Abstract

Based on current approved development plan of Senoro gas field, the field will be produced at rate 300 MMSCFD (net) to fulfill the gas demand. Existing study based on black oil reservoir simulation conducted on developing depletion plan of Senoro Field give an unexpected result of plateau time which is only 11.7 years while the field has gas delivery contract for 13 years. This possibility of shortfall gas tends to risk the company to get a penalty as termed in the contract.

Further analysis of the existing development plan also shows that the gas depletion plan is not yet optimal. It is indicated by the unbalance recovery factor between southern and northern reservoir area as it is shown by a significant difference of its reservoir pressure at the end of contract year. Furthermore, the design of production network planned for Senoro Field also indicating huge pressure losses will be encountered by the southern area wells.

To solve the problem, a new study has been conducted to optimize the development plan. The method used in this study is dynamic coupling simulation by connecting reservoir simulation and surface network system into a single package of simulation run. This study has successfully optimized the Senoro field depletion plan to achieve the target 13 years of plateau time. Strategies used to achieve the target are by rescheduling well, utilizing pressure booster in southern area, installing gas compressor after 9th years of production, introducing horizontal well S-22hw to substitute well S-22, and reducing the number of well to 19 from the original plan of 21 wells.

Introduction

The Senoro Field is an onshore gas field located in eastern arm of Sulawesi Island. The field was discovered after wildcat drilling of S-1 well in April 1999. After that, five delineation wells have also been drilled and tested in 2001, 2003, 2005, 2007 and 2009 which are well S-2, 3, 4, 5 and 6. The reservoir of Senoro Field is limestone formation, member of M-1 and M-2 Formation that existed at a depth around 5700 - 6600 ft TVD SS. Laterally, the reservoir is divided into two areas, the northern and southern area, separated by a saddle. The northern area is dominated by the M-2 Formation while the southern area by the M-1 formation. From the petrophysical analysis and DST results, it is found that in the northern part of reservoir, there is a gas zone with thickness up to 693 ft and oil rim of about 26 ft. In this section, the gas-oil contact (GOC) found at a depth of 6496 ft TVD SS while the oil-water contact (OWC) at a depth of 6522.34 ft TVD SS. In the gas zone, it has an average porosity of about 27.4%, average Net to Gross Ratio (NTG) about 98%, and average permeability around 202 md. For the oil rim part, average porosity reaches 30.9% but with average NTG only 76% and average permeability about 362 md. In the contrary, only gas zone found in the southern area. It has a thickness about 487 feet. Gas-water contact (GWC) is estimated exists at a depth of 6496 ft TVD SS. In this area, it has average porosity around 24.3% with average NTG 93% but with a very small average permeability of only about 5.5 md.

The development scenario is divided into 2 phases. The first phase is the development of the northern area focusing on 14 producing wells. The second phase is the development of southern area which is focusing on additional 7 wells that will be started after 3 years of production. To optimize land usage and cost of land acquisition, all new drilling wells will be executed in cluster system using existing well locations. In the northern area, 3 clusters will be prepared in the existing wells location, namely cluster #1, #2, and #5, while in the southern area 2 clusters will also be prepared, namely cluster #3 and #6.
Consequently, all new wells to be drilled would be deviated with maximum inclination angle 55 degree.

Construction of production facilities will also be divided into 2 phases following the subsurface strategy. In the first phase, the production facility will be built for the northern area that includes Central Processing Plant (CPP) and production network covering northern area wells to cluster and cluster to CPP. The second stage will focus on the development of southern area dealing with production network that cover wells to cluster and cluster to CPP and also the construction of future compressor in the CPP to anticipate the reservoir pressure declining.

**Background**

Existing reservoir model and simulation of Senoro Field had been developed by third party. The model is currently being used as a base case scenario of the field Plan of Development (POD). This POD is based on scenario of delivering 300 MMSCFD net gas (319 MMSCFD gross) to buyers with the total of contract up to 13 years. To meet the target of gas demand, 21 gas wells will be produced during the period of the contract, (5 wells reactivation and 16 new wells). Unfortunately, from the simulation results it is indicated that Senoro Field will only be able to deliver gas at plateau rate of 300 MMSCFD for 11.7 years. Consequently, there is a potential of shortfall gas for 1.3 years before its contract periods ends which is a considerable risk that could lead to penalties against company. Therefore, it is very important to do an optimization of the current development plan with expectation of that plateau time of 13 years can be achieved. In addition, based on further analysis of the current reservoir simulation result, it has been identified that there is a possibility of that field development plan is not optimal. It can be perceived from the indication of the unbalance abandonment pressure between southern and northern area.

From the simulation results as shown in the Figure 1, it is found that at the end of the 13th year after production, the reservoir pressure in the north is about 250 psi, while in the southern part of the reservoir is still about 1250 psi. This plot indicates that the current production scenario is not optimal especially in the southern part since the abandonment pressure is still high compared to the northern area. Thus, if this area could be optimally produced in such that its abandonment pressure equal to the northern area, it is expected that gas production will increase with hope that the 13 years of plateau time could be achieved.

**Metodology**

Research method used in this research is a coupling between reservoir simulation and surface production network model. The study involves some of petroleum engineering software i.e. reservoir simulator, well modeler, network modeler, and dynamic coupler. In the first step, well models must be developed to obtain the relationship between bottomhole condition and wellhead condition of each well. In this step, Duns and Ros method is used for estimating the pressure drop in tubing. All of well models will then be connected to pipelines, manifolds and separators using network modeler. Pressure drop in the pipeline is calculated using Begs and Brill method. In parallel, the existing reservoir simulation model should be re-evaluated to ensure that the model is ready to be used in a coupling with production network model. The most important step in this stage is preparing the schedule section on the simulation data file. Once the network model and simulation model is ready, all wells in the network model must be linked to the related wells in the reservoir simulation model by using dynamic coupler. And finally, in the most time consuming stage, the coupled model is optimized by conducting several runs in the hope of 13-year of plateau time can be obtained. General procedure of the coupled reservoir – surface network simulation is shown in Figure 2.

To achieve the target of delivering that value of gas rate, several development scenarios have been studied and the production forecast were run using reservoir simulation. Reviewing all possible scenarios, the most recommended development plan and also currently used as POD basis in Senoro Field is the case of developing 21 wells for producer following well schedule shown in Table 1. Locations of proposed wells are shown in Figure 3. Production forecasts are shown in Figure 4. To achieve the target of 13 years of plateau time, new strategies are used to perform the optimization i.e:

- Re-scheduling the well to reduce the impact of back pressure between producing wells
- Maximizing production in the south area in the following way:
  - Conducting rate management in the northern wells to minimize back pressure to the southern area wells
  - Utilizing pressure booster in the southern part to counter back the pressure drop from southern manifold to the CPP.
- Introducing new completion strategy i.e. horizontal well if possible
- Optimizing the number of well to increase the economic

Reservoir model used in this study is the same model as the existing development plan. Therefore, the detail reservoir modeling process won’t be discussed any further in this paper.

**Well Modeling**

**Production Rate Determination**

Total target of gas deliverability is 300 MMSCFD net. To minimize well cost, it is planned to maximize production rate of each well. However, the maximum gas rate of each well should be determined by considering some information such as well potential, minimum liquid loading rate, and also water coning.
• Well Potential

Results of DST test of existing wells in Senoro Field were good. Absolute Open Flow (AOF) was reported ranging from 160 – 210 MMSCFD. Based on rule of thumbs, it should be ok to produce well at 25% of its AOF. Therefore, based on that DST data, Senoro Field wells are allowed to be produced at rate of 40 MMSCFD. It should be noted that the DSTs were conducted on the specific interval that were selected for purpose of testing only. Most of DSTs were conducted in the lower interval of penetrated zone and also at a very limited perforation interval length. This kind of testing should give pessimistic result of gas rate rather than giving full well potential. Unlike the DSTs, the actual perforation for future production purpose will be conducted in the best perforation interval with sufficient length of perforation interval and the best available perforating gun. Therefore, it is highly expected that the AOF of the future perforation should be much higher that the DSTs results.

For new proposed wells, virtual well tests have also been conducted to predict the optimum rate of each well. The virtual test conducted by running well test program thru simulator on the existing eclipse model for each proposed well. One of the virtual test results conducted in proposed well S-7 shown in the Figure 5. The virtual test gives AOF about 1.43 BCF/day. Therefore, based on the rule of thumb, this well should be allowed to be produced at rate about 350 MMSCFD. Although the virtual test gives a huge value of well potential, the pessimistic value of AOF will be used as a base case of rate determination. In this case, 40 MMSCFD will be used as a default well rate constraint.

• Water Coning

Production rate of each well should be maintained below its critical rate to maintain the bottom water not to build the movable water cone that tends to give water production. One of the formulas to calculate the critical rate in gas well was presented by Trimble and DeRose (1976) as shown in equation (1). By conducting sensitivity of perforation length to the equation, estimated critical rate for S-1 can be plotted as Figure 6. Based on the figure, assuming perforation length 100 ft, critical rate of S-1 at initial reservoir condition should be around 101.5 MMSCFD. After reservoir pressure decline to 1500 psi, the critical rate of the well should be still at around 51.16 MMSCFD. Considering that fact, the previous proposed default rate constraint of 40 MMSCFD is considered to be safe in term of coning.

\[ q_c = \frac{0.000703 k b (P_p - P_w)}{z T_g H \ln(R_e/R_w)} \left[ b \left( 1 + \frac{P_w}{2h} \cos \frac{b}{2h} \right) \right] \] ................................................................. (1)

• Turner Liquid Loading Rate

Unlike the water coning, Turner Liquid Loading Rate gives a minimum limit of production rate to the well. The well should be produced above its minimum liquid loading rate to ensure that any associate liquid produced in the gas flow could be lift up without creating liquid hold up problem. By doing calculation to equation (2), (3), and (4) and also varying tubing size and liquid type, curve of minimum liquid loading rate can be generated as shown in Figure 7. For biggest tubing size of 4.5”, minimum liquid loading rate is about 7.5 MMSCFD which might happened if the fluid is water and operating pressure about 3000 psi. In-line with pressure decline, the minimum liquid loading rate will also be reduced. At reservoir pressure about 1500 psi, the minimum liquid loading rate getting down to 5.3 MMSCFD. Based on that information, to avoid any of liquid hold up problem, every well should be operated above 7.5 MMSCFD.

\[ v_h(water) = \frac{5.62 (67 - 0.0031 p)^{1/4}}{(0.0031 p)^{1/2}} \] ................................................................. (2)

\[ v_h(condensate) = \frac{4.02 (45 - 0.0031 p)^{1/4}}{(0.0031 p)^{1/2}} \] ................................................................. (3)

\[ q_b(MMSCFD) = \frac{3.06 p v_h A}{T z} \] ................................................................. (4)

Considering above well performance, well potential, and liquid loading rate calculation, it is decided to use 40 MMSCFD as base number of production rate.

Tubing Size Optimization

In order to fulfill requirement of delivering gas rate 40 MMSCFD, tubing size has to be design considering the flow capacity, cost effectiveness, and also flow constraint (critical erosional velocity). To do that, nodal analysis has been done by varying tubing size and reservoir pressure as sensitivity parameters. Figure 8 shows the result of nodal analysis of well S-2 based on the result of DST#3. Based on the sensitivity, it is obvious that increasing the tubing size will increase the well productivity. However 4.5” tubing seems sufficient to deliver gas at rate more than 40 MMSCF. Based on this sensitivity, 4.5” tubing is recommended to be used in all wells in Senoro Field.
Network Modeling

The network model technically will exemplify the real production network built in the field. The model will then be used to calculate the pressure interaction in the system by considering all aspect involved in the network i.e. wells, pipeline, pump, compressor, separator, and etc. In creating the Senoro Field production network model, there are some limitations used as assumption, such as:

- All pipe lines in northern area are fixed and ready to be installed. Technically no changes are possible to be applied.
- Pipe lines in southern area are still possible to be optimized.
- This entire field is located in the beach line. The variation of land elevation is ignorable.
- Joint, elbow, and other small equipment are considered to have insignificant effect to pressure system.

The Figure 9 shows the actual production network designed for Senoro Field. The network is divided into two areas Northern and Southern. Before gas delivered to the purchaser, it is processed in the central processing plant (CPP) that will be built in the area of about 1 km away from cluster#1. Each well located in the cluster#1 will be directly connected to the main manifold in the CPP through a 6” pipeline. Wells in the cluster#5 will also be directly connected to the main manifold in the CPP through 2.5 km of 6” and 8” pipeline. Wells in cluster#2, will be collected in a manifold before delivered to the CPP through 4.5 km of 16” pipeline. In the southern area, wells in cluster#3 and #6 will also be collected in a manifold before delivered to CPP through a 12 km of 12” pipeline.

This actual design technically has a major drawback. Locating CPP in the northern area causing a small restriction for northern area wells but is the same time it gives a huge pressure restriction for southern area wells. Furthermore, in term of reservoir properties the southern area has worse permeability compared to northern area. To produce at the same rate with northern area wells, the southern area wells require a much lower wellhead pressure. Therefore, there is a big chance for southern area wells to produce at not optimum condition, and also a chance of early well die due to severe back pressure system.

Flow Line Optimization

Since cluster system is already decided to be used in the Senoro Field, length of flow line technically not possible to be optimized. The only one parameter could be optimized from flow line network is the size of pipe. Method used to do flow line size optimization is by conducting sensitivity of size that give a best flowing condition. Based on rule of thumb, a good flowing condition should have an average mixture velocity between 3 – 50 ft/s. Figure 10 shows the pressure profile in pipeline from cluster#2 to manifold. Using smallest size of pipeline 3” will give huge pressure losses in the line up to 687 psi. The biggest size of pipeline 8” gives very small pressure losses up to 6 psi. However, using pipeline 6” the pressure losses of around 25 psi is still considered as acceptable. Using similar procedure, sensitivity analyses have been conducted for every piping point in the network. The result shows that most pipeline from well to cluster should use 6” pipeline while for cluster manifold to CPP will use 12 and 16” of pipe diameter.

After wells and pipeline models are ready, the network model can be built by simply connecting all wells and pipeline together. Figure 11 shows the network model of entire Senoro Field. As shown in figure, the CPP is simply symbolized by a separator instead of whole equipment. This simplification is due to awareness that the process after separator is belongs to facility processing team and should be excluded from this scope of study. It also noted that the network model is not final model since it still requires to be optimized during final phase of the integrated reservoir to network simulation.

Coupled Reservoir to Surface Network

Optimization has been conducted focused in well scheduling, number of wells, and system pressure management (possibility of southern area pressure booster). In order to get a preliminary trend of the optimization, initial run of the integrated reservoir to network simulation has been executed. It uses the original existing simulation model and network model. In this initial run, well schedule to be used in the simulation is similar to the existing Senoro Field development plan.

Initial Run

The Figure 12 shows result of gas rate of the initial run. Based on the chart, it is obvious that the simulation is unstable especially at period of additional new well. These phenomena explain that at that specific period, there are too many wells active at the same time flowing through a pipeline. As a result, back pressure effect gives divergence problems in the network simulator. Furthermore, the simulator decides to reduce the time steps which eventually increase the simulation run time significantly. The simplest way to solve this problem is by rescheduling the wells. Rescheduling wells (delaying) will reduce the gas potential flowing thru pipeline at specific time period and reduce the bottlenecking phenomena encountered by fluid.
Effect of Well Rescheduling

Figure 13 shows the result of gas rate after delaying additional well in the second year. It is obvious that delaying 3 wells at the specific period gives positive effect on reducing the back pressure in the production network. Divergence problem in the second and third year are significantly reduce since there is no additional well during that period. However, the phenomena still rise up in the following years. This means that the well schedule should be evaluated for all periods.

Effect of Pressure Booster

Southern area has never been able to deliver gas more than 110 MMSCFD. Comparing to the potential gas delivery from 7 wells in the southern area which is about 280 MMSCFD, that gas deliverability is very small which is only about 39%. This is why the abandonment pressure of the southern area is away higher compared to northern area. This problem happens not only because of the property of the reservoir but also due to pressure restriction encountered by southern wells. The northern area wells are easily to flow to the system even after the pressure is lower than the southern area since it has a much better reservoir property plus it has insignificant pressure losses since having a shorter pipeline to CPP. This is the reason of choking back that is encountered by southern area wells. To solve the problem, a pressure booster will be proposed to help the southern area wells against the back pressure and also to reduce well head pressure in such that the gas rate of southern wells should increase. Pressure booster should be installed after the manifold of cluster#3 to ensure that this tool will serve every well in the southern area. This pressure booster might be designed as multiphase compressor or multiphase pump.

Figure 14 shows a comparison of gas rate of the original development plan (without pressure booster) and with additional pressure booster (optimized) in the southern area. A significant effect has been resulted from the additional of pressure booster. After additional pressure booster, the southern area has capability to deliver gas at rate up to 220 MMSCFD (78.6% of its potential) or twice of the original plan. However, there is a negative effect in which the northern area should be produced at a lower rate to give opportunity of the southern area wells to produce at its maximum rate. This can be happened only if some of the northern wells are being shut in. This means that increasing gas rate from southern area should be balanced by decreasing the gas rate of the northern area at the same time.

Effect of Horizontal Well in Southern Area

Reservoir thickness of the southern area is relatively thinner compared to the northern area. Using vertical well, gas rate of the southern area well are very limited. Vertically, maximum reservoir contact would be only about 350 ft. Meanwhile, horizontally the reservoir contact of at least 2000 ft is still possible to be achieved. Therefore, horizontal well might give the best solution for this problem. There are limited candidates of horizontal well positions available in the southern area. Figure 15 shows possible locations to drill horizontal wells in the southern area. Candidate – 1 which is expected to replace well S-22 is located in the direction of northeast – southwest started from the subsurface target of S-6. The 2nd candidate of horizontal well in this area is expected to replace the existence of S-18 and S-19. It is located in the direction of west – east started from the subsurface target of S-6 well. The 3rd candidate which is located in the direction of southwest – northeast started from subsurface target of S-6 is expected to replace S-20.

Based on simulation result shown in Figure 16, the effect of adding the 1st candidate of horizontal well S-22hw is very significant. Without pressure booster, this scenario is able to deliver gas up to 210 MMSCFD initially or 20 MMSCFD higher than the scenario of all vertical well. The better result has also been achieved by boosting the pressure in which maximum gas rate reaches 220 MMSCFD or 30 MMSCFD higher than the scenario of all vertical wells.

Unfortunately, the 2nd and the 3rd candidate of horizontal well tend to give reducing effect compared to the 1st horizontal well case. Even after pressure booster applied in the scenario, those 2 candidates could not increase the gas rate above 210 MMSCFD. This mean that the last 2 candidates of horizontal wells S-19hw and S-21hw is not recommended to be proposed as alternative scenario which also means that the original vertical well of S-18, S-19, and S-21will still be used for further simulation.

Compressor Schedule

In the current development plan, schedule of compressor installation have been set at 7th year of production. This estimation was decided based on wellhead pressure estimation resulted from previous reservoir simulation. Once the wellhead pressure of any well has drop below 1400 psi, compressor has to be ready to back up the compression. This strategy is actually has no problem. But it tends to underestimate the well productivity since the wellhead pressure distribution resulted from the previous simulation was not in balance. Figure 17 shows the wellhead pressure data from the previous simulation. It shows that at 7th year of production, there are all of the southern area wells still have wellhead pressure more than 2000 psi. This means that the compressor is technically not yet required during that specific year. The figure also shows that the distributions of flowing tubing head pressure in southern area are much higher compared to northern area. Even after 13th years of production, the well head pressures in southern area are still about 600 psi. Comparing the result with the wellhead pressure from the combined reservoir to surface simulation shown in Figure 18, it seems that the new prediction of the wellhead pressure...
pressure distribution now become relatively equalized for all wells. Based on the simulation, the compressor is actually needed after 9th year of production. The southern well head pressures now can be optimized even lower than the northern area.

**Optimum Development Plan**

**Gas production and Plateau Time**
The simulation result of the optimized development plan estimates that gas rate of 300 MMSCFD net (319 MMSCFD gross) would be able to be delivered during plateau time of 13.1 years as shown in Figure 19. Southern area gives 319.85 (unit volume) of cumulative gas or 37.72% of recovery factor while northern area gives 1094.85 (unit volume) of gas or 58.87% of recovery factor. Comparing to the existing development plan, it is obvious that the optimized model is successfully increasing the recovery factor of the southern area which is the key of reaching plateau time 13.1 years.

**Abandonment pressure**
Figure 20 shows the comparison of the abandonment pressure between the existing development plan and the optimized plan at the end of contract time (13th years). Unlike the existing plan, the optimum development plan has successfully gives a distributed abandonment pressure for whole reservoir. The abandonment pressure is about 250 – 400 psi.

**Development Strategy**

- **Well Schedule**
  Table 3 shows comparison between well schedule of the current development plan and the optimized model. The optimized model shows that initially 8 wells are required to deliver the total gas demand. Those wells are estimated to be sufficient to maintain the plateau rate up to 6 years of production. After that, southern wells will be started to be produced. To make sure that the recovery factor of the southern reservoir optimum, all of the southern wells should be produced at the same time at its maximum rate. In the contrary, to facilitate southern wells, 5 northern wells should be closed. Closing northern wells should give space of flow line in such to reduce the back pressure occurrence encountered by southern wells. After 7th year of production, gas rate from 7 southern well and 3 northern wells started to decline and unable to fulfill the capacity. Therefore, shuted-in wells in the northern area should be opened gradually by considering the amount of gas shortage. Based on that schedule, optimum number of well reached at number of well of 19. Thus, there should be 2 well remaining that could be used for swing well for anticipation in case of some operational problems during drilling or gas delivery time which might require additional well.

- **Horizontal Well**
  A horizontal well (S-22hw) is recommended to be drilled in the direction of southeast-northwest started from the bottom hole of S-6. Simulation result shows significant additional gas rate by drilling this horizontal well compared to the original plan of the vertical well S-22. The length of horizontal section is estimated to be around 2000 ft and landed at depth of about 50 ft below top of M-2 formation. This well should able to deliver gas at rate 50 MMSCFD.

- **Southern Area Pressure Booster**
The best pressure booster strategy can only be achieved if the pressure booster installed as soon as possible after 7th years of production or since the southern area starts producing. Delta pressure of about 400 psi is considered to be sufficient to handle this boosting process. Operationally, pressure boosting could be directed using some alternative such as:
  - **Multiphase compressor**
    In the time being, a wide range of multiphase compressor products are commercially available in industry. Main multiphase booster i.e. Framo pump products have multi type of multiphase compressor that can handle fluid rate in a wide of range. This multiphase compressor might be the simplest solution to do pressure boosting in this Senoro field.
  - **Combination of pump and compressor**
    In case of multiphase compressor would not be available, combination of pump and compressor can also be utilized as another solution. However, small temporary separation facility should be installed in the southern area to make sure that gas and liquid could be completely separated before compression.

- **Gas Compressor**
  Estimated optimum compressor installation schedule have been defined at 9th years of production.

**Conclusion**
This study has successfully optimize the Senoro field development plan to achieve the target of delivering gas at rate 300 MMSCFD net during 13.1 years of plateau time. Economically, the strategy should increase net present value of the project.
and reduce the risk of contract penalty due to early shortfall gas. Strategies used to achieve the target are by rescheduling well, utilizing pressure booster in southern area, installing gas compressor after 9th years of production, introducing horizontal well S-22hw to substitute well S-22, and reducing the number of well to 19.

**Recommendation**

To have better understanding the effect of development plan changes, it is also recommended to run more comprehensive reservoir – production network – processing facility simulation. Choke management is not included in this study. For operational need, further study considering choke design should be conducted. The southern pressure booster needs to be re-evaluated in term of detail design and price estimation. The study was conducted based on the existing reservoir model. In case of new data available such as Seismic, Core, Logs etc., updated study should be re-run to ensure that the proposed development plan is always updated. The study was conducted based on trial and error approach. There might be a possibility that another development strategy should give a better result. Therefore, more comprehensive study involving optimizer software might help to find the better solution.

**Acknowledgment**

Authors would like to thank the management of JOB Pertamina–Medco E&P Tomori Sulawesi and SKKMIGAS for the permission to publish this paper.

**References**

8. JOB PMTS, 2011, POD Gas Revisi 2011 Lapangan Senoro, JOB PMTS, Jakarta
Table 1 – Existing Development Plan Well Schedule

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Table 2 – Recovery Factor Comparison

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Table 3 – Final Well Schedule

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- Multiphase pump starts
- Compressor starts
- 5 northern wells should be shut-in to avoid back pressure occurrence
Figure 1 – Existing Depletion Plan Abandonment Pressure Distribution

Figure 2 – Research Method Diagram

Figure 3 – Proposed Wells Location
Figure 4 – Existing Depletion Plan Gas Production Rate

Figure 5 – Well S-7 Virtual Test Result

Figure 6 – Critical Rate of S-1 Well
Figure 7 – Minimum Liquid Loading Rate of S-1Well

Figure 8 – Tubing Sensitivity Based On DTS Result (S-2)

Figure 9 – Actual Design of “S” Field Production Network System
Figure 10 – Pipeline Pressure Profile of Cluster#2 Wells to Manifold

Figure 11 – Production Network Model of “S” Field

Figure 12 – Gas Rate Result of Initial Run
Figure 13 – Effect of Well Rescheduling to Gas Rate

Figure 14 – Effect of Booster to Gas Rate (Left = Southern Area, Right = Northern Area)

Figure 15 – Proposed Location of Horizontal Wells in Southern Area
Figure 16 – Horizontal Wells Performance Comparison

Figure 17 – Flowing Tubing Head Pressure of Existing Plan

Figure 18 – Flowing Tubing Head Pressure of Optimized Plan
Figure 19 – Final Gas Production Forecast

Figure 20 – Abandonment Pressure Comparison