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Economic Implications of Initializing Reservoir Simulation Models with Compositional Grading Models

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Abstract — Accurate reservoir simulation initialization plays a vital role in predicting hydrocarbon recovery and assessing the economic potential of oil and gas projects. However, many traditional models assume uniform fluid composition and often ignore compositional grading (CG) effects such as gravity, temperature gradient, and thermal diffusion. This limitation can lead to unrealistic production forecasts and poor economic evaluations. Therefore, this study evaluated the economic viability of initializing reservoir simulation models with CG models that better capture real reservoir behavior. Using secondary data from the literature, cumulative oil and gas production data were analyzed for five models such as constant composition, isothermal, zero thermal diffusion, Haase's, and Kempers' CG models, respectively. Deterministic discounted cash flow (DCF) analysis was performed using Microsoft Excel at a 12% discount rate to compute Net Present Value (NPV) and Profitability Index (PI) for each model. The findings revealed that all models produced positive NPVs, ranging from \$1.85 × 10^8 to \$3.67 × 10^8 and PIs greater than 1, indicating strong profitability. The constant composition model achieved the highest PI of 3.675, mainly due to its overestimation of oil production of about 41.7 million barrels. However, the nonisothermal CG models recorded slightly lower oil output but showed improved financial performance through additional gas revenues exceeding \$25 million, which compensated for their higher modeling costs. The study concludes that incorporating CG effects in reservoir models not only enhances simulation accuracy but also improves economic viability, making it a practical approach for sustainable reservoir development.

Keywords— Economic Implication, Reservoir Simulation, Discounted Cash Flow, Profitability Index, Compositional Grading models.

I. INTRODUCTION

Petroleum reservoir simulation is a cornerstone in the petroleum industry, serving as a crucial tool for optimizing the extraction of hydrocarbons from subsurface reservoirs (Lee et al, 2018). Through the development of numerical models such as reservoir simulation models, engineers and decision-makers can predict reservoir behavior, assess potential recovery strategies, and make informed choices on reservoir management (Aziz & Settari, 1979; Fanchi, 2006; Ahmadi, 2019; Smith & Johnson, 2019).). The success of reservoir simulation is contingent upon the accurate representation of reservoir properties, including fluid composition, permeability, and porosity (Aziz & Settari, 1979; Cheng, et al, 2020).

Although, much attention has been given to factors such as permeability and porosity in reservoir simulation, the compositional grading effect has often been overlooked. Compositional grading (CG) or compositional variation with depth refers to the variation in fluid composition across different layers of the reservoir. (Schulte, 1980; Whitson & Belery, 1994; Igwe et al, 2020; 2022). Reservoir fluids typically consist of a mixture of hydrocarbons with varying molecular weights (Igwe & Ujile, 2015; Igwe & Taylor, 2023) and the distribution of these components can vary spatially within the reservoir. This variation can significantly impact fluid flow behavior, phase behavior, and ultimately, the recovery efficiency of hydrocarbons (Aziz & Settari, 1979; Montel & Gouel, 1985; Chen et al., 2006; Nikpor et al. 2011).

Recent advancements in technology, such as more sophisticated well logging and seismic imaging techniques, have provided reservoir engineers with a wealth of data for improving reservoir models. Despite these advances, the incorporation of compositional grading remains a challenging aspect due to computational complexities and the intricacies of fluid behavior under varying compositions (Reynolds et al., 2015). This challenge has led to a prevailing gap in understanding how the economic aspects of reservoir management are affected by neglecting compositional grading (Patel & Gomez, 2020).

Moreover, the economic landscape of the petroleum industry is continually evolving, influenced by factors such as fluctuating oil prices, environmental considerations, and geopolitical dynamics. In this context, accurate reservoir simulation becomes not only a technical imperative but also a strategic necessity for oil and gas operators aiming to navigate the complexities of the global energy market (Bose et al., 2020). Therefore, a comprehensive exploration of the economic implications associated with compositional grading is timely and aligns with the industry's overarching goal of maximizing resource recovery while ensuring financial viability.

As the industry faces increasing pressure to adopt sustainable practices and mitigate environmental impact, the economic feasibility of reservoir management strategies gains even more significance. Understanding how accurately considering compositional grading can contribute to sustainable and economically viable extraction practices is not only scientifically relevant but also aligns with broader industry trends and goals.

Traditional reservoir simulation models often simplify fluid composition assumptions, neglecting CG effects. Current research efforts have shown that this oversimplification leads to inaccurate predictions of reserve estimates and reservoir performance prediction, affecting economic assessments and decision-making processes (Lake, 1989; Igwe et al 2020; 2022). These research efforts also recommended initializing reservoir simulation models adequately with factors responsible for CG to minimize detrimental technical consequences such as underestimation of gas reserves and cumulative gas production, respectively, and overestimation of oil reserve and cumulative oil production, respectively (Igwe et al, 2020). However, there have not been significant research efforts towards quantification of the economic implications of adequately initializing reservoir simulation models with factors such as gravity effect, temperature gradient, and thermal diffusion, which contributes significantly to CG in the reservoir. Initializing reservoir simulation models with these CG contributing factors will increase the complexities of the resultant models, which will in turn increase the simulation and overall field development cost, respectively. It is therefore, necessary to evaluate the economic viability of adequately initializing reservoir simulation models by accounting for the combined effects of the factors responsible for CG in the reservoir. Hence, the need for this current research effort.

II. MATERIALS

The materials used in this research are as follows:

- Microsoft Excel software
- Secondary data (oil and gas cumulative production data) from Igwe et al (2022)

Method

Models Used

The CG models used in this work are:

- Constant Composition (Control Data) model
- Isothermal CG model
- Zero Thermal Diffusion CG model
- Haase's Thermal Diffusion CG model
- Kamper's Thermal Diffusion CG model

Economic Assessment

The modelling of the economic implications of the predicted performances of the various initialized reservoir models are presented in this section. Reservoir performance indicators considered for the economic assessment are the cumulative oil and gas produced by each initialized reservoir model (reservoir model initialized without CG model (control data); reservoir model initialized with isothermal CG model; reservoir simulation model initialize with passive (zero) thermal diffusion CG model; reservoir simulation model initialized with Haase's thermal diffusion model; and reservoir simulation model initialized with Kamper's CG model). Economic models were built based on oil and gas productions, respectively, for each initialized reservoir models. Undiscounted cashflow model and discounted cashflow model were used to assess the economic implications of the various initialized reservoir models.

Cash Flow Model

Project cashflow is one of the available economic models for assessing the economic viability of oil and gas investments. It generates parameters that measures the value of investment in the project and the economic performance of the entire venture. Non-cash items such as depreciation of asset value are introduced in order to obtain meaningful measures of short-term performance. A project Cashflow is therefore, an assessment of money needed or generated on an annual basis by the project. The economic status of the venture (cash surplus or cash deficit) is obtained by subtracting the cash out from the cashin. The cash out is the sum of money invested in the venture, such as technical costs and host government take, while the cashin is the revenue generated by the project. Investors in the project pays for the initial deficit in anticipation of subsequent cash surplus as their profit (Shell Learning Centre, 2001).

Two sets of cashflow models were constructed using Microsoft Excel and based on the base case simulated oil and gas productions. One set of five cashflow models for the various initialized reservoir model based on oil production and the other set based on gas production. The main reason for constructing cashflow model for gas production case is to assess whether the additional revenue from sales of gas could improve the economic performances of CG initialized reservoir models. The following are examples of the cashflow models:

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$$Gross\ Revenue = Production * Oil\ Price\ or\ Gas\ Pri \quad (1)$$

$$Total\ Capex = Sum\ of\ all\ Capex\ items \quad (2)$$

$$Fixed\ Opex = Percentage\ of\ Total\ Capex\ for\ each\ y \quad (3)$$

$$Variable\ Opex = \$/bbl * Oil\ Production\ per\ year \quad (4)$$

$$Variable\ Opex = \$/mcf * Gas\ Production\ per\ year \quad (5)$$

$$Total\ Opex = Fixed\ Opex * Variable\ Opex \quad (6)$$

$$Royalty = Gross\ Revenue * Royalty\ Rate \quad (7)$$

$$Depreciation = First\ year\ Total\ Capex * Depreciatio \quad (8)$$

$$Fiscal\ Cost = Total\ Opex + Royalty + Depreciation \quad (9)$$

$$Taxable\ Income = Gross\ Revenue - Fiscal\ Costs \quad (10)$$

$$Tax = Taxable\ Income * Tax\ Rate \quad (11)$$

$$Cashin = Gross\ Revenue \quad (12)$$

$$Technical\ Costs = Total\ Capex + Total\ Opex \quad (13)$$

$$PreTax\ Cashflow = Cashin - Technical\ Costs \quad (14)$$

$$Government\ Take = Royalty + Taxes \quad (15)$$

$$Net\ Cashflow = Pre-Tax\ Cashflow - Government\ Take \quad (16)$$

$$Cumulative\ Cashflow = Net\ Cashflow\ for\ the\ first\ year \quad (17)$$

For subsequent years,

$$Cumulative\ Cashflow = Previous\ year\ Cumulative\ Cashflow + Present\ year\ Net\ Cashflow \quad (18)$$

Profitability Indicators from Cumulative Cashflow Model

The cumulative cashflow is the consecutive total of the annual cash calls (Net cashflow) of a venture. Cumulative cashflow model provides some measures of economic performance of a venture. Economic performance information derived directly from the cumulative cashflow model associated with this work include:

- Ultimate Cash Surplus: This is the maximum cash surplus generated by the venture before its economic limit.
- Exposure: It is the maximum value of cumulative cash deficit posted by the project. It represents the amount the investor stands to lose if the project fails to breakeven.
- Payout Time: It is the time taken for the cumulative cashflow to turn positive. It represents the amount of time the investor will take to breakeven (recover his initial investment).

Elements of Project Cashflow Model

A typical oil and gas project cash-flow model consist of three major classes of economic elements: the cashin elements or items; the technical cost items; and host government take or fiscal regimes. Depreciation is introduced to generate the shot-term value of the project.

Cash in Elements

The only cash in element considered in this work is the gross revenues generated from the sale of hydrocarbon (oil and gas) produced from the initialised reservoir models. The cumulative oil and gas produced per year by the various initialized reservoir models are presented in Tables 1 and 2, respectively.

Table 1: Oil produced per year by the Various Initialized Reservoir Models (Igwe et al, 2020)

Year	Without CG (stb)	Isothermal (stb)	Zero Thermal (stb)	Haase's (stb)	Kempers (stb)
1	890192	890192	890192	890190.9	890190.81
2	4421931.5	4421927	4421929	4421930	4421931
3	7953671.5	7953671.5	7953669	7953669	7953674
4	11495087	11495087	10137044	10127552	10131378
5	15026828	15026828	11748556	11734893	11740547
6	18558566	17951084	12792383	12748888	12767917
7	22090306	19711430	13316744	13263879	13287220
8	25631598	21352030	13898335	13839418	13865574
9	29163156	22709178	14485508	14422599	14450574
10	32695328	23819946	15128241	15060694	15090825
11	36227064	24846994	15793552	15724047	15755037
12	39184368	25832734	16489506	16417500	16449594

13	40833940	26778388	17187820	17114614	17147200
14	41739724	27469080	17692864	17619434	17652080

Table 2: Gas produced per year by the Various Initialized Reservoir Models (Igwe et al, 2020)

Year	Without CG (mmscf)	Isothermal (mmscf)	Zero Thermal (mmscf)	Haase's (mmscf)	Kempers (mmscf)
1	887560384	2974361344	5544934400	5533529088	5539735040
2	4408859648	1.2276E+10	2.575E+10	2.573E+10	2.5742E+10
3	7930159104	2.0263E+10	5.0144E+10	5.0309E+10	5.024E+10
4	1.1461E+10	2.8988E+10	6.9192E+10	6.9454E+10	6.9338E+10
5	1.4982E+10	4.1133E+10	8.282E+10	8.3173E+10	8.3015E+10
6	1.8504E+10	5.6674E+10	9.0494E+10	9.0696E+10	9.0605E+10
7	2.2025E+10	6.5281E+10	9.4415E+10	9.4593E+10	9.4513E+10
8	2.5534E+10	7.2945E+10	9.7996E+10	9.8167E+10	9.809E+10
9	2.9004E+10	7.9289E+10	1.0144E+11	1.0161E+11	1.0154E+11
10	3.2978E+10	8.3946E+10	1.0475E+11	1.0492E+11	1.0484E+11
11	3.9105E+10	8.7566E+10	1.078E+11	1.0798E+11	1.079E+11
12	5.0055E+10	9.0591E+10	1.1064E+11	1.1082E+11	1.1074E+11
13	5.969E+10	9.3361E+10	1.1342E+11	1.1359E+11	1.1351E+11
14	6.5142E+10	9.5275E+10	1.1546E+11	1.1563E+11	1.1555E+11

Technical Cost Elements

Technical cost elements are grouped into:

- Capital Expenditures (Capex) – all project costs that generate an asset value of more than one year is referred to as capital expenditures. The project capex are grouped into two main capital cost items (drilling/well costs and production facilities cost)
- Operating Expenditures (Opex) – these include maintenance costs, cost of reservoir simulation study, insurance, lifting cost, well repairs and workover costs, overheads and all other costs of short-lived assets, perishable goods and services. A fixed opex is assumed based on percentage of total capex while a variable opex per barrel of oil produced or per mcf of gas produced is assumed. The additional costs due to initialized reservoir model complexity was accounted for in the fixed opex for oil production cashflow model presented in Table 3. Tables 4 and 5 presents the other technical cost elements for oil and gas production cash-flow models, respectively.

Table 3: Different Fixed OPEX for Oil Production Cashflow Models due to Additional Cost Associated with Reservoir Model Complexity.

Models	Description	Fixed Opex/Year
Constant Composition	Without CG (Simple Model)	30 % of Total Capex
Isothermal	Effect of Gravity only	30.5 % of Total Capex
Zero Thermal Diffusion	Effects of gravity and temperature gradient	31 % of Total Capex
Haase's	Effect of gravity and thermal diffusion	31.5 % of Total Capex
Kempers	Effect of gravity and thermal diffusion	31.5 % of Total Capex

Table 4: Assumptions for Oil Production Based Cashflow Models

Item	Unit	Amount ($)
Oil Price	$/bbl	53
well cost (CAPEX)	$	600,000,000
Surface Facilities CAPEX	$	215,636,363
Variable OPEX	$/bbl	5
Royalty	$	5
Depreciation	%	25
Tax	%	20
Discount Factor	%	12

Table 5: Assumptions for Gas Production Based Cashflow Models

Item	Unit	Amount ($)
Gas Price	$/scf	2
Drilling/well costs (Capex)	$	0
Production Facilities Capex	$	45,000,000
Fixed Opex	% Total Capex/Year	30
Variable Opex	$/scf	0
Royalty	$	0
Depreciation	%	25
Tax	%	0
Discount Factor	%	12

Hydrocarbon Prices and Fiscal Regimes

A constant oil and gas price were assumed as shown in Tables 4 and 5, respectively. This work adopted the Nigeria's Petroleum Industry Act, 2021 for the assumed fiscal regime. The assumed fiscal regime (royalty and tax – host government take) for oil and gas production based cashflow models are presented in Tables 4 and 5, respectively. The adopted PIA 2021 fiscal regime is based on oil and gas production rates for deep-water field and indicated zero fiscal incentive for gas production. This is to encourage gas commercialization and curtail gas faring in Nigeria.

Depreciation

Although, depreciation on its own is not an element of the cashflow, it is used only in the calculation of tax (fiscal cost). The Straight-Line depreciation method was used for this work. The total capex is depreciated in equal amount over certain number of years. For the purpose of this research, the total capex was depreciated at 25 % for the first year as indicated in Table 4 and 5.

Discounted Cashflow Model

Economic performance information obtained from the cumulative cashflow model are not true profitability indicators since they did not account for the future economic performance of the project. To generate true profitability indicators for the project, the future value (FV) of the project net cashflow need to be converted to present value (PV). The process of converting a FV to a PV is known as discounting. The principle of compound interest can be used to bring the FV to PV. The principle of compound interest states that if a principal amount P is invested for t number of years at an interest rate r (in fraction), it will increase to a future value P (Shell Learning Centre, 2001). That is:

$$F = P*(1+r)^t \tag{19}$$

Therefore, the present worth, P of the future value is thus:

$$P = F*(1+r)^{-t} \tag{20}$$

where,
P = present Value ($)
F = future value ($)
r = discount rate (fraction)
t = reference date (year)

Profitability indicators obtained from the discounted cashflow model are the net present value (NPV) and the profitability index (PI):

Net Present Value (NPV)

The NPV is a true measure of project profitability since it accounts for the future financial behaviour of the venture by discounting the NCF. Therefore, the NPV depends on the applied discount rate. It will decrease as the discount rate increases (for a conventional cashflow model – all deficits' years precedes the first surplus year) (Shell Learning Centre, 2001). The NPV model used for this research is stated mathematically thus:

$$NPV = \sum_{n=1}^{n}\left(\frac{NCF}{(1+r)^t}\right) \tag{21}$$

Where,
NPV = Net Present Value ($)
NCF = Net Cashflow ($)
i = discount rate (fraction)
t = reference date (year)
$(1+r)^t$ = end of year discount factor

A positive NPV indicates that the project is profitable while a negative NPV suggest a non-profitable venture.

Profitability Index (PI)

The various profitability indicators presented previously are either expressed in monetary values or in years. To adequately compare, rank or optimize projects of difference sizes or scopes, it is important to express the measure of profitability as a ratio. PI, also known as profit to investment ratio (PIR) is suited for this purpose (Shell Learning Centre, 2001). PI is the ratio of the profit to investment of an anticipated venture. It quantifies the amount of value generated per unit of investment. It is expressed as:

$$PI = \frac{PV\ of\ \ future\ Cashflows}{Initial\ Investment} \tag{22}$$

Alternatively,

$$PI = 1 + \left(\frac{NPV}{Initial\ Investment}\right) \tag{23}$$

where,
Initial investment = total capex
If PI > 1 then the venture is economically viable. If PI is < 1, the project is not profitable.

III. RESULTS AND DISCUSSION

1. Net Cashflow (NCF)

Figure 1 illustrates the NCF profiles of the various initialized reservoir models based on revenue generated from sales of produced oil. It indicated deficits in years 1 and 2 followed by increasing cash surplus in subsequent years. Constant composition (without CG) initialized reservoir model, due to overestimated oil production, generated the highest net cash surplus while the nonisothermal CG initialized reservoir models indicated the least net cash surplus.

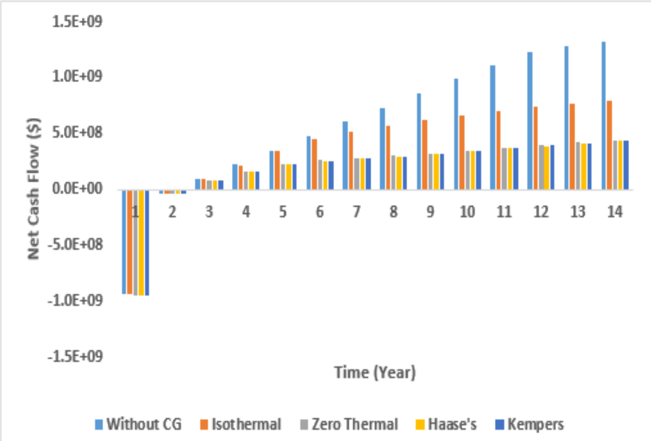

Figure 1: Net Cashflow Profile of the Various Initialized Reservoir Model Based on Oil Production

Figure 2 shows the NCF profile of the various reservoir models based on gas production. All the models exhibited net cash deficit in the project first year with the Constant composition initialized reservoir model generating the highest deficit because of its underestimated gas production. While other reservoir models indicated positive net cashflow in the second year of the project life, the constant composition initialized reservoir model indicated net cash deficit as shown in Figure 2. Figure 2 also shows that isothermal CG model generated more net cash surplus than the constant composition initialized reservoir model. The nonisothermal models generated the highest cash surplus with respect to revenue from gas production due to their high gas production record.

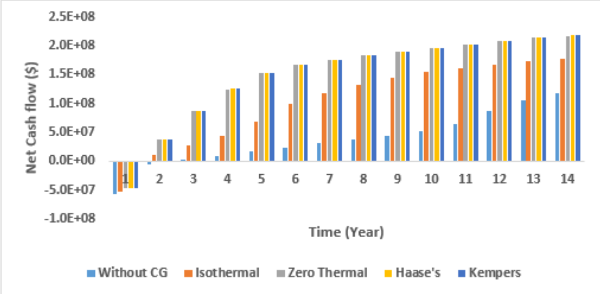

Figure 2: Net Cashflow Profile of the Various Initialized Reservoir Model Based on Gas Production

2. Cumulative Cashflow (CCF)

The calculated CCF profiles for the different initialized reservoir models based on revenue from produced oil are presented in Figure 3. Figure 4 presents the cumulative cashflow profiles of the various reservoir models based on revenue from gas production. Economic performance indicators derived from Figures 3 and 4 for the respective reservoir models includes ultimate cash surplus, payout time, and maximum exposure. The values of these profitability indicators were tabulated and discussed subsequently.

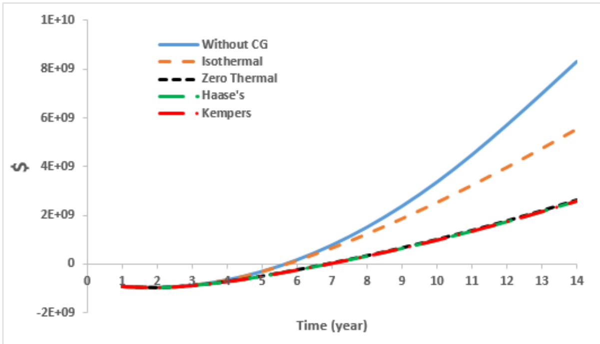

Figure 3: Cumulative Cashflow Profile of the Various Initialized Reservoir Model Based on Oil Production

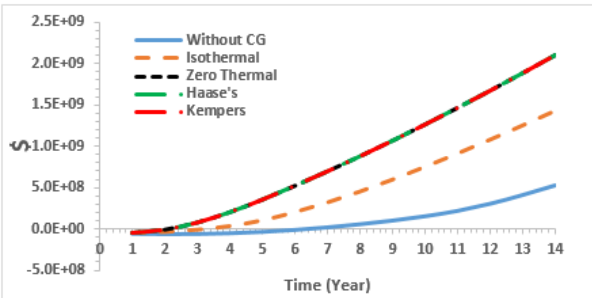

Figure 4: Cumulative Cashflow Profile of the Various Initialized Reservoir Model Based on Gas Production

3. Ultimate Cash Surplus

The values of the ultimate cash surplus generated by the various initialized reservoir models were obtained from Figures 3 and 4 for OOIP and GOIP, respectively. The total values for each reservoir model were calculated and presented in Table 6, which shows that constant composition initialized reservoir model generated unrealistically high ultimate cash surplus due to its overestimation of production while Haase's thermal diffusion CG initialized reservoir model produced a realistic low ultimate cash surplus due to the fact that it accounted for all the factors responsible for CG in the reservoir (igwe et al, 2020).

Table 6 also indicates that revenues from sales of produced gas significantly improved the economic performances of reservoir models initialized with isothermal and nonisothermal CG models.

Table 6: Ultimate Cash Surplus Produced by the Various Initialized Reservoir Models

Models	Ultimate Cash Surplus ($)		
	Oil	Gas	Total
Constant Composition	8,308,685,928.3	529,410,694.5	8,838,096,622.8
Isothermal	5,518,312,540.6	1,427,124,009.5	6,945,436,550.1
Zero Thermal Diffusion	2,631,106,508.7	2,105,731,740.7	4,736,838,249.4
Haase's	2,563,770,419.9	2,110,396,388.4	4,674,166,808.3
Kempers	2,573,364,119.4	2,108,316,612.6	4,681,680,732.1

4. Payout Time

The time taken for the various initialized reservoir models to breakeven were derived from Figures 3 and 4 for OOIP and GOIP, respectively, Table 7 shows that with respect to produced oil, constant composition and isothermal CG initialized reservoir models took an unrealistic shorter time to breakeven compared to about 6.9 years it took the nonisothermal CG initialized reservoir models to breakeven.

However, with respect to produced gas, investors started recouping their investment within 2.2 years from the nonisothermal CG initialized reservoir models while it took about 6.4 years, which was unrealistic, for the constant composition initialized reservoir model to breakeven due to its underestimation of gas production (Igwe et al, 2020).

Table 7: Payout Time for the Various Initialized Reservoir Models

Models	Payout Time (Year)	
	Oil	Gas
Constant Composition	5.8	6.4
Isothermal	5.8	3.4
Zero Thermal Diffusion	6.9	2.2
Haase's	6.9	2.2
Kempers	6.9	2.2

5. Maximum Exposure

The maximum exposures for the various initialized reservoir models were obtained from Figures 3 and 4 for OOIP and GOIP, respectively, and the total exposure (sum of maximum exposures based on produced oil and gas) calculated and presented in Table 8, which indicates that based on the total value of the maximum exposures, investors are at higher risk if the reservoir model is initialized with constant composition model and at reduced risk if it is initialized with nonisothermal CG models. Table 8 also show that if the project fails, the investors stand to lose less with isothermal CG initialization than constant composition initialization.

Table 8: Maximum Exposure for the Various Initialized Reservoir Models

Models	Maximum Exposure ($)		
	Oil	Gas	Total
Constant Composition	973,636,158.51	61,407,159.9	1,035,043,318.4
Isothermal	980,161,412.7	52,551,277.3	1,032,712,690.0
Zero Thermal Diffusion	986,686,431.0	9,409,812.5	996,096,243.5
Haase's	993,211,544.6	9,472,997.4	1,002,684,542.0
Kempers	993,211,492.4	9,435,542.5	1,002,647,035.0

5. Discounted Cashflow Model

Discounting the project net cashflow generates true economic performance indicators of the venture. Two major performance indicators obtained from the discounted cashflow models and used to assess the economic viability of the various initialized reservoir models are the net present value (NPV) and the profitability index (PI):

Net Present Value (NPV)

NPV relates value to time. It brings future value of a project to present worth, thereby, indicating the real economic performance or value of the venture. The NPVs obtained by discounting the oil production based NCF and the produced gas based NCF, respectively, are presented in Table 9 The total

NPV indicated in Table 9 for the various initialized reservoir models, is the sum of the oil production based NPV and produced gas based NPV. Table 9 illustrates that based on produced oil, constant composition initialized reservoir model generated the highest NPV while the Haase's thermal diffusion CG initialized reservoir model indicated the least NPV. The converse is the case with respect to produced gas based NPV. The indicated total NPVs shows that, although, the constant composition initialized reservoir model indicated better economic performance due to high oil production, revenue from sales of produced gas greatly improved the economic viability of CG initialized reservoir models. Table 9 also shows that all the initialized reservoir models produced positive NPV, an indication that despite the additional costs associated with the complexity of CG initialized reservoir models, they are economically viable.

Table 9: NPV for the Various Initialized Reservoir Models

Models	NPV ($)		
	Oil	Gas	Total NPV
Constant Composition	2,181,965,839.9	125,465,670.8	2,307,431,510.7
Isothermal	1,393,488,520.5	472,877,382.5	1,866,365,903.0
Zero Thermal Diffusion	421,217,979.8	789,513,438.5	1,210,731,418.3
Haase's	392,401,498.2	791,504,923.3	1,183,906,421.4
Kempers	395,575,695.6	790,624,549.7	1,186,200,245.3

6. Profitability Index (PI)
Unlike the previously presented performance indicators, PI quantifies the amount of value generated per unit of investment. It is used to compare and rank projects of different sizes and scopes. The PI of the various initialized reservoir models based on revenue from sales of produced oil are illustrated in Figure 5.

It shows that all the initialized reservoir models exhibited PI values greater than one (PI >1) with the constant composition initialized model generating the highest PI. Therefore, the indicated PIs suggest that the initialized reservoir models, especially, the CG initialized models, are economically viable simulation study options for the development of the study reservoir.

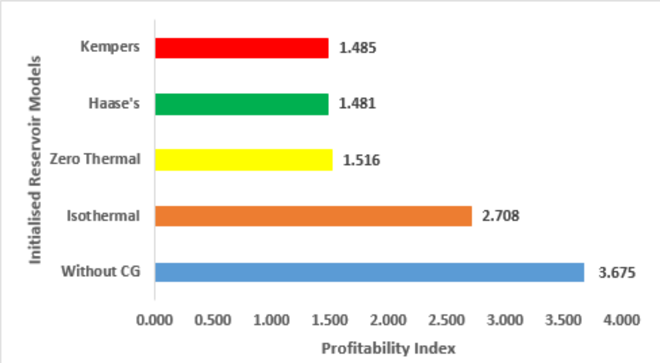

Figure 5: PI for the Various Initialized Reservoir Models Based on Oil Production

IV. CONCLUSION

This study evaluated the economic implications of initializing reservoir simulation models with compositional grading (CG) models and the following conclusions were drawn;

- The constant CG model indicated the highest value economic performance indicators (net cash, cumulative cash flow, ultimate cash surplus, NPV, and PI) due to its overestimation of cumulative oil production.
- The earliest payout for oil production was obtained with constant composition while Kemper's, Haase's and Zero thermal diffusion generated similar earlier payout.
- Revenues generated from the sales of cumulative gas, which was adequately estimated by the nonisothermal CG models (Kemper's, Haase's and Zero thermal diffusion CG models), improved their economic viability.
- CG models, including the nonisothermal CG models indicated positive NPVs and PI>1, which suggest that initializing reservoir simulation models with appropriate CG models is economically viable.

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