A Techno- Economic Analysis of the Guapo Cruse E Heavy Oil Sands in Trinidad and Tobago

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Abstract

Trinidad and Tobago (T&T) is a mature province with approximately five billion barrels of heavy oil in place. Optimal recovery of these resources can be achieved when comprehensive reservoir simulation studies of various improved oil recovery (IOR) methods are conducted such as in situ combustion, solvent flooding, thermal methods, steam assisted gravity drainage and chemical or polymer. This paper presents a commercial plan and a novel workflow for the exploitation of the Cruse E heavy oil sands located in the Guapo field, onshore South Trinidad by analysing various IOR techniques. Geo-models of the field were created and validated through the use of Original Oil in Place (OOIP) data and field history production data. Differing IOR scenarios were designed using the commercial software by Computer Modelling Group Ltd. (CMG) in order to predict production performance by optimising injection pore volume and injection pattern. Finally, an economic evaluation was conducted, on the optimised models. The detailed workflow presented in this paper can be applied to other fields to optimise heavy oil recovery. Response Surface Methodology was utilised to develop a first pass screening tool which would provide a potential recovery factor for the IOR methods presented. This would allow for the selection for the best IOR methods to perform numerical simulation since this process can be costly and time consuming. The results from the numerical studies indicated that steam flooding was the most efficient EOR method with an additional recovery of 21.5% and an additional cumulative oil production of 10.2 MMSTB. Further investigation of hybrid IOR methods showed that Water Alternating Gas (WAG) was the most efficient combined IOR method with an additional cumulative oil recovery of 8.46 MMSTB. Overall, WAG was also shown to be the most economical.

Keywords: improved and enhanced oil recovery, heavy oil, water alternating gas, reservoir simulation; response surface methodology

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Introduction

The World Energy Council (2016) classifies oil as being heavy if its American Petroleum Institute (API) gravity is less than or equal to (≤) 22.3˚API. Additional international heavy oil classification is discussed in the Literature Review section of this report. Heavy oil definition for Trinidad and Tobago as outlined by the Petroleum Act is less than 18˚API (Ministry of Energy and Energy Affairs, 2016). However, it does not take into consideration the oil's viscosity. According to Hosein and Bertrand (2011), heavy oil in Trinidad is classified as having an API gravity between 10 to 22˚ API with a viscosity ranging from 30,000 to 10,000 centipoise (cP).

Worldwide, less than 10% of heavy original oil in place (OOIP) is produced from primary production (Rajnauth, 2012). As such, various enhanced oil recovery (EOR) methods such as in situ combustion, solvent flooding, thermal methods, steam assisted gravity drainage, and chemical or polymer injection can be used to help recover as much as 80% of OOIP of these heavy oil (Rajnauth, 2012; Sinanan et al., 2016). According to Sinanan et al. (2016), IOR is a term used to improve the recovery of oil by any means, which includes both secondary oil recovery and EOR. In T&T, IOR has played a significant role for more than eighty years and accounts for 7% of T&T's total oil production (Sinanan et al., 2016). They also report that approximately 320 million barrels (bbl) of oil have been produced in T&T by the application of IOR techniques. Heavy oil production in T&T represents a daily oil production of 5% from small steam injection and cyclic steam injection projects (Hosein et al., 2011). To further develop the work done by Rajnauth (2012) where the potential of developing unconventional resources which include heavy oil were assessed, this paper focuses on the use of IOR methods to increase ultimate recovery factors of some of the known heavy oil accumulations of the Guapo Cruse E sands.

The techniques studied in this work include water flooding, CO_2 flooding, steam flooding, and polymer flooding. The water flooding process is the application of pressurised water being injected into the reservoir via an injection well to provide energy to the oil to assist in reaching the producing wells. Singh and Kiel (1982) classified all water injection projects as one of two mechanisms. Firstly, water flooding by displacement of oil of semi-depleted and/or depleted reservoirs; and secondly, pressure maintenance of the reservoir for sustaining the production rate. Thermal EOR processes include all processes that supply heat energy to a reservoir. Four main factors contribute to the success of this CO_2 project: oil swelling, viscosity reduction, interfacial tension reduction, and blowdown recovery. The primary beneficial property of polymer flooding in crude oil reservoirs is the aqueous solution's enhanced viscosity. Polymer flooding is normally executed when the mobility ratio of a waterflood is high or the reservoir's heterogeneity is high. During a polymer waterflood, a high molecular weight and viscosity enhancing polymer is added to the water of the waterflood in order to decrease the mobility ratio of the flood water. As a result, the sweep efficiency of the waterflood in increased.

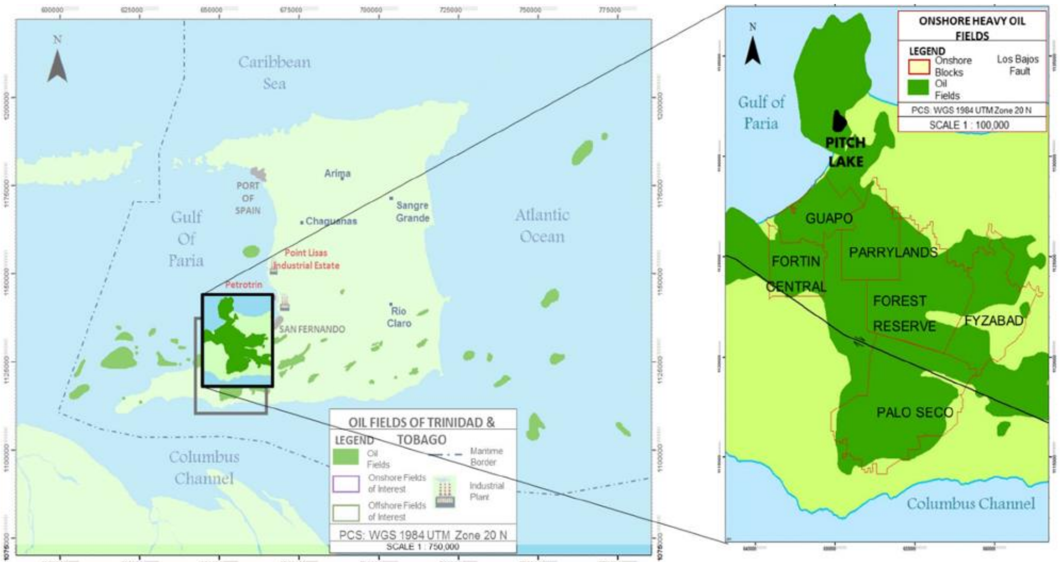
With the advancement of technology, there are several hybrid IOR methods that have been developed (Hu et al., 2020; Pourafshary & Mouradpour, 2019; Xu & Saeedi, 2017). These methods are essentially combinations of various IOR methods suited for any particular condition. Through the use of computer modelling and reservoir simulation studies, this work investigates the effect of some hybrid IOR methods on the Guapo Cruse E heavy oil reservoir. The IOR combination methods included in this work include water alternating gas (WAG), steam alternating CO_2, steam followed by CO_2, and polymer followed by water. Additionally, this paper highlights production optimisation through the use of suitable IOR techniques and IOR hybrids with respect to pore volume and injection pattern. Associated economic evaluation is included to determine the most feasible IOR option for the Guapo Cruse E sands.

Guapo Cruse E Geological Setting

Structurally, the Guapo Field lies north of the Los Bajos Fault, and straddles the North West/South East trending Morne L'Enfer Syncline (Geological Society of Trinidad and Tobago, 2017). There are two anticlines of prominence associated with the area. These are the Vance River Anticline and the Lot One Anticline (Figure 1 and Figure 2). Both anticlines trend East North East/West South West. The area is disturbed by faults, with basic orientations being subparallel or at right angles to the fold axis. The stratigraphic succession ranges from Pliocene to Eocene with the main producing reservoirs occurring within the Upper Miocene to Lower Pliocene as seen in Figure 3. The trapping mechanism has been attributed to a combination of stratigraphic and structural, and the field operates on a solution gas depletion drive with gravity as a secondary influence.

Figure 1

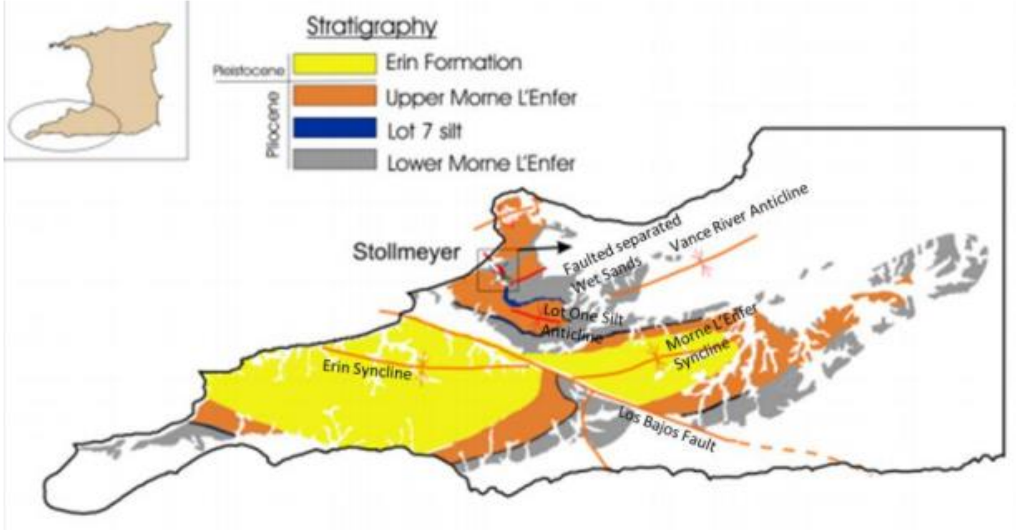
Location of Guapo Field



Source: Boodlal, D., Alexander, D., John, E., & Ramnath, D. (2022)

Figure 2

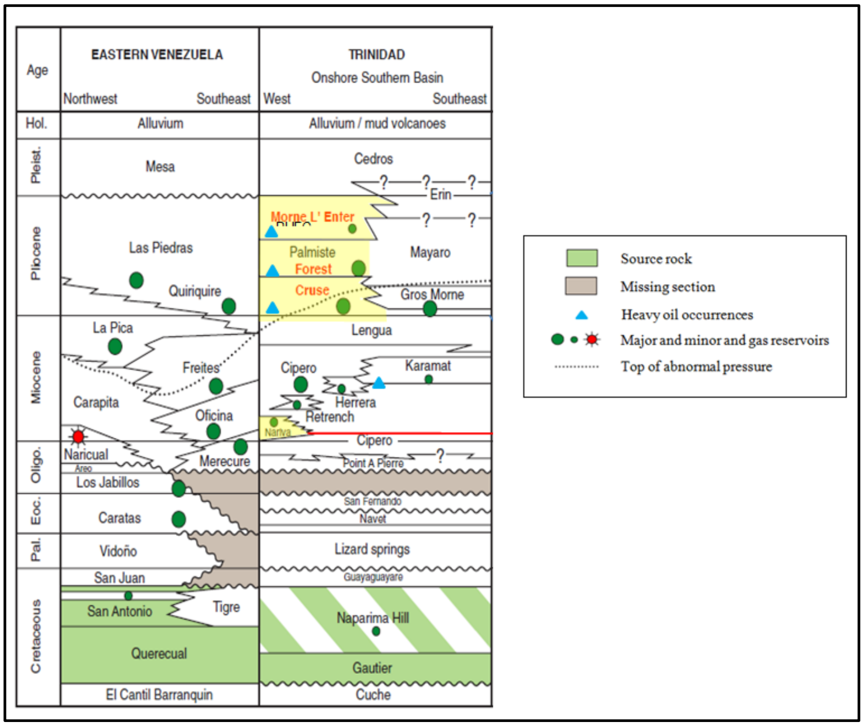
Plio-pleistocene Geology of South-West Trinidad



Source: Geological Society of Trinidad and Tobago (2017)

Figure 3

Stratigraphic Column of the Rocks Located Onshore Trinidad & Eastern Venezuela



Ninety-seven (97%) of the field's cumulative production is from the Cruse formation sands. Porosity and permeability (air) average 33% and 450 mD respectively. The average gravity of the crude produced is approximately 10° API (Xu & Saeedi, 2017). Cruse sands are generally fine-grained and lenticular, and are postulated to have been deposited in a near shore deltaic environment (Bertrand, 1985; Bower et al., 1968). The net oil sand (NOS) map and the sand structure map for the Guapo field are illustrated in Figure 4 and Figure 5, respectively. These figures were useful in obtaining data for building the reservoir model and simulating the performance of this field for the different recovery techniques investigated.

In building the model for Guapo, related reservoir properties shown in Table 1 were used.

Table 1

Reservoir Data for Guapo field

Reservoir Properties	Values
Horizon	Upper Cruse
Area (acres)	224
Depth (ft)	1700-2300

Thickness (ft)	25-175
Porosity (%)	35
Permeability (mD)	1284
Oil Saturation (%)	80
Oil Gravity (API)	10-12
Oil Viscosity (cp)	1600
Oil Formation Volume Factor (rbbl/bbl)	1.08
Temperature (°F)	120

Figure 4

Guapo Sands Net Oil Sand Map

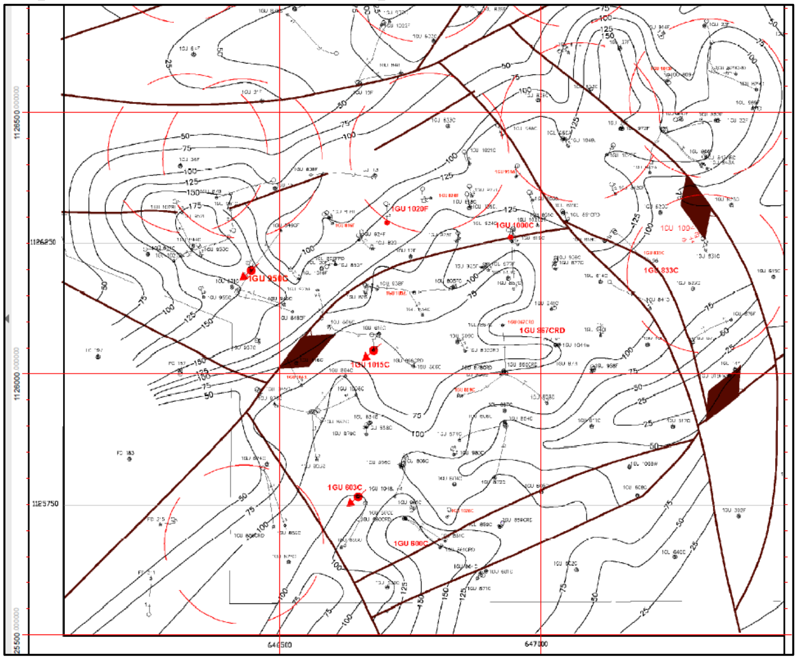
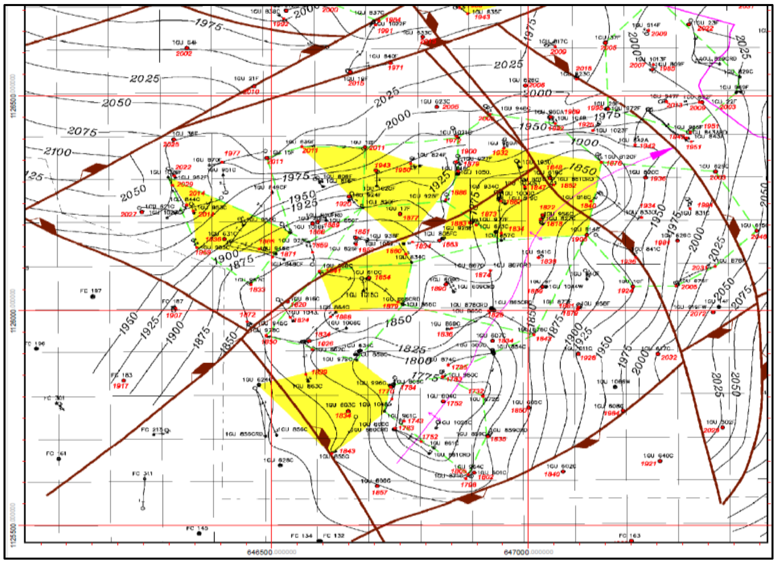


Figure 5

Guapo Sands Structure Map

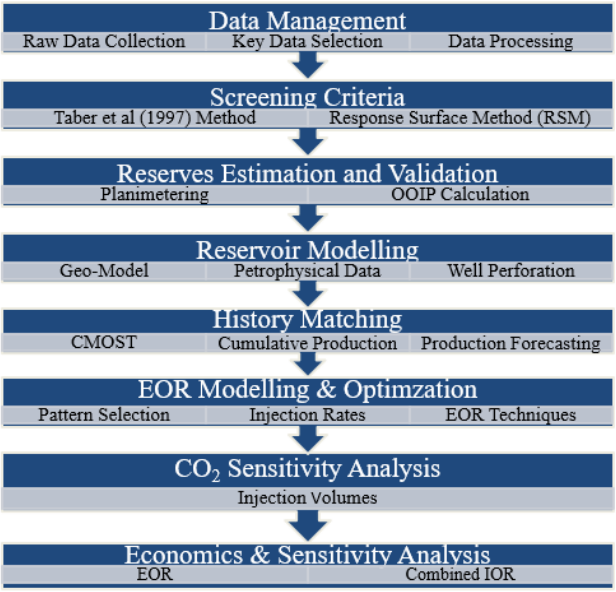


Method

This study followed the workflow in Figure 6 below.

Figure 6

Method Process for Simulation



A short description of the key aspects of Figure 6 above is outlined in this paper.

Data management

Data management consisted of three sections. Firstly, raw data was collected, followed by key data for the purpose of investigation, and finally data processing which included sorting of the data needed for the application of simulation and research per field. The following gives a detailed insight to each section and its processes.

Raw Data Collection

Data was collected from three main sources as follows: (1) Ministry of Energy & Energy Industries (MEEI), (2) the Technical Data Center (TDC) of the Petroleum Company of Trinidad and Tobago (Petrotrin), and (3) The Society of Petroleum Engineers (SPE) One Petro Journal and Technical Papers. An initial supply of reports and well files were received from the MEEI that were written by technical personnel from the oilfield operators (past and present) in Trinidad. These reports were used to gauge the scope of the work already done in the heavy oil acreages in T&T as well as to gain preliminary estimates of the heavy crude resources already exploited. Petrotrin's TDC provided crucial information needed in the form of field and well reports. These reports consisted of production data and maps that were used to model each reservoir within this report.

In house research was then conducted using published technical papers which were downloaded from the SPE One Petro website. These papers bore references to the fields of interest and their history in the heavy oil regions. These papers accounted for gaps of literature that were excluded from the MEEI's and Petrotrin's data collections.

Key Data Selection

This stage was the most critical stage of this section of the project because the quality and quantity of data obtained at this stage would have introduced or removed limitations associated with the completion of the project objectives. Most of the map, production figures, and pressure, volume and temperature (PVT) data were from previous oilfield operators in the field. Selection of structure maps, isopach maps, production data, PVT data, and petrophysical data was conducted in this stage.

Data Processing

Data processing mainly consisted of extraction of data for each particular field with respect to the reservoir description, properties, volumetric and field production. At this point the production data was sorted and cleaned for any stages, sands and perforations that were not within the region of study. These files were deleted and the specific data retained.

Table 2

List of Data Selected for This Study

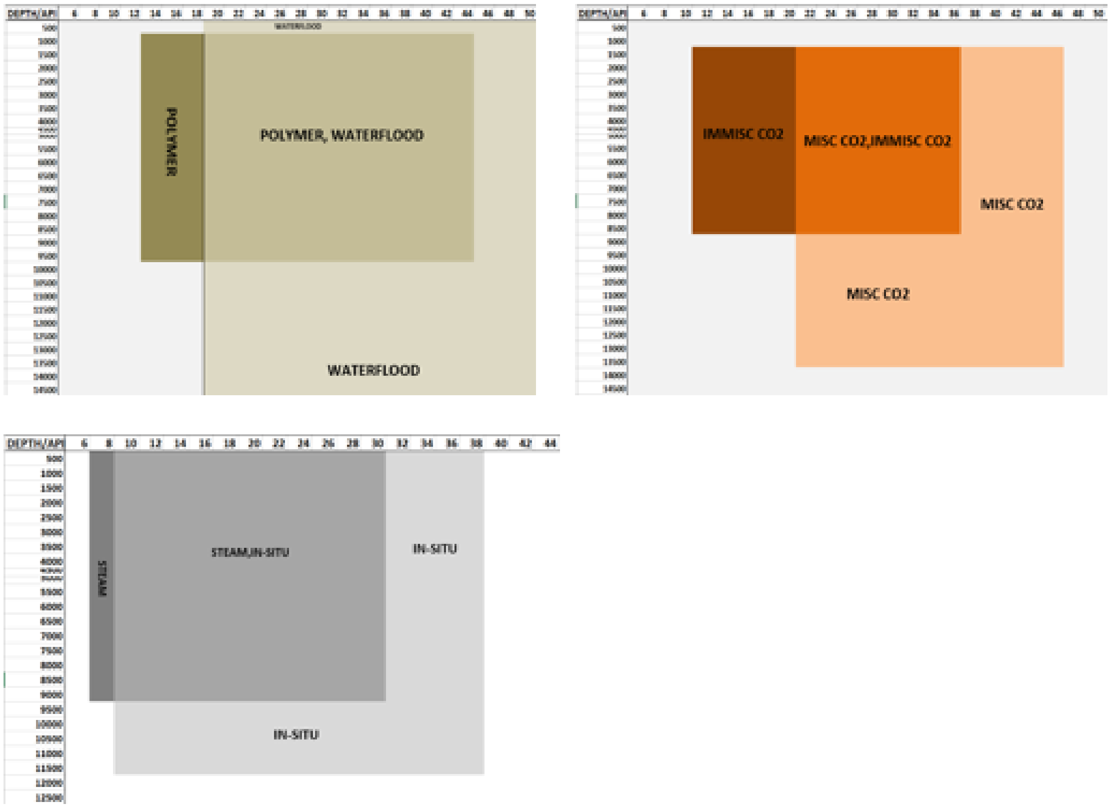
Data Selected for this study
Reservoir Properties (Fig. 1)
Guapo Cruse E NOS map (Fig 2)
Guapo Cruse E structure map (Fig 3)
Geological Production data

Stage 2: Screening criteria

A preliminary reservoir screening was done to determine the applicable EOR methods for reservoirs in Trinidad. Two methods were used in this work: the Taber et al. (1997) method and the Response Surface Method (RSM).

Figure 7

Range of Applicability of Water/Polymer, CO_2 and Steam Injection on API & Depth



Source: Taber et al. (1997)

Taber et al. Method

Taber et al. (1997) reported a range of reservoir and fluid properties for different successful EOR methods around the world. The most important parameters in their work were API and depth. Using their reported data, simple graphs were created to visualise the range of applicability of water/polymer flood (Figure 7), CO_2 injection and thermal EOR (steam injection/in-situ combustion) that was applied to the Cruse E heavy oil sands located in the Guapo field. It should be noted that waterflood was not discussed in Taber et al.'s paper and therefore the strategies described in Singh and Kiel (1982), Willhite (1986) and Sinanan et al. (2016) were utilised in this paper.

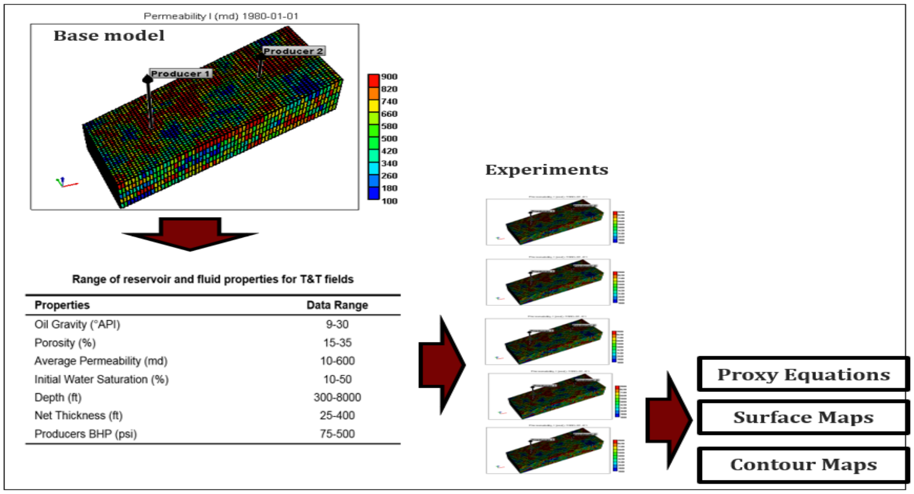
Response Surface Method (RSM)

The RSM method consists of two-parts, a numerical simulation part using CMG-STARS and experimental design part using CMOST and Minitab. The first step was to create a base model in CMG-STARS taking into consideration average values of the rock and fluid properties as seen in Figure 8 representing different fields in T&T. The base model was an integral part of the proprietary screening tool developed using RSM. This method was utilised as a first pass method to determine if a chosen IOR method was worth investigating via simulation modelling. Reservoir pressure was estimated based on a hydrostatic gradient (0.46 psi/ft×Vertical depth in ft). Permeability was distributed in the model using geostatistical models to incorporate heterogeneity effect in the EOR methods. In this base model, producers were constrained to operate at 200 psi bottomhole pressure since this was the general trend observed from analysing the data available. The model was allowed to run for 20 years to allow for a proper estimate of recovery factors to be observed. One of the producers was replaced by an injector and four more models were created to emulate possible IOR scenarios such as: waterflood, polymer flood, steam, and CO_2 injection. For CO_2 and steam injection, the up-dip well was selected as the injector, but for water and polymer injection, the down-dip well was chosen as injector to avoid gravity segregation. Due to the gravity force, lighter fluids tend to rise upward and heavier fluids flow downward to the bottom of reservoir. This resulted in four base models to represent each type of EOR process based on the average reservoir parameters in T&T outlined in Figure 8.

In statistics, RSM explores the relation between explanatory variables (independent or input variables) and response variables (objective functions, dependent or output variables). RSM is used for generating a sequence of design experiments to obtain an optimal response or relation between explanatory and response variables. Additionally, RMS can be employed to maximise the production or profit. One of the other outcomes of RMS is a proxy model (for example first or second-degree polynomial) of response variables as a function of explanatory variables. These proxy models can be used for prediction of response variables for other fields if their explanatory variables are in the range which has been used to create these proxy models. It should be noted that this screening tool had to be designed in this manner so that it can screen other reservoirs not considered in this study. It should also be noted that the proxy models are only valid for reservoirs that fall within the ranges shown in Figure 8, which is based on data gathered for T&T. These ranges were used as the input parameters of the CMOST experimental designs and proxy models were generated using RF as objective functions. The following proxy models (Equations 1 to 5) were created for these four EOR methods and primary production experiments. While the Taber method shows a qualitative idea about the applicability of EOR techniques (Figure 6), RSM gives an approximate preliminary quantitative assessment of their feasibility using proxy models. More detailed reservoir simulation should be conducted for final accurate assessment.

Figure 8

Screening Method Flowchart Using RSM



Range of reservoir and fluid properties for T&T fields

Properties	Data Range
Oil Gravity (°API)	9-30
Porosity (%)	15-35
Average Permeability (md)	10-600
Initial Water Saturation (%)	10-50
Depth (ft)	300-8000
Net Thickness (ft)	25-400
Producers BHP (psi)	75-500

Proxy model for primary production RF= 2.968 + 0.4567 API + 0.001054 Depth – 19.47 Sw + 0.000509 Permeability – 3.54 Φ − 0.006501 ProdBHP + 0.00072 Thickness *eqn 1*

Proxy model for waterflood RF=12.26 + 1.6554 API+ 0.004698 Depth –58.31 Sw + 0.05206 Permeability − 46.56 Φ− 0.01884 ProdBHP + 0.0122 Thickness *eqn 2*

Proxy model for polymer injection RF=−1.58 + 1.1714 API +0.005659 Depth –50.97 Sw 0.06850 Permeability−59.74 Φ− 0.00312 ProdBHP+ 0.00341 Thickness *eqn 3*

Proxy model for stream injection RF=19.05 + 1.241 API + 0.003049 Depth –46.31 Sw + 0.04977 Permeability − 47.4 Φ− 0.00257 ProdBHP+ 0.0458 Thickness *eqn 4*

Proxy model for CO2 injection RF=−0.72 + 1.3963 API + 0.002576 Depth –41.46 Sw + 0.02768 Permeability – 5.70 Φ− 0.01075 ProdBHP− 0.0043 Thickness *eqn 5*

Figure 9 below shows the contour plots developed from the RSM method to conduct the first pass estimate of the F for these four EOR and primary production versus depth and API (as these were identified as the two parameters having the highest effect on RF). The figure depicts that for lower API values and shallow reservoirs, RF is low, which is mostly due to the low injection pressure. Injection pressure is low because the cap rock should not be fracked. These contour plots can be used as a quantitative screening to have a rough estimate of RF and feasibility of any EOR method before starting the project.

Stage 3 Reserves Determination & Validation

This stage consisted of determining the reserves within the Guapo Cruse E sand by using OOIP data and production data. To verify the OOIP actual field to the simulated field, the NOS map was planimetered and previous literature reviewed and compiled to justify the OOIP of the sand.

Using Table 1 as well as geological NOS and structure maps, a numerical model was built. The reservoir parameters such as porosity, water saturation and initial oil formation volume factor were obtained from reports. The volumetric method was used to calculate the OOIP. Using the following formula:

$$OOIP = \frac{[7758Ah\Phi(1-S_w)]}{B_{oi}}$$

Where: OOIP = Original Oil in Place (Stock Tank barrels); 7758 = Conversion factor from acre-ft to bbls; A = Area of reservoir (acres) from map data; h = Thickness of pay zone (ft) from log and/or core data; Φ = Porosity (%) from log and/or core data; S_w = Connate Water Saturation (fraction) from log and/or core data; B_{oi}= Initial Oil Formation Volume Factor

The results of this calculation are shown below.

Table 3

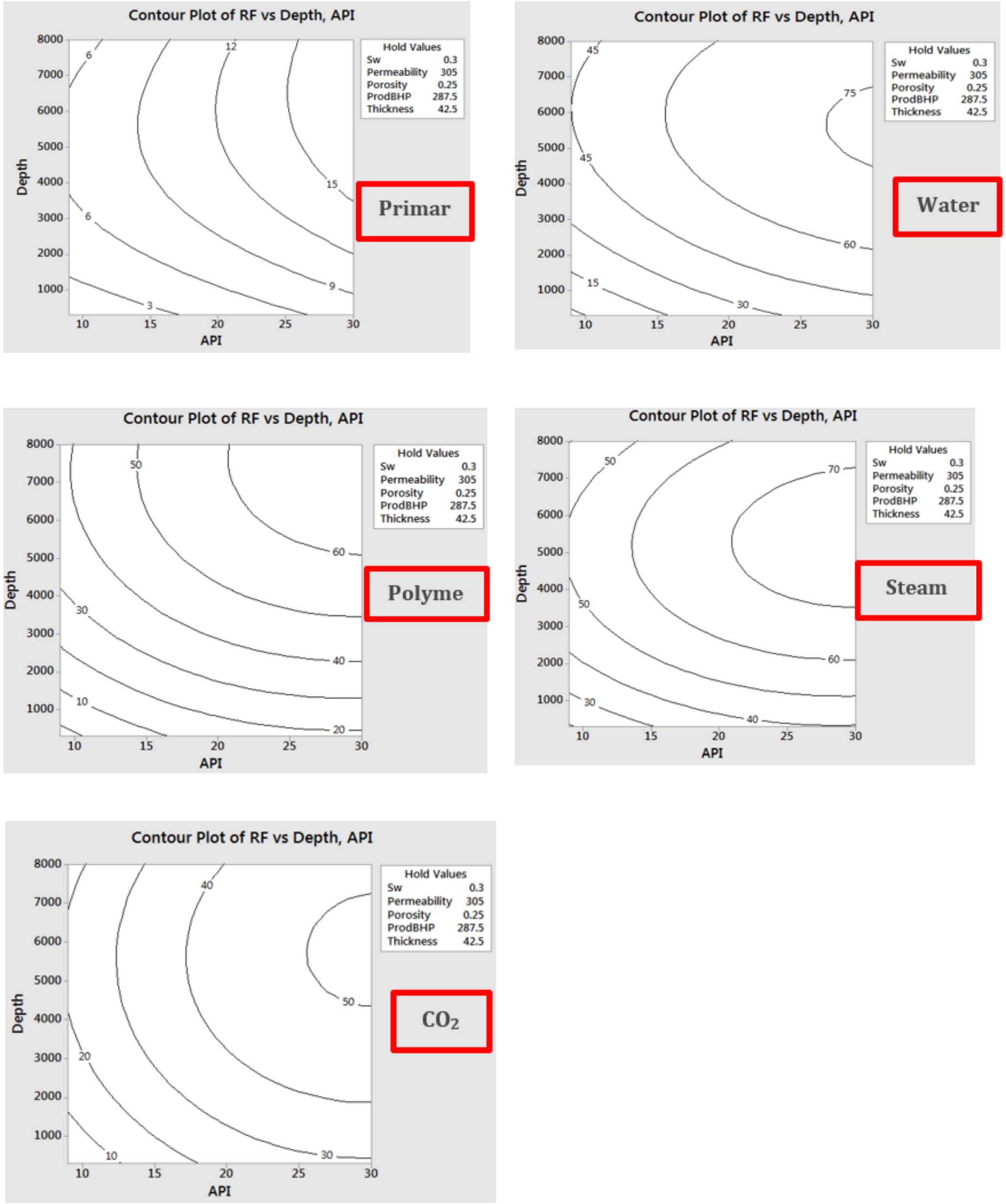
Comparison of OOIP

Calculated OOIP value	Reported OOIP value (model)
44.1 MMSTB	44.3 MMSTB

As seen in Table 3, the planimetered meter value was 44.1 MMSTB whist the reported value was 44.3 MMSTB.

Figure 9

Contour Plot of RF Using RSM



Stage 4 Reservoir modelling

Based on the outcome from stages 2 and 3, reservoir modelling was conducted for the Cruse E Guapo sand. This entailed three sections: (1) building of the Geo-model, (2) the input of Petrophysical data and (3) Wellbore modelling.

Geo-model

To construct the base geo-model for each field, firstly the structure and NOS maps were digitized using the Didger 5 software. In this program, the structure map was uploaded and after tracing the contour lines, boundaries and well positions, an Atlas Boundary (.bna) file was outputted. This file was then transferred to Petrel where well trajectory, surface coordinates, and the NOS and oil sand maps were integrated to create a rescue file.

Petrophysical Data

The rescue file was then exported from Petrel and imported to CMG-STARS to be populated with specific reservoir parameters such as porosity, permeability, reservoir temperature, bubble point pressure, fluid API and water saturation. Using geostatistics for permeability distribution in CMG, the model was made heterogeneous using Gaussian geostatistical simulation with secondary variables as the calculation method.

Wellbore Modelling

To model the wells the production data was used to gather information on each well associated with the sand and area of interest. Information such as perforation depths, dates of completion and last produced and well stages were all imported into the CMG model. The selection of the accurate stage, perforation depth and sand package is critical at this point due to the reservoirs being stacked and perforation depths extending across different sands, creating the avenue to produce from multiple sands and causing comingling of production fluids as a result.

Stage 5 History Matching

History matching is the process by which the numerical model being built represents the actual reservoir in both observed and measured data. The two methods used to history match the mentioned reservoirs were based on the measured data acquired for each field. Manual history matching was utilised for fields that had cumulative production history only and automatic history matching via CMG-CMOST was used for fields with daily production rates and field history files.

CMG-CMOST

For CMOST to be utilised, a field history file and production file were created using data from both literature and the production data. CMOST is an automated software that uses advanced calculation engines in collaboration with statistical methods to create and assemble the best match. Oil, water and gas production were matched.

Cumulative Production

Based on the data available the resulting model was history matched using cumulative production data for the Cruse E sand.

Production Forecasting

To evaluate and justify the need for an advanced method of recovering the hydrocarbons in place, a production forecasting was completed using the base models after history matching to 2018. They were simulated to run for 20 years without any additional EOR mechanism. This additional step was crucial in observing the significant difference on the employment of a secondary and tertiary method within the Guapo Cruse E sand.

Stage 6 EOR Modelling and Optimisation

Following the history match, it was observed that 91.5% of the oil was still in the reservoir. The oil saturation was shown to be approximately 75%. Because of this high oil saturation and remaining oil, EOR mechanisms were investigated in order to simulate if any more oil can be recovered from the reservoir. Each of the four base models outlined in the methodology, that is, waterflooding, steam flooding, polymer flooding, and CO_2 injection were optimised using varying injection rates and injection patterns. The injection patterns used were the Five Spot, Line Drive and Irregular patterns. Further analysis on combined IORs including water alternating CO_2, steam alternating CO_2, polymer followed by water, and steam followed by CO_2 was investigated on the created based model. For simplicity, an overall injection volume of one (1) and two (2) hydrocarbon pore volumes were used as injection rates.

Stage 7 CO_2 sensitivity analysis

Injection strategy for CO_2 was based on pore volume injection as outlined in Table 5. Due to high compressibility of CO_2 and the fact that CO_2 injections in Trinidad are immiscible, the injection rate was varied to perform a detailed sensitivity analysis in order to optimise CO_2 performance.

Stage 8 Economics

To assess the economic viability of various EOR and combined IOR methods presented in this paper, economic spreadsheet templates were developed to calculate the Net Present Value (NPV) after 20 years. The selected simulations for economic evaluation were for EOR (steam, water, polymer, and CO_2) and for combined IOR (WAG, SAG, Steam Followed by Gas (SFG) and Polymer followed by Water (PFW)).

Table 4 presents the various considerations that were taken for the development of the economic spreadsheets which consist of two main parts: User Inputs and NPV Breakdown. The 'User Input' tab allows the input of all considerations of expected oil production and overall injection. It allows flexibility of different variables (EOR and combined IOR method specific) to be selected. For the economic modelling, no new wells were drilled (using existing producing wells for injection) and assumes no well reworking was done over the 20-year lifespan. For projects including CO_2 EOR, additional costs must be incurred assuming pipeline installation is used (purchase/transport/injection costs) (Serpa et al., 2011; Vora, 2013). For steam, water, and polymer, the cost of generation of fluid (raw material or generation for steam) in addition to the cost of injection are considered. An overall base operational cost per barrel of oil produced, an interest rate, and an oil price was used for each sheet (Table 4). The taxes applied were taken from the Petroleum Act 62:01, the Petroleum Production Levy and Subsidy Act 62:02, the Petroleum Taxes Act 75:04, and a detailed, annual breakdown was done on each spreadsheet titled 'NPV Detailed Sheet'.

The revenue was calculated using the oil produced over the 20 years of the project. Subsequently, the appropriate tax laws were then incurred to observe how the NPV would vary over the life-cycle of the project.

Each well, drilled at a specific depth, would have a corresponding CAPEX in the form of reworking existing producing wells into injection wells. Typically, the cost of reworking a single production well for EOR is cited to be USD$17.38/ft. The CAPEX investment (USD) for the Guapo field at depth 2300 ft for seven injectors was calculated as 280,000 USD. The economic analysis was conducted using the variables corresponding to each EOR and IOR method. The analysis allows classification on the most economic recovery method for each of the fields analyzed. The NPV is calculated using the tax laws as well as the OPEXs and CAPEXs for each method. The present value of cash flow was calculated using the equation:

$$PV_n = \frac{CF_n}{(1+i_n)^n}$$

Where PV_n = present value of cash, CF_n = cash flow, i_n = interest rate, n = period

Table 4

User Variables for Economic Evaluation

Components	Base Value Used
Cost of Purchase of CO_2	\$3.00 t/CO_2
Cost of Transport of CO_2 for 10 miles	\$1.50 t/CO_2
Cost of Injection of CO_2	\$1.30 /bbl oil produced
Cost of Generation/Production of Steam at 200C and 1000psi is assumed to be 6500kW/h	\$0.30 /bbl of steam produced

Cost of Injection of Steam	$0.50 /bbl of steam injected
Cost of Water	$0.02 /bbl of water
Cost of Injection of Water	$0.25/bbl of water injected
Cost of Polymer	$0.20/bbl
Cost of Polymer Injected	$0.50/bbl
Oil Price (All)	$58 /bbl
Interest Rate (All)	10%

The net present value over time (NPV_n) was then calculated for each year over a 20-year simulation period. This will allow the user more flexibility in observing how the NPV changes over time, and which years are the most economical. The NPV function in MS Excel was used to calculate this.

The results were explored classified by EOR and combined IOR simulation. This allowed better comparison of each pure EOR method, and also for observation of which combined IOR method was better suited. The base costs were used, then sensitivities were conducted on the most economic EOR and combined IOR.

The results were represented for the EOR and combined IOR simulations as the change of NPV per year over the 20-year period. This representation was utilised to observe how profitable various years of oil recovery were; with a steep positive slope correlating to high profits, and a plateau shaped slope corresponding to a lower recovery of oil.

Sensitivities and conclusions were done using the sensitivity analysis tool of Oracle Crystal Ball (MS Excel Add-in). This allowed the modification of all variables (excluding the tax rate) and demonstrating the resultant change in NPV. The range of sensitivities used were between -50% and +150% for each variable in Table 4.

Results and Discussion

Guapo - Reservoir Simulation

Primary Production

The total primary production for this field was 3.8 MMSTB, which accounts for approximately 8.5% recovery of the OOIP as seen in Figure generated using CMG. This percentage recovery is typical for heavy oil reservoirs under primary production. Primary production for heavy oil reservoirs usually accounts for 8 to 12 % recovery (Rajnauth, 2012).

Figure 10

Oil Recovery Factor for Primary Recovery

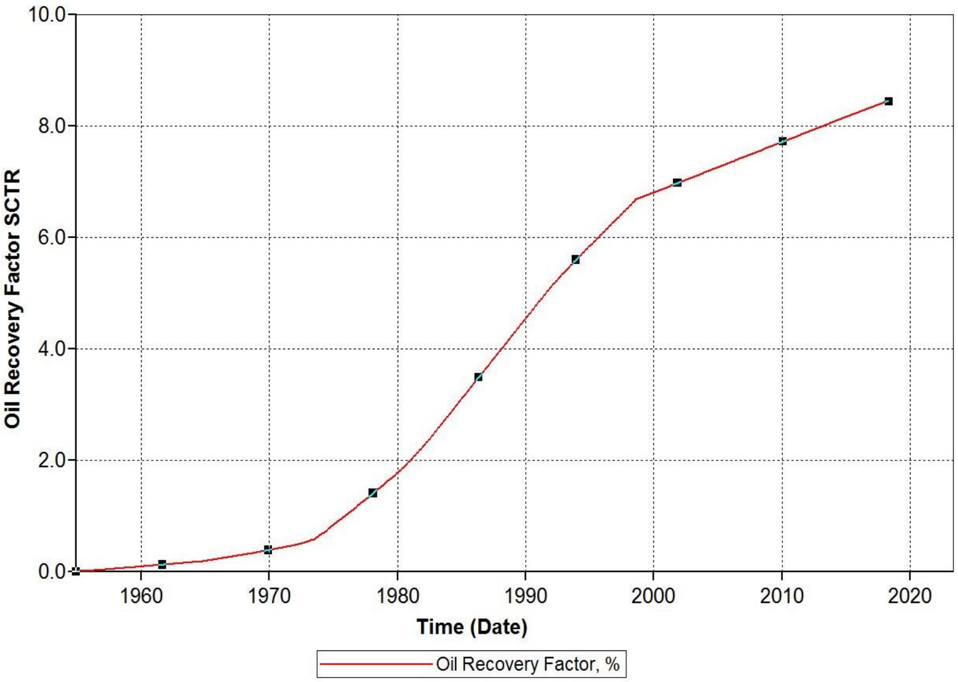
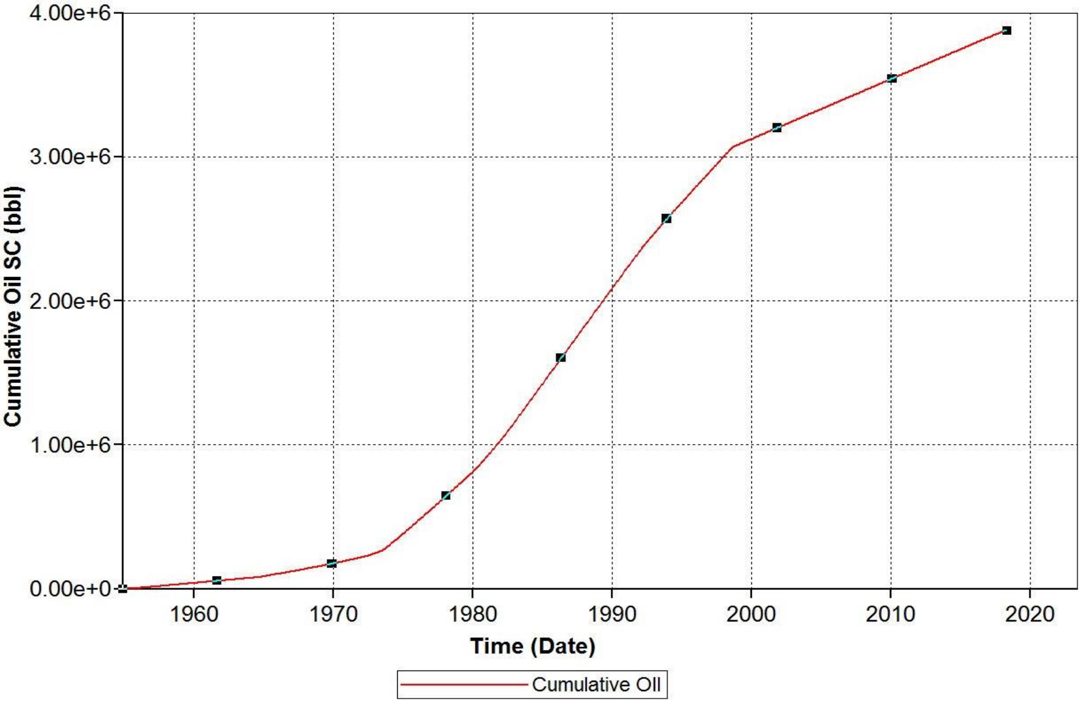


Figure 11

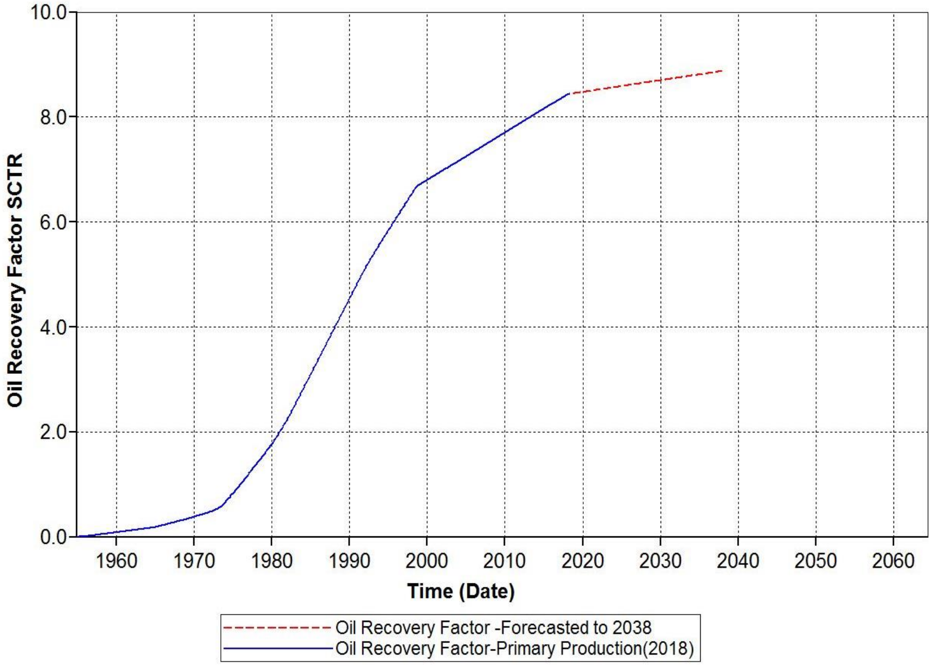
Primary Production Cumulative Oil Produced



This production was estimated using the production data for the wells that were simulated in the reservoir. For wells that did not have an end production date, the date of last production was assumed to be April 30th 2018. This date was chosen as it is the date that the production data file was received from Petrotrin. The cumulative primary production curve can be seen in Figure 11 as generated from CMG. Before the increased oil recovery methods were tested, it was important to know how much oil would be produced or the recovery factor of the field had it been left on primary recovery alone. As such the simulator was allowed to run for another 20 years (2038) to see what the production would be. This was treated as the base case scenario. Only 0.3% increased recovery or a total of 8.8% recovery was achieved (Figure 12). This amounts to only approximately 130,000 STB being produced over 20 years. As such IOR and EOR are valid to be tested.

Figure 12

Oil Recovery Factor for An Additional 20 Years of Primary Production



Guapo IOR and EOR

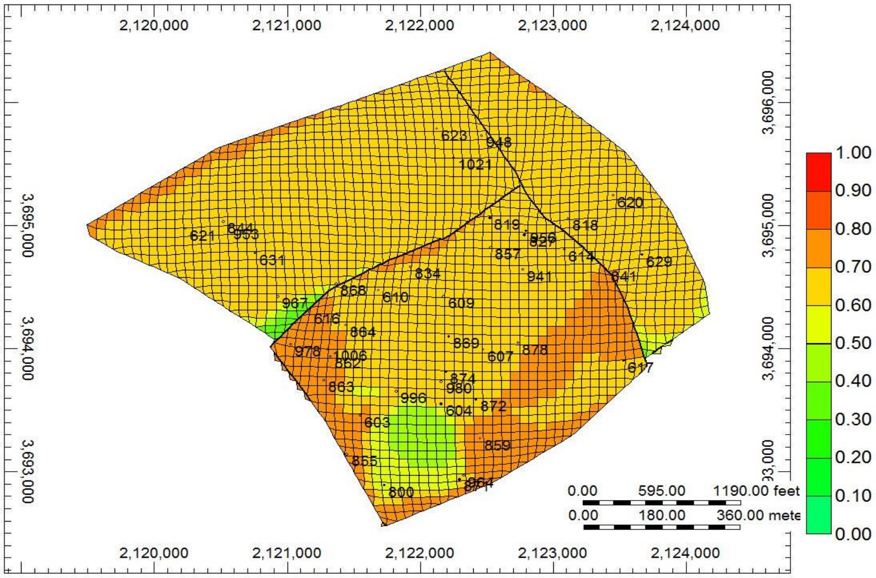
From the simulation results, approximately 91.5% of the oil was still in the reservoir. The oil saturation was shown to be approximately 75%. Figure 13 shows the oil saturation at the end of the primary production phase (April 30th, 2018).

Pattern Selection and Injection

Three different injection patterns were studied based on the oil saturation of the reservoir after the primary production period. These three patterns were tested with water flooding, steam flooding, polymer flooding and carbon dioxide flooding. In addition, each of these methods was simulated by injecting one and two hydrocarbon pore volumes over a twenty-year study period following the primary production stage. For each of the patterns simulated, the existing wells were used as much as possible in order to minimise cost and economic expenses. The injection pressure was used as a constraint in the injector wells to prevent fracturing of the reservoir. This pressure constraint was used throughout all the patterns tested. As such, this was calculated as follows: Fracture Pressure = 0.7 * depth. The reference depth for the reservoir was approximately 1775 ft.

Figure 13

Reservoir Oil Saturation after Primary Production



For the steam models, the steam was injected at a temperature of 600°F with a steam quality of 0.8. Wellbore heat loss was also added to simulate how much heat was absorbed and lost to the casing or the metallic wellbore. Finally, when injecting carbon dioxide into the formation, it was done at reservoir conditions and not at surface conditions. This is to prevent compression of the gas as it goes downhole. As such the reservoir conditions would represent the volume of gas entering the formation.

Irregular Pattern A

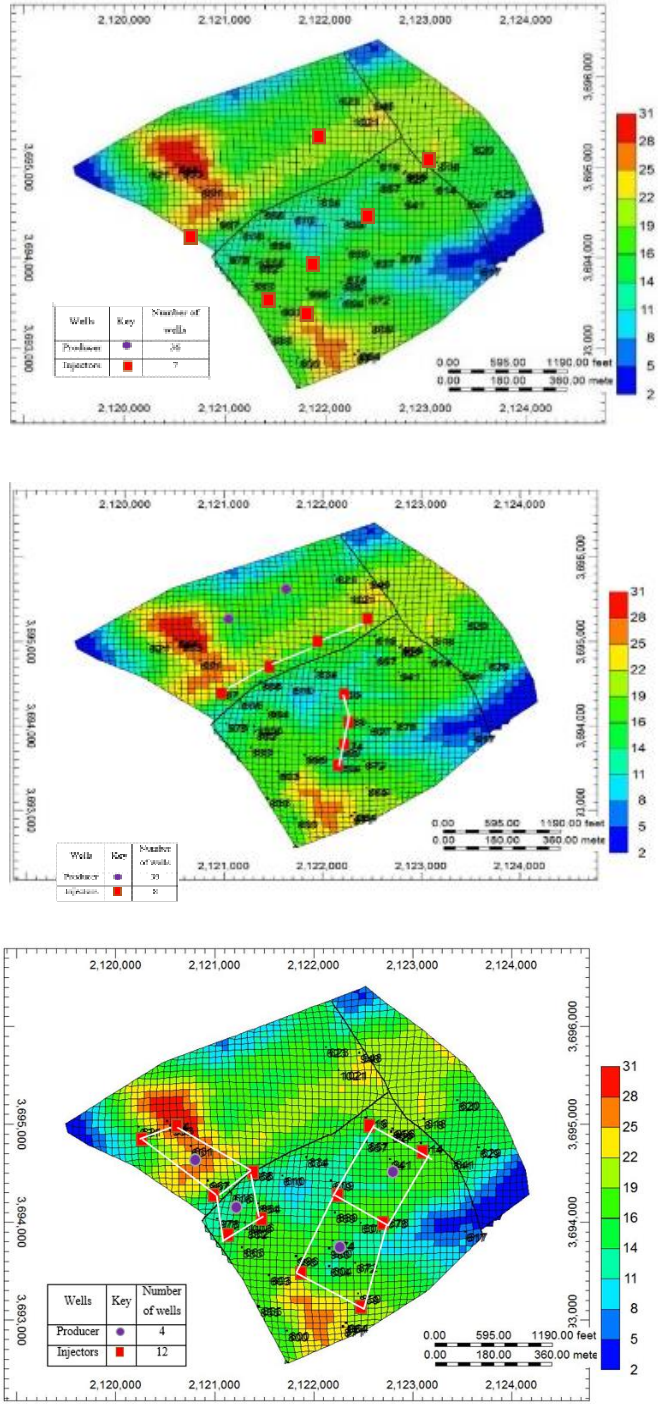
This pattern does not have a distinct shape or number of injectors to producers. Because of this fact, the oil saturation after primary recovery is critical. The location of injectors or conversion of former producers to injectors is based on the type of fluid being injected and where in the structure the fluid should be injected. Based on the oil saturation after primary production (Figure 13), seven former producers were converted to injectors at the crest of the structure in each fault block as these were the places of lowest hydrocarbon saturation. The pattern can be observed in Figure 14a.

Line Drive Pattern

For this pattern, five of the existing wells were utilized and converted to injectors, while three more injectors were added to the reservoir to increase the sweep efficiency and to complete the pattern. All other existing wells were used as off takes or producers. Two more producers were added to complete the pattern and to produce more oil from the sweep of the injectors. These wells were placed approximately 500 ft apart and calculated with a drainage radius of approximately 200 ft – 250 ft since a 5–6-acre pattern was suggested by Petrotrin's reports. This pattern is seen in Figure 14b.

Figures 14a-c

Net Pay Map for Guapo field for (a) Irregular Pattern A (top) (b) Line Drive Pattern (middle) (c) Irregular Pattern B (pseudo 5-spot) (below)



Irregular Pattern B/Pseudo 5-Spot Pattern

For this pattern the existing wells were used to mimic a 5-spot type pattern. As can be seen in 14c, twelve previous producers were converted to injectors and only 4 producers were left online to fulfill the pattern. When all experiments were run, the recovery factor and cumulative oil produced were plotted for each pattern. For the Pseudo 5-Spot Pattern (Irregular B), Figure 15 and Figure 16 show the cumulative oil recovered and oil recovery factor for the 5-spot pattern using all of the mechanisms tested. From the graphs it can be seen that for all the mechanisms tested, steam had the best recovery, followed by water, polymer, and then carbon dioxide respectively over the twenty-year period. However, the carbon dioxide injection at a volume of 2HCPV over a ten-year period would have done better than the polymer flood. Even though the steam flood did not complete its simulation run, the 2HCPV outperforms all the other mechanisms tested.

Figure 15

Cumulative Oil Produced – Irregular B Pattern

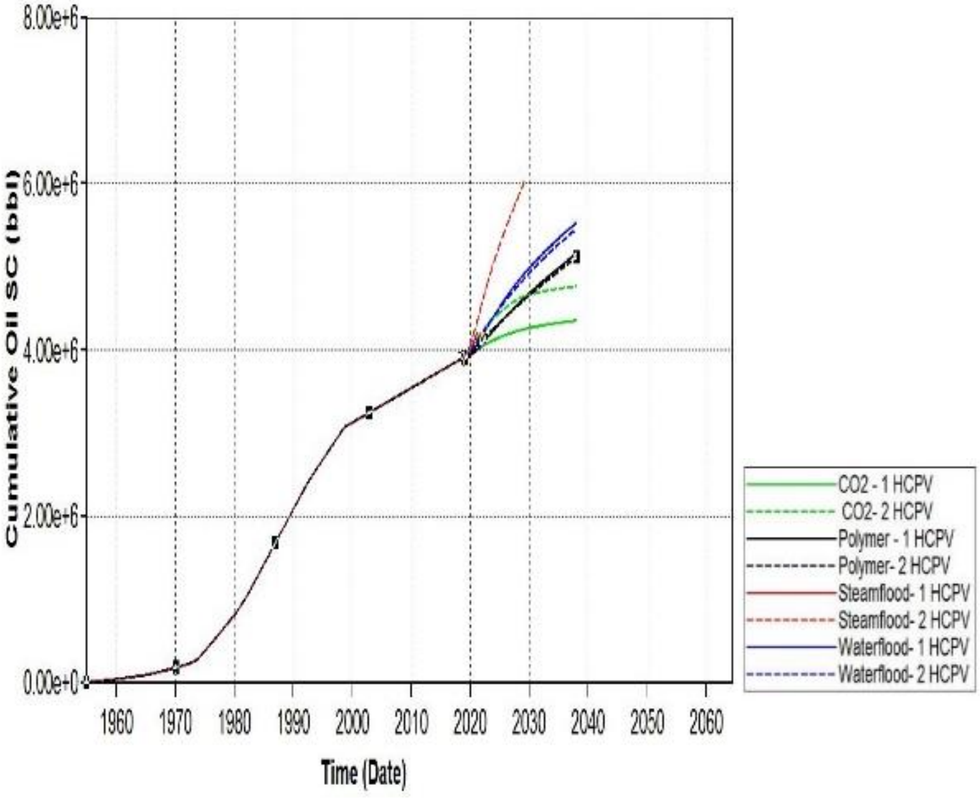
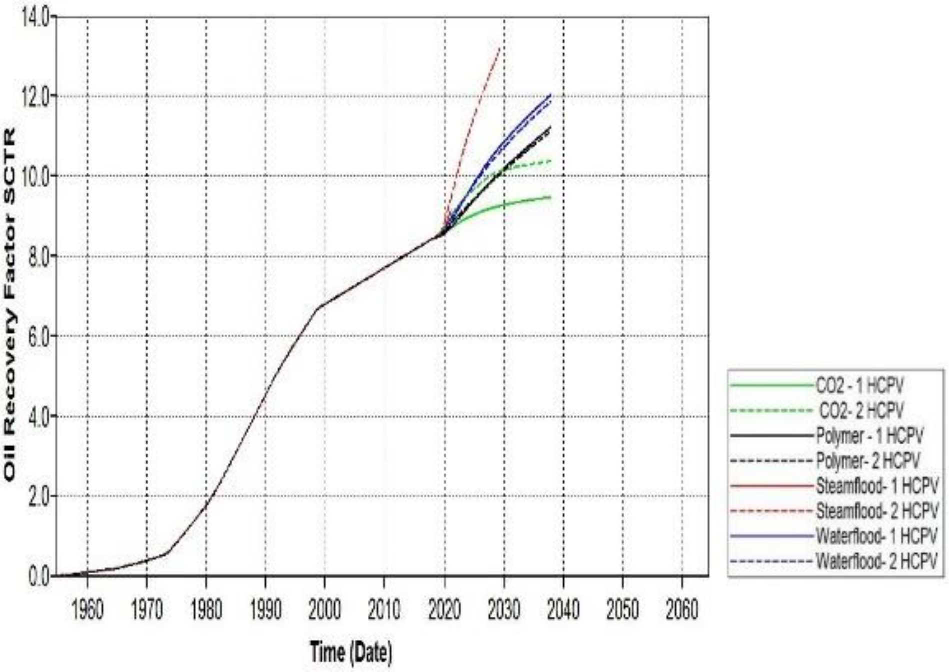


Figure 16

Oil Recovery Factor - Irregular B Pattern



For the line drive pattern, Figure 17 and Figure 18 show the cumulative oil recovered and oil recovery factor for the line drive pattern using all of the mechanisms tested. Similar results were seen for this pattern where the steam flood at 2HCPV was by far the outstanding mechanism. However, it can be noticed that the 2HCPV polymer flood was second best whilst carbon dioxide performed the least favorably. Polymer flooding, steam at 1HCPV, and water flood at 2HCPV only varied in recovery by approximately 2% and thus economic evaluation would be needed to assess which would be most profitable.

For Irregular pattern A, Figure 19 and Figure 20 show the cumulative oil recovered and oil recovery factor for the irregular pattern using all of the mechanisms tested.

Figure 17

Cumulative Oil Produced for Line Drive Pattern

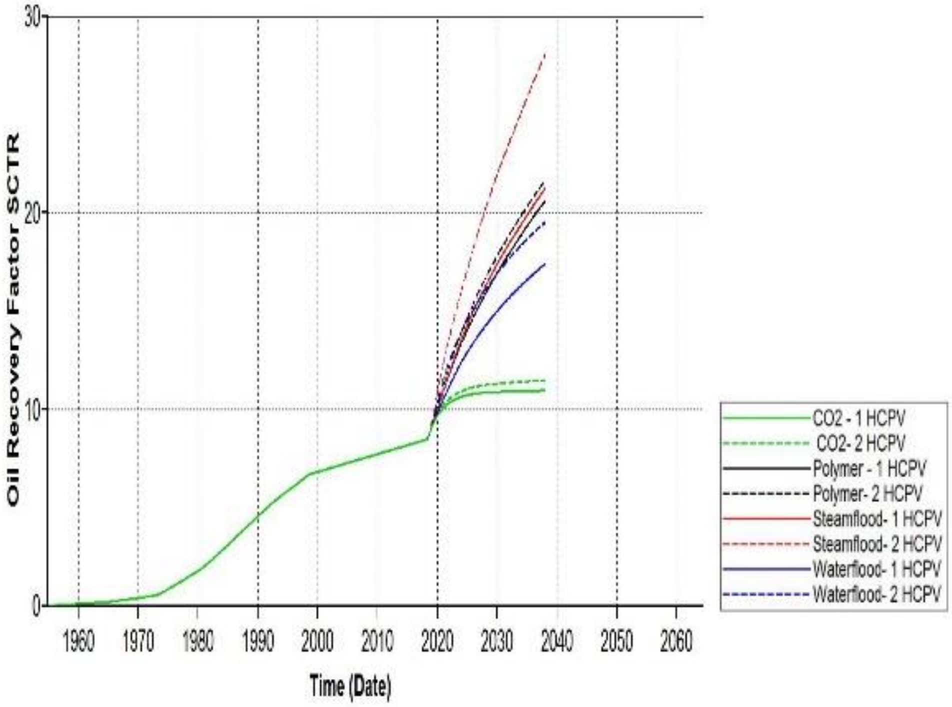


Figure 18

Oil Recovery Factor Using Line Drive

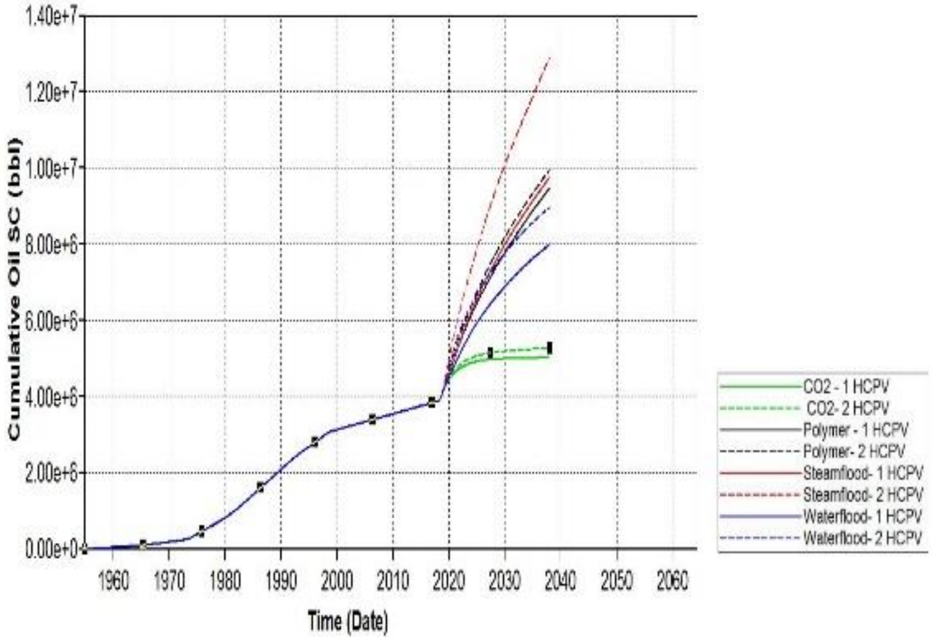


Figure 19

Cumulative Oil Produced - Irregular A Pattern

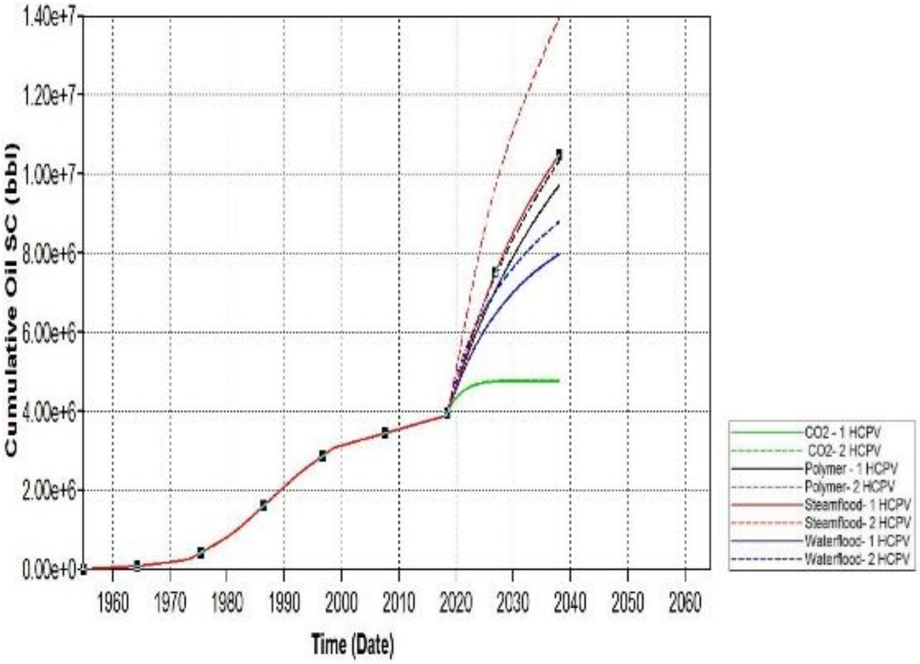
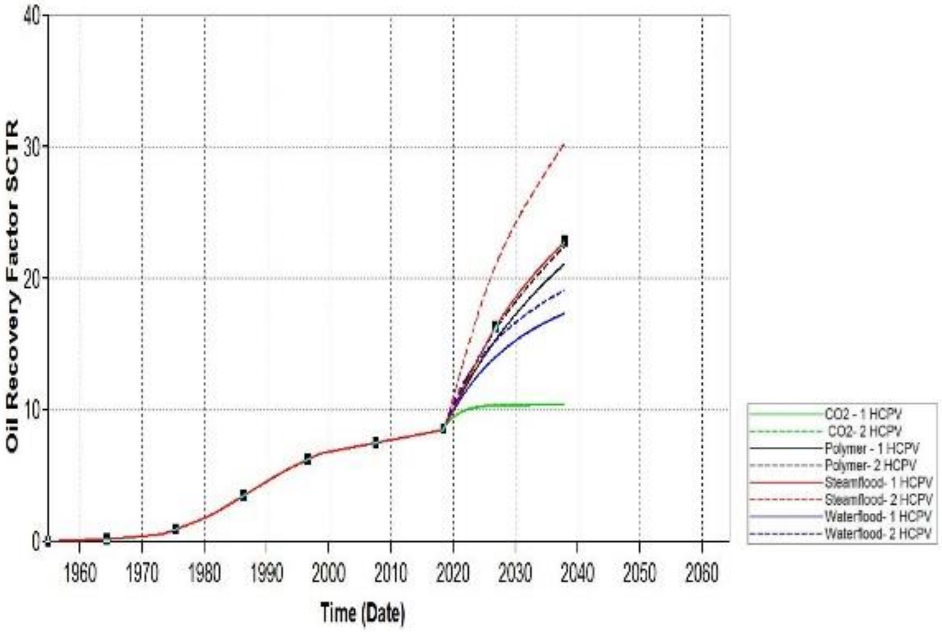


Figure 20

Oil Recovery Factor - Irregular A Pattern



With the irregular A pattern, almost identical results were seen when compared to the line drive, with approximately 2% more recovery on each of the mechanisms used. 2HCPV steam gave the highest results again with steam at 1HCPV, polymer, and water flood having an approximate difference of about 4% overall. Carbon dioxide was lowest overall. The primary oil recovery factor for this field was determined to be 8.5% and cumulative oil of 3.8 MMBBL. From Table 5, it shows that steam flooding using the irregular pattern A and injecting a volume of 2HCPV over a period of 20 years has the best recovery of oil. This may be because of the effect that steam has on the viscosity of the oil. The steam lowers the viscosity of the oil allowing it to move more freely. It also performs a dual function as it pushes the oil toward the producer wells.

Guapo Combined IOR Techniques

Various combined IOR techniques were adapted for the Guapo field and investigated including WAG, steam alternating CO_2, steam followed by water, and polymer followed by water. For WAG, one half HCPV of water was used for the injection volume whilst a slug size of 10% of HCPV injected every half cycle being tested. This injection volume was chosen as several tests had been done before including a 1:1, 1:2 and 1:4 ratio of water to gas. These all failed within the first year of injection and therefore higher amounts of carbon dioxide had to be injected in order to get a substantial result. Three different half cycles were simulated over a period of 20 years. The half cycles used were 60, 90 or 120 days (Figure 21). Firstly, only the 60-day half cycle executed to completion. The 90- and 120-day half cycles stopped after nine and eight years respectively due to a low bottom hole pressure injection error. Even though this occurred, the trends can still be seen as they have almost plateaued. From the results it can be seen that the 60-day half cycle yields the most favorable result recovering approximately 18% over the 20-year period whilst the 120-day half cycle recovers the least.

Table 5

Summary of Results Guapo EOR Mechanisms

Patterns	IOR/EOR	Oil Recovery Factor, %	Ultimate Cumulative Oil, MMBBL	Additional Recovery, %	Additional Cumulative Oil, MMBBL	Fluid Injected/Oil Produced (stb/stb or scf/stb)
Irregular 1 HCPV	CO_2	10.4	4.7	1.9	0.9	298
	Polymer	21.2	10.3	12.7	6.5	6.85
	Steamflood	22.7	10.4	14.2	6.6	6.71
	Waterflood	17.3	7.9	8.8	4.1	10.7
Irregular 2 HCPV	CO_2	10.4	4.7	1.9	0.9	597
	Polymer	22.4	9.7	13.9	5.9	15.0

	Steamflood	30	14	21.5	10.2	8.7
	Waterflood	19.1	8.8	10.6	5.0	17.7
Line Drive 1 HCPV	CO_2	10.9	5.0	2.4	1.2	224
	Polymer	20.6	9.4	12.1	5.6	7.87
	Steamflood	21	9.7	12.5	5.9	7.5
	Waterflood	17.4	7.9	8.9	4.1	10.7
Line Drive 2 HCPV	CO_2	11.5	5.2	3	1.4	384
	Polymer	21.6	9.9	13.1	6.1	14.5
	Steamflood	28	12.9	19.5	9.1	9.7
	Waterflood	19.5	8.9	11	5.1	17.3
5 Spot 1 HCPV	CO_2	9.4	4.3	0.9	0.5	538
	Polymer	11.1	5.0	2.6	1.2	37.0
	Waterflood	11.8	5.4	3.3	1.6	27.7
5 Spot 2 HCPV	CO_2	10.3	4.7	1.8	0.9	597
	Polymer	11.2	5.1	2.7	1.3	68.2
	Steamflood	13.1	6.0	4.6	2.2	40.3
	Waterflood	12	5.5	3.5	1.7	52.2

Steam Alternating CO_2

For this, only one test was done for a 60-day half cycle. Again, one half HCPV of steam was injected over the 20-year period whereas 10% of the HCPV was injected every 60 days. The result is shown in Figure 22.

Figure 21

Oil Recovery Factors for WAG Cycles

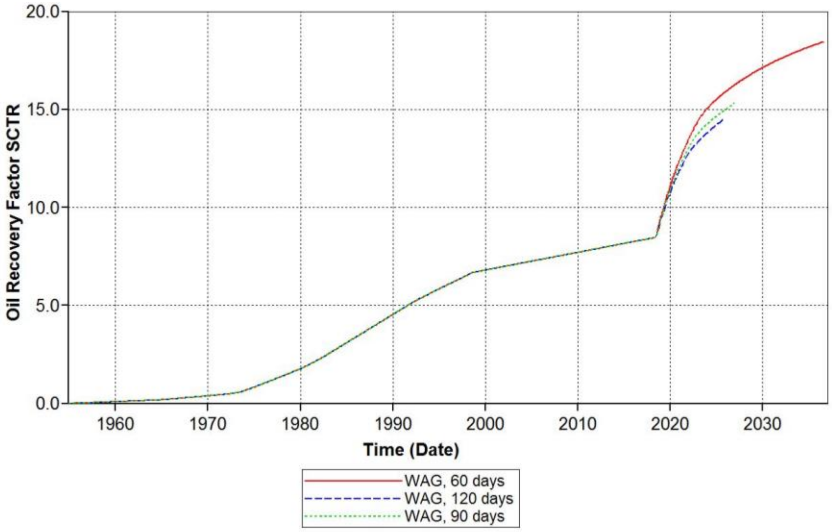
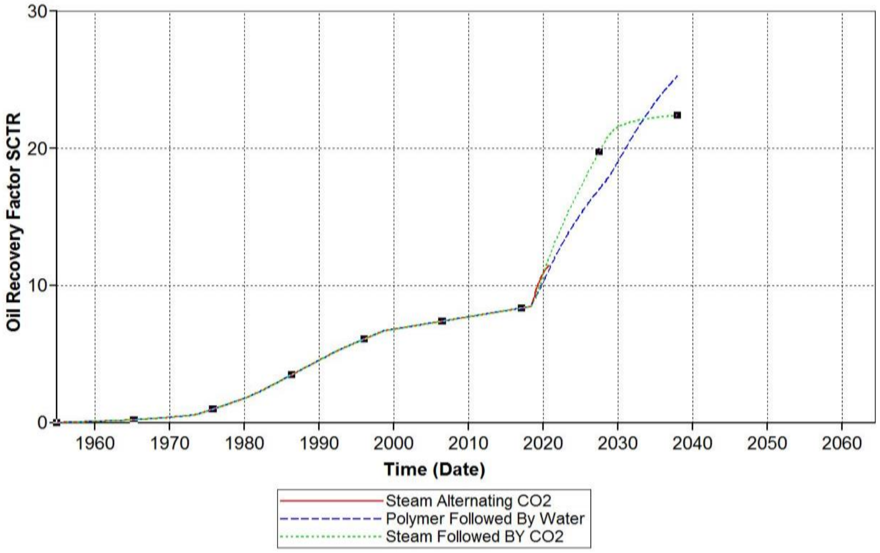


Figure 22

Oil Recovery Factors for Combined IOR Methods



Steam Followed by CO_2

A slightly different approach was used for this method. It is not considered an alternating method but one mechanism follows another. This can be taken to mean that a secondary recovery method was first employed then a tertiary method of recovery was used. Therefore, steam was injected for ten years and then CO_2 was injected for a further ten years. One HCPV of each fluid was injected for each of the ten-year periods. It is assumed that the same injectors that were used for the steam flooding were then converted to injecting CO_2. The result of the oil recovery factor is shown in Figure 22.

Polymer Followed by Water

Similarly, a polymer was used as a secondary recovery method followed by water. Each of the fluids again was injected for a period of ten years at a volume of one HCPV each. The result is shown in Figure 22. From the graph it can be seen that the polymer followed by water has the highest recovery over the 20-year period. Oil recovery is estimated to be 25%. However, the steam followed by CO_2 shows great potential for the first ten years where steam is injected. It surpasses the polymer followed by water at this stage but then falls away as soon as the carbon dioxide injection phase begins. This may be because of the low amount of carbon dioxide used for injection. Further work can be done where higher volumes of carbon dioxide are injected in this phase to see if a higher recovery is achievable. Table 6 shows a summary of all further work done. When these values are compared to that of the initial experiments that were run the following observations can be seen: WAG 60 days outperforms all the CO_2 and 1 HCPV water. The water flood 2 HCPV recovers only 1.5% higher than the WAG. As can be seen the polymer followed by water recovers the most oil over the given period. It performs better than polymer and water by themselves. Therefore, this may be a suitable choice when thinking about implementing an IOR/EOR for this field.

Table 6

Summary of Additional Tests Oil Recovery Factors

Method	Recovery Factor (%)
WAG 60 Days	18
WAG 90 Days	15.5
WAG 120 Days	14.5
Polymer Followed by Water	25
Steam Followed by CO_2	22
Steam Alternating CO_2	

Finally, this method showed great promise for the first ten years but then overall recovery was limited to just 22%. Despite this, it is still a viable option instead of CO_2 alone. Steam flood alone however, injecting a volume of 2 HCPV, still has the highest recovery of the lot. Table 10 shows a breakdown of the combined IOR techniques result.

Table 7

Comparison of Line Drive IOR and EOR Methods with WAG

Line Drive Oil Recovery Factors (%)						
WAG			Water		CO_2	
60D	90D	120D	1HCPV	2HCPV	1HCPV	2HCPV
18	15.5	14.5	17.4	19.5	10.9	11.5

Table 8

Comparison of Line Drive IOR & EOR Methods with Polymer Followed by Water

Line Drive Oil Recovery Factors (%)				
Polymer followed by Water	Polymer		Water	
	1HCPV	2HCPV	1HCPV	2HCPV
25	20.6	21.6	17.4	19.5

Table 9

Comparison of Line Drive IOR and EOR Methods with Steam Followed by CO_2

Line Drive Oil Recovery Factors (%)				
Steam Followed by CO_2	Steam		CO_2	
	1HCPV	2HCPV	1HCPV	2HCPV
22	21	28	10.9	11.5

Guapo CO_2 Injection Rates Sensitivity

Because carbon dioxide as a gas was injected at the same volume as the other fluids, the amount of gas going into the reservoir is much smaller and thus gives the lowest recovery for every pattern run. Therefore, increased volumes of carbon dioxide were injected to see if there would be any significant difference. The volumes tested were as follows: 1 Pore Volume, 10 Pore Volumes and 100 Pore Volumes. Each scenario was simulated for the duration of 20 years using the irregular pattern (best recovery). The outcomes can be seen in Figure 23. The carbon dioxide injections were compared to the best recovery for the irregular pattern (steam 2HCPV). The highest recovery for carbon dioxide was approximately 13% from injecting 100PV. This injection volume is very high and thus an economic evaluation would be needed to see if this is feasible. It is still incomparable to the recovery using steam, which surpasses it by 17%.

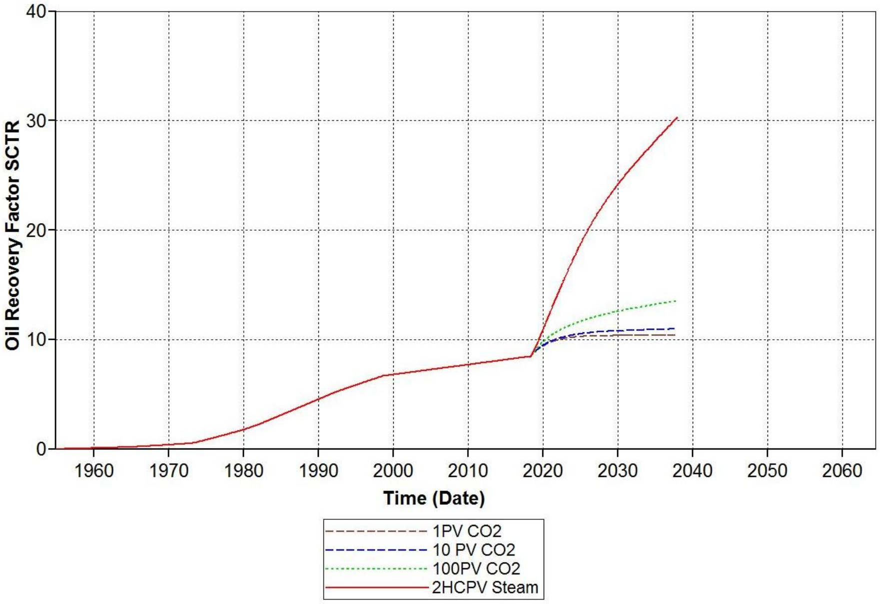
Table 10

Guapo Combined IOR Results Summary

Combined IOR/EOR	Oil Recovery Factor (%)	Cumulative Oil (MMBBLS)	Additional Recovery (%)	Additional Cumulative Oil (MMBBLS)	Fluid Injected/ Oil Produced (MMSTB/MMSTB)
WAG (10% HCPV, 60 days)	19.34	8.88	10.91	5.01	4584.85
WAG (10% HCPV, 90 days)	26.85	12.33	18.42	8.46	315691.06
WAG (10% HCPV, 120 days)	17.89	8.22	9.47	4.35	2312.52
SAG	15.07	6.92	6.65	3.054	3365.29
Steam followed-by CO_2	22.39	10.29	13.97	6.41	65.36
Polymer followed-by Water	25.33	11.64	16.90	7.76	14.17

Figure 23

Oil Recovery Factor for 1, 10 and 100PV CO_2 Injected



Guapo Economics

The graph below shows the NPV change over the years of operation. The results on Figure 24 reveal that for the Guapo field, the steam injection EOR method would be the most economical over the 20-year period; with the most profitable years being 1-11 and a final NPV of MMUSD \$23.17 after 20 years. For polymer injection, a final NPV of MMUSD \$20.11 is expected, with water following with MMUSD \$19.60 after a 20-year injection period. Water was more economic than polymer for the first 10 years of injection, according to Figure 24. CO_2 is comparable in NPV to other EOR methods for the first two years, however, after year 3, it starts to plateau as oil production slows down.

In Figure 25, different combined IOR methods' economics were compared for this field. Both SAG and WAG were similar in NPV until year 1; with WAG being the best choice with a final NPV of MMUSD \$54.33. SAG, PFW, and all SFG models predicted final NPVs of MMUSD \$46.07, MMUSD \$22.18, and MMUSD \$18.27 respectively; making each IOR method economical for this field.

Two sensitivities were conducted for each of the most economic EOR and combined IOR method. For EOR, steam recovery was selected and for IOR, WAG was selected as the most economical models. Using the base case values, a -50% and +150% range of values were used. According to Figure 26 and Figure 27, oil price had the highest effect on NPV, however, the taxes incurred (SPT tax mainly) severely affected the profits if oil prices were increased. This is due to the range of oil price affecting the SPT tax rate. Between both simulations, the combined IOR (WAG) method appears to be more economical with oil price being the only variable to positively impact the NPV over time.

Figure 24

Guapo Field NPVs over Time for EOR Methods

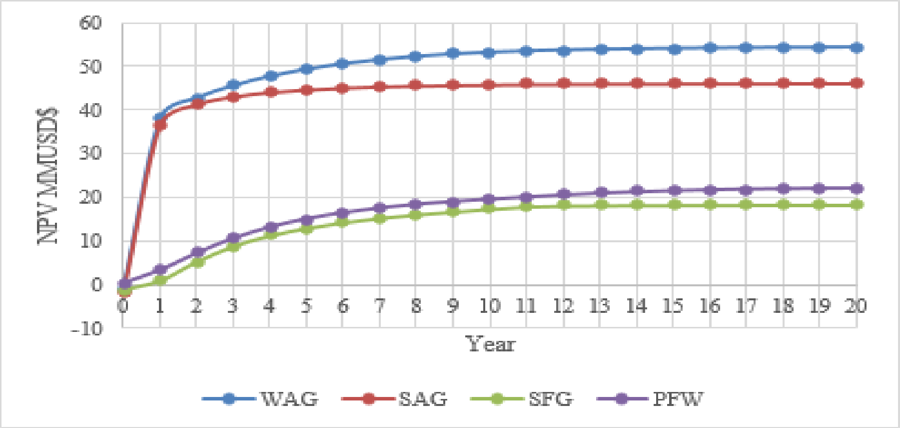


Figure 25

Guapo NPV versus Year for Combined IOR

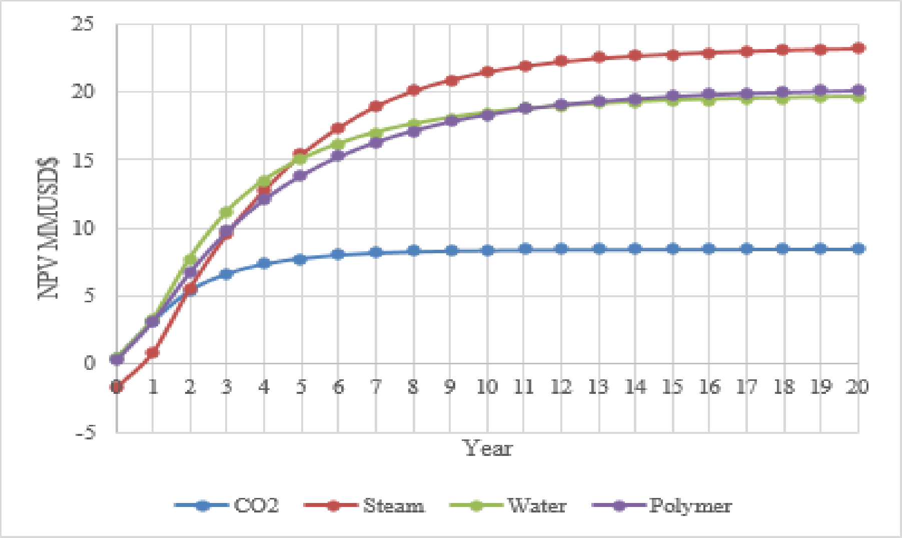


Figure 26
Guapo EOR Sensitivity for Steam

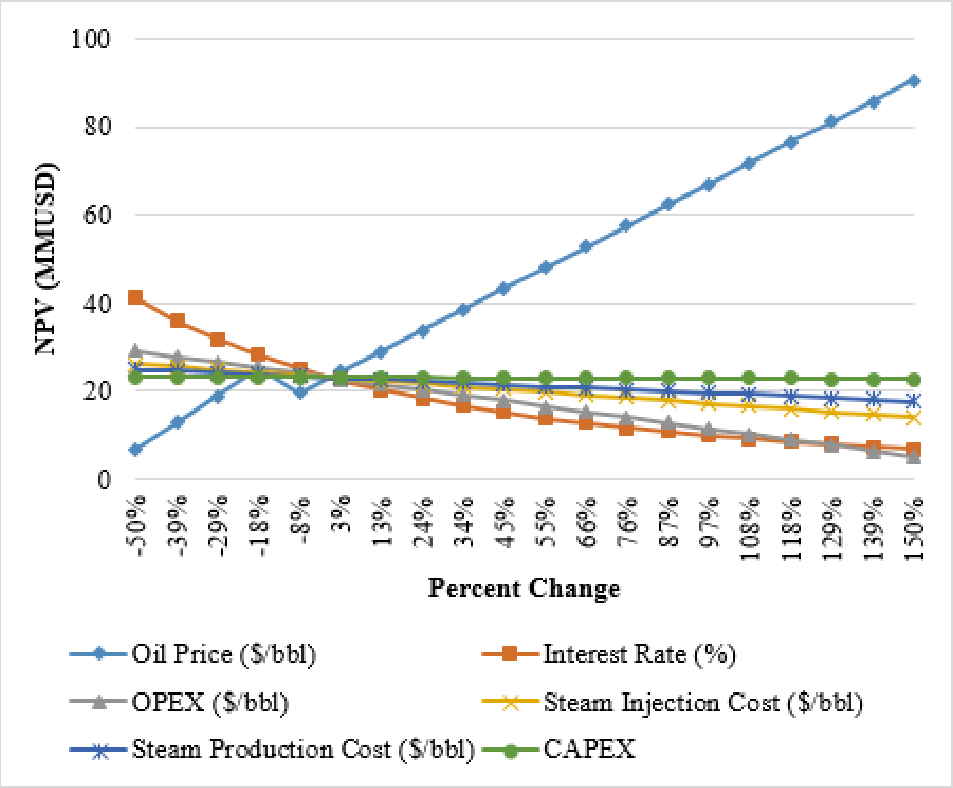
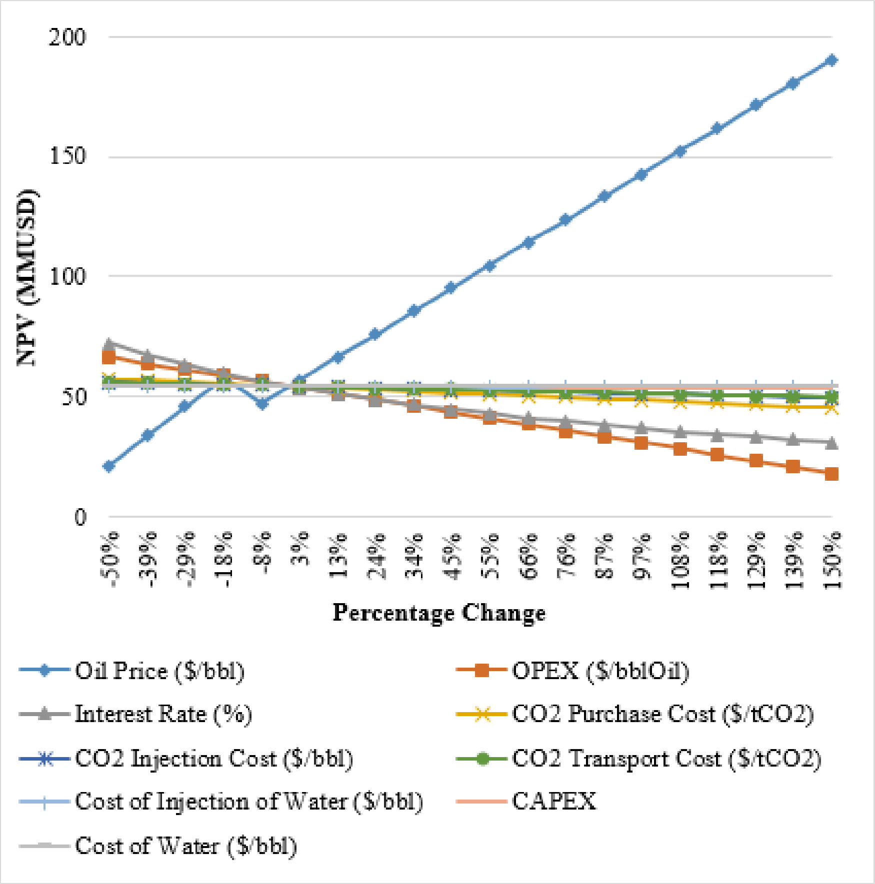


Figure 27

Guapo IOR Sensitivity for WAG



Conclusion and Recommendations

A commercial plan and a novel workflow for the exploitation of the Cruse E heavy oil sands located in the Guapo field, Trinidad was investigated. Differing IOR scenarios were designed in order to predict production performance: WAG, steam alternating CO_2, steam followed by water, and polymer followed by water.

Suitable EOR techniques and combined IOR techniques were optimised with respect to injection pore volume and injection pattern. Injection patterns included line drive, irregular pattern A and irregular pattern B. Three different half cycles were simulated over a period of 20 years. During WAG the half cycles used were 60-, 90- or 120-days. Results showed that steam flooding was the most efficient EOR method with additional recovery of 21.5% and additional cumulative oil of 10.2 MMSTB. WAG was the most efficient combined IOR method with additional cumulative oil recovery of 8.46 MMSTB. WAG was shown to be the most effective and economical model overall.

Economic evaluation was conducted on the best optimization for each model. Two sensitivities were conducted for each of the most economic EOR and combined IOR method. For EOR, steam recovery was selected and for IOR, WAG was selected as the most economical models. Oil price had the highest effect on NPV, however, the taxes incurred (SPT tax mainly) severely affected the profits if oil prices were increased. This is due to the range of oil price affecting the SPT tax rate. Between both simulations, the combined IOR (WAG) method appears to be more economical with oil price being the only variable to positively impact the NPV over time. The recommended commercial plan for the exploitation of the Cruse E heavy oil sands located in the Guapo field can be adopted to enhance the expected income from the reservoir. Furthermore, the method used in this publication's approach can be used to exploit other local reservoirs to increase potential earnings from T&T's oil resources, which would ultimately benefit the citizens of T&T.

It is also recommended that before proceeding to detailed simulation modelling, proper screening of the reservoirs and a first pass estimate of the potential recovery factors be done in order to determine which IOR methods make sense since simulation modelling can be expensive and time consuming. RSM provides a pathway for conducting this first pass estimate of recovery factors. The equations and contour plots developed using this methodology can be applied to many reservoirs that have similar reservoir and fluid characteristics as the Cruse E heavy oil sands (Guapo field). Further research can be done on the RSM methodology to cater for hybrid IOR techniques. From the results, it is recommended that both steam flooding and/or WAG be used as the preferred choices of IOR.

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