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Reservoir Simulation Modeling With Polymer Injection in Naturally Fractured Carbonate Reservoir

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Abstract

Naturally fractured carbonate reservoirs (NFCR) generally have very large residual reserves and are suitable for advanced production stages, where oil recovery in the Naturally fractured carbonate reservoir can be carried out by polymer injection. This study uses a hypothetical model using 5 wells, where during the initialization it has an Original Oil In Place (OOIP) of 12.129 MMSTB. The reservoir simulation was performed at basecase and showed a Recovery Factor (RF) of 8% with cumulative production of 973.66 MSTB. This recovery factor is the reason why polymer is used, the working mechanism of the polymer is by reducing the mobility ratio so that the viscosity of the water will increase and be able to sweep away the oil that is still left in the reservoir rock. There are 5 scenarios used in this study, where each scenario has different concentrations of 50 lb/d, 100 lb/d, 150 lb/d, 150 lb/d, 200 lb/d, 250 lb/d, respectively, then each scenario is tested with different rates in a succession of 500 bbl/day, 750 bbl/day, 1000 bbl/day, 1250 bbl/day, 1500 bbl/day, but the pattern of each scenario is the same as using an inverted-5-spot pattern. From all the scenarios, the best scenario is the third scenario, namely using a polymer concentration of 150 lb/d and a rate of 1250 bbl/d which can increase recovery factor from 10.81 to 18.81% with cumulative production of 2.282 MMSTB.

Keywords: Naturally Fractured Reservoir, Reservoir Simulation, Carbonate, Polymer Injection, Inverted 5-Spot.

I. INTRODUCTION

Naturally fractured carbonate reservoirs (NFCR) generally have very large residual reserves and are suitable for further production stages. The remaining oil in naturally fractured reservoir is trapped in the matrix than the fractured, it caused by the function from the fracture is more like rock permeability. Advanced oil recovery in NFCR can be carried out by chemical Enhanced Oil Recovery (EOR) with the type of chemical that is a polymer. The mechanism of polymer injection is to increase the viscosity of the injection fluid, namely water, thereby causing a decrease in the mobility ratio between the injection fluid and the injected fluid. This study has a purpose to get the characteristic of the polymer injection in NFCR and increase the cumulative oil production and recovery factor (RF) by using reservoir simulation modeling.

II. LITERATURE REVIEW

II.1. Naturally Fractured Reservoir

Naturally fractured reservoir modeling is very important, because this reservoir has unique properties, namely having two flow media that occur in the production mechanism. The McNaughton & Garb method is a method commonly used to classify naturally fractured reservoirs. Reservoir classification using the McNaughton & Garb method is quite easy to determine based on core analysis and interpretation of well testing data.

Omega (ω) or commonly referred to as storage capacity coefficient is the ratio of fluid stored in fractures to all fluid stored in matrix, and lambda (λ) or commonly known as the inter-porosity coefficient is the ratio between permeability in the matrix and fracture permeability. Storage capacity coefficient and inter-porosity coefficient can be shown by the following equation:

$$\omega = \frac{\varphi_f C_f}{\varphi_f C_f + \varphi_m C_m} \qquad (2\text{-}1)$$

$$\lambda = a \, \frac{k_m}{k_f} \, r_w^2 \qquad (2\text{-}2)$$

The calculation results obtained based on equation (2-1) can be concluded as follows:

When ω = 1 : All storage in fracture (Type C)

When ω = 0.1 : Storage in matrix equal to 9x in fracture (Type A)

When ω = 0.01 : Storage in matrix 90% ; 10% in fracture (Type A)

When ω = 0.5 : Storage in matrix = storage in fracture (Type B)

The calculation results obtained based on equation (2-2) will show the value of λ, the greater the value of λ means that the heterogeneity of the fracture-matrix system is getting smaller. Classification of type A, type B, and type C based on the McNaughton & Garb method describes the natural fracture reservoir as follows:

Type A: Reservoir with high fluid storage capacity in matrix and low in fractures.

Type B: Reservoir in which matrix and fractured have nearly the same fluid storage capacity.

Type C: Reservoir with high fluid storage capacity in fractured and low in matrix.

Based on the Mc Naughton & Grab classification, reservoir type A will have a large matrix storage capacity, and the contribution of fracture porosity to total porosity is usually only about 10%. This type of reservoir often creates lost circulation problems during drilling operations. In addition, this type of reservoir will have a small recovery factor, especially if the permeability of the matrix is tight. Reservoir with type B shows the fluid storage capacity in the matrix and fractures that are almost balanced. If this is supported by high matrix permeability, it will produce a reservoir with a high flow rate and recovery. Reservoir with type C will have almost all of its fluid stored in the fractures. This type of reservoir can provide a high flow rate at first, but in a short time, the flow rate can drop very drastically to a critical level or become uneconomical.

II.2. Polymer Injection

Polymer injection is basically an enhanced water injection. The addition of polymers to injection water is intended to improve the properties of the pressing fluid, with the hope that the oil recovery will be greater. Polymer injection can increase the oil recovery considerably compared to conventional water injection. However, the mechanism for pushing it is very complex and not fully understood.

If the reservoir oil is more difficult to move than pressing water, the water tends to penetrate the oil, this will cause water to be produced quickly so that the pressing efficiency and oil recovery are low. Polymer injection can be used in this reservoir. The polymer dissolved in injection water will thicken the water, reduce water mobility, and prevent water from penetrating the oil. Two things that need to be considered in polymer injection are reservoir heterogeneity and the ratio of reservoir fluid mobility.

Determination of Injection-Production Well Pattern
One of the ways to increase the oil recovery factor is design an injection-production well pattern, which aims to obtain an efficient sweeping pattern. The considerations in determining the injection-production well pattern depend on:

1. Formation uniformity level, namely permeability distribution, to lateral and vertical directions,
2. Structure of reservoir rock includes fault, slope, and size,
3. Existing wells (location and distribution),
4. Topographic conditions, and
5. Economic factors.

Waterflooding operations, injection and production wells are generally formed in a certain regular pattern, for examples, three-point, five-point, and seven-point pattern. Normal 5-spot pattern is a production well surrounded by injection Wells, of the opposite is called inverted 5-spot pattern. Each pattern has its own network system that provides different flow paths so as to provide different sweeping areas. The most commonly used injection-production patterns include:

Direct Line Drive, injection and production wells form a certain line and are opposite each other. Two important things to note in this system are the distance between similar wells (a) and the distance between different wells (d).

Staggered Line Drive, wells that form a certain line where the injection wells and their production are opposite each other with an equal distance, is generally a / 2 drawn laterally with a certain size.

Four Spot consists of three types of injection wells that form a triangle and one production well is located in the middle.

Five Spot, the most recognizable pattern in waterflooding where the injection well forms a rectangle with one production well located in the middle.

Seven Spot, injection wells are placed at the corners of the hexagonal shape and the production well is located in the middle.

From Figure 1. It can be seen that there are several patterns of injection wells, including four-spot, five-spot, seven-spot, and nine-spot. Where there are normal and inverted patterns. The normal pattern is shown by 1 production well surrounded by several injection wells, while for an inverted pattern there is 1 injection well surrounded by several production wells.

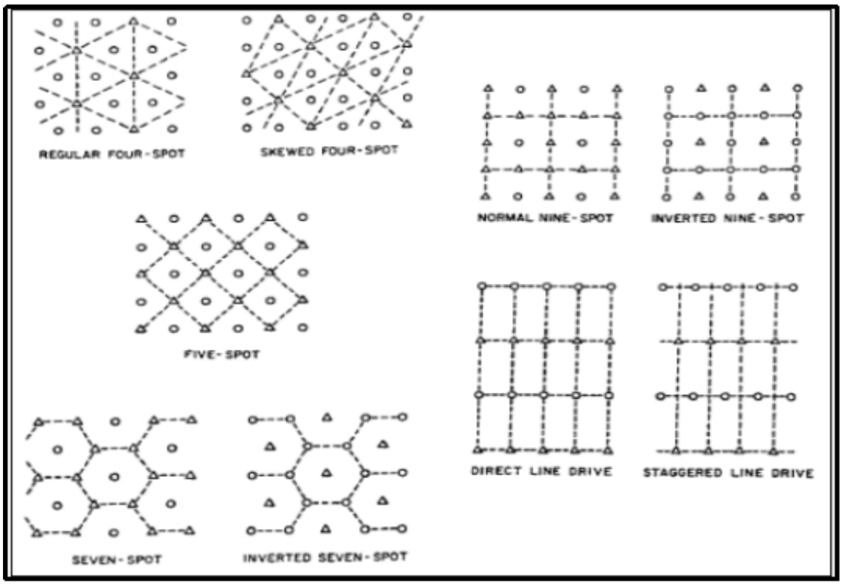

Figure 1.
Injection-Production Well Patterns
(Craig, Jr., Forrest F, 1971.)

Reservoir Simulation Concept

Reservoir simulation is a mathematical process used to predict reservoir behavior through a model that is assumed to have similar properties to the actual reservoir state. This model has two types, namely a physical model and a mathematical model. Physical models are modeled using visible objects that are easy to study or evaluate, while mathematical models use mathematical equations that take into account the physical, chemical, and thermal properties or behavior of the reservoir in its interpretation.

The purpose of reservoir simulation is to estimate reservoir behavior of a field with various production scenarios using software as the processing equipment. In addition, simulations can also be used for the following purposes:

1. Determine the initial reservoir reserve,
2. Studying fluid motion in the reservoir,
3. Determine the production schedule,
4. Determine the behavior of oil production when the fluid is injected,
5. Estimating drainage limits in heterogeneous fields, and so on.

Reservoir simulation uses a simulator in the form of software commonly used in reservoir engineering in the oil and gas industry, especially for reservoir engineers, where at this time the use of reservoir simulation software has become a standard in making a field development design in the primary, secondary, and tertiary stages. With the reservoir simulation software, reservoir performance estimates can be carried out, before the field development design is applied to the real reservoir.

Reservoir Simulation Stages
In carrying out a reservoir simulation plan, there are several steps that need to be carried out :

1. Data preparation, data collection, data processing and data validation,
2. Build and determining the model to be used in the simulation based on GGR (Geology, Geophysic, Reservoir) and petrophysical data,
3. Data input,
4. Initialization and history matching of reservoir models to be used,
5. Create several forecasting scenario,
6. Implementation of simulations to obtain production performance data, as well as visualization of oil saturation distribution, and
7. Analysis and evaluation of simulation results.

III. RESEARCH METHODOLOGY

The application that will be used for reservoir simulation modeling in this study is IMEX CMG (2017) Simulator. The steps in carrying out the simulation are as follows:

1. The hypothetical model in this study is describing by matrix and fracture porosity and permeability
2. Component input consist of characteristic from oil, brine, and polymer.
3. This study use inverted 5-spot, it consist of one injection well in the middle and four production well in each corner for the pattern
4. Initialization Original Oil In Place (OOIP)
5. Running forecasting for polymer injection.

IV. FINDING AND DISCUSSION

In the initialization stage, an OOIP was obtained of 12.129 MMSTB, with a basecase from 2020 to 2030, a Cumulative Oil Production of 973.66 MSTB was obtained, with an RF of 8%. Because of the Remaining Reserve (RR) is still large, it is necessary to carry out an advanced scenario, where this time using polymers with a total of 5 scenarios having consecutive concentrations of 50 lb/d, 75 lb/d, 100 lb/d, 125 lb/d, and 125 lb/d, then each scenario will vary the injection rate of 500 bbl/d, 750 bbl/d, 1000 bbl/d, 1250 bbl/d, and 1500 bbl/d, respectively. Injection using this polymer is carried out continuously, starting from injection in 2030 to 2050.

Scenario I uses a polymer concentration of 50 lb/d and varies the injection rate, and the best results are obtained using a rate of 1500 bbl/d with the RF increasing to 18.11%. For complete results, see Figure 2. and Table 1.

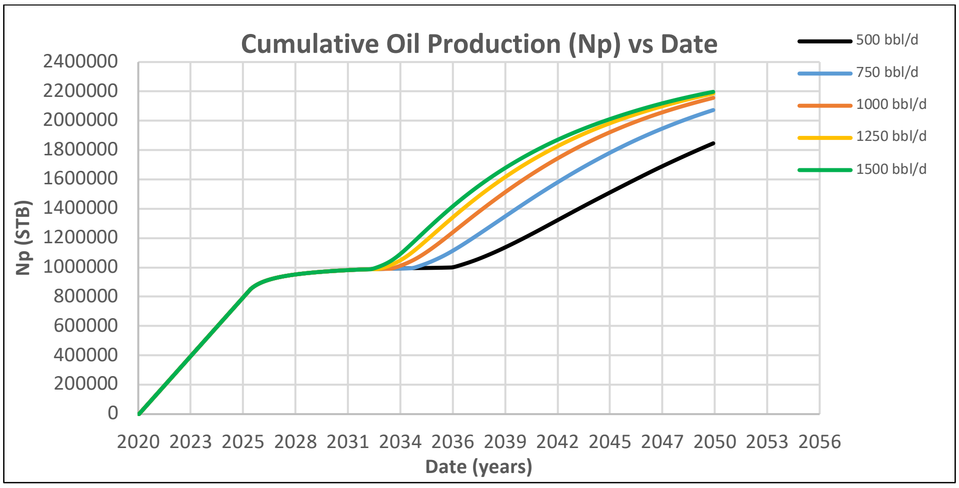

Figure 2. Cumulative Production Oil (Np) vs Date of Scenario I

Table.1. Result of Scenario I : Polymer Concentration 50 lb/day

Injection Rate	Oil Cumulative	Gas Cumulative	Recovery Factor
bbl/day	**MMSTB**	**MMSCF**	**%**
500	1.846	113.720	15.22
750	2.073	113.740	17.09
1000	2.156	113.730	17.77
1250	2.186	113.713	18.02
1500	2.197	113.697	18.11

Scenario II, the concentration is increased to 100 lb/d and the injection rate is still varied. The best results were obtained when the injection rate was 1500 bbl/d with an RF of 18.55%. Complete results for scenario II can be seen in Figure 3. and Table 2.

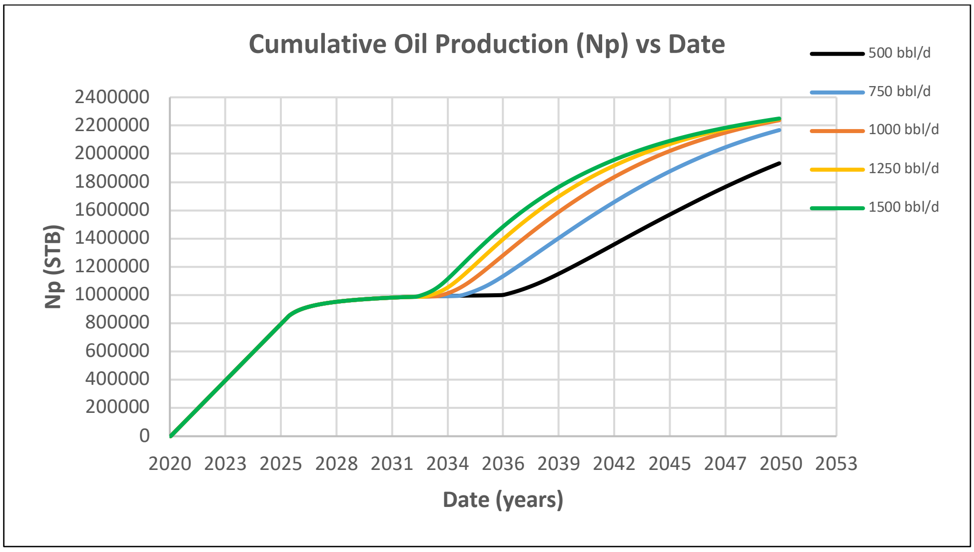

Figure 3. Cumulative Production Oil (Np) vs Date of Scenario II

Table 2. Result of Scenario II : Polymer Concentration 100 lb/day

Injection Rate	Oil Cumulative	Gas Cumulative	Recovery Factor
bbl/day	**MMSTB**	**MMSCF**	**%**
500	1.933	113.749	15.93
750	2.168	113.769	17.87
1000	2.237	113.755	18.45
1250	2.246	113.734	18.52
1500	2.250	113.716	18.55

Scenario III, with a concentration of 150 lb/d, the best results are obtained using rate of 1250 bbl/d with an RF of 18.81%. The complete results of scenario III can be seen in Figure 4. and Table 3.

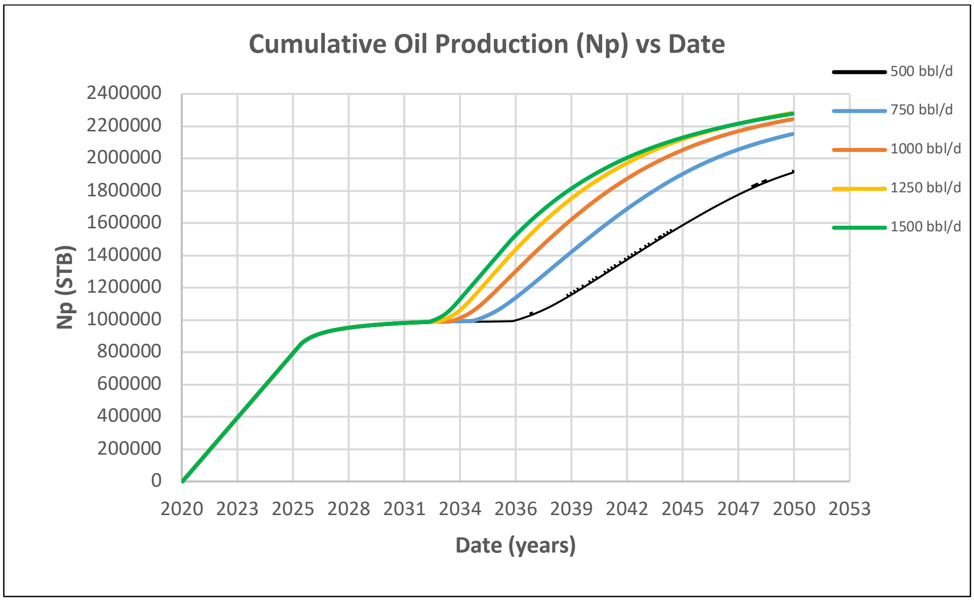

Figure 4. Cumulative Production Oil (Np) vs Date of Scenario III

Table 3. Result of Scenario III : Polymer Concentration 150 lb/day

Injection Rate	Oil Cumulative	Gas Cumulative	Recovery Factor
bbl/day	MMSTB	MMSCF	%
500	1.918	113.744	15.81
750	2.151	113.764	17.74
1000	2.243	113.758	18.50
1250	2.282	113.745	18.81
1500	2.277	113.724	18.77

Scenario IV, using a concentration of 200 lb/d, obtained the best results when using an injection rate of 1500 bbl/d where the RF became 18.81%. Complete results for scenario IV can be seen in Figure 5. and Table 4.

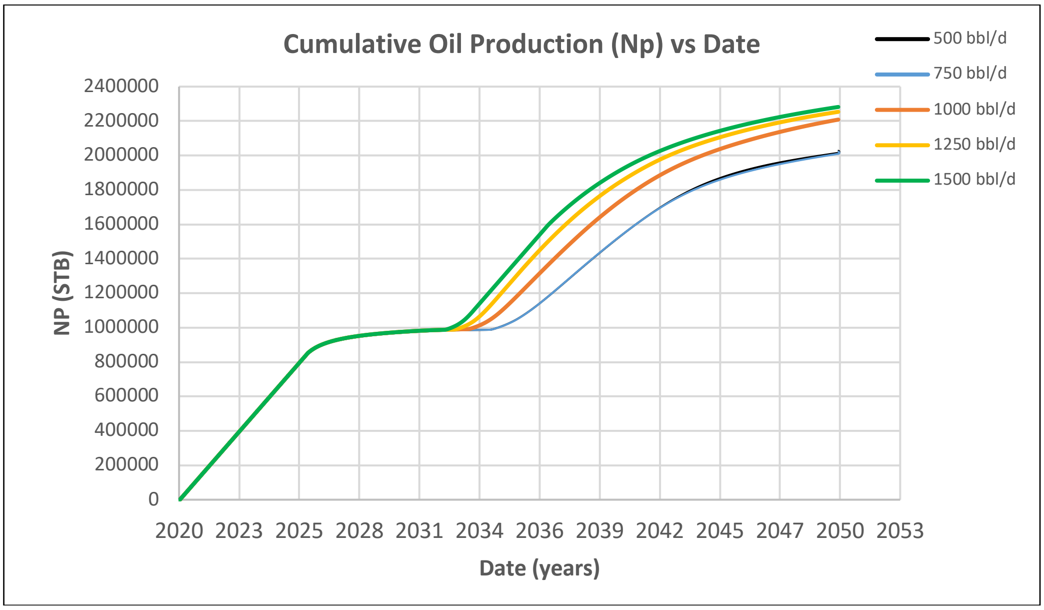

Figure 5. Cumulative Production Oil (Np) vs Date of Scenario IV

Table 4. Result of Scenario IV : Polymer Concentration 200 lb/day

Injection Rate	Oil Cumulative	Gas Cumulative	Recovery Factor
bbl/day	**MMSTB**	**MMSCF**	**%**
500	2.021	113.722	16.66
750	2.016	113.722	16.62
1000	2.208	113.746	18.21
1250	2.25	113.735	18.58
1500	2.282	113.725	18.81

And the last scenario is Scenario V, using a concentration of 250 lb/d obtained the best results using an injection rate of 1500 bbl/d, where the RF obtained was 18.51%. Complete results for scenario V can be seen in Figure 6. and Table 5.

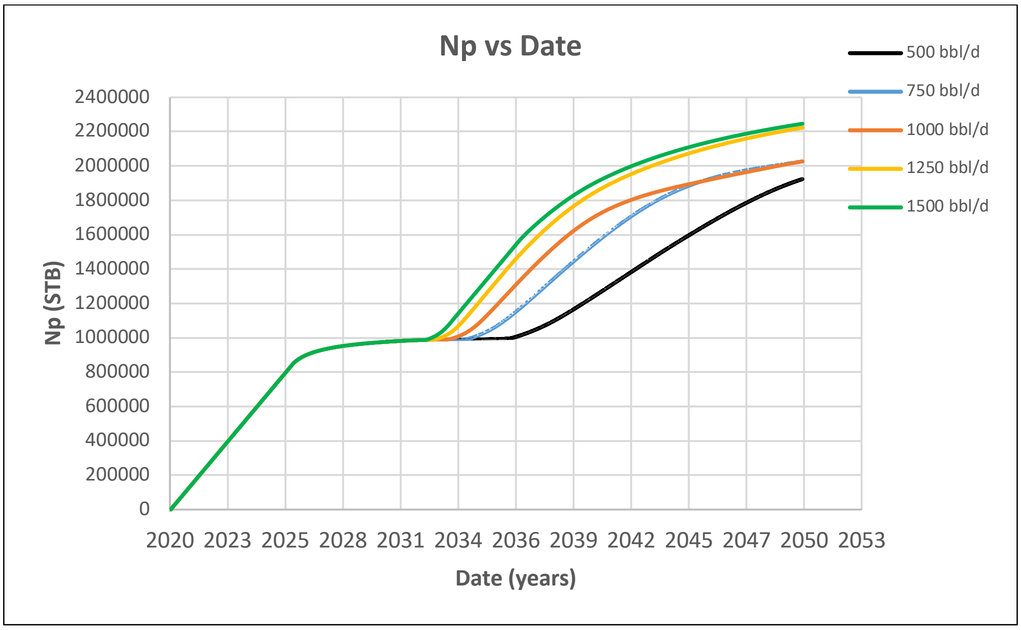

Figure 6. Cumulative Production Oil (Np) vs Date of Scenario V

Table 5. Result of Scenario V : Polymer Concentration 250 lb/day

Injection Rate	Oil Cumulative	Gas Cumulative	Recovery Factor
bbl/day	MMSTB	MMSCF	%
500	1.923	113.745	15.86
750	2.027	113.723	16.71
1000	2.027	113.695	16.71
1250	2.223	113.724	18.32
1500	2.246	113.716	18.51

V. CONCLUSION AND FURTHER RESEARCH

The residual reserves in the case study of Naturally fractured carbonate reservoirs with an inverted 5-spot pattern are still very large. Polymers are used to increase RF which is still sufficient from basecase, which is 8%. The best scenario for a case study of a natural fracture reservoir of carbonate rock with an inverted 5-spot pattern using Scenario III, where using a polymer concentration of 150 lb/d and an injection rate of 1250 bbl /d can increase the recovery factor by 10.81% to 18.81%.

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