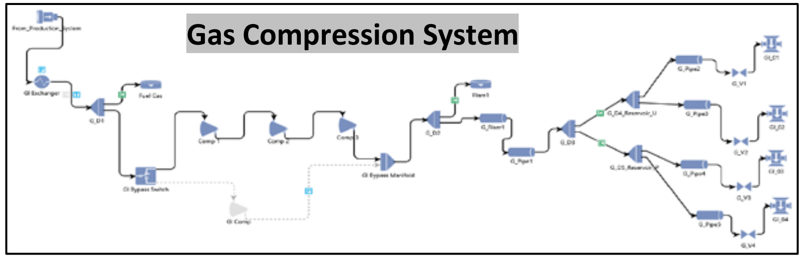
- All wells are equipped with well trajectories, perforation data, constraints including maximum rate and pressure limits at both the top node and bottomhole conditions.
- The same pressure constraint is consistently applied across all producers.

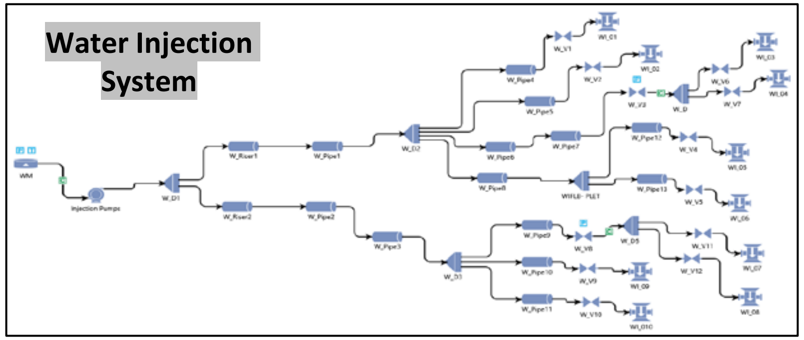
Coupling to CoFlow at well-bottom hole

- For this IPSM model, the low-fidelity option is used, which comprise of tubing tables that were exported from well modelling software.
- However, as shown by the figure, there are many fidelity options for both pressure and heat loss calculations for the well tubing equipment.

Model Description – Surface Facilities







The flowline between the wellhead and facilities/equipment is modeled, as well as the production system, gas compression system, water injection system, and produced water treatment system. Constraints for each piece of equipment are captured in the surface facilities model.

IPSM start date until Aug 2022

$$\left(\frac{GI}{GP}\right)_{U\ Res.} = 1.0$$

Offset (Fuel) = 19 MMSCF per day

Injecting the remaining gas into P reservoir.

Aug 2022 until IPSM end date

$$\left(\frac{GI}{GP}\right)_{U\ Res.} = 0.9$$

Offset (Fuel) = 19 MMSFC per day

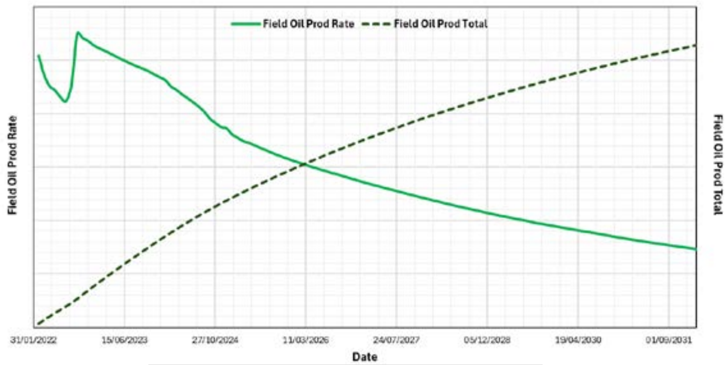
Injecting the remaining gas into P reservoir.

Gi/Gp Handling

- The Gi/GP algorithm is implemented by using Process Controllers (PC) in CoFlow. A specific PC named “Direct Setting Controller” is used to set a fixed Gi/Gp ratio into the U & P reservoir.
- This PC can be modified to vary the Gi/Gp target ratio and offset (fuel gas) over time. The PC modification is activated after Aug 2022.

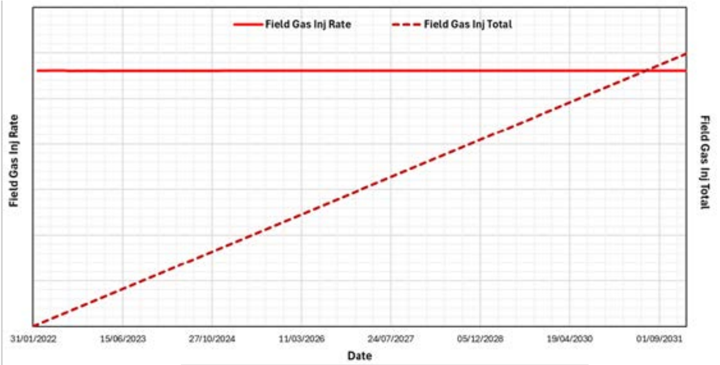
Base Case Results & Discussion

- The forecast of the IPSM model was set for 10 years, starting from 2022 until 2032. CoFlow's Network Constrained solver (NCS) was used to honor facility and well level constraints as well as GOR-based cutback for the producers.
- The Gi/Gp ratio was set at 1.0 and handled by Process Controllers from Aug 2022 onwards. The water injection VRR for the field was set at 0.224 (as per RMP).

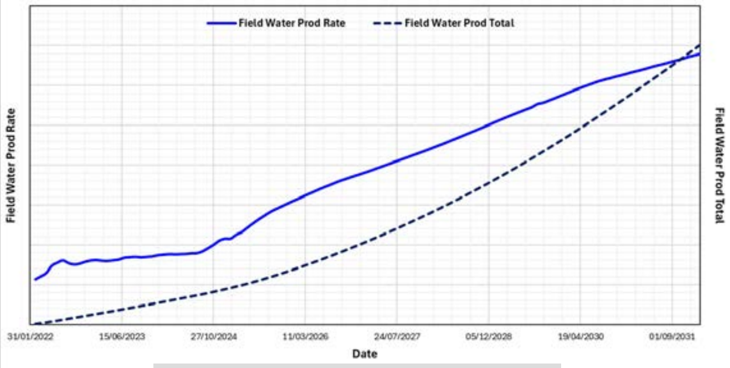


Field Oil Production

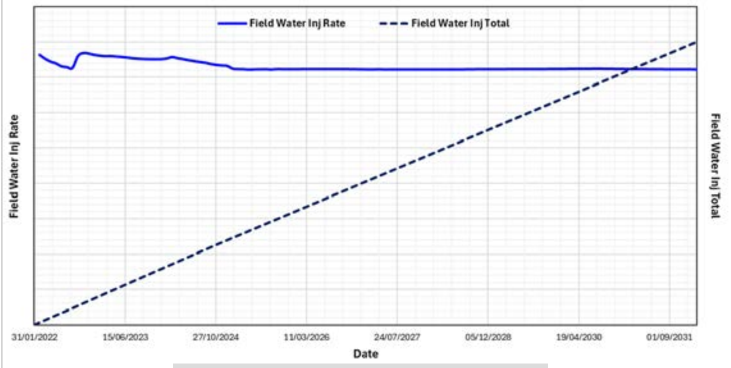
Field Gas Production



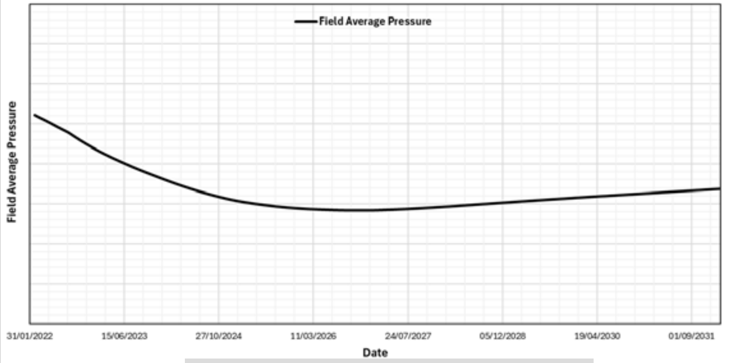
Field Gas Injection



Field Water Production

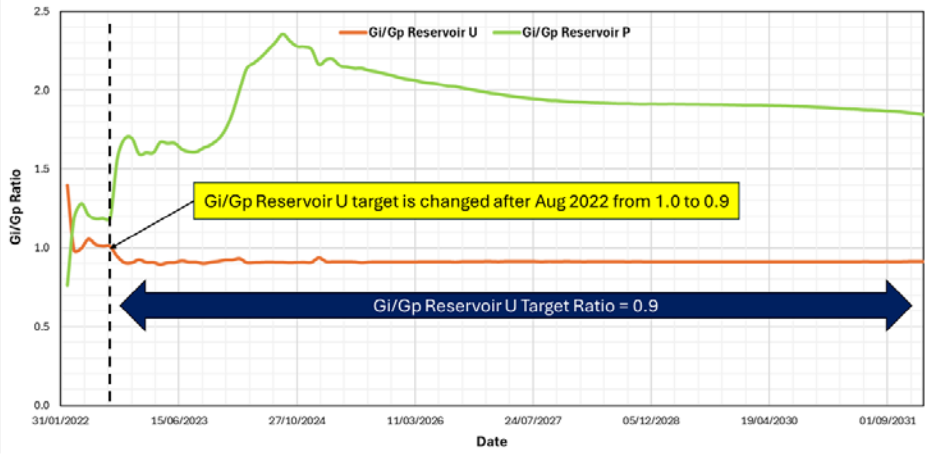


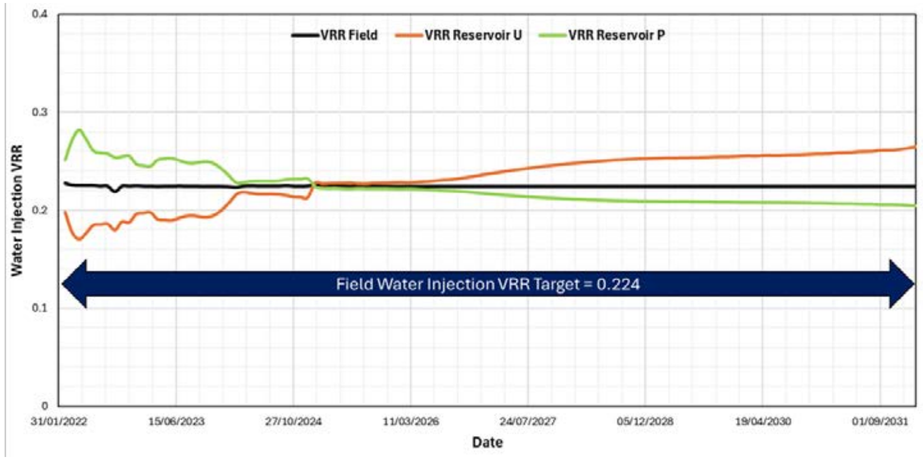
Field Water Injection



Field Average Pressure

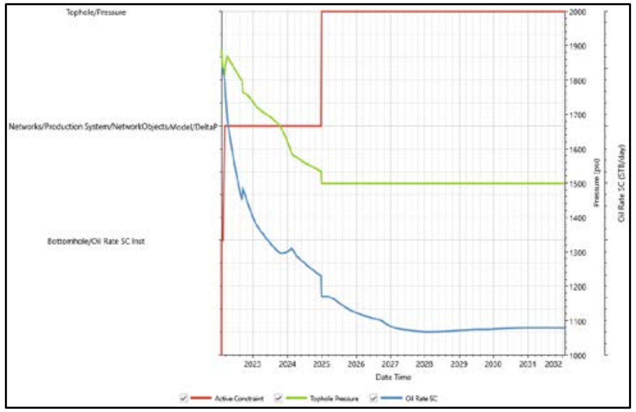
Base Case Results & Discussion

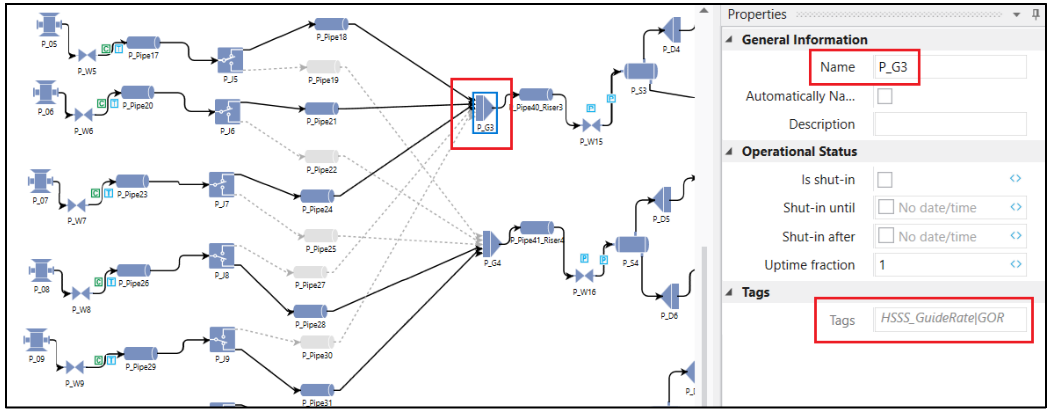




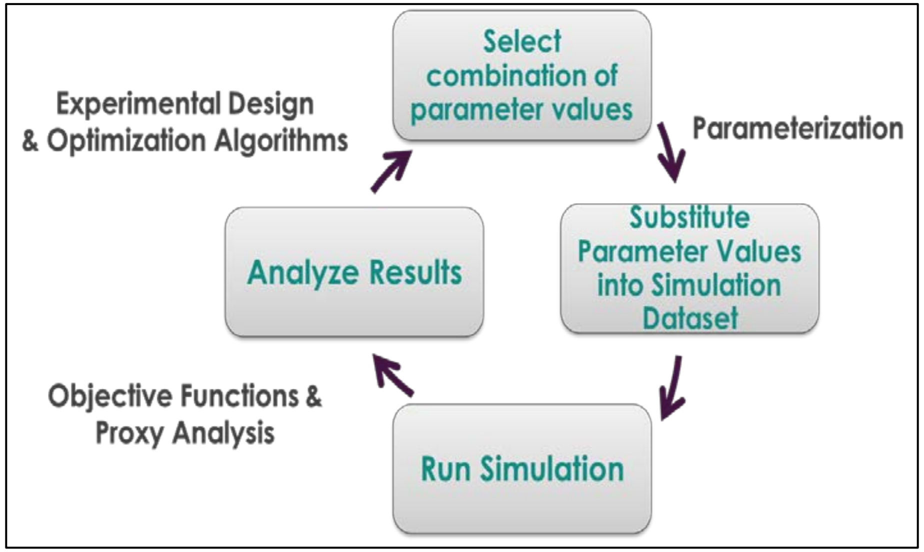
Cutback rules for producer - Guide Rates based on GOR :

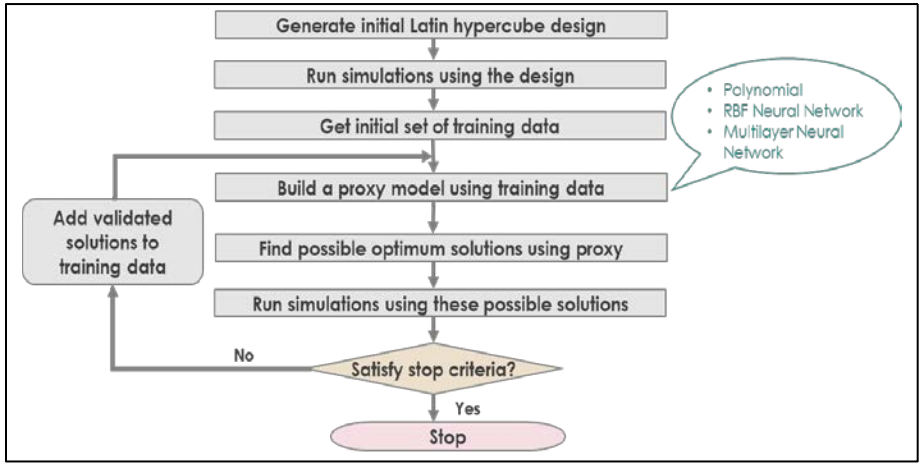
- The model had been set with GOR guide rate cutback tags on the manifolds downstream of each producer thus instruct the network solver to cutback the production based on the GOR of each well (higher GOR, lower guide rate).
- Fixed inlet pressures are set for each separator, imposing a minimum back pressure on the wells and this results in well-head pressures being dynamically controlled based on pressure drops across the riser, pipes, and separators downstream of the well-head.





Optimization Approach





The two most important operational parameters:

- Voidage Replacement Ratio (VRR) & Gi/Gp ratio.

Objective:

- Optimize oil production by utilizing both parameters and by using an automated optimization tool (CMOST).

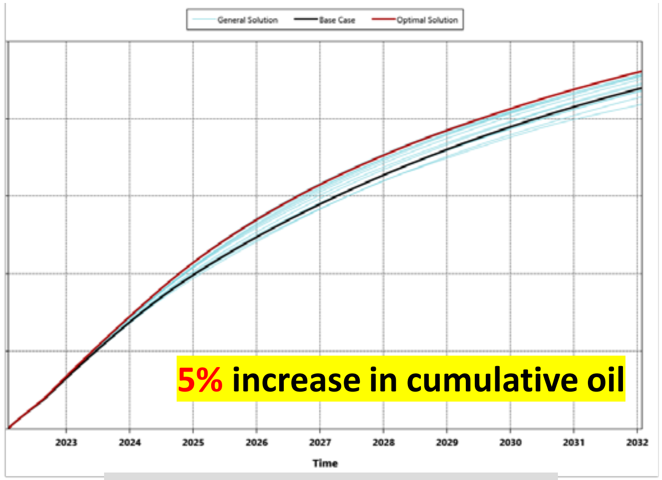
Parameter values:

- VRR was varied from 0.18 to 0.34 while Gi/Gp ranging from 0.6 to 1.2.

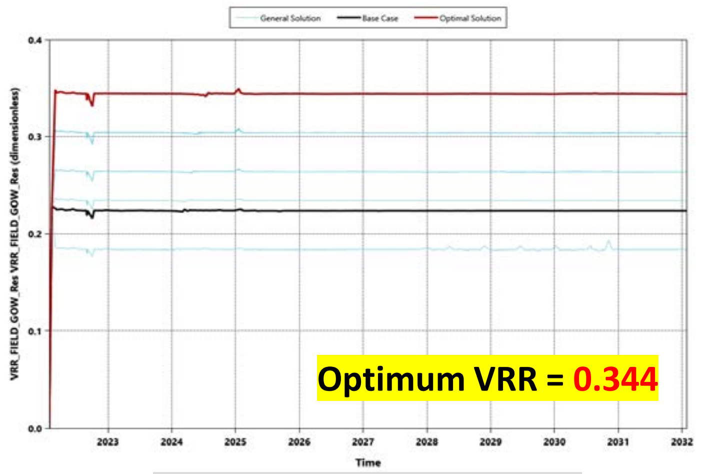
Optimization Process

- Using the Latin hypercube experimental design, the two optimization parameters are varied simultaneously through the response surface methodology (RSM). This statistical approach maximizes information extraction with minimal simulation runs.
- The objective function (OF), which is cumulative oil at the end of the simulation, is analyzed by fitting a response surface to the OF results.
- CMOST first builds a proxy model, typically a quadratic polynomial function, and then uses this proxy to find the optimal solution.

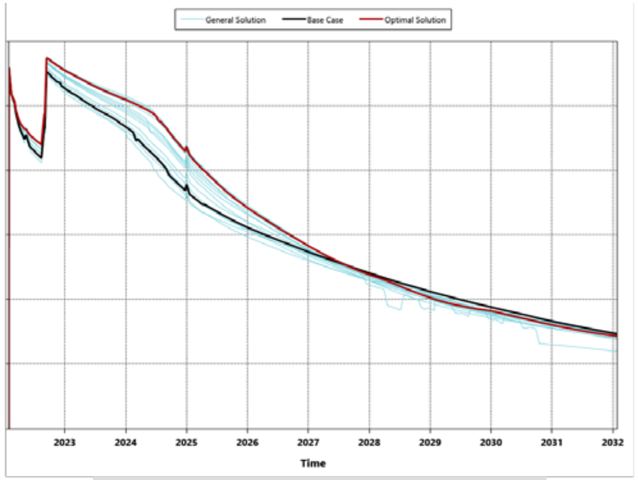
Optimization Results & Discussions



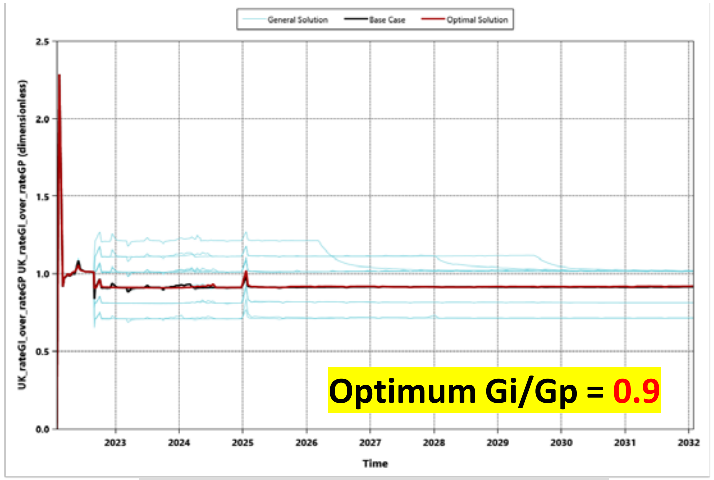
Field Oil Production Total



VRR for The Whole Field



Field Oil Production Rate



Gi/Gp Ratio for Reservoir U

14 cases were generated and run:

- Base case is black bold curve.
- Optimum solution is a red bold curve.
- All the other experiments (cases) are shown in light blue color.

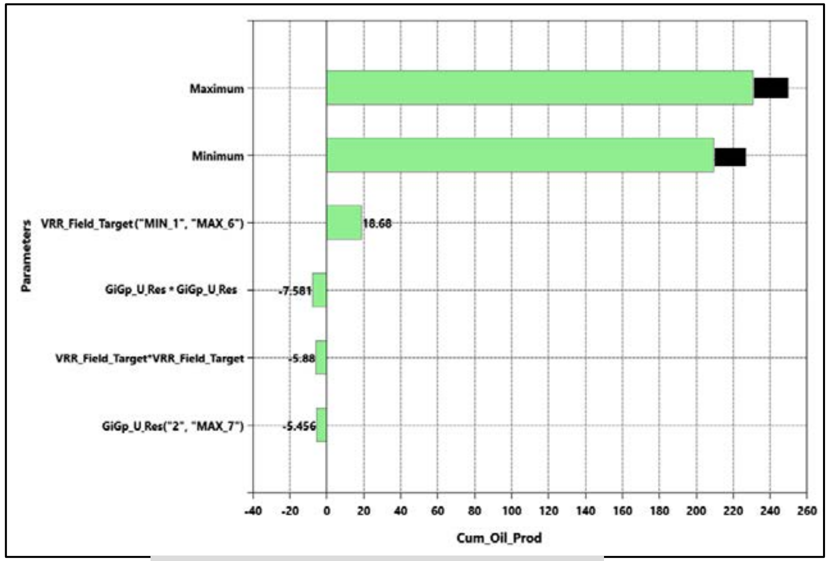
Optimum case

- Case with the highest cumulative oil production.
- Combination of a VRR value of 0.344 and a Gi/Gp value of 0.9.
- Cumulative production is 5% higher compared to the base case.

Discussion:

- Gi/Gp value greater than 1 could not be maintained as the upper bottom-hole pressure limit of the gas were reached, hence delta pressure get less caused the injection rate drop
- Optimum case suggest higher VRR indicating with more water injection could counter the gas cap over-expansion.

Optimization Results – Sensitivity Analysis & Uncertainties Analysis



SA - Tornado Plot

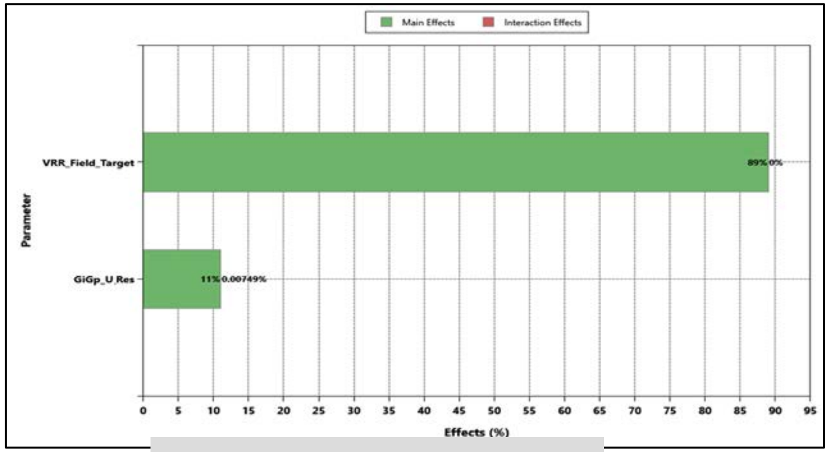
Using proxy models, CMOST is to be able to conduct additional analysis such as sensitivity analysis (SA) and uncertainty analysis (UA).

Sensitivity Analysis results from Tornado Diagram:

- "VRR_Field_Target" is the most sensitive parameter, indicates a strong linear relationship between VRR parameter and cumulative oil. "GiGp_Res" indicates a negative quadratic relationship between Gi/Gp parameter and cumulative oil.

Sensitivity Analysis results from Sobol Plot:

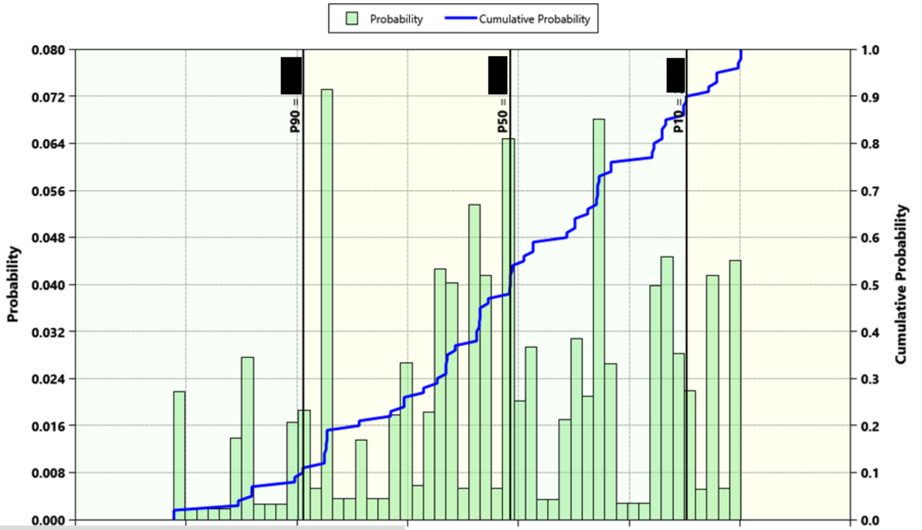
- Indicated VRR parameter contributes 89% to the variance in the value of the objective function. The Gi/Gp parameter only contributes around 11% of the variance.



SA - Sobol Plot

Uncertainty analysis which takes the form of a Monte Carlo simulation.

- Utilizing the proxy, thousands of unique predictions are then made to assess the probability density function of the objective function which is shown by the green bars.



UA - Probability distribution

Conclusions

- The G field IPSM model was operated under both network-level and well-level constraints, with the primary limitation being the surface network's gas handling capacity. Produced gas was separated and re-injected using a custom Gi/Gp algorithm. CMOST was employed to maximize cumulative oil production by optimizing the water injection VRR and the Gi/Gp ratio. VRR proved to be the most significant parameter, with higher values leading to greater oil production. The Gi/Gp ratio was less critical but influenced production more at lower VRR values.
- The IPSM model facilitated the simulation of the entire fluid journey, enabling long-term optimization (10 years plus) and demonstrating the value of integrated simulation for complex, multi-reservoir projects. The model's fast runtime allowed multiple scenarios to be evaluated, leading to about 5% increase in total oil recovery.
- This multidisciplinary integration improved collaboration, captured complex interactions, and ensured continuous optimization under existing constraints, ultimately enhancing reservoir management, maximizing reserves recovery, and increasing asset value through production acceleration.

Thank you for your attention.