STUDY OF PRODUCTION-INJECTION STRATEGIES OF SYNTHETIC GEOTHERMAL RESERVOIR LIQUID-DOMINATED MODEL WITH NUMERICAL SIMULATION

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ABSTRACT

The main issue in the management of liquid-dominated reservoir is the rapid decline of reservoir pressure. Therefore it is interesting to learn the reservoir characteristic changes due to mass and heat extraction from reservoir, at various production and injection strategies. To understand the changes in the reservoir characteristics, reservoir modelling or numerical simulation can be used.

The model developed on liquid-dominated geothermal fields is a synthetic model based on field data adopted from Wairakei, Tongonan, Awibengkok and Wayang Windu Geothermal Field. The model was assessed under various production and injection scenarios.

A synthetic liquid-dominated geothermal reservoir model has successfully been developed based on field data adopted from selected geothermal fields. The model has successfully carried out 32 scenarios of production-injection.

The simulation results showed the scenario with lowest reservoir pressure and steam flow rate decline is when 25% of the fluid is extracted from steam cap and 75% from brine reservoir, while fluid is injected with deep and dispersed reinjection strategy. The implementation of production-injection strategy needs to be planned right from the beginning of exploitation therefore it can adapt to changes in reservoir characteristics.

1. INTRODUCTION

The main issue in the management of geothermal field is the considerable pressure and production decline. During production which cause considerable pressure decline in liquid dominated reservoir, a boiling reservoir can be formed. According to Grant (1982, 2011), there are two possibilities that can occur in the liquid dominated reservoir after production. First is that the steam is mixed uniformly and the fluid dryness around the production well increases. The second possibility is that the steam zone and water zone will be separated due to gravity and steam cap is formed at top of reservoir. With a good vertical permeability, the reservoir boiling causes the steam which has lower density than liquid phase, moves up and is formed at top reservoir.

This phenomenon occurred in several geothermal fields with high power plant capacity, such as Wairakei – New Zealand (Grant and Bixley, 1982, 2011), Tongonan – Philippines (Seatres et al, 2000), Awibengkok – Indonesia (Stimac et al, 2008; Acuna et al, 2008), and Wayang Windu – Indonesia (Mulyadi and Ashat, 2011).

These fields have similar characteristic change and pressure decline. The production induced pressure decline, as a consequence, the amount of fluid that fills the pores of the reservoir rock and the fracture is reduced. Fluid produced in the reservoir will cause boiling or increase boiling. This process occurs in most areas or in the whole reservoir. Boiling will increase dryness and fluid enthalpy in the reservoir to form steam cap at the top of reservoir.

In general, after steam cap is formed, the production strategies will be focused into steam cap formed at relatively shallow depth. From drilling aspect, drilling cost will be reduced due to shallower drilling. From the number of injection wells, brine separator will reduce with the results reducing injection wells. From surface facilities, the use of separator diminishes, because steam fraction flows into separator increasing. The economic reason makes the geothermal developer attempt to produce mass and heat from steam cap reservoir.

Based on study of two-phase liquid dominated geothermal fields as described earlier, the exploitation of steam from steam cap cannot be offset by the formation of steam cap itself. Therefore, the impact will result in decrease of steam production and will not meet the production target. Therefore, the production strategies must be balanced with reinjection strategies, even when steam cap is formed. The injection strategies should be optimized so the pressure drop in reservoir can be maintained at a level as low as possible.

Axelsson (2012) explained the purpose of injection aside from maintaining pressure drop is water disposal from brine separator and steam condensate, additional recharge, counterbalance the water level drop caused by production. The injection strategies that can be applied is either brine separator or steam condensate injection to deeper level of reservoir (deep injection) or inject at shallow depth (shallow injection). In the beginning of exploitation, injection is performed on infield by utilizing the unproductive well(s), that caused the thermal breakthrough in production well(s). Hence the developer changed the injection strategies with dispersed injection surrounding the production reservoir. For a geothermal field to be developed, the injection strategies should be implemented well, so it can be adapted to production strategies.

The study of production-injection strategies above is a series of reservoir management which have a goal to implement a variety of proper overall production-injection strategies, with the goal is sustainable production. The use of improper production-injection strategies will lead to irreversible reservoir change. Therefore careful strategies planning and implementation should be done in the early state of field development.

Consider the matters mentioned above, it is interesting to do a study of liquid dominated reservoir using numerical simulation. The model was run under various production-injection strategies. By observing pressure and temperature drop, vapour saturation and mass flow in reservoir model as function of time, this model can predict the performance of the reservoir with various production-injection strategies to exploitation time.

This study consist three production strategies, including:

1) Production strategy from steam cap.
2) Production strategy only from brine reservoir located below steam cap.
3) Production strategy is combined from both steam cap and brine reservoir.

The production strategies were combined with injection strategies, namely:

1) Injection strategy at deeper level of reservoir (deep injection) and injection at shallow depth (shallow injection).
2) Peripheral injection strategy which are either centered injection or dispersed injection.

The outputs from simulation will be compared one another. Therefore, the best result of proper production-injection strategies can be seen in order to manage the mass and heat production from the reservoir for a sustainable geothermal field management.

2. RESERVOIR MODELING

2.1 Methodology

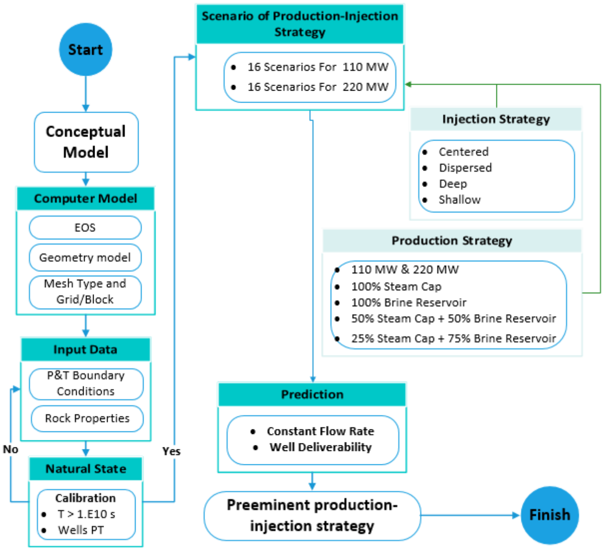

Figure 1: Methodology.

In general, the methodology of this study is shown by Figure 1. The flow chart of this study begins with development of computer model from conceptual model. The reservoir model will be run at various production-injection strategies. The best scenario will be proposed as the best production-injection scenario of liquid dominated reservoir.

2.2 Conceptual Model

The model for this study is based on four liquid dominated geothermal fields (Wairakei, Tongonan, Awibengkok and Wayang Windu. These fields show a behavior of liquid dominated reservoir with steam cap at the top of reservoir, the reservoir characteristic is shown in Table 1. Geology, geophysics, geochemical data are not used in this study.

This study used six exploration wells (XXA-1, XXB-1, XXC-1, XXD-1, XXE-1 and XXF-1) and is shown in Figure 2. These wells delineate the reservoir. The pressure and temperature profile of XXX-1 and XXB-1 show a high temperature well and will be used as production well, whereas the rest of the wells have a medium enthalpy and will be used as injection well.

Table 1: Characteristics of the synthetic model.

Reservoir	Liquid dominated with steam cap at top reservoir
Proven Area	Steam cap = 13 km^2 Brine res. = 23 km^2
Temperature	240-320^{o}C
Pressure	Steam cap = 34 bar Brine res. = 55 bar
Thickness	Steam cap = 500-1000 m Brine res. = 1400-1500 m
Power Density	Steam cap = 17 MW/km^2 Brine res. = 11 MW/km^2

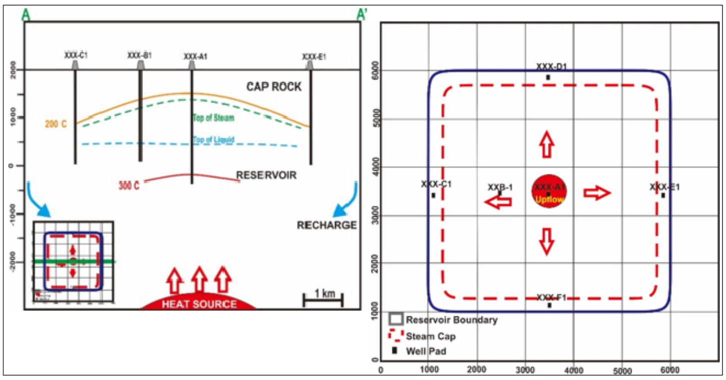

Figure 2: Conceptual model of synthetic reservoir model.

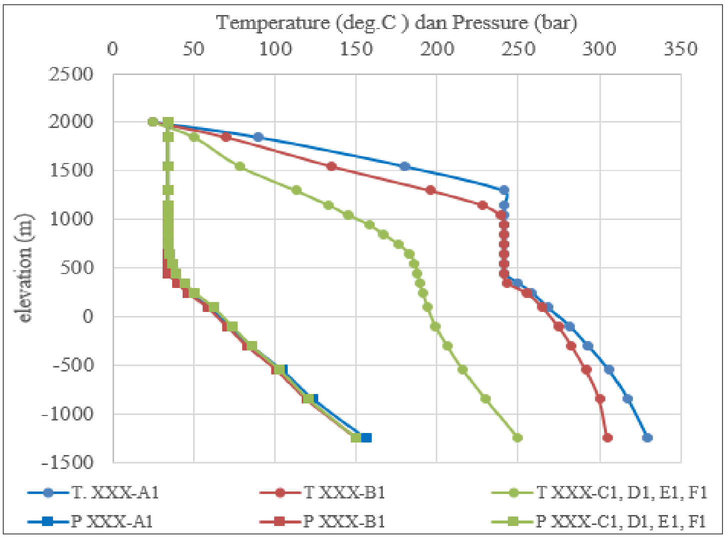

Figure 3: Pressure and temperature profile at two-phase liquid dominated geothermal wells with steam cap above brine reservoir.

2.3 Computer Model

The characteristics data that represented geothermal system such as heat source, cap rock and reservoir have been assigned in a computer model and set to reach the natural state condition of liquid dominated reservoir. The properties of the rocks that represent geological conditions in the model is shown in Table 2 and a distributed parameter approach is used. Each grid in the model has properties that represent the reservoir properties. Each block is connected with another block (Figure 4).

Table 2: Material data for computer model.

Material Type Legend		Rock Density (kg/m^3)	Porosity	Heat Conductivity (W/m^oC)	
				XY	Z
Atmosphere		2600	0.99	1E-10	1E-12
Ground Water		2500	0.02	2E-18	2E-18
Caprock		2600	0.05	1E-18	1E-18
Boundary1		2600	0.001	1E-19	2E-19
Boundary2		2600	0.01	1E-20	1E-20
Heat source		2650	0.07	1E-14	1E-15
Reservoir1		2500	0.25	1E-13	5E-14
Reservoir2		2550	0.2	8E-14	4E-14
Reservoir3		2600	0.15	6E-14	3E-14
Reservoir4		2600	0.15	5E-14	2E-14
Reservoir5		2600	0.1	3E-14	1E-14
Reservoir6		2600	0.1	9E-15	6E-15
Reservoir7		2600	0.1	7E-15	3E-15
Reservoir8		2600	0.09	5E-15	2E-15
Reservoir9		2500	0.05	3E-17	1E-17

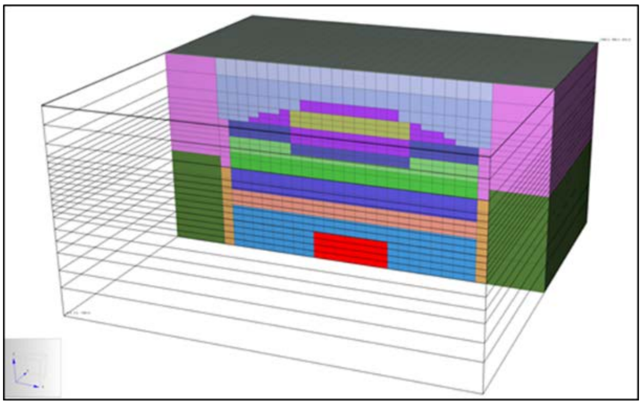

Figure 4: 3D block model at computer model.

The boundary conditions such as outside, heat source and atmosphere was assigned in this model. The objective is to give initial conditions from a model therefore the simulator can calculate every thermodynamic properties in each block. The assumptions of boundary condition are:

1) The top of layer is atmosphere layer. In this layer, each block is considered to have similar properties with typical atmosphere condition (1 atm and 25^oC).
2) The Outside layer is the boundaries representing a surrounding environment.
3) The heat source layer is located in the bottom of model. The thickness is 500 m.

The data input is very tricky because there are a lot of unknown information in subsurface Material data should be updated to gain natural condition of model computer hence the reservoir model computer can represent their natural conditions.

2.4 Natural State

Pressure and temperature profile at natural state is shown at Figure 5. It shows a perfectly match between a model output and actual well data. The cross-section of natural state model of liquid dominated at the top reservoir is shown at Figure 6. This natural state at steam cap zone has a similarities with model conceptual model of vapour dominated proposed by White et al (1971) and enhanced by D'amore and Trusdekk (1979). The conductive heat transfer occurs from heat source into reservoir and convective entire steam cap reservoir. Hot water is heated by hot reservoir rock and will go up because high temperature fluid has lower density. Throughout the heat transfer, the boiling zone will segregate vapour phase and liquid phase. The greater boiling zone, the greater of steam cap will be formed. The steam has formed will be moved laterally through the reservoir and spread, steam cap formed. Steam saturation formed at steam cap zone is 80% and close to value of 85% of vapour dominated geothermal field (Grant et al, 2011).

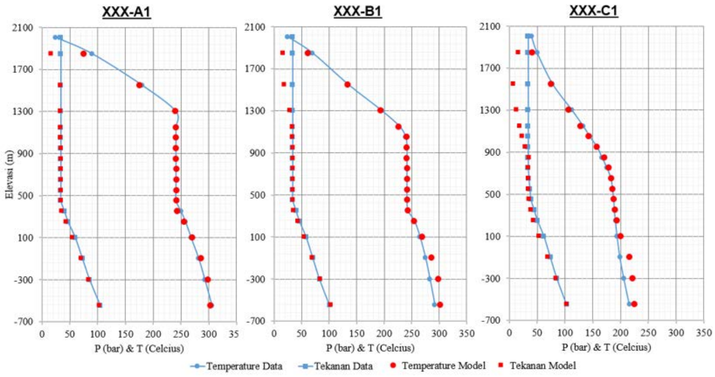

Figure 5: Matching pressure and temperature data between model computer and actual well data.

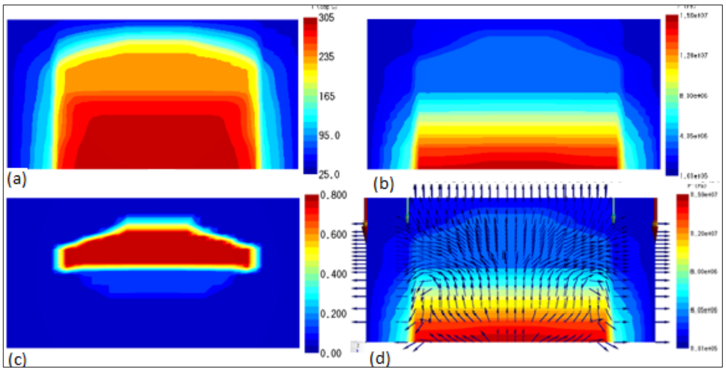

Figure 6: Natural state, (a) 2D temperature profile, (b) 2D pressure profile, (c) 2D steam saturation profile, (d) heat transfer.

Steam mass transfer is hindered by impermeable layer above the top reservoir and the heat loss from steam take place. Therefore steam will be condensed and move downward by the influence of gravity. The concept of steam and condensate movement is counterflow heat transfer. The steam move upward while the condensate move downward. This counterflow heat transfer occur continuously hence the pressure gradient will show the steam gradient pressure (34 bar) and uniform temperature 245^oC throughout the whole steam cap (Grant et al, 2011).

The energy reserve of the reservoir model is then calculated after the natural state reached. Monte Carlo simulation is used as the calculation method (Figure 7). The thickness of steam cap is set to be around 500-1000 m, generates 30 MW as P10, while the brine reservoir with thickness around 1400-1500 m generate 190 MW as P10. The total of geothermal reserve model is 220 MW and the maximum power plant capacity is 220 MW. This was calculated for 30 years of exploitation.

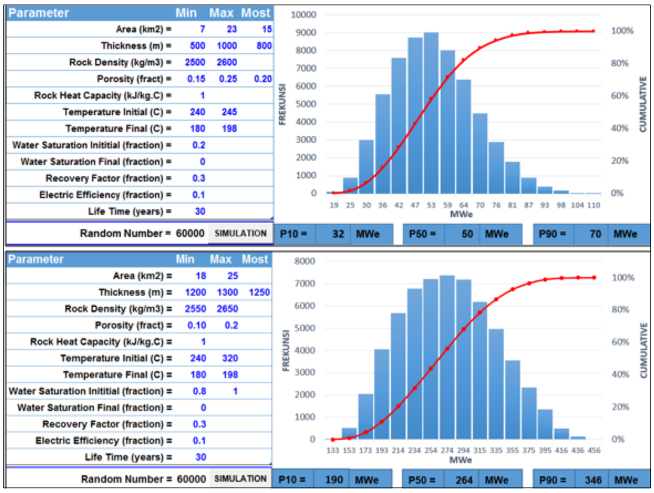

Figure 7: Monte Carlo simulation, (above) steam cap is 32 MW, (under) brine reservoir is 190 MW.

3. FIELD DEVELOMPENT PLANS AND PRODUCTION-INJECTION STRATEGIES

3.1 Power Plant Design and Steam Consumptions

Power plant design in this study used the assumption of separated steam cycle. Wellhead pressure, separator pressure, turbine inlet pressure, condenser pressure and specific steam consumption (SSC) as result of calculation for 110 MW and 220 MW shown at Table 3. Both of steam cap production wells and brine production wells supply the steam for power plant as shown at Figure 8.

Table 3: Design and steam consumption calculation for power plant.

		110 MW	220 MW
WHP	bar	12.0	12.0
$P_{Separator}$	bar	10.6	10.6
TIP	bar	10.0	10.0
$P_{Condensor}$	bar	0.1	0.1
$\eta_{Turbine}$	%	80.0	80.0
m_{steam} total	kg/s	199.0	397.0
SSC	kg/s/MW	1.80	1.80

3.2 Production and Injection Strategies

This study used four production strategies to learn the behaviour or two-phase reservoir with steam cap at the top of reservoir:

1) Production strategy is focused on 100% from steam cap.
2) Production strategy is focused on 100% from brine reservoir.
3) The combination from both 50% of steam cap and 50% of brine reservoir.
4) The combination from both 25% of steam cap and 75% of brine reservoir.

The four of production strategies combined with injection strategies, which are:

1) Centered injection (single well pad for each brine and condensate)
2) Dispersed injection (multiple well pad for brine injection and single well pad for condensate, both areas are surrounding the reservoir)
3) Deep injection (both brine separator and condensate injected into the liner of 1100 – 400 msal or 900 – 1600 meter depth).
4) Shallow injection (both brine separator and condensate injected into the liner of 300 – (-500) msal or 1700 – 2500 meter depth).

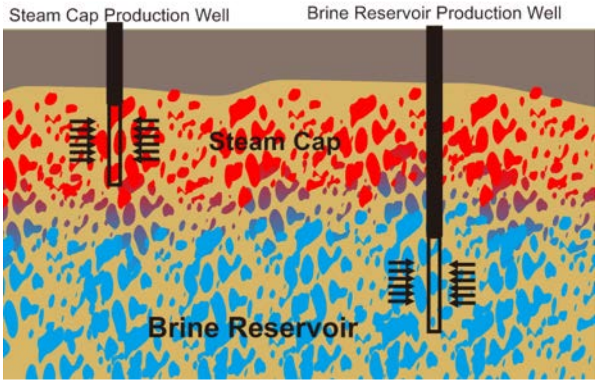

Figure 8: Schematic both of steam cap production well and brine reservoir production well.

Table 4: Mass flow and the number of well for 110 MW.

110 MWe	*Brine*	*Steam*	50% *Steam*	50% *Brine*	25% *Steam*	75% *Brine*
W (MW)	110	110	55	55	27.5	82.5
m_{well} (kg/s/Well)	40	20	20	40	20	40
$X_{well\ head}$	0.37	0.82	0.82	0.37	0.82	0.37
$X_{separator}$	0.38	0.83	0.83	0.38	0.83	0.38
m_{steam} separator (kg/s/Well)	16	17	17	16	17	16
m_{brine} separator (kg/s/Well)	24	3	3	24	3	24
m_{steam} total (kg/s)	199	199	99	99	50	149
m_{brine} total (kg/s)	313	40	20	156	10	235
SSC (kg/s/MW)	1.8	1.8	1.8	1.8	1.8	1.8
Production Well	13	12	6	7	3	10
Well Capacity (MW/Well)	8.5	9.2	9.2	7.9	9.2	8.3

Table 5: Mass flow and the number of well for 220 MW.

220 MWe	*Brine*	*Steam*	50% *Steam*	50% *Brine*	25% *Steam*	75% *Brine*
W (MW)	220	220	110	110	55	165
m_{well} (kg/s/Well)	40	20	20	40	20	40
$X_{well\ head}$	0.37	0.82	0.82	0.37	0.82	0.37
$X_{separator}$	0.38	0.83	0.83	0.38	0.83	0.38
m_{steam} separator (kg/s/Well)	16	17	17	16	17	16
m_{brine} separator (kg/s/Well)	24	3	3	24	3	24
m_{steam} total (kg/s)	397	397	199	199	99	298
m_{brine} total (kg/s)	626	79	40	313	20	469
SSC (kg/s/MW)	1.8	1.8	1.8	1.8	1.8	1.8
Production Well	26	24	12	13	6	20
Well Capacity (MW/Well)	8.5	9.2	9.2	8.5	9.2	8.3

The results of calculation, design and the number of wells from both of production strategies and injection strategies is shown at Table 4, Table 5, Table 6 and Table 7

Table 6: Injection capacity of brine and the number of injection well for 110 MW.

110 MW	*Brine*	Steam	50% Steam	50% *Brine*	25% Steam	75% *Brine*
m_{steam} total (kg/s)	199	199	99	99	50	149
m_{brine} total (kg/s)	313	40	20	156	10	235
Condensate Injection Capacity (kg/s/Well)	60	60	60		60	
Brine Injection Capacity (kg/s/Well)	104	40	88		82	
Brine Injection Well	3	1	2		3	
Condensate Injection Well	1	1	1		1	

Table 7: Injection capacity of brine and the number of injection well for 220 MW.

110 MW	*Brine*	Steam	50% Steam	50% *Brine*	25% Steam	75% *Brine*
m_{steam} total (kg/s)	397	397	199	199	99	298
m_{brine} total (kg/s)	626	79	40	313	20	469
Condensate Injection Capacity (kg/s/Well)	119	119	119		119	
Brine Injection Capacity (kg/s/Well)	104	79	117		82	
Brine Injection Well	6	1	3		6	
Condensate Injection Well	1	1	1		1	

4. ANALYSIS OF RESERVOIR SIMULATION STRATEGY FOR THE STUDY OF PRODUCTION-INECTION

Thirty two model and simulations have been carried out. Numerical simulations used both of constant flow rate and well deliverability method. Pressure and temperature at both of steam cap and brine reservoir, mass flow and the steam cap expansion is observed to learn the change of reservoir characteristics versus exploitation time.

4.1 Study of Production-Injection Strategies for 110 MW

The constant flow rate method is used to see both the changing of pressure and temperature. Figure 9 shows the changes in steam cap pressure for 110 MW:

1) 100% Production from steam cap generate a highest pressure drop at steam cap reservoir.
2) 100% Production brine generate a lowest pressure drop at steam cap reservoir.
3) A combined production both of steam cap and brine generate a pressure drop between 100% from steam cap and 100% brine reservoir. The accepted pressure drop generated by production 25% from steam cap and 75% brine reservoir.

If the change of pressure viewed at brine reservoir, it is shown at Figure 10, as a result below:

1) 100% Production from steam cap generate a lowest pressure drop at brine reservoir.
2) 100% Production from brine generate a highest pressure drop at brine reservoir.
3) A combined production both of steam cap and brine generate a pressure drop between the value above (ΔPsteam cap < ΔPcombination < ΔPbrine reservoir).

The accepted pressure drop generated by production 25% from steam cap and 75% brine reservoir.

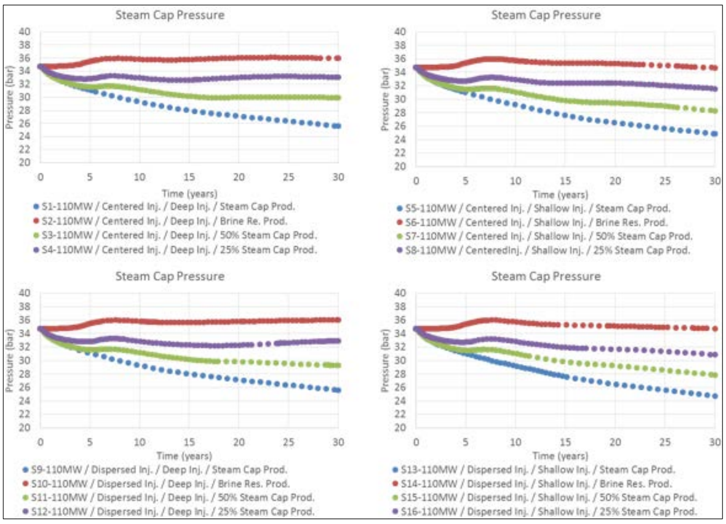

Figure 9: The changing of pressure in steam cap as a results in production-injection for 110 MW. The lowest decline is production 100% from brine reservoir with various injection strategies.

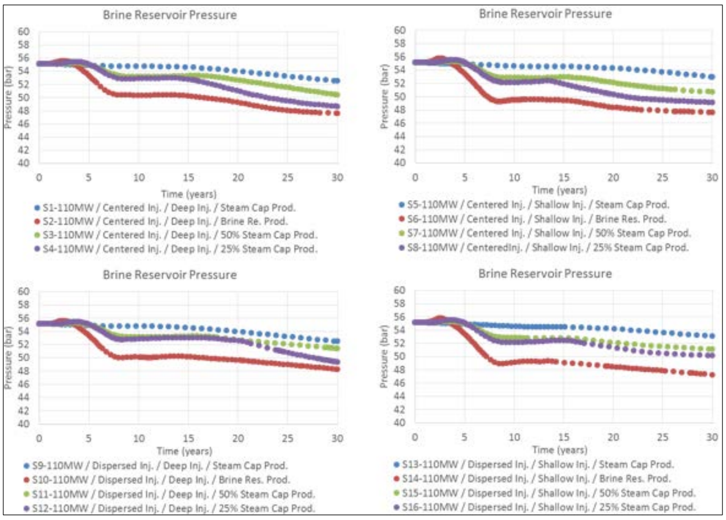

Figure 10: The changing of pressure in brine reservoir as a results in production-injection for 110 MW. The lowest decline is production 100% from steam cap with various injection strategy.

The pressure drop for 32 production-injection strategies, initial reservoir pressure subtracted with final reservoir pressure at 30 years (Figure 11). Data showed, both pressure at steam cap and brine reservoir, had the largest decrease was the 100% Production from steam cap, and it is possible that the strategy cannot maintain its production capacity for a longer period. The lowest pressure drop in the reservoir is 100% Production from brine, but this has little likelihood that carried out by the developers because with a layer of steam cap will be valuable economical aspect to be develop. Therefore the strategy with high likelihood to be develop is a combination strategy of production from steam cap and brine reservoir with the proportion is 25% from steam cap and 75% from brine. With various injection strategies.

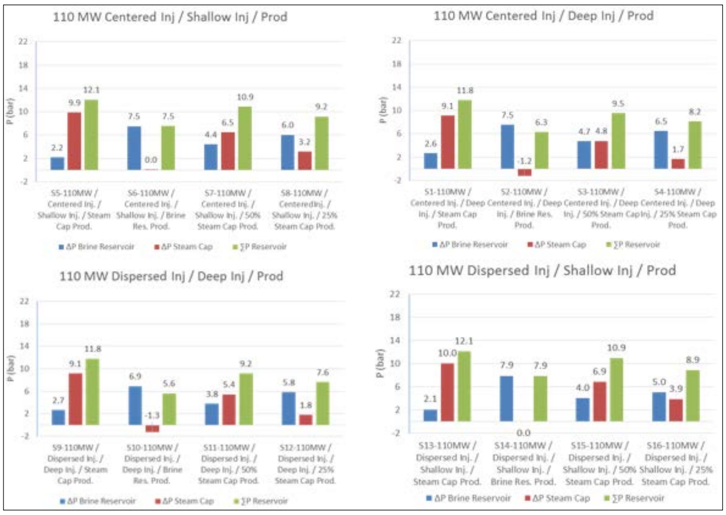

Figure 11: the Pressure decline each production-injection strategies for 110 MW. The lowest decline is 100% brine reservoir.

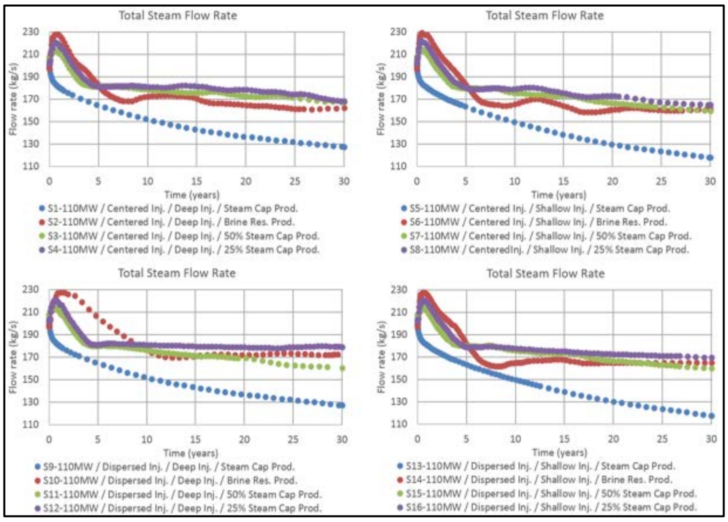

Figure 12: The decline rate for each production-injection strategies for 110 MW. The lowest decline rate is combination production of 25% from steam cap and 75% from brine reservoir.

A justification for the best production strategy from combination of production from steam cap and brine reservoir shown by a decline rate of each strategies. This data achieved by summing up every mass flow at each block that has through by completion area at production well in the output of model computer. Figure 12 shown a decline rate for each production-injection strategies for 110 MW. Based on the data from pressure drop and decline rate, the best production strategy is a combination of 25% from steam cap and 75% from brine reservoir.

Right after the best production strategy obtained, the next step choose the injection strategy. The best production strategy mentioned above is used for all of injection strategies carried on. The simulation results shown at Figure 13. Dispersed and deep injection generate a relatively lower of pressure drop both in steam cap and brine reservoir. This is because the reinjection of brine separator performed spreading with well pad surrounding the production reservoir. Therefore, this strategy give additional pressure uniformly for balancing the production induced pressure drop and maintain the pressure drop at a lowest level as possibly. While the deep injection strategy improve a thermal recovery because both of brine separator and steam condensate injected at deeper reservoir which have a higher temperature and minimize a cooler reinjected fluid back to production reservoir.

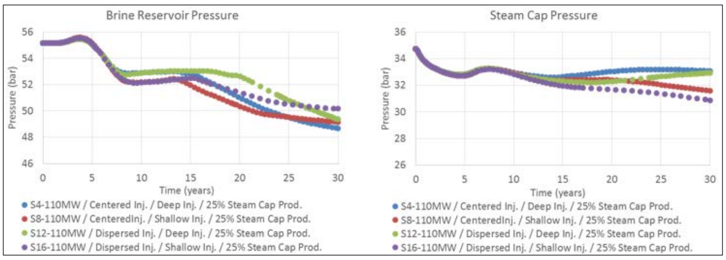

Figure 13: Pressure decline of a combination production 25% from steam cap and 75% brine reservoir with various injection. The lowest decline is dispersed and deep injection.

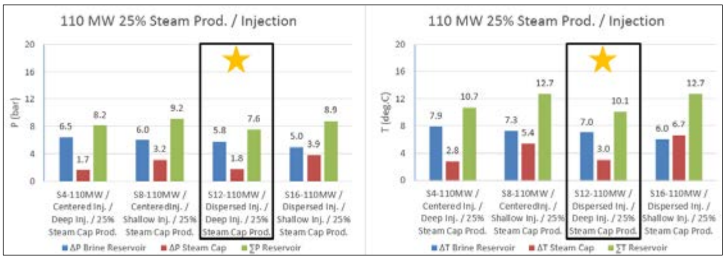

Figure 14: The histogram of pressure at production 25% from steam cap and 75% from brine reservoir for 110 MW. The lowest decline is dispersed and deep injection.

Hence the best production-injection strategy for 110 MW is production 25% from steam cap and 75% from brine reservoir paired with dispersed and deep injection (Figure 14).

4.2 Study of Development 110 MW versus 220 MW

The best of production-injection strategy for 220 MW achieved by using the same method as 110 MW. The production production 25% from steam cap and 75% from steam cap paired with dispersed and deep injection.

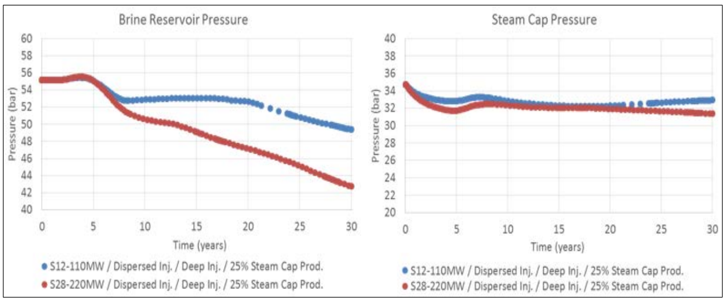

Figure 15: The changing of pressure for 110 MW vs 220 MW, production 25% from steam cap and 75% brine reservoir paired with dispersed and deep injection.

The change of pressure both of steam cap and brine reservoir is shown at Figure 15. The steam cap pressure for 220 MW has a lower pressure drop than 110 MW but has a higher pressure drop at brine reservoir. After 10 year of exploitation time, stabilization pressure occurs at steam cap for both 110

MW and 220 MW. The magnitude order of reduction both pressure and temperature for 220 MW is almost twice than 110 MW (Figure 16).

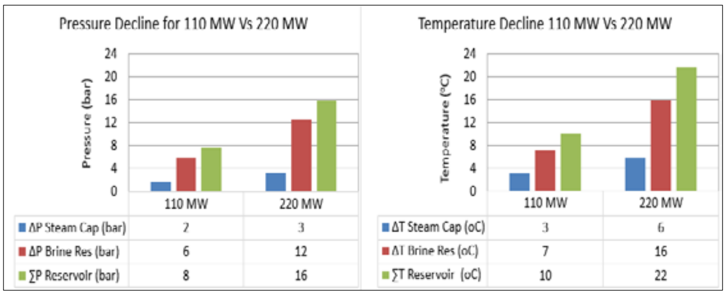

Figure 16: The comparison both of pressure and temperature for 110 MW vs 220 MW. The magnitude order is twice.

2D Isobar contour as a result of simulation (Figure 17) is denser at reservoir, meaning the pressure decreasing with depth. The steam cap pressure has almost no difference ($\Delta P_{110\ MW-\ 220\ MW}$ = 1 bar) even though the amount of fluid produce twice as much. The pressure in brine reservoir for 110 MW still influenced by reinjection. Higher pressure occurs near the injection well by the return of fluid reinjection. It doesn't occur at 220 MW, as 800 kg/s of brine produced from brine reservoir resulting a uniform pressure drop in a whole of brine reservoir and it is not able overcome by 470 kg/s brine reinjection. Based on the analysis above, it can be concluded that the process of fluid filling pores or fracture in reservoir is not as fast as the production.

Isothermal contour is affected by injection fluid temperature (Figure 18). Steam condensate (45^{o}C) has bigger impact of cooling the reservoir than brine separator (180^{o}C). Increasing the rate of injection has an impact of a wider uniform cooling area of reservoir. Based on the analysis above, it can be concluded, the process of heating fluids reinjection back into reservoir is not as fast as the process of extracting heat from reservoir rock. A higher reinjection rate has an impact at a higher and wider of cooling reservoir. A reinjection has advantageous in pressure support to reduce the effect of production induced pressure drop but has disadvantageous at thermal breakthrough in partially area of reservoir or a whole reservoir.

Increasing the installed capacity to 220 MW will increase boiling in reservoir (Figure 19). This resulted in increasing and expansion of steam saturation both in steam cap and brine reservoir. A higher production rate from brine reservoir will be accelerated the increase of steam saturation that fills into reservoir rocks hence the expansion of steam saturation. The higher production rate will have a rapid decline pressure and increased the boiling, hence the two-phase zone will expand.

The increasing of production will rate will expand the two-phase zone (Figure 20). In this study, both steam cap and transition zone expanded. Increasing installed power plant capacity twice, from 110 MW to 220 MW will increase the thickening of steam cap and transition zone with the same order that is two times.

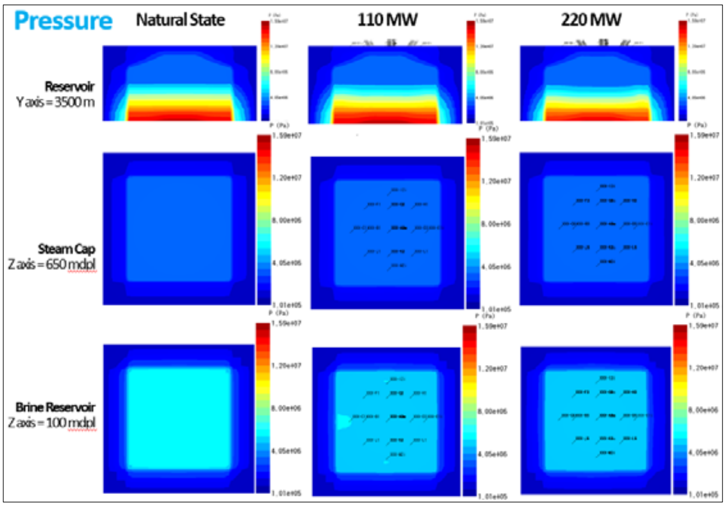

Figure 17: Profile of pressure between natural state, 110 MW and 220 MW.

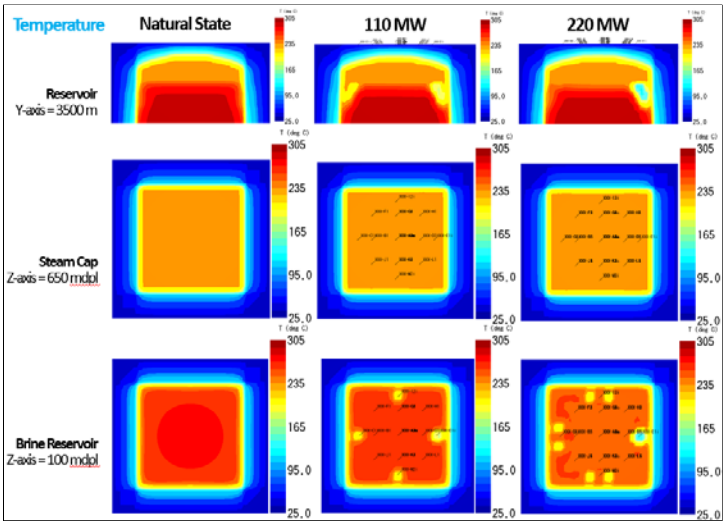

Figure 18: Profile of temperature between natural state, 110 MW and 220 MW.

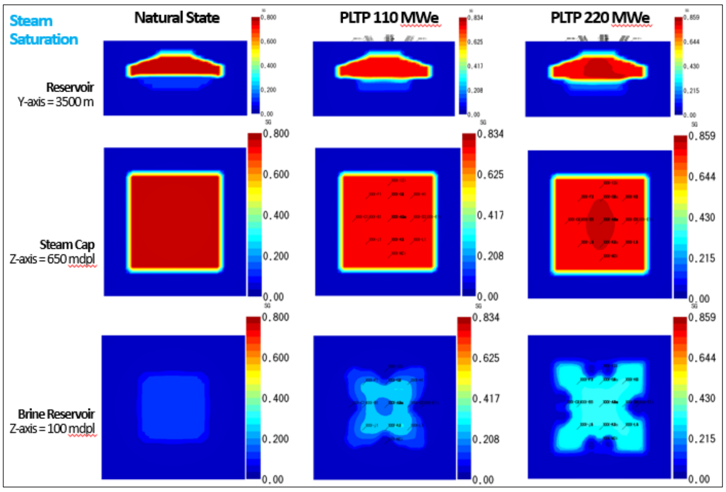

Figure 19: Profile of steam saturation between natural state, 110 MW and 220 MW.

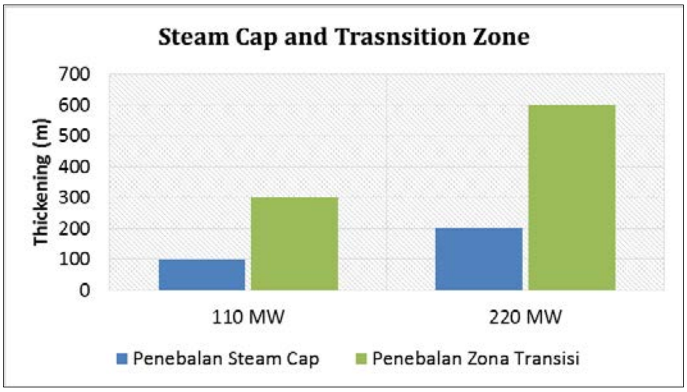

Figure 20: The comparison of the expansion both of steam cap and transition zone for 110 MW and 220 MW.

5. CONCLUSIONS

1) The model of liquid dominated reservoir with steam cap covering 4-23 km^2 and range of thickness's 500-100 m, successfully developed and tested and validated with well data and showed a good match with actual data.
2) The computer model which has a reserve of 220 MW has the best of production strategy if fluid is produced from 25% of steam cap and 75% of brine reservoir and paired with dispersed and deep injection.
3) The lowest decline in pressure and temperature in both steam cap reservoir and brine reservoir is if the fluid is produced from 25% of steam cap and 75% of brine reservoir and paired with dispersed and deep injection strategy.
4) The thickening steam cap at 110 MW is 100 m, while the 220 MW is 200 m. Thickening the transition zone at 110 MW is 300 m, while at 220 MW is 600 m.

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