



Optimizing the development strategy of combined steam flooding & cyclic steam stimulation for enhanced heavy oil recovery through reservoir proxy modeling

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Abstract

Thermal injection methods are usually used for high viscosity oil. The results of previous studies showed that the combination of SF and SFF had the highest increase in oil recovery but still requires further study to determine the optimum strategy. This work is purposed to optimize the development scenario of a combined CSS-SF applied to a heavy oil field located in Sumatera, Indonesia. The recovery factor and NPV become the objective function, and several given and controlled parameters sensitivity toward the objective function are studied. A proxy model based on quadratic multivariate regression is developed to evaluate and get the desired objective function. The reservoir simulation of the thermal recovery process is done using CMG-STARs simulator. The overall workflow of scenario optimization is conducted using CMOST™ module. Optimum development scenario is obtained through maximization of the objective function. This work shows that the combination of proxy model development and optimization results in the best scenario of combined CSS-SF for heavy oil recovery.

Keywords Steam flooding (SF) and Cyclic steam stimulation (CSS) · Heavy oil reservoir · Proxy model · Recovery factor · NPV

Introduction

The development of heavy oil reservoir is a challenging project. The oil is more difficult to flow due to its high viscosity therefore the oil recovery is usually very low. A thermal recovery method is needed to recover this type of oil, by lowering its viscosity in the reservoir through temperature increasing. The steam flooding is a thermal recovery method performed by continuously injecting a hot steam into the reservoir. The steam from injection well distributes throughout the reservoir, therefore the heat propagates and the condensed steam will displace the oil to the production well.

The accomplishment of a steam flooding project is affected by the distribution of the steam in the reservoir. In the area close to the production well, the steam already lost its heat to the surrounding reservoir so that its temperature drops and condenses. It takes some period before the heat uniformly distributed and the incremental production takes place. The cyclic steam stimulation could accelerate the heat distribution in the reservoir by injecting the steam through the production well and therefore increase the production in the early phase of thermal recovery method.

Several factors affect the success of a thermal recovery project such as the development scenario, thermal property of reservoir, residual oil saturation, reservoir heterogeneity, oil viscosity, and well spacing. It is also a large capital project with additional investment needed, especially for steam generation. However, from several case studies in low API oilfield, it shows a good performance in enhancing the oil recovery (Al Yousef, AlDaif, & Al Otaibi, 2014; Ramkhalawan et al., 1995). Therefore, a fast and robust method to optimize the steam injection development scenario is urgently required.

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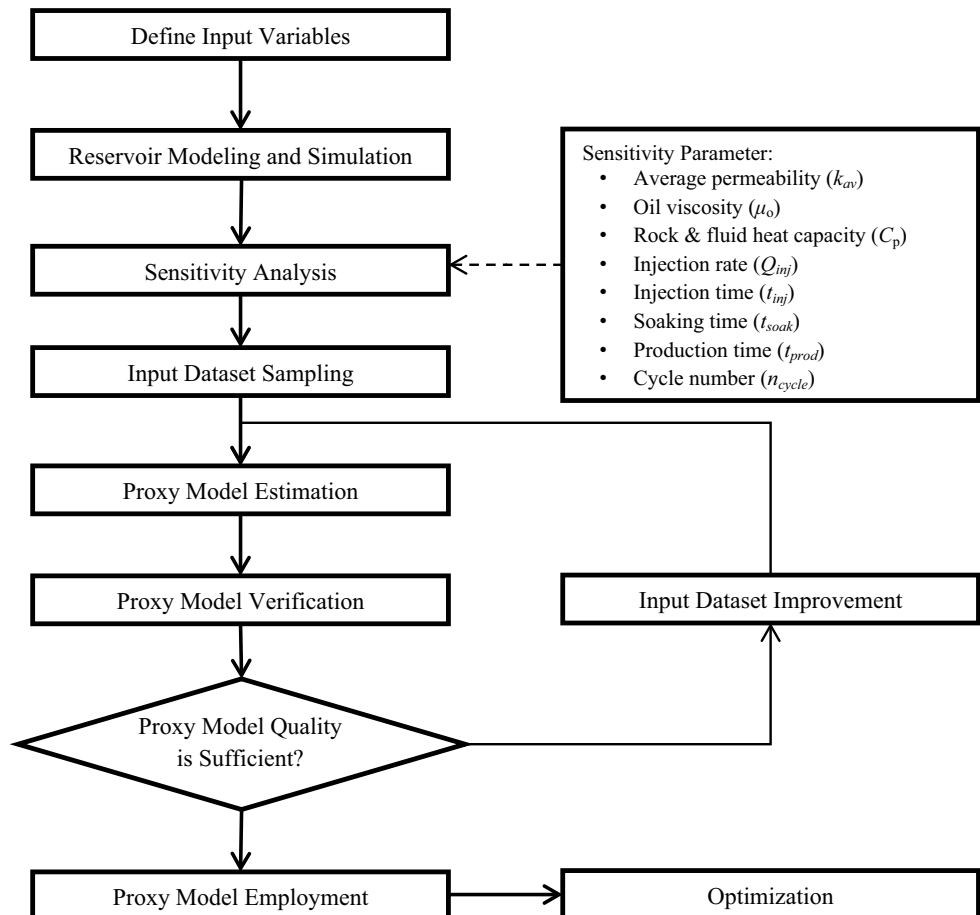
Our previous work in selecting the thermal recovery method resulted the combined CSS-SF gave the best performance (Swadesi et al., 2020a, 2020b). Other work focused on the implementation of proxy model in assessing and optimizing the steam flooding process (Panjalizadeh et al., 2014b). However, both works still used a synthetic-homogeneous reservoir model to perform the optimization. The proxy model-assisted optimization workflow is applied for combined steam flooding and cyclic steam of heavy oil field. The optimization scheme presented here is aimed to maximize the recovery factor and project NPV. The reservoir model is based on an actual field data of a Sumatran heavy oil field featuring its heterogeneity and property distribution. Therefore, this work presents a more evident approach toward the implementation of the workflow for the development strategy optimization in a heavy oil field EOR project.

Research methodology

Methods

The methods of this work follow the flowchart developed by previous work of Swadesi et al., (2020). The workflow is developed to implement proxy model for the optimization and risk assessment of steam flood project. (Panjalizadeh et al., 2014a), consist of data preparation, simulation model building, sensitivity analysis, proxy model development, and optimization (Fig. 1). The key difference is the actualization presented in the study on the sensitivity perform at given and controlled parameters and the economic being the objective instead of uncertainty parameters. Reservoir model volume model made in certain value, unlike previous study at given parameters this time oil saturation has been defined according to petrophysical analysis and no pore volume uncertainty. Also in this study, the location of production-injection wells is certain too, the selection of well location was carefully chosen according to several criteria such as pattern and distance. The reservoir modeling consists of static modeling and property distribution is performed in Petrel™. The

Fig. 1 Research Flowchart (modified Swadesi B., et al., 2020)



reservoir simulation was run by CMG-STARSTTM simulator, while the optimization workflow (sensitivity analysis, proxy model development, and optimization) is run in CMOSTTM, also the product of CMG.

Reservoir description

The field data used are from a Sumatran heavy oilfield. Based on two available data in observed layers the oil API

gravity ranges from 16° to 21° API, at the reservoir temperature of 135° F the viscosity ranges from 146 to 537 cp, however in the extreme cold season the viscosity of 100° F increases drastically to 912 to 2,298 cp, respectively. Observed was content from fluid sample ranges from 9 to 12% wt, and asphalts content ranges from 1.3 to 1.75% wt. The reservoir is sandstone with a shallow depth about 120–600 ft below surface (Fig. 2a). Structurally, it is bounded by a fault at the southwest part with the

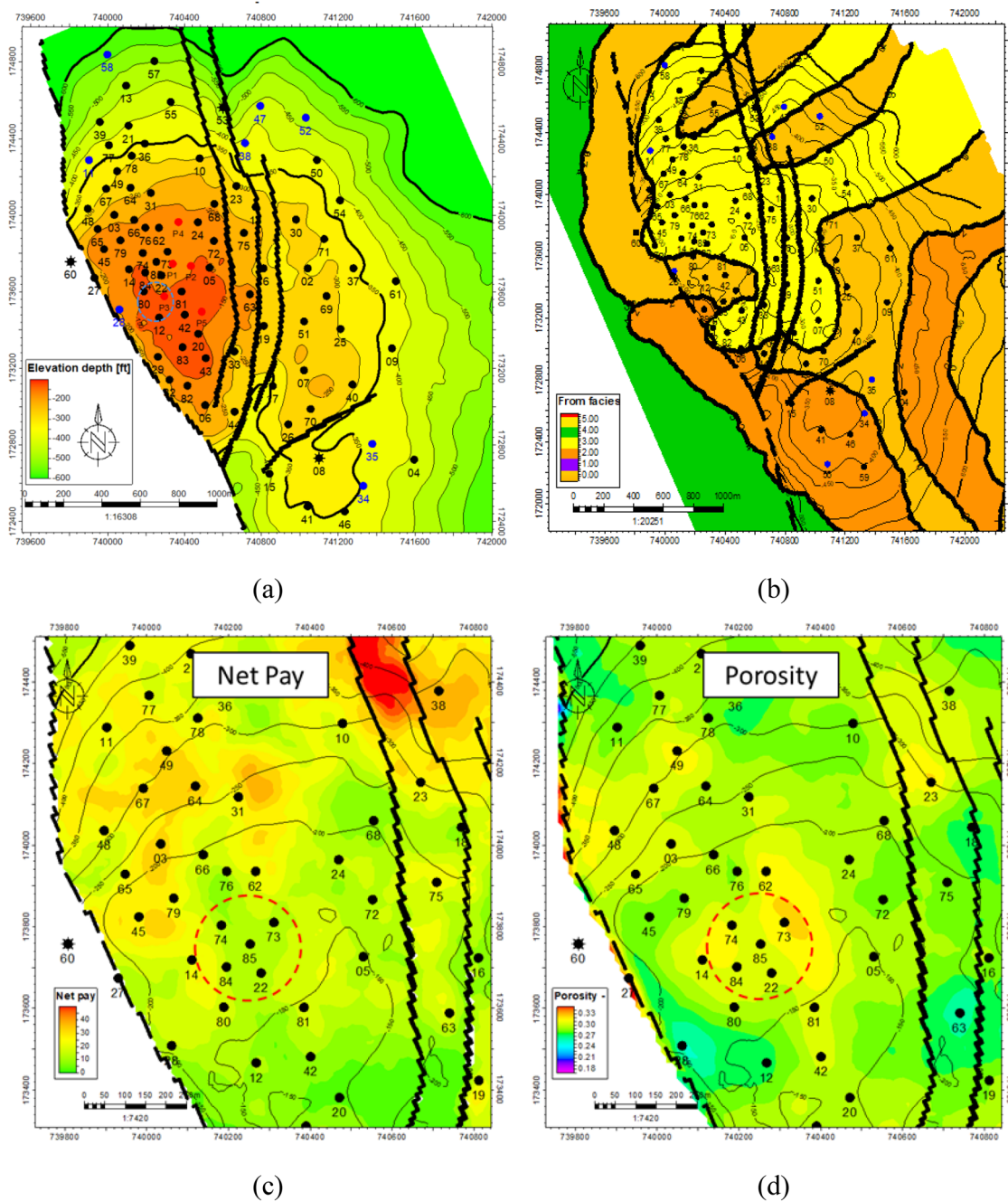


Fig. 2 a Depth Structure b Facies c Net thickness d Porosity

direction of north to south. The facies of the formation is categorized into 3 types: tidal channel, estuarine, and tidal sand flat (Fig. 2b). The thickness of the formation layer is between 10 and 30 ft (Fig. 2c). Also, the porosity and permeability of sand are categorized as good to high, with the average porosity is 30% and average permeability is 700 md (Fig. 2d). Based on those characteristics, using Taber et al. (1997) table this oilfield is a good candidate for thermal recovery method. The parameters in the screening criteria are the API are below 20°API and the viscosity 200 until 2000 cP, and have some asphaltic component.

The field produced since mid-1970's, with current cumulative production of 20 MMSTB from 11 productive intervals with total OOIP about 144 MMSTB, therefore the recovery factor is 14%. The latest production data in 2017 show that the field production rate is 1677 BOPD and the average water cut is about 86%. Among 11 layers, D350 is the lowest reservoir with the highest recovery due to good rock properties, with 38 MMSTB Oil in Place and 6.8 MMSTB oil cumulative according to latest production data in December 2018. The 18% recovery factor is believed to be potentially increased by implementing an appropriate method. By studying the reservoir rock and fluid properties with relatively high viscosity and good to high permeability, steam can be one of the candidates to effectively lower the viscosity and thus, the oil will be easily transported from injection to production wells. According to the above characteristics, the field is compatible to use the thermal flooding for improving the oil recovery.

The D350 interval is selected in this study, and the object area is chosen at one of isolated 5-spot pattern, to resemble a pilot project of a steam injection method. The selected area as shown in Fig. 3 is based on reservoir quality with the range of porosity from 10 to 30% and it transform to the permeability range from lower than 200 mD to over than 1500 mD. The lowest depth of the object area is at 190 ft, and therefore, its distance from initial water oil contact at 580 ft will reduce the interference of water from aquifer while optimizing the injection performance. The well spacing between the center to surrounding wells are 80 m in average, and the distance of surround wells in range of 100 to 120 m. Based on those criteria, 5 wells are selected as the object of study, i.e.,: Well No. 22, 73, 74, 84, and 85. The average production rate of each well is about 30 BOPD, with total cumulative oil production is 61 MSTB. As shown in Fig. 4, the production hardly maintains the sustainability of flow rate for unmentioned reason, but this behavior is wildly observed in heavy oil production. The decline trend is low and showing the potential to improve the influx hence stabilized the flow rate by maintaining pressure and lowering viscosity when the injection is performed.

Reservoir modeling

The reservoir model is constructed to cover the area around the candidate wells for 5-spot pattern with the radius about 150 m. The selected grid size is 12.5 × 12.5 m laterally, while the vertical section is divided into 20 layers, the model consists of 11,520 total grid blocks.

The grid properties used in simulation are NTG (from V_{shale}), effective porosity, water saturation, and permeability. These are derived from log interpretation, which is later upscaled and then distributed by considering the matched variogram and histogram as shown in Fig. 5. The first grid distributed is V_{shale} , and since V_{shale} and porosity are known to have strong correlation, therefore the porosity is distributed by co-kriging to the V_{shale} . The same process is applied on water saturation based on the good correlation to the porosity. Then the permeability is distributed with co-kriging to porosity and application of uncertainty in mean and standard deviation value studied from petrophysical interpretation. In this model, the Oil in Place is calculated as much as 376 MSTB. It is known that South area has better quality over the North, this distribution is affected by available logs from wells outside the area, also the rock quality across observed wells is quite varying.

Parameter sensitivity & proxy model development

The sensitivity analysis is implemented for two types of parameters, i.e., reservoir parameters (average permeability, oil viscosity, and rock and fluid heat capacity) and operational parameters (injection rate, injection time, soaking time, production time, and cycle number). The range of each parameter is listed in Table 1.

The proxy model is implemented to replace the actual simulation using a simpler functional relation between objective function and parameter. In this work, polynomial regression will be used as a proxy model. This method has several advantages such as: simpler, more flexible, and computational efficient. However, this method could give a poor performance for highly nonlinear multidimensional problem. The general quadratic polynomial regression model will use the following equations (Zubarev, 2009):

$$y(x) = \beta_0 + \sum_{i=1}^{nd} \beta_i x_i + \sum_{i=1}^{nd} \sum_{\substack{j=1 \\ j>i}}^{nd} \beta_{ij} x_i x_j + \sum_{i=1}^{nd} \beta_{ii} x_i^2$$

For higher order polynomial, the equation used for proxy model development can be derived from following form:

$$y(x) = (\alpha + \sum_i \beta_i x_i)^n$$

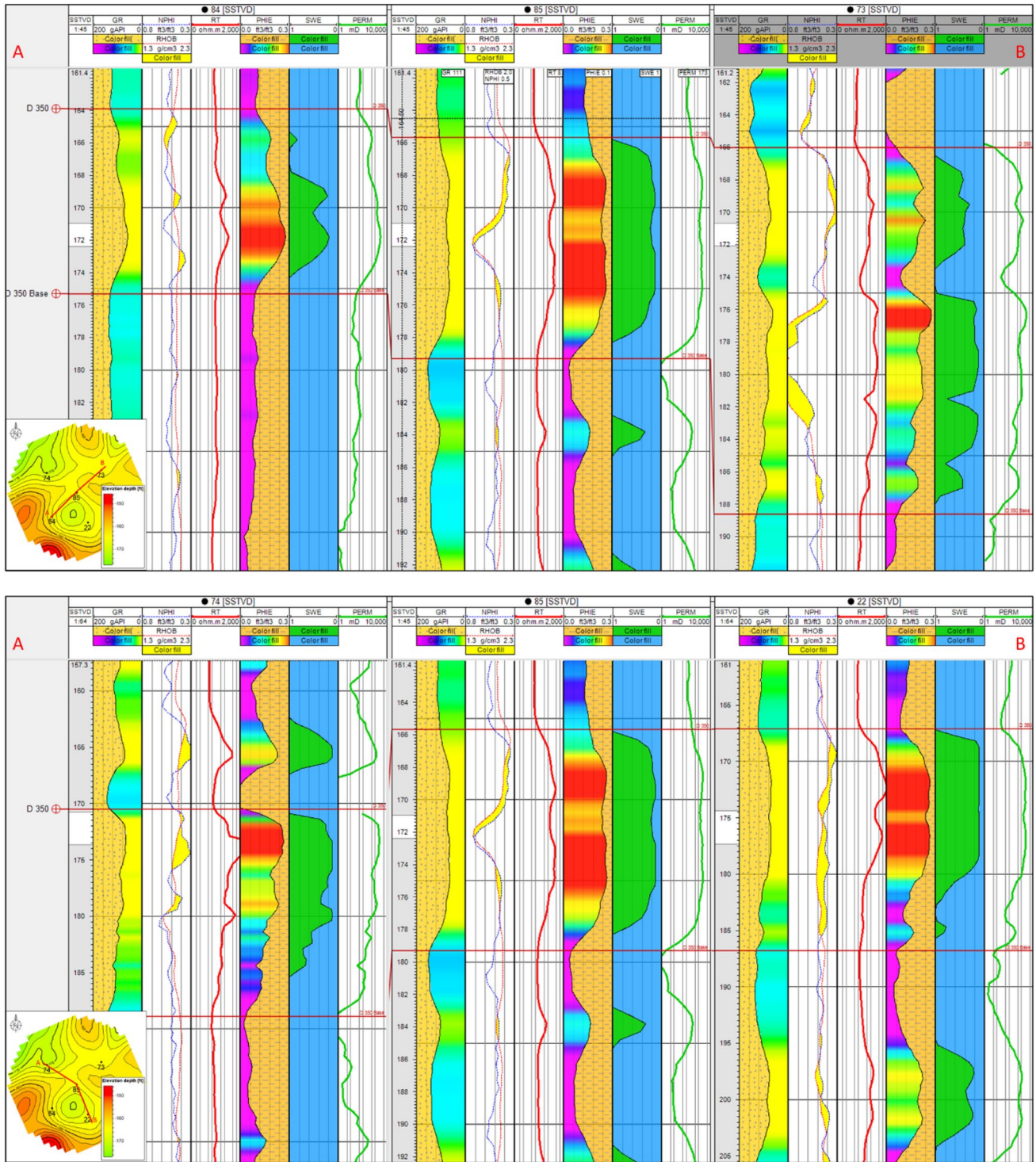


Fig. 3 Log and Interpretation of studied wells

where α and β as a constant that after derivation become the regression parameter.

Proxy model is constructed by solving a least square problem, i.e., selecting the polynomial coefficient that minimize the sum of squared error between the objective

function obtained from experiment (in current case by running a simulation) and objective function calculated using above polynomial equation. The model is progressively

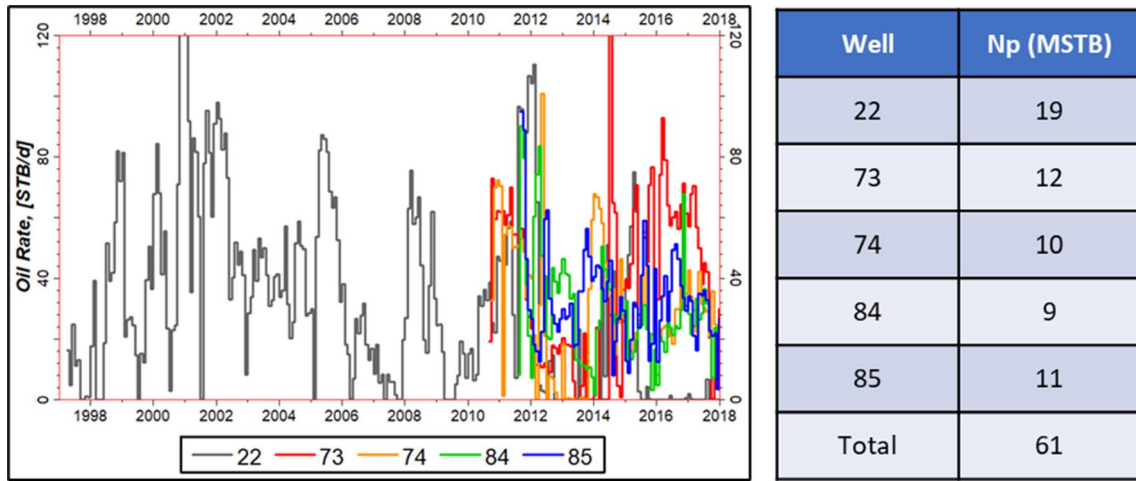


Fig. 4 Production data of candidate wells

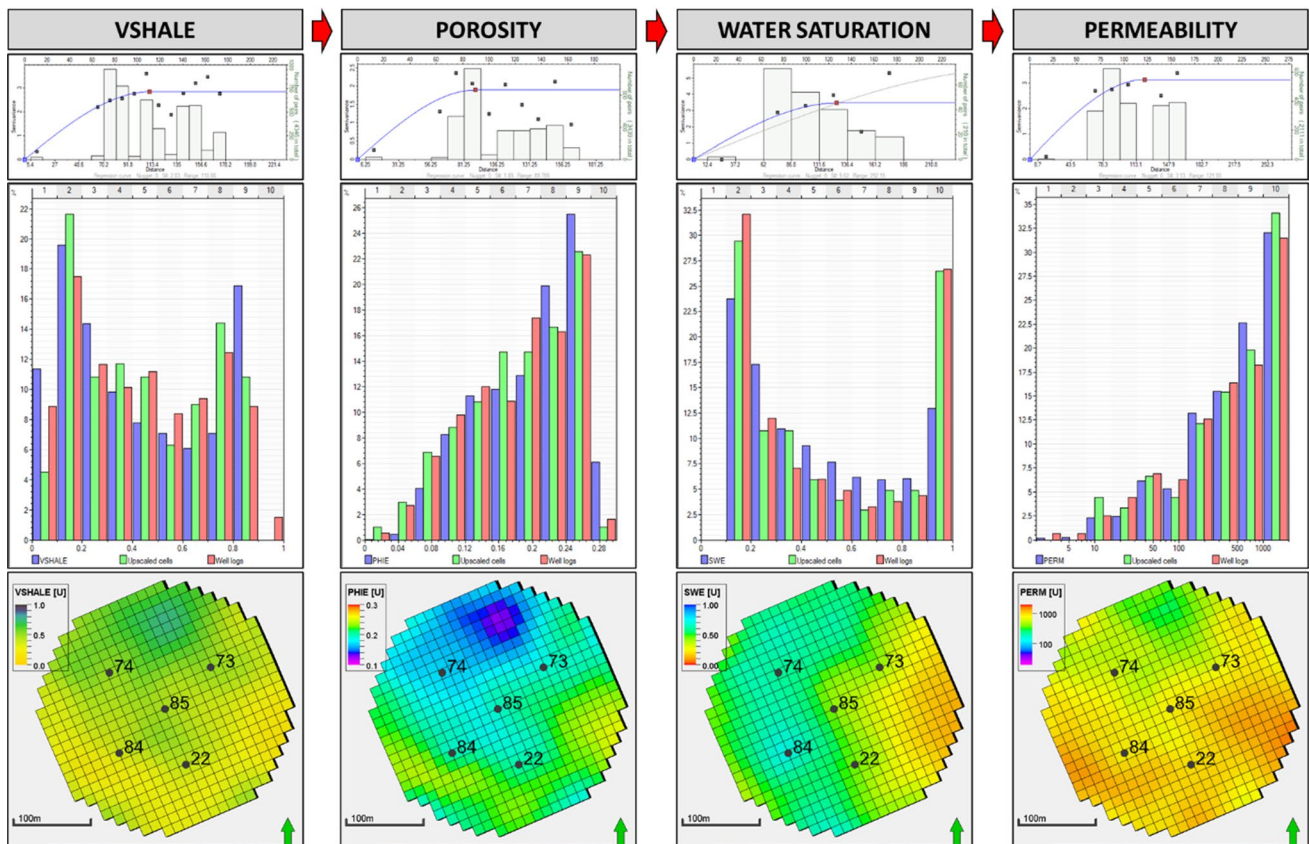


Fig. 5 Local grid refinement (LGR) on pattern sector

improved by additional simulation result of a new sample. After the model quality meets the criteria, it is then used to predict the outcome of objective function for the optimization.

Optimization

The optimization problem presented here is aimed to maximize the recovery factor (RF) and NPV of the combined CSS-SF project. The assumptions taken are: US\$ 45 for

Table 1 Range of parameter sensitivity

Parameters	Low	Mid	High
Average permeability (mD)	200	700	1500
Oil viscosity(cp)	400	800	1200
Rock & fluid heat capacity (BTU/ft ³ °F)	29.88	33.2	36.52
Injection rate/ Q_{inj} (Bbl/d)	50	100	150
Injection time/ t_{inj} (day)	5	17	30
Soaking time/ t_{soak} (day)	5	5	15
Production time, t_{prod} (day)	30	60	90
Cycle number / n_{cycle}	10	22	30

oil price and US\$ 10/bbl for steam generation cost. For the NPV calculation, the project lifetime is set for 10 years.

Results and discussion

Sensitivity analysis

The sensitivity of each parameter is presented using Sobol analysis to evaluate the effect of each parameter to the outcome of the simulation (Figs. 6, 7). Based on those charts,

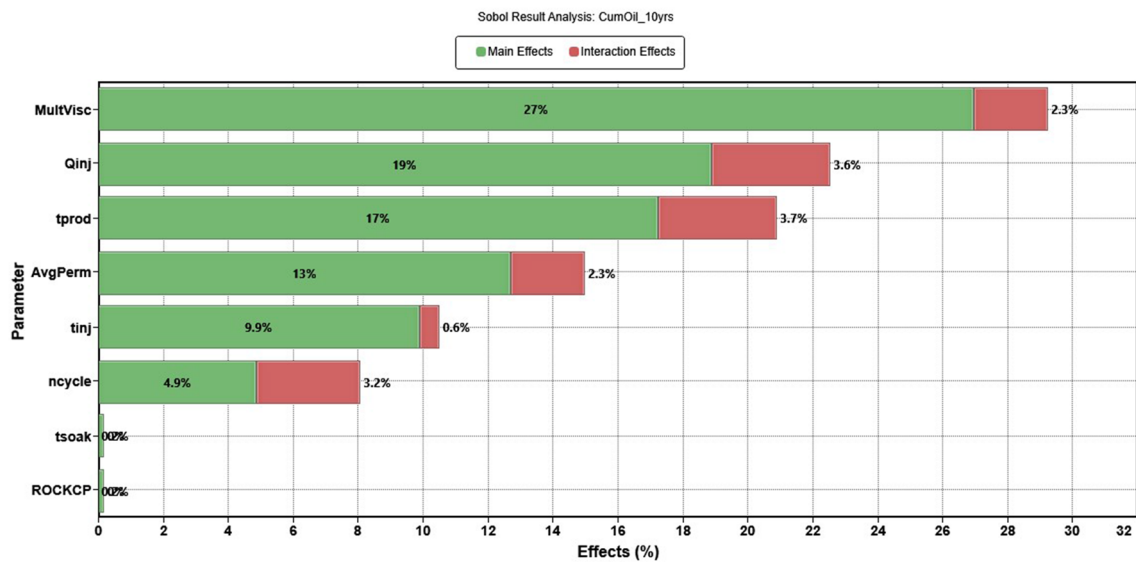


Fig. 6 Sobol analysis toward the oil recovery

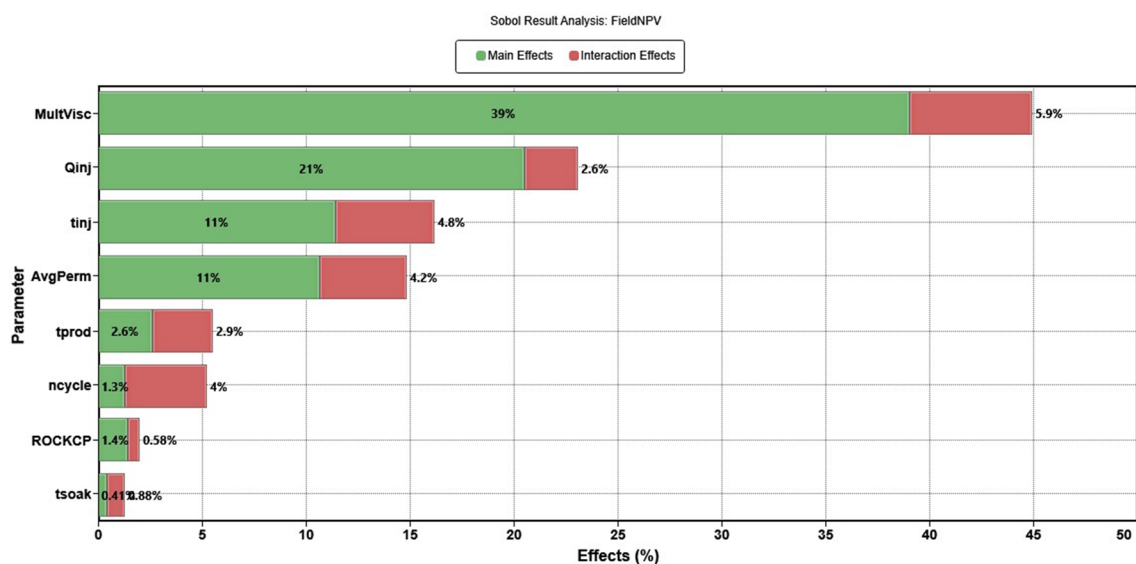


Fig. 7 Sobol analysis toward the project NPV

it seems that for the reservoir parameters, the oil viscosity is the most dominant factor that affects the success of steam injection project, and then it is followed by the average permeability of the reservoir, while the heat capacity of the rock and fluid have least effect toward the simulation result. For the operational parameters, the injection rate is the most affecting factor, followed by injection time, production time, cycle number, and soaking time.

The relation of each parameter toward the simulation result is more clearly displayed in Figs. 8, 9. It can be observed that permeability is positively correlated with

cumulative oil recovery, while viscosity and rock heat capacity is negatively correlated. High oil mobility value (high permeability and low viscosity) gives higher oil rate for equal pressure drawdown hence more cumulative recovery, while lower Cp means lower steam heat loss to rock and overburden thus the steam is more effective in heating the oil and lowering its viscosity. However, for the operational parameters, the behavior is slightly different, especially for parameters that highly with the cost of the project, such as injection rate. With respect to the cumulative production, higher injection rate will enhance the oil recovery, and

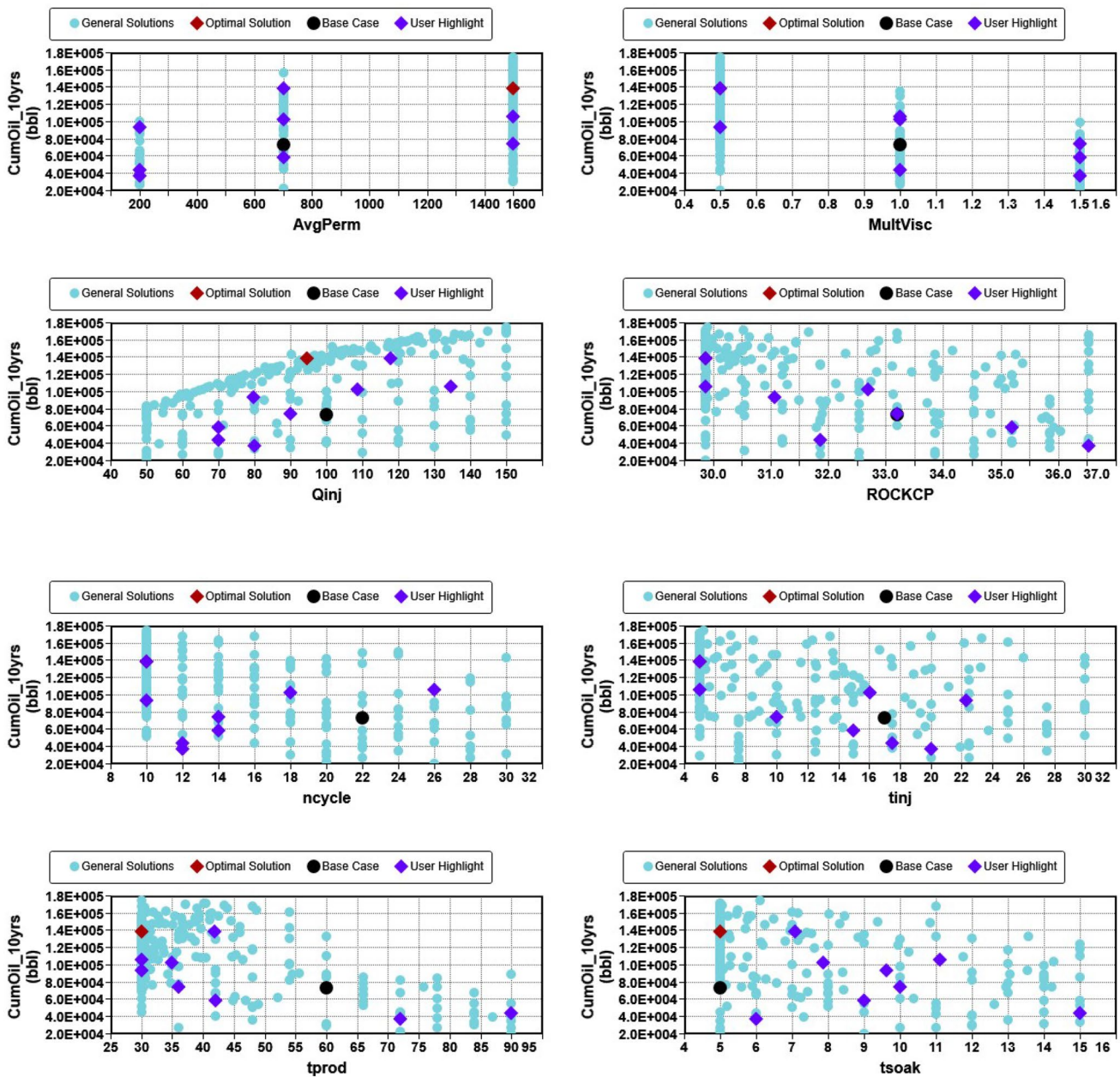


Fig. 8 Distribution of the oil recovery toward each parameter

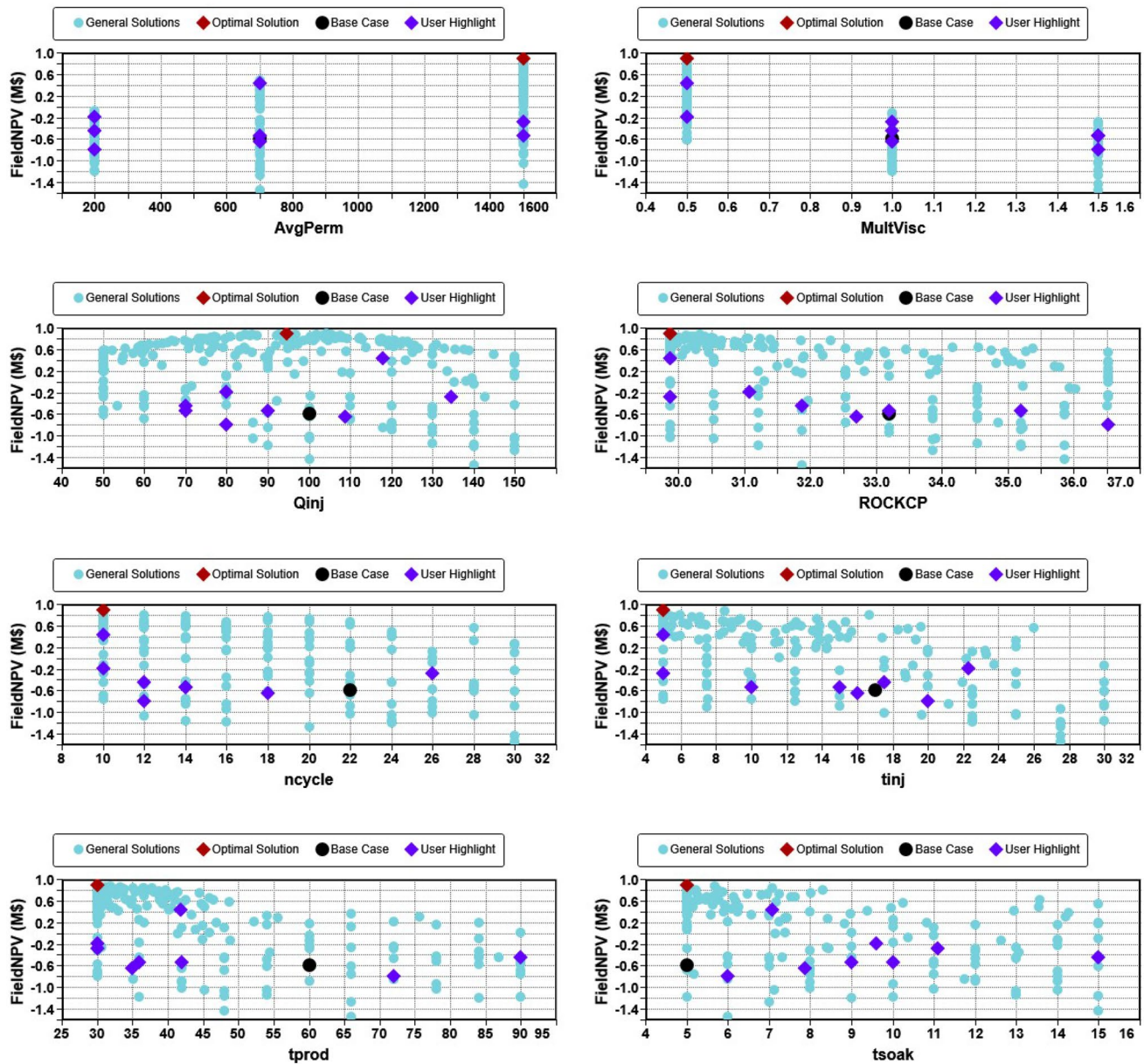


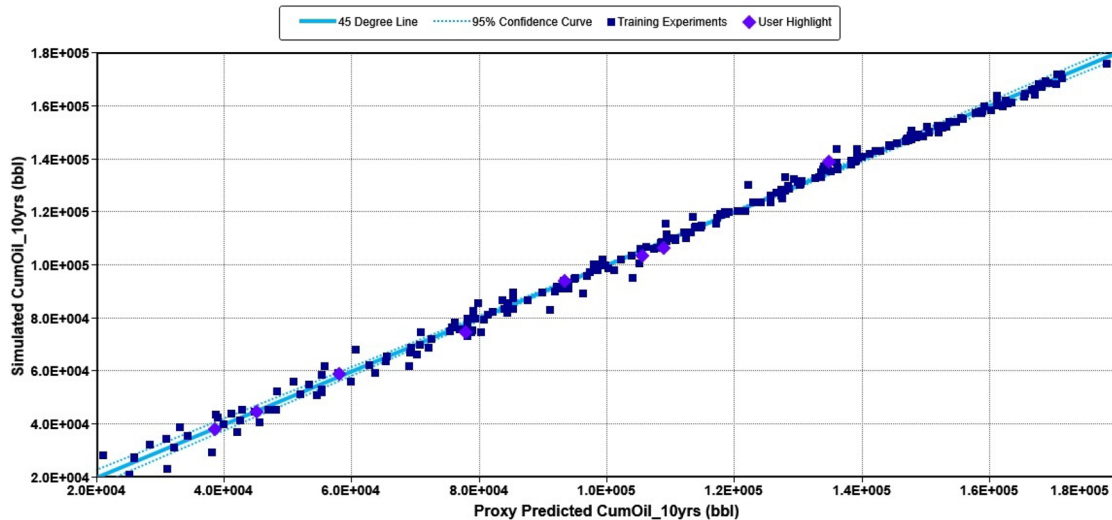
Fig. 9 Distribution of NPV toward each parameter

however, at some point, the cost of steam generation exceeds the revenue by additional oil recovery. Therefore, for the cost related result, the optimized value is always encountered related with the project NPV.

Proxy model development

The proxy model is developed as the multivariable polynomial equation, as featured in Fig. 10 for cumulative oil production at 10 years and Fig. 11 for field NPV. Visually, both graphs show a good match between the

proxy-predicted and the simulated value of cumulative production and NPV. Also, the coefficient of correlation for both objective functions shows the value of > 0.98 , and therefore, the model for both objective functions is reliably accurate to represent simulation result. It is also possible to use the developed proxy model for production forecast in similar scenario and similar properties range. The application of this model has accelerated the evaluation of objective function, based on the value of each sensitivity parameter.



Summary of Fit

R-Square	0.995735
R-Square Adjusted	0.995042
R-Square Prediction	0.991533
Mean of Response	108760
Standard Error	2823.48

Analysis of Variance

Source	Degrees of Freedom	Sum of Squares	Mean Square	F Ratio	Prob > F
Model	33	3.7787E+11	1.14506E+10	1436.34	<0.00001
Error	203	1.61833E+09	7.97206E+06		
Total	236	3.79488E+11			

Equation in Terms of Actual Parameters

$$\begin{aligned} \text{CumOil}_{10\text{yrs}} = & -120666 + 110.597 * \text{AvgPerm} - 66329.5 * \text{MultVisc} + 2141.72 * \text{Qinj} + 5672.35 * \text{ROCKCP} - 188.73 \\ & * \text{ncycle} - 383.727 * \text{tinj} + 877.373 * \text{tprod} + 654.32 * \text{tsoak} - 0.038396 * \text{AvgPerm} * \text{AvgPerm} + 3.79796 * \text{AvgPerm} \\ & * \text{MultVisc} + 0.232143 * \text{AvgPerm} * \text{Qinj} - 0.43995 * \text{AvgPerm} * \text{ROCKCP} - 0.584471 * \text{AvgPerm} * \text{ncycle} - 0.297834 * \text{AvgPerm} \\ & * \text{tinj} - 0.317614 * \text{AvgPerm} * \text{tprod} + 16544.5 * \text{MultVisc} * \text{MultVisc} - 413.433 * \text{MultVisc} * \text{Qinj} + 810.742 * \text{MultVisc} \\ & * \text{ncycle} + 192.112 * \text{MultVisc} * \text{tprod} - 5.55251 * \text{Qinj} * \text{Qinj} - 8.30248 * \text{Qinj} * \text{ncycle} + 2.25043 * \text{Qinj} * \text{tinj} - 4.35889 \\ & * \text{Qinj} * \text{tprod} - 115.15 * \text{ROCKCP} * \text{ROCKCP} + 39.7434 * \text{ROCKCP} * \text{ncycle} + 42.9175 * \text{ROCKCP} * \text{tinj} + 49.7523 * \text{ncycle} \\ & * \text{tinj} - 43.7559 * \text{ncycle} * \text{tprod} - 21.6138 * \text{tinj} * \text{tinj} - 6.35115 * \text{tinj} * \text{tprod} + 42.9854 * \text{tinj} * \text{tsoak} - 9.72745 \\ & * \text{tprod} * \text{tsoak} - 65.1676 * \text{tsoak} * \text{tsoak} \end{aligned}$$

Fig. 10 Proxy model for the oil cumulative production as the objective function

Scenario optimization

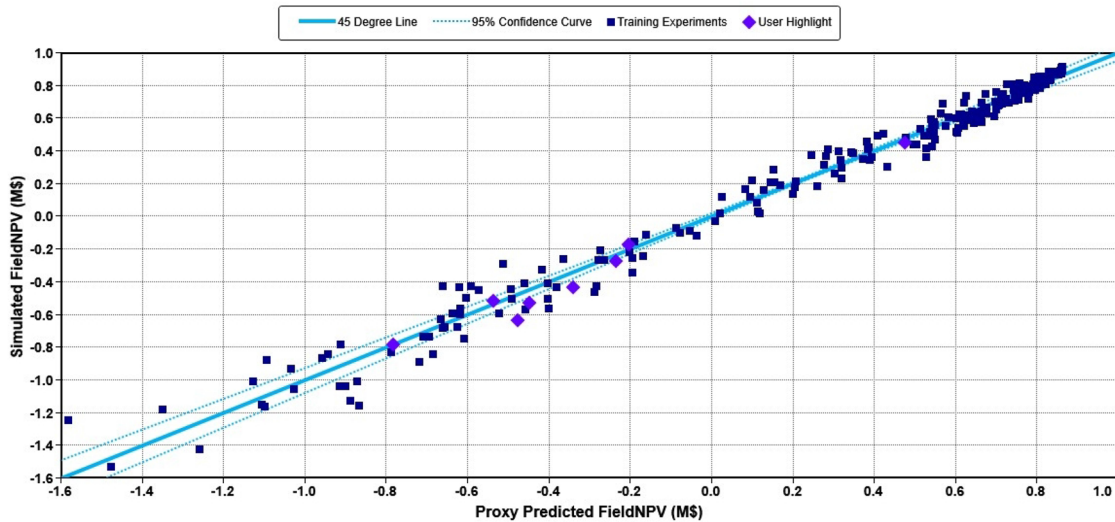
From all the range of sensitivity parameter, the global maximum value for objective function is obtained as shown in Table 2.

With respect to global optimization, the maximum objective function is obtained at higher permeability, lower viscosity, and lower heat capacity. Higher permeability and lower viscosity make the oil is easier to flow into the production well, so basically both values are more favorable. The lower heat capacity will decrease the heat loss of steam to the formation, so the steam is more effective to decrease the oil viscosity. The injection rate is optimized at the mid-range value, because it is closely related with the injection cost. At the higher injection rate, the oil recovery will generally

higher, however, the operating cost for steam generation will also escalate. For other parameter related with the CSS operation, the optimized value is found at the lower range. That shows the optimized scenario for the combined CSS-SF scenario is to start the steam-flooding earlier, especially if the reservoir property is favorable (with higher permeability and lower viscosity).

The result of each category of viscosity and average permeability is presented in Table 3. The trend for each category is rather different with the global optimization result. For higher viscosity, more CSS cycle is needed (as indicated by total days of CSS in Table 3) to obtain the optimum criteria.

The RF for all scenario shows the lower value than the typical steam-flooding project. This is generally caused by



Summary of Fit

R-Square	0.984070
R-Square Adjusted	0.981661
R-Square Prediction	0.971147
Mean of Response	0.248072
Standard Error	0.0836879

Analysis of Variance

Source	Degrees of Freedom	Sum of Squares	Mean Square	F Ratio	Prob > F
Model	31	88.6923	2.86104	408.507	<0.00001
Error	205	1.43575	0.00700366		
Total	236	90.1281			

Equation in Terms of Actual Parameters

$$\begin{aligned} \text{FieldNPV} = & -1.19846 + 0.00248324 * \text{AvgPerm} - 1.86758 * \text{MultVisc} + 0.0368578 * \text{Qinj} + 0.017021 * \text{ROCKCP} - 0.0190774 \\ & * \text{ncycle} + 0.0170911 * \text{tinj} - 0.007231 * \text{tprod} + 0.0178301 * \text{tsoak} - 5.86687\text{E-}07 * \text{AvgPerm} * \text{AvgPerm} - 0.000432946 \\ & * \text{AvgPerm} * \text{MultVisc} - 1.15719\text{E-}05 * \text{AvgPerm} * \text{ROCKCP} - 5.71414\text{E-}06 * \text{AvgPerm} * \text{ncycle} + 7.50579\text{E-}06 * \text{AvgPerm} \\ & * \text{tinj} - 4.24179\text{E-}06 * \text{AvgPerm} * \text{tprod} - 1.47967\text{E-}05 * \text{AvgPerm} * \text{tsoak} + 0.64064 * \text{MultVisc} * \text{MultVisc} - 0.00504886 \\ & * \text{MultVisc} * \text{Qinj} + 0.0156277 * \text{MultVisc} * \text{ncycle} - 0.00903424 * \text{MultVisc} * \text{tinj} + 0.00566298 * \text{MultVisc} * \text{tprod} + 0.0207201 \\ & * \text{MultVisc} * \text{tsoak} - 0.000106374 * \text{Qinj} * \text{Qinj} - 0.000436625 * \text{Qinj} * \text{ROCKCP} - 0.000194655 * \text{Qinj} * \text{tinj} + 4.07902\text{E-}05 \\ & * \text{Qinj} * \text{tprod} - 0.000151058 * \text{Qinj} * \text{tsoak} + 0.000419776 * \text{ROCKCP} * \text{ncycle} - 0.00172275 * \text{ncycle} * \text{tinj} + 0.000259139 \\ & * \text{ncycle} * \text{tprod} + 0.000309633 * \text{tinj} * \text{tprod} - 4.39257\text{E-}05 * \text{tprod} * \text{tprod} \end{aligned}$$

Fig. 11 Proxy model for the NPV as the objective function

Table 2 The global optimization result

Parameters	Value	Range
Average permeability (mD)	1,500	High
Oil viscosity(cp)	400	Low
Rock & fluid heat capacity (BTU/ft ³ °F)	29.88	Low
Injection rate/ Q _{inj} (Bbl/d)	95	Mid
Injection time/ t _{inj} (day)	5	Low
Soaking time/ t _{soak} (day)	5	Low
Production time, t _{prod} (day)	30	Low
Cycle number /n _{cycle}	10	Low

the selection of the area to be modeled, that only cover the small portion of the field. Also, the production period is cut only for 10 years of production.

The NPV value for almost all scenario shows a negative NPV that indicates the project is unfavorable to execute. However, NPV is determined not only by technical aspect (RF, production rate, injection rate, etc.) but also economical such as oil price, steam generation cost, production cost, etc. For current study, those economical parameters are still taken as single value. It still needs for further investigation regarding the effect of each economical parameter toward the project NPV, especially to determine the baseline economics condition that makes this project is favorable to develop.

Figure 12 shows the production profile comparison between the CSS, SF, and combined CSS-SF that fulfill

Table 3 Optimization result for each category of oil viscosity and average permeability

k_{avg} mD	Visc cp	Q_{inj} bbl/d	Rock CP $\frac{BTU}{ft^3 \cdot ^\circ F}$	ncycle	t_{inj} days	t_{prod} days	t_{soak} days	t_{total} days	Np MSTB	RF %	NPV M\$
200	400	80	31	10	22	30	10	619	94	25	- 0.2
	800	70	32	12	18	90	15	1470	44	12	- 0.4
	1200	80	37	12	20	72	6	1176	38	10	- 0.8
700	400	118	30	10	5	42	7	540	139	36	0.5
	800	109	33	18	16	35	8	1059	103	27	- 0.6
	1200	70	35	14	15	42	9	924	59	15	- 0.5
1500	400	95	30	10	5	30	5	400	139	36	0.9
	800	135	30	26	5	30	11	1199	106	28	- 0.3
	1200	90	33	14	10	36	10	784	74	19	- 0.5

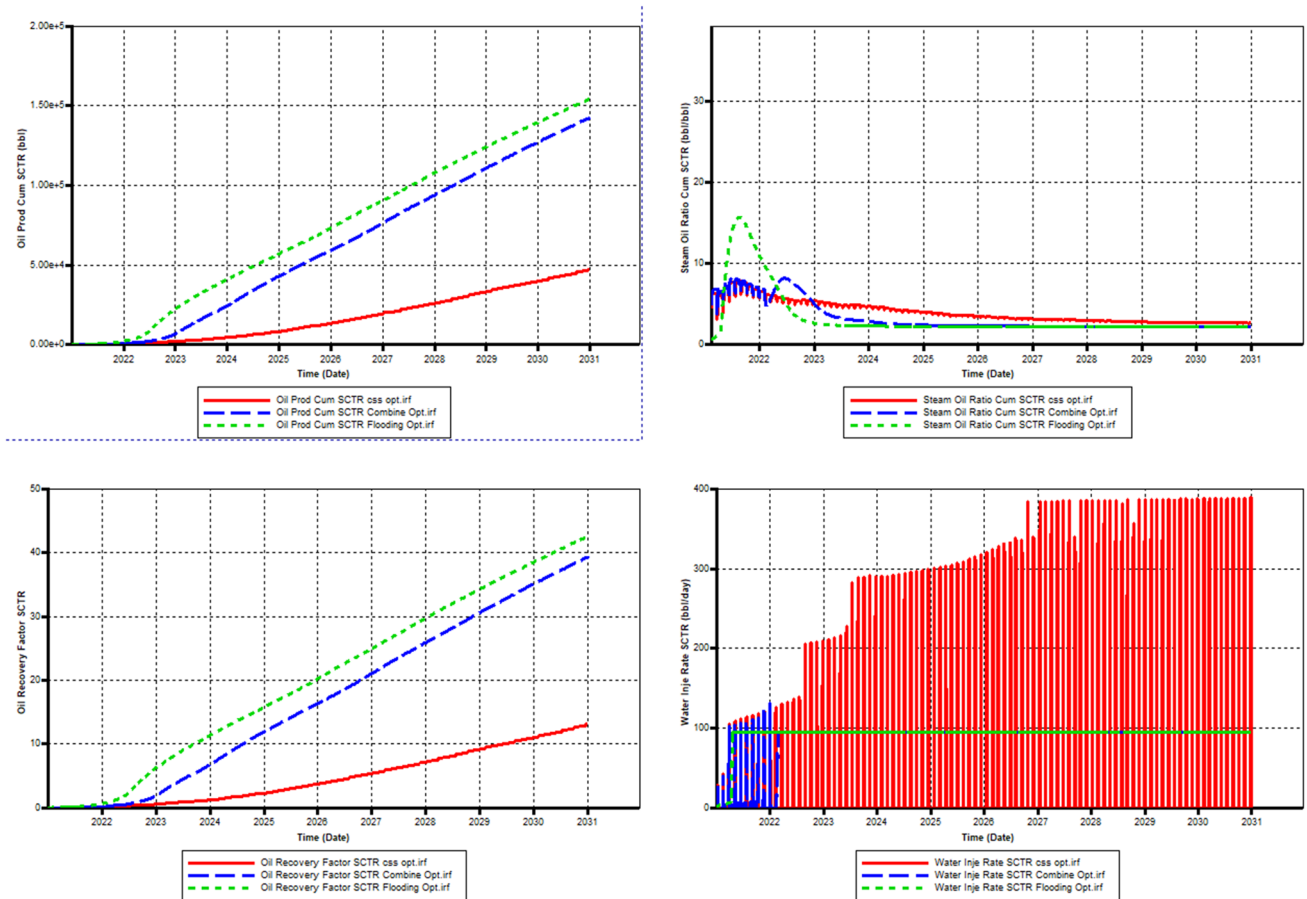


Fig. 12 Production profile comparison between CSS, SF, and optimum combined CSS-SF

the global optimum criteria. The results indicate that the combined CSS-SF has the recovery factor 3.3% lower than the full SF. However, the SF scenario generates higher cumulative steam-oil ratio at its early phase. It has consequence that the larger volume of steam is needed to produce same amount of oil. This can be attributed to

the difference in heat transfer events in continuous steam flood and cyclic steam stimulation. CSS benefit from heat transfer during soaking period hence it may need lower injected steam to reach similar temperature compared to continuous flood.

Conclusion

Our work has presented the application of proxy model workflow to assist the optimization of a combined CSS-SF. The proxy model developed is tested statistically and shows a good coefficient of correlation. This model is then used to evaluate the objective function and to obtain the optimized parameter. The global optimum is achieved at higher permeability and lower viscosity. The optimum injection rate is taken at 95 bbl/d or the mid-range. Other operating parameters are obtained at low-range. By similar method, the optimum operating parameter also can be estimated for each category of average permeability and oil viscosity.

The overall time needed for the evaluation can be cut drastically by applying the proxy model; therefore, the multivariable optimization problem can be handled in a reasonable time frame.

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